FILED 3/28/2018
DOCUMENT NO. 02559-2018
FPSC - COMMISSION CLERK

Docket Nos. 20170266-EC and 20170267-EC
Comprehensive Exhibit List for Entry into Hearing Record
March 21-22, 2018

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
1		Exhibit List	Comprehensive Exhibit List		
SEMINOLE ELECTRIC COOPERATIVE, INC. (Direct)					
2	Michael P. Ward II	**MPW-1**	Resume of Michael P. Ward II.	1A, 2A, 3A, 4A, 5A, 5C, 6A, 7A	
3	Michael P. Ward II	**MPW-2**	Sections 1, 2, 3.1, 3.2, and 3.3 of Seminole Need Study.	1A, 2A, 3A, 4A, 5A, 5C, 6A, 7A	
4	Michael P. Ward II	**MPW-3**	Seminole Electric Service Areas.	1A, 2A, 3A, 4A, 5A, 5C, 6A, 7A	
5	Michael P. Ward II	**MPW-4**	Seminole's Purchase Power Contracts (as of Dec. 31, 2016).	1A, 2A, 3A, 4A, 5A, 5C, 6A, 7A	
6	Michael P. Ward II	**MPW-5**	Seminole's New Power Purchase Contracts.	1A, 2A, 3A, 4A, 5A, 5C, 6A, 7A	
7	David Kezell	**DK-1**	Resume of David L. Kezell.	3A, 4A, 5A, 5C, 6A	
8	David Kezell	**DK-2**	Preliminary Arrangement of the SCCF at the SGS Site.	3A, 4A, 5A, 5C, 6A	
9	David Kezell	**DK-3**	Summary of Estimated Capital Costs.	3A, 4A, 5A, 5C, 6A	
10	David Kezell	**DK-4**	P2021 Single Fuel Facility Analysis.	3A, 4A, 5A, 5C, 6A	
11	David Wagner	**DW-1**	Resume of David Wagner.	4A, 5A, 5C, 6A	
12	David Wagner	**DW-2**	Seminole Fuel Price Forecast.	4A, 5A, 5C, 6A	
13	Roberto Demelo	**RD-1**	Resume of Robert DeMelo.	5A, 5C, 6A	
14	Kyle D. Wood	**KDW-1**	Resume of Kyle D. Wood.	1A, 2A, 3A, 4A, 6A	

15	Thomas Hines	**TH-1**	Resume of Thomas Hines.	2A	
16	Thomas Hines	**TH-2**	Energy Efficiency & Demand Management Savings Report.	2A	
17	Thomas Hines	**TH-3**	Energy Efficiency & Demand Management Program Analysis.	2A	
18	Jason Peters	**JP-1**	Resume of Jason Peters.	2A, 3A, 4A, 5A, 5C, 6A	
19	Jason Peters	**JP-2**	Summary of RFP Responses.	2A, 3A, 4A, 5A, 5C, 6A	
20	Julia A. Diazgranados	**JAD-1**	Resumé of Julia Diazgranados.	1A, 2A, 3A, 4A, 5A, 5C, 6A	
21	Julia A. Diazgranados	**JAD-2**	Seminole's gap chart (forecasted winter peak demands plus reserves vs. committed resources).	1A, 2A, 3A, 4A, 5A, 5C, 6A	
22	Julia A. Diazgranados	**JAD-3**	Seminole's Initial Economic Analysis Results.	1A, 2A, 3A, 4A, 5A, 5C, 6A	
23	Julia A. Diazgranados	**JAD-4**	Seminole's scorecard analysis.	1A, 2A, 3A, 4A, 5A, 5C, 6A	
24	Julia A. Diazgranados	**JAD-5**	Seminole's sensitivity analysis.	1A, 2A, 3A, 4A, 5A, 5C, 6A	
25	Julia A. Diazgranados	**JAD-6 (Revised)**	Seminole's revised economic analysis.	1A, 2A, 3A, 4A, 5A, 5C, 6A	
26	Alan S. Taylor	**AST-1** (Doc. 1)	Resume of Alan S. Taylor.	2A, 3A, 5A, 5C, 6A,	
27	Alan S. Taylor	**AST-1** (Doc. 2)	Sedway Consulting's Independent Evaluation Report. **CONFIDENTIAL DN. 10831-2017**	2A, 3A, 5A, 5C, 6A	
SHADY HILLS ENERGY CENTER, LLC (Direct)					
28	Michael P. Ward II	**MPW-1**	Resume of Michael P. Ward II.	1B, 2B, 3B, 4B, 5B, 5D, 6B, 7B	
29	Michael P. Ward II	**MPW-2**	Sections 1, 2, 3.1, 3.2, and 3.3 of Seminole Need Study.	1B, 2B, 3B, 4B, 5B, 5D, 6B, 7B	
30	Michael P. Ward II	**MPW-3**	Seminole Electric Service Areas.	1B, 2B, 3B, 4B, 5B, 5D, 6B, 7B	

31	Michael P. Ward II	**MPW-4**	Seminole's Purchase Power Contracts (as of Dec. 31, 2016).	1B, 2B, 3B, 4B, 5B, 5D, 6B, 7B	
32	Michael P. Ward II	**MPW-5**	Seminole's New Power Purchase Contracts.	1B, 2B, 3B, 4B, 5B, 5D, 6B, 7B	
33	Ankur Mathur	**AM-1**	Resumé of Ankur Mathur.	3B, 4B, 5B, 5D, 6B	
34	Ankur Mathur	**AM-2**	Site Vicinity Map for SHCCF.	3B, 4B, 5B, 5D, 6B	
35	David Wagner	**DW-1**	Resumé of David Wagner.	4B, 5B, 5D, 6B	
36	David Wagner	**DW-2**	Seminole Fuel Price Forecast.	4B, 5B, 5D, 6B	
37	Roberto Demelo	**RD-1**	Resumé of Robert DeMelo.	5B, 5D, 6B	
38	Kyle D. Wood	**KDW-1**	Resumé of Kyle D. Wood.	1B, 2B, 3B, 4B, 6B	
39	Thomas Hines	**TH-1**	Resumé of Thomas Hines.	2B	
40	Thomas Hines	**TH-2**	Energy Efficiency & Demand Management Savings Report.	2B	
41	Thomas Hines	**TH-3**	Energy Efficiency & Demand Management Program Analysis.	2B	
42	Jason Peters	**JP-1**	Resumé of Jason Peters.	2B, 3B, 4B, 5B, 5D, 6B	
43	Jason Peters	**JP-2**	Summary of RFP Responses.	2B, 3B, 4B, 5B, 5D, 6B	
44	Julia A. Diazgranados	**JAD-1**	Resumé of Julia A. Diazgranados.	1B, 2B, 3B, 4B, 5B, 5D, 6B	
45	Julia A. Diazgranados	**JAD-2**	Seminole's gap chart (forecasted winter peak demands plus reserves vs. committed resources).	1B, 2B, 3B, 4B, 5B, 5D, 6B	
46	Julia A. Diazgranados	**JAD-3**	Seminole's Initial Economic Analysis Results.	1B, 2B, 3B, 4B, 5B, 5D, 6B	
47	Julia A. Diazgranados	**JAD-4**	Seminole's scorecard analysis.	1B, 2B, 3B, 4B, 5B, 5D, 6B	
48	Julia A. Diazgranados	**JAD-5**	Seminole's sensitivity analysis.	1B, 2B, 3B, 4B, 5B, 5D, 6B	
49	Julia A. Diazgranados	**JAD-6 (Revised)**	Seminole's revised economic analysis.	1B, 2B, 3B, 4B, 5B,	

				5D, 6B	
50	Alan S. Taylor	**AST-1** (Doc.1)	Resumé of Alan S.Taylor.	2B, 3B, 5B, 5D, 6B	
51	Alan S. Taylor	**AST-1** (Doc.2)	Sedway Consulting's Independent Evaluation Report. **CONFIDENTIAL DN. 10833-2017**	2B, 3B, 5B, 5D, 6B	
QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY (Direct)					
52	Paul M. Sotkiewicz, Ph.D.	**PS- 1**	Resume' of Paul M. Sotkiewicz, Ph.D.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A,6B	
53	Paul M. Sotkiewicz, Ph.D.	**PS- 2**	Summary of Seminole's Winter Peak Forecast Errors, 2005-2016.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A,6B	
54	Paul M. Sotkiewicz, Ph.D.	**PS- 3**	Summary of Seminole's Summer Peak Forecast Errors, 2005-2016.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A,6B	
55	Paul M. Sotkiewicz, Ph.D.	**PS- 4**	Summary of Seminole's Total Energy Requirements Forecast Errors, 2005-2016.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
56	Paul M. Sotkiewicz, Ph.D.	**PS- 5**	Seminole Gap Chart (Seminole Exhibit JAD-2).	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
57	Paul M. Sotkiewicz, Ph.D.	**PS- 6**	Peak Load, Energy, and Number of Customers History and Forecast Tables from Seminole's Ten Year Site Plans, 2005-2016.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
58	Paul M. Sotkiewicz, Ph.D.	**PS- 7**	Seminole's Existing Generating Facilities and Purchased Power Resources, Excerpt from Seminole's 2017 Ten Year Site Plan.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
59	Paul M. Sotkiewicz, Ph.D.	**PS- 8**	Seminole's Revised Economic Analysis Results of Portfolios (Seminole Exhibit JAD-6).	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	

60	Paul M. Sotkiewicz, Ph.D.	**PS- 9**	Specifications of FPL's Proposed Dania Beach Clean Energy Center, Schedule 9 from FPL's 2017 Ten Year Site Plan.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
61	Paul M. Sotkiewicz, Ph.D.	**PS- 10**	Seminole's 2017 Specifications for Planned Combined Cycle Facilities as stated in Seminole's 2017 Ten Year Site Plan, Schedule 9 for SGS CC Unit 1 and Unnamed Generating Station CC Unit 2.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
62	Paul M. Sotkiewicz, Ph.D.	**PS- 11**	Combined Cycle Costs for 2010-2016, U.S. Energy Information Administration, contained in presentation by Paul M. Sotkiewicz, Ph.D. to Harvard Electricity Policy Group, March 31, 2017.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
63	Paul M. Sotkiewicz, Ph.D.	**PS- 12**	FPL Specifications and Escalation Rates associated with a 1,163 MW Combined Cycle Unit with In-Service Date of June 1, 2022, FPL Tariff Sheets No. 10.311 and No. 10.311.1.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D, 6A, 6B	
SEMINOLE ELECTRIC COOPERATIVE, INC. (Rebuttal)					
64	Kyle D. Wood	**KDW-2**	Seminole's current forecasting methodology & model/variable selection process.	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	
65	Kyle D. Wood	**KDW-3**	Comparison of historical error rates based on Sotkiewicz approach.	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	
66	Kyle D. Wood	**KDW-4**	Historical Seminole error rates based on corrected Sotkiewicz approach.	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	
67	Kyle D. Wood	**KDW-5**	Seminole 2017 Load Forecast Error Analysis.	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	
68	Tao Hong, Ph.D	**TAO-1**	Tao Hong Curriculum Vitae.	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	
69	Tao Hong, Ph.D	**TAO-2**	"Long Term Probabilistic Load Fore-casting and Normalization With Hourly Information."	1A, 1B, 2A, 2B, 3A, 3B, 6A, 6B	

70	David Kezell	**DK-5**	Excerpts from Site Certification Application for DBEC.	3A, 3B, 5A, 5B, 5C, 5D, 6A, 6B	
71	David Kezell	**DK-6**	Excerpt from DBEC Air Permit.	3A, 3B, 5A, 5B, 5C, 5D, 6A, 6B	
72	David Kezell	**DK-7**	Excerpt from SCCF draft Air Permit.	3A, 3B, 5A, 5B, 5C, 5D, 6A, 6B	
73	David Kezell	**DK-8**	USDOE/EIA report entitled "Capital Cost Estimates for Utility Scale Electricity Generating Plants."	3A, 3B, 5A, 5B, 5C, 5D, 6A, 6B	
STAFF'S EXHIBITS					
74	Julia A. Diazgranados (1-5, 7, 14, 29-32) David Wagner (8, 16a, 17) Jason Peters (11, 20, 21) David Kezell (12-13, 15, 16c) Ankur Mathur (16b, 16d, 19, 34) Kyle D. Wood (9-10, 21, 23-28)		SECI's responses to Staff's First Set of Interrogatories, Nos. 1, 2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 19, 20, 21, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 34. **Additional files contained on Staff's Hearing Exhibits CD Nos. 1, 2, 4, 5, 14, & 30.** *(Bates Nos. 00001-00042)*	1A, 1B, 2A, 2B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	
75	David Wagner		SECI's responses to Staff's First Set of Interrogatories, No. 18. **CONFIDENTIAL DN. 01988-2018.***(Bates Nos. 00043-00043)*	4A, 4B	
76	Jason Peters (33)		SECI's responses to Staff's First Set of Interrogatories, No. 33. **CONFIDENTIAL DN. 01988-2018.***(Bates Nos. 00044-00044)*	2A, 2B, 5A, 5B, 5C, 5D	
77	David Kezell (35) Ankur Mathur (36)		SECI's responses to Staff's Second Set of Interrogatories, No. 35-36. **CONFIDENTIAL DN. 01826-2018.***(Bates Nos. 00045-00045)*	3A, 3B	
78	Julia A. Diazgranados (37) David Kezell (38) Michael P. Ward		SECI's responses to Staff's Second Set of Interrogatories, Nos. 37, 38, 40, 41.	1A, 1B, 2A, 2B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	

	II (40) Kyle D. Wood (41)		*(Bates Nos. 00046-00054)*		
79	Thomas Hines (42, 44) Alan S. Taylor (46, 48-51) David Kezell (52, 57) Ankur Mathur (53) Julia A. Diazgranados (54) Kyle D. Wood (55, 59, 60, 61, 62)		SECI's responses to Staff's Third Set of Interrogatories, Nos. 42, 44, 46, 48, 49, 50, 51, 52, 53, 54, 55, 57, 59, 60, 61, 62. **Additional files contained on Staff's Hearing Exhibits CD Nos. 44 & 62.** *(Bates Nos. 00055-00083)*	1A, 1B, 2A, 2B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	
80	Jason Peters (58)		SECI responses to Staff's Third Set of Interrogatories, No. 58. **CONFIDENTIAL DN 02223-2018.***(Bates Nos. 00084-00084)*	1A, 1B, 2A, 2B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	
81	Kyle D. Wood		SECI's responses to Staff's Fourth Set of Interrogatories, Nos. 63, 64, 65, 66. **Additional files contained on Staff's Hearing Exhibits CD Nos. 63***(Bates Nos. 00085-00104)*	1A, 1B, 3A, 3B, 5A, 5B, 5C, 5D	
82	David Kezell		SECI's responses to Staff's Fifth Set of Interrogatories, No. 67 **CONFIDENTIAL DN. 02190-2018.***(Bates Nos. 00105-00105)*	3A, 3B, 5A, 5B, 5C, 5D	
83	Julia A. Diazgranados		SECI's responses to Staff's Fifth Set of Interrogatories, No. 68. **Additional files contained on Staff's Hearing Exhibits CD Nos. 68.***(Bates Nos. 00106-00108)*	3A, 3B, 5A, 5B, 5C, 5D	
84	Kyle D. Wood		SECI's responses to Staff's Sixth Set of Interrogatories, 69, 70. *(Bates Nos. 00109-00112)*	1A, 1B, 3A, 3B, 4A, 4B	
85	David Kezell (2), Thomas Hines (5,7, 8), Kyle D. Wood (10, 11, 13-18)		SECI's responses to Staff's First Request for Production of Documents, Nos. 2, 8, 10, 11, 13, 14, 15, 16, 17, 18. **Additional files contained on Staff's Hearing Exhibits CD**	1A, 1B, 2A, 2B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	

			Nos. 2, 8, 10, *11, *13, 14, 16, 17, 18.*CONFIDENTIAL DN. 02379-2018. *(Bates Nos. 00113-00123)*		
86	Michael P. Ward, II		SECI's responses to Staff's First Request for Production of Documents, No. 6. **CONFIDENTIAL DN. 01988-2018.** *(Bates Nos. 00124-00124)*	2A, 2B	
87	Kyle D. Wood		SECI's responses to Staff's First Request for Production of Documents, No. 12. **CONFIDENTIAL DN. 01988-2018.***(Bates Nos. 00125-00125)*	1A, 1B, 3A, 3B, 4A, 4B	
88	Kyle D. Wood		SECI's responses to Staff's Third Request for Production of Documents, Nos. *21, 22. ***CONFIDENTIAL DN. 02379-2018.***(Bates Nos. 00126-00128)*	1A, 1B, 3A, 3B, 4A, 4B	
89	David Kezell		SECI's responses to Quantum's First Set of Interrogatories, No. 2. **CONFIDENTIAL DN. 02397-2018.** *(Bates Nos. 00129-00129)*	3A, 3B	
90	Julia A. Diazgranados (5, 15, 26) Jason Peters (14, 25) David Wagner (16-19) Kyle D. Wood (21-24)		SECI's responses to Quantum's First Set of Interrogatories, Nos. 5, 14, 15, 16, 17, 18, 19, 21, 22, 23, 24, 25, 26. **Additional files contained on Staff's Hearing Exhibits CD Nos. 17.***(Bates Nos. 00130-00149)*	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	
91	Michael P. Ward II (36-37, 39) Julia A. Diazgranados (40, 42-44, 50c) Alan S. Taylor (50a, 50b)		SECI's responses to Quantum's Second Set of Interrogatories, Nos. 36, 37, 39, 40, 42, 43, 44, 50. *(Bates Nos. 00150-00160)*	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	
92	Julia A. Diazgranados (56-57, 77) Alan S. Taylor (76)		SECI's responses to Quantum's Third Set of Interrogatories, Nos. 56, 57, 76, 77, 81, 82.	1A, 1B, 3A, 3B, 4A, 4B, 5A, 5B, 5C, 5D	

	Kyle D. Wood (81-82)		*(Bates Nos. 00161-00171)*		
93	David Kezell		SECI's responses to Quantum's Fourth Set of Interrogatories, Nos. 85, 86. *(Bates Nos. 00172 00175)*	3A, 5A, 5C	
94	Michael P. Ward, II		SECI's responses to Quantum's First Request for Production of Documents, No. 2. **CONFIDENTIAL DN. 02397-2018.***(Bates Nos. 00176-00176)*	1B, 3B, 5B, 5D	
95	Paul M. Sotkiewicz, Ph.D.		Quantum's Responses to Staff's First Set of Interrogatories, Nos. 1, 2, 3.*(Bates Nos. 00177-00185)*	1A, 1B, 3A, 3B, 4A, 4B	
96	Paul M. Sotkiewicz, Ph.D.		Quantum's Responses to Staff's First Request for Production of Documents, No. 1. **Additional files contained on Staff's Hearing Exhibits CD Nos. 1.***(Bates Nos. 00186-00187)*	1A, 1B, 3A, 3B, 4A, 4B	
97	Kyle D. Wood		Deposition of Kyle D. Wood, Exhibits Nos. 1, 2, 3, 4. **Additional files contained on Staff's Hearing Exhibits CD. Exhibits Nos. 1, 2, 4.** *(Bates Nos. 00188-00281)*	1A, 1B, 3A, 3B, 4A, 4B	

98	James Maiz		Deposition of James Maiz.* *[Bates Nos. 00282-00326]*	5A, 5B, 5C, 5D, 6A, 6B	
99	Michael P. Ward II		Deposition of Michael Ward, II, Pages 63, lines 2-14 and Page 64, lines 8-20** **CONFIDENTIAL DN. 02381-2018 [***Bates Nos. 00327-00327]*	3A, 3B, 5A, 5B, 5C, 5D	

HEARING EXHIBITS

Live Exhibit Number	Witness	Party	Description		Moved In/Due Date of Late Filed
100	Ward	Quantum, Daly, Tulk	CONFIDENTIAL CPP, CC Portfolio Revenue Requirement, by General Resource		
101	Ward	Quantum, Daly, Tulk	CONFIDENTIAL SGS debt service		
102	Ward	Quantum, Daly, Tulk	CONFIDENTIAL 5.10.17 Board P2021 Workshop Excerpt		
103	Ward	Quantum, Daly, Tulk	CONFIDENTIAL 7.12.17 P2021 Process update and recommended actions		
104	Ward	Quantum, Daly, Tulk	CONFIDENTIAL EXH 99, Pages 63 and 64		
105	Ward	Quantum, Daly, Tulk	PSC Comparative Rate Statistics for Electric Utilities as of 12.13.16		
106	Ward	Quantum, Daly, Tulk	Withlachoochee River Electric Cooperative Billing Statements		Withdrawn
107	Kezell	Quantum, Daly, Tulk	Emails produced in resonse to Quantum's 4th POD		
108	Wood	Quantum, Daly, Tulk	PSC 2017 Annual Report on FEECA Activities		
109	Wood	Quantum, Daly, Tulk	FRCC 2017 Load and Resource Plan		
110	Wood	Quantum, Daly, Tulk	Tampa Electric 2017 10-Year Site Plan		

111	Wood	Quantum, Daly, Tulk	FRCC Presentation 2017 Ten-Year Site Plan Workshop		
112	Wood	Staff	Winter Park Peak Demand Forecaset changes in Seminole load forecast studies		
113	Hines	Quantum, Daly, Tulk	Article AZ Corp COMM, Andy Tobins Proposed amendment No. 4		Not Admitted
114	Hines	Quantum, Daly, Tulk	3.17.18 AZ Corp COMM ordering TEP and APS to Add Renewables and Impose Moratorius on Gas Plants		Not Admitted
115	Peters	Quantum, Daly, Tulk	CONFIDENTIAL Quatum Pasco updated proposal dated 10.11.16		
116	Diazgranados	Quantum, Daly, Tulk	CONFIDENTIAL Seminole annual income statement revenue projections CPP and no Build Risk All PPA Porfolios 2017 to 2015		
117	Diazgranados	Quantum, Daly, Tulk	Direct Testimony of Timonthy Woodbury on behalf of SEC Inc 12.4.2000		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 2
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Michael P. Ward II MPW-1

Michael P. Ward II

Experience

Vice President, Strategic Initiatives
2017-Present
SEMINOLE ELECTRIC COOPERATIVE INC.

- Executive management responsibility for identifying, analyzing, developing and implementing strategic opportunities that fulfill Seminole's strategic resource plan.
- Oversee, direct and manage Seminole's self-build combined cycle facility, tolling agreements, purchased power agreements, solar generation, coal unit retirement, headquarters building renovation and back-up control center/business continuity projects.

Director of System Operations **2014-2017**
SEMINOLE ELECTRIC COOPERATIVE INC.

- Managed operations, maintenance and engineering department responsible for all aspects of power systems engineering and energy delivery, including control center operations, planning, NERC compliance, member billing, and substation field operations.

Manager of Maintenance, Midulla Generating Station
2014-2014
SEMINOLE ELECTRIC COOPERATIVE INC.

- Managed Maintenance and Engineering department responsible for all preventative and corrective maintenance, as well as plant modifications.

Plant Engineer and Project Manager
2013-2014
SEMINOLE ELECTRIC COOPERATIVE INC.

- Plant Engineer for Combined Cycle facility.

Submarine Officer
1987-2014
UNITED STATES NAVY

- Progressive assignments on seven different nuclear submarines, up to and including commanding officer of a crew of 152 personnel. Six staff shore assignments with responsibility for national level policy-making, strategic planning, capital and operational budgeting, and expert technical advice.

Education

Bachelors of Science in Electrical Engineering, University of Florida **1994**
Masters of Business Administration, University of Maryland University College **2002**
Certificate in National Security Affairs, Naval War College and National Defense University **2011**

Skills

Previous Top Secret/SCI security clearance
Certified for Command and Supervision of Nuclear Powered Warships
Completed Prospective Commanding Officer course for Naval Nuclear Propulsion
Proficient in Microsoft Office Suite of applications, including Microsoft Project and Visio
Naval Nuclear Engineer

ERRATA FOR

KYLE D. WOOD

Direct Testimony Filed in Docket Nos. 20170266-EC and 20170267-EC on December 21, 2017

Page	Line(s)	Correction
10	24	Change "14,655MWh" to "14,601 MWh"
10	24	Change "16,470 MWh" to "16,437 MWh"

Rebuttal Testimony Filed in Docket Nos. 20170266-EC and 20170267-EC on February 19, 2018

Page	Line(s)	Correction
5	15	Change "biannually" to "biennially"

In Exhibit No. __ (KDW-5) to Rebuttal Testimony Filed in Docket Nos. 20170266-EC and 20170267-EC on February 19, 2018, the reference in the footnote to "January 201" should be changed to "January 2018"

EXHIBIT NO. ___ (MPW-2)
SEMINOLE NEED STUDY
Filed in Docket Nos. 20170266-EC & 20170267-EC

Section	Page	Sponsor	Correction
5.2.4	46 of 153	Wood	Change Table 14 to attached revised Table 14
5.2.4	47 of 153	Wood	Change Table 15 to attached revised Table 15

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 3
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Michael P. Ward II MPW-2

ERRATA SHEET FOR
EXHIBIT NO. ___ (MPW-2)
SEMINOLE NEED STUDY
Filed in Docket Nos. 20170266-EC & 20170267-EC

Section	Page	Correction
1.5	8 of 153	Change "$363 million" to "$530 million"
6.8	65 of 153	Change Figure 13 to attached revised Figure 13 (Note: Figure 13 is the same as Exhibit (JAD-6)
8.0	72 of 153	Change "$388 million" to "$530 million"

Figure 13 Summary of Updated Economic Analysis

Portfolio Summaries
Revised Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	~~11,571~~ 11,666
NPV @ 6.0%	8,641	8,568	8,549	~~8,432~~ 8,499
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	56,465	58,312	~~58,289~~ 58,616
NPV @ 6.0%	20,981	20,618	21,120	~~21,006~~ 21,148



NEED STUDY

Submitted to the Florida Public Service Commission in support of Petitions to Determine Need for Electric Power Plants

December 2017

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APPENDICES

A. Seminole's 2017 Ten Year Site Plan
B. 2016 Request for Proposals

1.0 EXECUTIVE SUMMARY

Seminole Electric Cooperative, Inc. ("Seminole") submits this Need Study in support of two proposed natural gas-fired combined cycle ("CC") facilities, including: the Seminole Combined Cycle Facility ("SCCF"), a self-build 1,050 MW (nominal) two-on-one generating facility to be constructed adjacent to the existing Seminole Generation Station ("SGS") site in conjunction with the removal from service of one of the existing SGS coal-fired units; and the Shady Hills Combined Cycle Facility ("SHCCF"), a 573 MW (winter) one-on-one generating facility to be constructed by Shady Hills Energy Center, LLC ("SHEC"), an indirect subsidiary of General Electric Company ("GE"), at the existing Shady Hills power plant site in Pasco County pursuant to a tolling agreement with Seminole. The analyses discussed throughout this Need Study demonstrate that the two combined cycle facilities are needed to meet the electrical demands of Seminole and its Member Cooperatives.

1.1 The Primarily Affected Utilities

Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales; it does not make retail sales. Seminole's nine members ("Members" or "Member Cooperatives") are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use member-consumers in Florida. Seminole's Members are: Central Florida Electric Cooperative, Inc., Clay Electric Cooperative, Inc., Glades Electric Cooperative, Inc., Peace River Electric Cooperative, Inc., SECO Energy, Suwannee Valley Electric Cooperative, Inc., Talquin Electric Cooperative, Inc., Tri-County Electric Cooperative, Inc., and Withlacoochee River Electric Cooperative, Inc. Approximately 1.6 million people and businesses in parts of 42 of Florida's 67 counties rely on Seminole and its Member Cooperatives for electricity.

1.2 The Power Plant Siting Act and Need Determination Process

The Florida Electrical Power Plant Siting Act ("PPSA"), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection ("DEP") and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity;
- The need for adequate electricity at a reasonable cost;
- The need for fuel diversity and supply reliability;
- Whether the proposed plant is the most cost-effective alternative available;
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available; and
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

1.3 The Proposed New Facilities

Seminole has determined that the most cost effective, risk-managed resource plan to meet its projected capacity need is a mix of resources consisting of existing generation resources, PPAs, and the construction of two natural gas-fired combined cycle facilities, including: the self-build 1,050 MW SCCF along with the removal from service of one of the two existing 664 MW SGS coal units; and the 573 MW SHCCF to be constructed, owned and operated by SHEC under a tolling agreement with Seminole.

1.4 Seminole's Need for Generation Capacity

Based on its continuing evaluation of its Member Cooperatives' electricity needs, Seminole projects a need for 901 MW of additional generating capacity by the end of 2021. This projected need results primarily from the expiration of power purchase agreements ("PPAs"), including the expiration of a 150 MW PPA on December 31, 2020, followed by the expiration of two more PPAs totaling 750 MW of winter capacity in May, 2021. Because an additional 300 MW PPA expires the following year, along with load growth, Seminole's projected need increases to 1,265 MW by the end of 2022.

1.5 Major Generating Alternatives

Seminole's Board of Trustees selected the resource plan that includes the SCCF and the SHCCF facilities based on the results of a multi-stage resource planning process. That process included extensive economic analyses of self-build options and multiple power purchase alternatives, including numerous renewable energy proposals, identified during a robust Request for Proposal ("RFP") process, as well as careful consideration of non-economic attributes and risk factors. Seminole's analyses demonstrate that the resource plan containing the SCCF and the tolling agreement with SHEC for the SHCCF is the most cost-effective alternative to meet Seminole's capacity needs and would result in projected net present value ("NPV") savings of approximately $363 million as compared to the next ranked alternative over the study period. The selected resource plan also includes multiple PPAs with significant optionality in terms of available capacity. This provides Seminole a hedge against economic acceleration/downturns or faster/slower load growth rates.

1.6 Non-Generating Alternatives

As a wholesale supplier of electric energy to its Members, Seminole is not directly responsible for demand-side management ("DSM") programs. However, Seminole encourages conservation through its wholesale rate structure, which provides price signals that reflect Seminole's cost of supplying power in aggregate and thereby encourages Members to concentrate their load management efforts on controlling

Seminole's overall system peak. Seminole also assists its Members in the evaluation of potential DSM measures. Despite the DSM savings achieved by Seminole's Members, the need for additional capacity still exists and there is not a reasonable scenario in which sufficient DSM or conservation could be added to avoid the need for additional capacity.

1.7 Adverse Consequences of Denial

Non-approval of the requested need determination would mean that Seminole's Members and the Members' end-use member-consumers would be denied the most cost-effective, risk-managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021. While additional off-system purchases could perhaps be made to fulfill Member power requirements and maintain the target reserve margin, Seminole would not be able to remove a coal unit from service and the costs of the resulting resource plan would be substantially higher.

1.8 Conclusion

The analyses and other information described above demonstrate that affirmative need determinations are warranted for the new SCCF and SHCCF projects based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to the expiration of existing PPAs, Seminole will have a need for 901 MW of additional generating capacity by the end of 2021, and that need will grow to 1,265 MW by the end of 2022. Seminole's Board of Trustees selected the resource plan that includes the SCCF and SHCCF based on the results of a rigorous, multi-stage planning process that involved extensive economic analyses of generation alternatives, including numerous power purchase alternatives identified during a robust RFP process, as well as careful consideration of non-economic attributes and risk factors. In recognition of the energy value of solar, the selected resource plan also includes 40 MW from a new solar resource. Seminole and its Members continue to explore additional DSM/conservation measures even though there is no reasonable basis to conclude that such measures could offset Seminole's projected need.

2.0 PURPOSE AND OVERVIEW OF NEED STUDY

Seminole is submitting this Need Study in support of separate petitions for determination of need for the new SCCF and SHCCF pursuant to secton 403.519, Florida Statutes. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each petition for need determination must include to allow the Commission to address the statutory factors. This Need Study is organized as follows to provide the information required for such need determinations by Rule 25-22.081:

- Section 3 provides a general description of the utility or utilities primarily affected, including the load and electrical characteristics, generating capability, and interconnections;
- Section 4 provides a general description of the proposed electrical power plants, including the size, number of units, fuel type and supply modes, the approximate costs, and projected in-service date or dates;
- Section 5 provides a statement of the specific conditions, contingencies or other factors which indicate a need for the proposed electrical power plant including the general time within which the generating units will be needed;
- Section 6 provides a discussion of the major available generating alternatives (including renewable energy sources) which were examined and evaluated in arriving at the decision to pursue the proposed generating units;
- Section 7 provides a discussion of non-generating alternatives; and
- Section 8 provides an evaluation of the adverse consequences which will result if the proposed electrical power plants are not added in the approximate size sought or in the approximate time sought.

3.0 PRIMARILY AFFECTED UTILITIES

3.1 Seminole Electric Cooperative & its Member Cooperatives

Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales; it does not make retail sales. Seminole's nine Members are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use member-consumers in Florida. The names and headquarters locations of each of the Member cooperatives, along with the counties which each Member serves, are:

- Central Florida Electric Cooperative, Inc.
  Chiefland, Florida
  Counties: Alachua, Dixie, Gilchrist, Levy, Lafayette, Marion

- Clay Electric Cooperative, Inc.
  Keystone Heights, Florida
  Counties: Alachua, Baker, Bradford, Clay, Columbia, Duval, Gilchrist, Lake, Levy, Marion, Putnam, Suwannee, Union, Volusia

- Glades Electric Cooperative, Inc.
  Moore Haven, Florida
  Counties: Glades, Hendry, Highlands, Okeechobee

- Peace River Electric Cooperative, Inc.
  Wauchula, Florida
  Counties: Brevard, DeSoto, Hardee, Highlands, Hillsborough, Indian River, Manatee, Osceola, Polk, Sarasota

- SECO Energy
  Sumterville, Florida
  Counties: Citrus, Hernando, Lake, Levy, Marion, Pasco, Sumter

- Suwannee Valley Electric Cooperative, Inc.
  Live Oak, Florida
  Counties: Columbia, Hamilton, Lafayette, Suwannee

- Talquin Electric Cooperative, Inc.
  Quincy, Florida
  Counties: Gadsden, Leon, Liberty, Wakulla

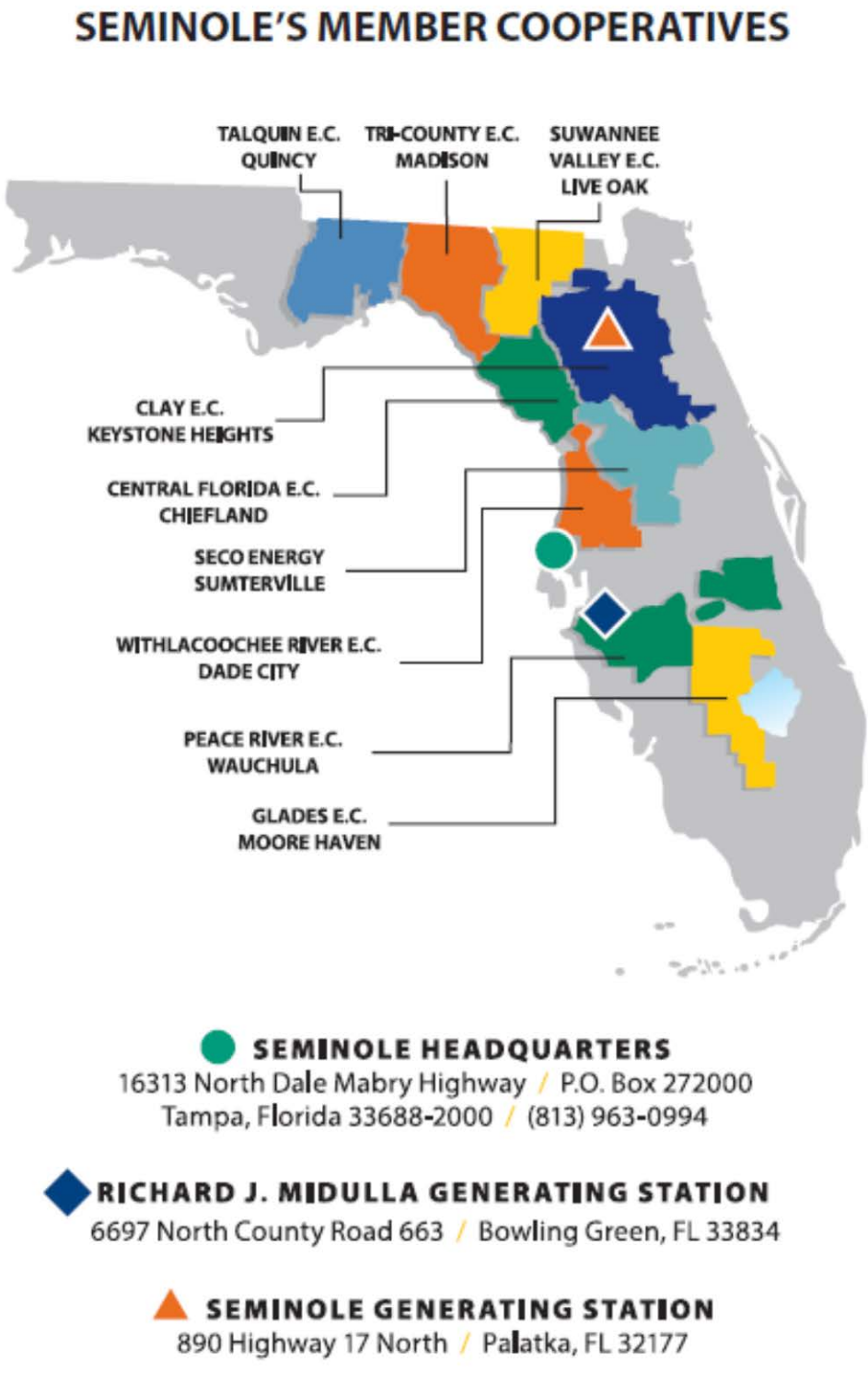
- Tri-County Electric Cooperative, Inc.
  Madison, Florida
  Counties: Dixie, Jefferson, Lafayette, Madison, Taylor

- Withlacoochee River Electric Cooperative, Inc.
  Dade City, Florida
  Counties: Citrus, Hernando, Pasco, Polk, Sumter

Seminole is owned by its Members and governed through a Board of Trustees, and it exists to provide reliable electric service at competitive rates to its Members. Seminole was organized in 1948, but remained relatively inactive until shortly after the 1973 oil embargo. In 1974, Seminole's Board determined that Seminole should develop independent power supplies for its Members. In 1975, each Member entered into a long term "All Requirements" contract with Seminole for the purchase of wholesale power. Under these contracts, each Member purchases from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts. Four of Seminole's Members had pre-existing contracts with the Southeastern Power Administration, which provides 26 MW of the total capacity required by these Members.

Seminole is one of the largest electric generation and transmission cooperatives in the country. Seminole and its Members serve approximately 1.6 million people and businesses in parts of 42 of Florida's 67 counties. Figure 1 shows the areas of the State serviced by Seminole's nine Member Cooperatives.

Figure 1 Seminole Member Service Areas



3.2 Load and electrical characteristics

Seminole Members serve electricity to primarily-rural areas within 42 counties in the north, central, and south regions of Florida, which differ uniquely in geography, weather, and natural resources. Seminole has historically been a winter-peaking utility and is expected to remain winter-peaking due to the concentration of service territory load in the north/central portion of peninsular Florida.

3.3 Generating Capability

Seminole meets the power supply needs of its Members and their member-consumers with Seminole-owned generation in combination with purchased power or tolling agreements with independent power producers, investor-owned and municipal utilities, and renewable energy providers. As of December 31, 2016, Seminole had total winter capacity resources of approximately 4,700 MW consisting of owned, installed net winter capacity of 2,178 MW and the remaining capacity in firm purchased power. As a result of the RFP process discussed in Section 6, Seminole recently extended its existing Oleander Power PPA through 2021 and entered into a new long-term PPA with Southern Company Services ("SCS") and two new long-term PPAs with Duke Energy Florida ("DEF").

3.3.1 Seminole's Owned/Leased Generation Facilities

Seminole's existing owned or leased generating resources are located at three generating facilities:

- SGS Units 1 and 2 comprise a 1,329 MW (winter) coal-fired power plant located in Putnam County near Palatka, Florida.
- Midulla Generating Station ("MGS") Units 1-3 comprise a 539 MW (winter) gas-fired two-on-one combined cycle plant located in Hardee County, Florida. MGS Units 4-8 comprise a 310 MW (winter) peaking plant consisting of five twin-pack gas turbines. The MGS units all have fuel oil capability.

- The 2.2 MWac (summer) Cooperative Solar facility is located in Hardee County, Florida adjacent to MGS.

Table 1 summarizes Seminole's existing owned generating facilities.

Table 1 Seminole's Existing Owned Generation Facilities

Plant	Unit No.	Location	Unit Type	Fuel		Fuel Transportation		Alt Fuel Days Use	Com In-Svc Date (Mo/Yr)	Expected Retirement (Mo/Yr)	Gen. Max Nameplate (MW)	Net Capability (MW)	
				Pri	Alt	Pri	Alt					Summer	Winter
SGS	1	Putnam County	ST	BIT	N/A	RR	N/A	N/A	02/84	Unk	736	626	664
SGS	2	Putnam County	ST	BIT	N/A	RR	N/A	N/A	12/84	Unk	736	634	665
MGS	1-3	Hardee County	CC	NG	DFO	PL	TK	Unk	01/02	Unk	587	482	539
MGS	4-8	Hardee County	CT	NG	DFO	PL	TK	Unk	12/06	Unk	310	270	310
Schedule Abbreviations:		General		Unk – Unknown N/A – Not applicable									
		Unit Type ST – Steam Turbine CC – Combined Cycle CT – Combustion Turbine PV – Photovoltaic		Fuel Type BIT – Bituminous Coal NG – Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy						Fuel Transportation PL – Pipeline RR – Railroad TK – Truck			

3.3.2 Power Purchase Agreements

Seminole uses wholesale market purchases to maintain competitive flexibility in its power supply portfolio. In 2016, approximately 26% of Seminole's energy and 54% of its capacity came from wholesale purchased power. Table 2 summarizes Seminole's purchased power and tolling contracts as of December 31, 2016. As a result of the RFP process discussed in Section 6, Seminole has extended the Oleander PPA through December 31, 2021, and has entered into additional system PPAs for intermediate and peaking power and a new PPA for solar resources. These new agreements are summarized in Table 3.

Table 2 Seminole's Power Purchase Contracts
(as of December 31, 2016)

SUPPLIER	FUEL	MW (WINTER RATINGS)	IN SERVICE DATE	END DATE
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	50	6/1/2016	12/31/2018
DEF	System	200-500	6/1/2016	12/31/2024
DEF	System	50-600	1/1/2021	3/31/2027
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026

Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

Table 3 Seminole's New Power Purchase Contracts

SUPPLIER	FUEL	MW	IN SERVICE DATE	END DATE
Shady Hills Energy Center LLC	Gas	575*	12/1/2021	11/30/2051
Oleander Power Project	Gas/Oil	546*	6/1/2021	12/31/2021
Southern Company Services	System	100-150*	6/1/2021	5/31/2026
DEF	System (IM)	50-400*	1/1/2021	12/31/2030
DEF	System (Peaking)	50-400*	1/1/2021	12/31/2035
Tillman Solar Center LLC	Solar/PV	40**	6/1/2021	5/31/2041

*Winter ratings
**Summer rating

3.3.3 Renewable Resources

Seminole's generation portfolio includes a mix of technologies and fuel types, including renewable energy. Seminole currently receives 87.8 MW from renewable

energy sources via PPAs, including 13 MW from Biomass, 16.8 MW from landfill gas-to-energy, and 58 MW from waste-to-energy. Additionally, as a result of the RFP process explained in Section 6, Seminole has entered into a new PPA for 40 MWac of solar capacity beginning in January, 2021. Seminole may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

In addition to renewable power purchases, Seminole operates a 2.2 MWac (summer) Cooperative Solar facility located in Hardee County, Florida. The Cooperative Solar project took shape in 2014, as the price of solar technology was declining and the abundance of government incentives for the industry provided the path to incorporate large-scale solar projects in Florida. Seminole's Members' end-use member-consumers were interested in utilizing solar power, but wanted to do so without large, personal financial commitments. Cooperative Solar provided the opportunity for Members and their member-consumers to participate and the project provides ongoing value to Seminole, as well. The information learned from designing and operating this solar facility will help inform future decisions as Seminole evaluates adding renewable resources to its energy mix.

Seminole's Members also operate small biomass facilities (1.6 MW) and wind turbines (7.4 kW), as well as small photovoltaic facilities connected to their administration buildings. Several Members are considering future community solar projects.

3.4 Transmission Interconnections

Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 127 circuit miles of 69 kV lines. However, Seminole's transmission facilities have limited direct interconnections with Seminole's Members' load. Seminole is therefore primarily a transmission dependent utility ("TDU") that relies mainly upon the transmission systems of DEF and Florida Power & Light Company ("FPL") for the delivery of Seminole's owned and/or contracted power supply resources to Seminole's

Members' load. Seminole is a Network Integration Transmission Service ("NITS") customer of DEF and FPL under each of their respective Open Access Transmission Tariffs ("OATT"). Approximately 76%, or 2,294 MW, (based on 2016-17 actual winter net firm peak demand) of Seminole's Members' load is served by DEF's transmission system, approximately 16%, or 483 MW, is served by FPL's transmission system, and approximately 8%, or 241 MW, is served directly by Seminole's transmission system.

Seminole's facilities are interconnected to Florida's electric grid at nineteen (19) 230 kV transmission interconnections with the entities shown in Table 4.

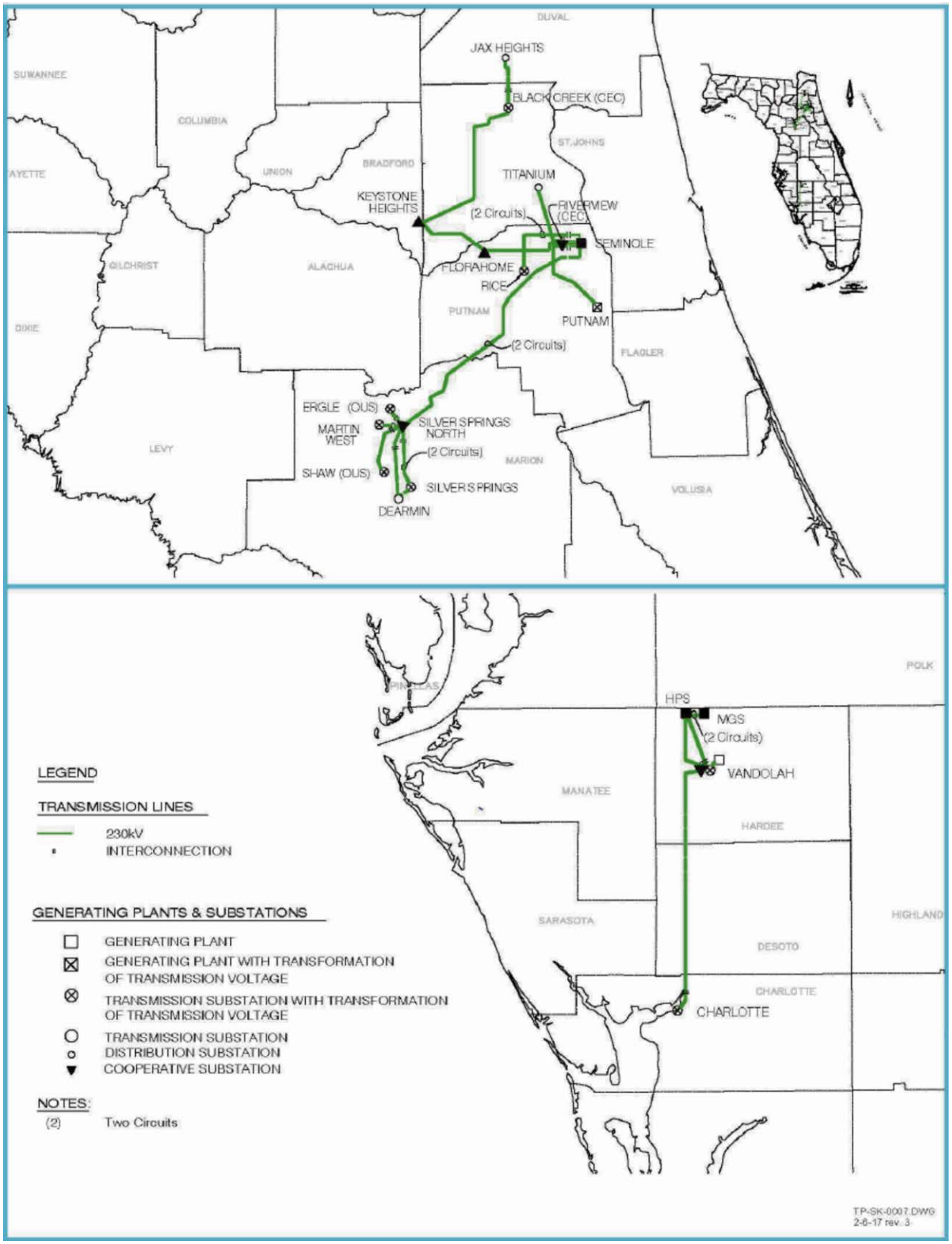
Table 4 Seminole's Transmission Interconnections

Entity	Voltage (kV)	Number of Interconnections
Florida Power & Light	230	5
Duke Energy Florida	230	7
JEA	230	1
City of Ocala (OUS)	230	2
Tampa Electric Company	230	1
Invenergy, LLC	230	3

Note: This table describes physical facility interconnections, which do not necessarily constitute contractual interconnections for purposes of transmission service or interconnections between balancing areas.

Figure 2 depicts Seminole's 230 kV transmission lines, including its interconnections with those entities identified in Table 4.

Figure 2 Seminole's Bulk Transmission Facilities



4.0 DESCRIPTION OF THE PROPOSED GENERATING UNITS

4.1 The Proposed Seminole Combined Cycle Facility ("SCCF")

The SCCF involves construction and operation of a new state-of-the-art natural gas-fired "two-on-one" combined cycle generating facility and onsite associated facilities on an approximately 32 acre parcel adjacent to the existing SGS plant. The SCCF will have a nominal net generating capacity of 1,050 MW and will be fired on natural gas only. The SGS site currently contains two 664 MW (net winter) coal-fired steam electric generating units (SGS Units 1 and 2) and associated facilities. One of the two existing SGS Units will be taken out of service coincident with the declared commercial operation of the SCCF. Figure 3 provides a conceptual rendering of the SCCF.

Figure 3 Conceptual Rendering of SCCF
(looking southwest to northeast)



4.1.1 The SGS Site

The SGS site is located 5.25 miles north-northeast of Palatka, Florida. As shown in Figure 4, the proposed SCCF site area is located southeast of the existing plant and southwest of the existing hyperbolic cooling towers.

Figure 4 Proposed Location of SCCF



4.1.2 Proposed Combined Cycle Technology

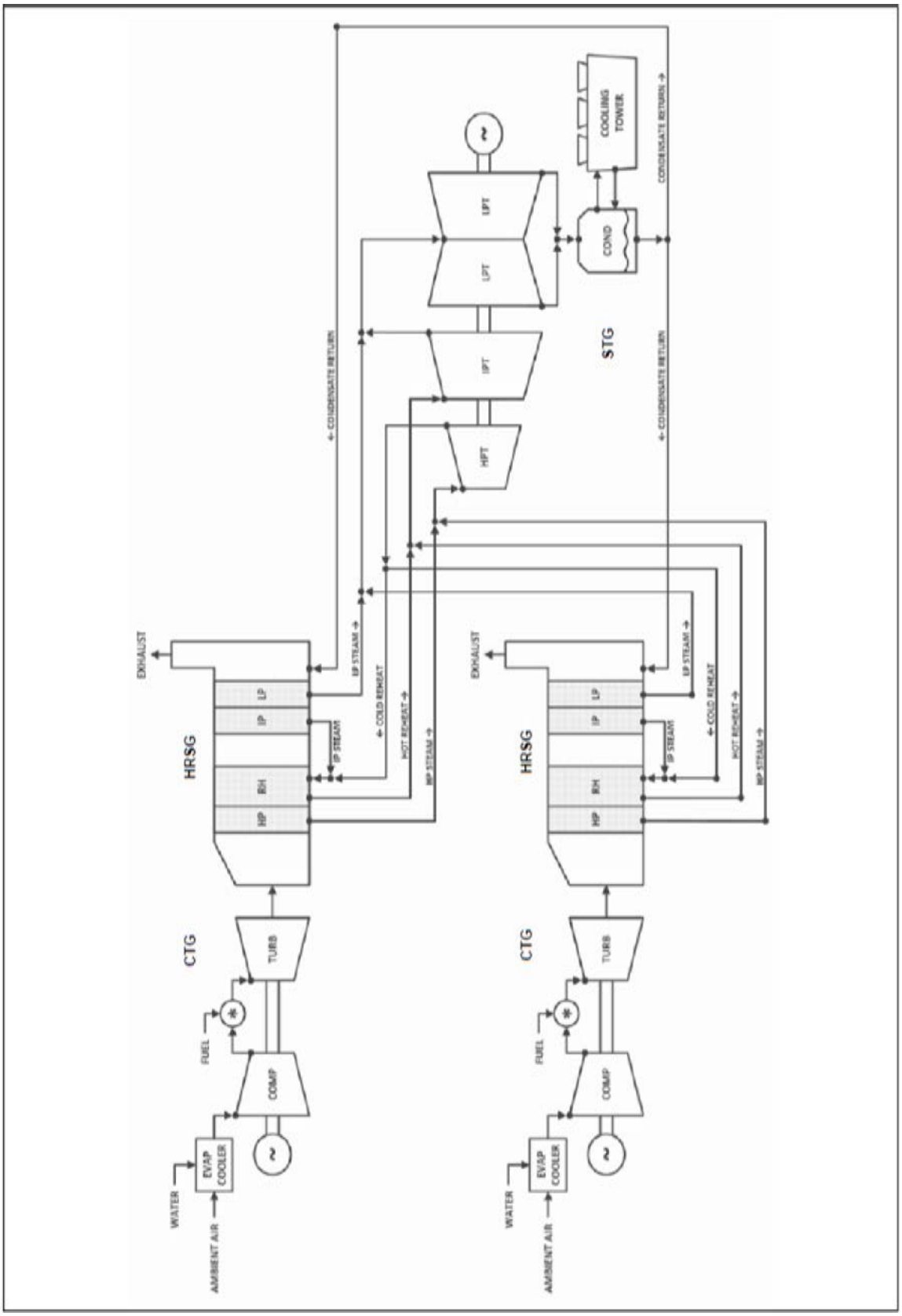
The SCCF will consist of two combustion turbine generators ("CTG"), two heat recovery steam generators ("HRSGs"), and one steam turbine generator ("STG"). Seminole has selected the advanced, large-frame GE Model 7HA.02 CTG for the SCCF. When operated in combined cycle mode, these large CTGs create the most efficient electric generating technology currently available for utility-scale power plants. These combined cycle plants can achieve an efficiency of up to 60 percent, compared to CTGs alone in simple-cycle mode at 35 to 38 percent and coal-fired steam plants at 32 to 42 percent. When a CTG is operated alone in simple-cycle mode, the hot exhaust gases from the CTG are released to the atmosphere. In combined cycle configuration, the hot exhaust gases from the CTG are used to produce steam in the HRSG, and the steam is used to drive an STG to generate additional electricity. Thus, a combined cycle power plant can generate 25 to 30 percent more electricity without burning more fuel or producing additional air emissions.

The facility is expected to have a "gross nominal" output of 1,183 MW and a "net nominal" output of 1,050 MW which it is anticipated to achieve across the entire range of ambient conditions typically experienced in Palatka, Florida. However, the facility will have significant flexibility in terms of its operational characteristics. During peak load periods, the SCCF will be able to fire supplemental natural gas in duct burners in the HRSGs to get additional generation out of the STG.

The 7HA.02 gas turbines have an extended "turndown" capability which will allow them to meet their required emissions levels while firing the turbines down to as low as 25 percent of their full-fire levels. This low turn-down capability is valuable as it will allow the SCCF to remain operational during low load periods typically experienced at night and avoid the thermal stresses, wear, and additional emissions associated with a shut-down / start-up cycle.

Figure 5 presents a conceptual schematic of a two-on-one combined cycle unit.

Figure 5 Schematic of Two-on-One Combined Cycle Unit



4.1.3 Existing Infrastructure

The SCCF will utilize existing infrastructure, including the cooling water supply and wastewater discharge pipelines to the St. Johns River and the intake and discharge structures in the river. The new electrical switchyard for the SCCF will be interconnected with the existing SGS switchyard and electricity generated by the SCCF will be transmitted to the Florida transmission network through the existing 230 kV transmission lines running west from the SGS site.

4.1.4 Associated Facilities

The SCCF also includes other associated facilities, such as electrical equipment enclosures, a mechanical draft cooling tower, exhaust stacks, an administration building that will include a control room and maintenance area, a warehouse, parking, fuel gas regulation station and heaters, diesel fired emergency fire water pump, aboveground service/fire water storage tank, aqueous ammonia tanks, a switchyard expansion, step-up transformers, potable water and sanitary wastewater treatment facilities, a stormwater management system/stormwater ponds, piping tie-ins, and other facilities necessary to integrate with existing intake and discharge water infrastructure.

4.1.5 Air Emission Controls

The SCCF will be designed with technologies to minimize air emissions. The two CTGs will be equipped with dry low-NOx combustors to control air emissions of nitrogen oxides ("NOx"). The HRSGs will be equipped with selective catalytic reduction ("SCR") systems to further reduce NOx emissions. Emissions of carbon monoxide ("CO") and volatile organic compounds ("VOCs") will be limited through use of oxidation catalyst systems. Emissions of other regulated air pollutants, such as sulfur dioxide ("SO2") and particulate matter (PM), will be controlled through use of pipeline-quality natural gas and good combustion practices. In addition, the SCCF will minimize greenhouse gas ("GHG") emissions through the use of clean-burning natural gas along with the highly efficient, combined cycle electric generating technology.

4.1.6 Water Use and Supply

The proposed SCCF is also designed to minimize the use of water. The condenser cooling system will be a closed-loop system consisting of a 16 cell mechanical draft cooling tower. Cooling tower makeup water for the SCCF will be provided from the St. Johns River through an interconnection with the existing water intake pipeline and structure. No in-water construction activities are expected for the SCCF.

Higher quality freshwater needs for plant service and potable uses for the SCCF will be provided through groundwater withdrawals from new wells within the SCCF area. Plant service water uses will include steam cycle makeup water, equipment wash water, pump seals, and emergency fire water. The service water will be filtered and treated in trailer-mounted demineralization systems, which will be regenerated offsite to avoid the need for onsite disposal of treatment wastewaters. Potable water for drinking, safety showers, eyewash stations, and other sanitary uses will be treated in a new potable water treatment facility within the SCCF site area.

Sanitary wastewater will be treated in a packaged treatment facility. The treated sanitary wastewater and other treated low-volume wastewaters will be collected in a wastewater collection sump and discharged in combination with the cooling tower blowdown through the existing water discharge pipeline and structure to the St. Johns River, similar to existing SGS operations. Any solids produced by the treatment system will be disposed offsite at the existing SGS landfill.

4.1.7 Stormwater Management

The stormwater management system for the SCCF is designed to handle and treat the 25 year, 24 hour storm event and is designed to meet all federal, state, regional, and local requirements. Potential contact stormwater runoff from the power block and equipment areas will be collected and treated through an oil/water separator and routed to the wastewater collection sump prior to discharge to the St. Johns River. Noncontact stormwater runoff from the facility area will be collected and routed to a stormwater retention pond. During construction, stormwater runoff from the construction

laydown and parking areas will also be collected and treated in swales and ponds, and best management practices will be utilized to minimize erosion from the disturbed areas during construction activities.

4.1.8 Fuel Type & Supply

The SCCF will burn natural gas as its fuel. At peak operation, including duct-firing, the SCCF will require approximately 173,000 million British thermal units ("MMBtu") of natural gas per day.

The natural gas supply for the SCCF will be purchased as a part of Seminole's procurement of its gas portfolio needs. Seminole's gas procurement process diversifies the timing and duration of such gas purchases. For example, when planning for the upcoming calendar year, Seminole will purchase a portion of its gas supply on an annual and/or seasonal basis, purchase incremental supply on a month-ahead basis, and then procure any remaining supply needs on a daily basis. Such supply is typically purchased at market based index prices. In addition, Seminole may contract for gas supply on a longer-term basis with a duration of up to five years or longer based on its projected needs and available supply.

Natural gas supply will be transported from the Florida Gas Transmission ("FGT") mainline to the SCCF via a new approximately 21-mile pipeline lateral that will be constructed, owned and operated by a third-party. Seminole will contract for firm transportation service on the pipeline lateral from FGT to the SCCF. This third-party will be an authorized natural gas transmission company in Florida as defined in section 368.103(4), Florida Statutes.

Seminole is finalizing negotiations with multiple entities for natural gas transportation service and/or natural gas supply for delivery to Putnam County, Florida and ultimately to the SCCF via the new gas pipeline lateral. These arrangements provide for up to 187,000 MMBtus per day of gas transportation rights to the lateral serving the SCCF. Some of this is existing capacity that will be re-purposed for the SCCF, some is existing capacity that will require additional facilities on FGT's system to provide the

incremental transportation capacity to Putnam County, Florida, and some of the capacity will be new transportation service into Florida enabled by additional facilities on existing pipeline(s).

Seminole is finalizing its contracts for adequate gas transportation capacity that will provide a firm transportation path from geographic locations that are expected to have adequate natural gas supply available over the horizon of the Need Study. More specifically, it is anticipated that reliable gas supply from various production basins will continue to be transported to the areas at which Seminole will have transportation rights to purchase gas supply.

4.1.9 Transmission Interconnections

The transmission interconnection process involves a System Impact Study that identifies potential impacts and mitigation plans for addressing such impacts on Seminole's transmission system as well as neighboring systems. The analysis is performed by Seminole in coordination with the Florida Reliability Coordinating Council ("FRCC") through the FRCC's Reliability Evaluation Process for Generator and Transmission Service Requests. The System Impact Study incorporates the use of steady-state load flow, short circuit, and stability analysis using industry standard tools and software programs to ensure that Seminole's transmission system operates reliably over a broad spectrum of system conditions and following a wide range of probable planning and extreme events.

In general, Seminole's transmission planning process includes the single contingency loss of any transmission circuit, transformer, bus section, shunt device, internal breaker fault, or generator. Such analysis is performed for multiple load levels, including but not limited to peak, off-peak, and high-import (Southern to Florida transfers) for select summer and winter conditions as modeled and made available by the FRCC. Additional analysis is performed to determine system response to credible, less probable extreme events, to assure the system meets Seminole, FRCC, and North American Electric Reliability Corporation ("NERC") transmission planning criteria. The

additional analysis includes the loss of multiple elements, including the loss of multiple transmission circuits, transformers, generators, or the combination of each. Seminole utilizes planned operational system adjustments, corrective action plans which can include projects that require construction of new facilities or upgrades to existing facilities, and load loss if permissible by Seminole, FRCC, and NERC transmission planning reliability criteria.

Seminole's transmission planning process also includes the evaluation of multiple fault types at various locations, consistent with the criteria of FRCC and NERC, to understand the magnitude of the resultant fault current that may be experienced by Seminole's interrupting devices and to ensure that such magnitude is safely mitigated. Lastly, Seminole's transmission interconnection process evaluates critical clearing time at multiple load levels to ensure that the system is able to respond to planning and extreme events to not compromise the existing transmission system and to ensure the system remains adequate, reliable, and secure.

Typically, new generation interconnections, such as for the SCCF, are evaluated for both interconnection and deliverability simultaneously. However, because Seminole is a TDU within the FRCC region, Seminole will be required to submit separate Transmission Service Requests ("TSR") to DEF and FPL after completion of the interconnection analyses, in accordance with their respective OATTs, for the deliverability of the SCCF to Seminole's Members' load in the respective control areas in order to determine transmission impacts on the systems of FPL and DEF, in addition to any impacts on neighboring systems that may result due to the SCCF. In order to request a TSR from DEF and FPL on their respective Open Access Same Time Information Systems ("OASIS"), via the designation of network resource ("DNR") process, Seminole is required to attest it either owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service, in accordance with FERC pro-forma OATT. Thus, Seminole could not submit the TSRs in advance of the interconnection process in order to obtain estimates of the costs for

delivery of the SCCF on DEF's or FPL's systems. Consequently, when evaluating alternatives to meet its projected 2021 need, Seminole did not have alternatives to evaluate deliverability of the resource into the respective areas to determine transmission impacts on DEF, FPL and neighboring systems. Instead, Seminole was limited to evaluating the SCCF interconnection for short circuit and stability impacts, including limited steady-state load flow analysis across Seminole's own transmission system emanating from the SGS Switchyard.

In late 2016, in order to evaluate the deliverability of the SCCF with a complete steady-state load flow analysis, Seminole and the members of the FRCC Transmission Technical Subcommittee ("TTS") agreed to perform a "quasi" study to evaluate the impacts of interconnection and deliverability simultaneously, with the recognition that deliverability would need to be studied again once TSRs were submitted after the completion of the interconnection process. In order to model the deliverability of the SCCF, the power output was modeled as being delivered to the DEF control area for ultimate delivery to Seminole's Members' load in DEF's area. The "quasi" study for deliverability of the SCCF included the assumption that the two existing SGS units, Unit 1 and Unit 2, were also running at full output in addition to the SCCF.

Seminole's original interconnection evaluation of the SCCF identified the required expansion of the existing SGS Switchyard, including the addition of ten (10) new 230 kV circuit breakers and associated relay protection, and twenty (20) new circuit breaker disconnect switches. Additionally, the FRCC deliverability steady-state load flow results identified the potential need for eight upgrade projects. However, the initial FRCC deliverability study assumed that both SGS unit 1 and unit 2 were at full output in addition to the SCCF, resulting in an aggregate net output emanating from the SGS Switchyard. As Seminole performed its economic analyses for this Need Study, the study assumptions changed to include the removal from service of one existing SGS unit. This resulted in a lower net incremental difference of ~~484~~ 386 RUN MW from the existing installed capacity. This change significantly reduces the magnitude of potential

overloads associated with four of the projects originally identified, leaving only three required to be evaluated further during the TSR process.

4.1.10 Approximate Capital Costs

The estimated capital cost of the SCCF is approximately $727 million. As summarized in Table 5, this estimate includes plant structures, equipment, construction, interest during construction, and other owner's costs.

Table 5 SCCF Capital Cost Estimate

Equipment and Interconnection	$220,000,000
Development and EPC Contract	$381,000,000
Other Owner's Costs and Contingency	$ 63,000,000
Interest During Construction	$ 45,000,000
Financing	$ 1,000,000
Insurance	$ 17,000,000
TOTAL	$727,000,000

4.1.11 Construction Schedule & Projected In-Service Date

Construction activities for the SCCF are scheduled to begin in mid to late 2019 or early 2020, with targeted commercial operation approximately 36 months later. Seminole currently projects an in-service date of December 1, 2022.

4.2 PROPOSED SHADY HILLS COMBINED CYCLE FACILITY

The new SHCCF will include a new state-of-the-art natural gas-fired 573 MW (winter), one-on-one, combined cycle generating unit and onsite associated facilities. The SHCCF will be designed, constructed, owned and operated by SHEC on a portion of the existing Shady Hills power plant site located in Shady Hills, Florida, approximately 30 miles north of Tampa, Florida. A new generator tie-line will be constructed as off-site facilities required to connect the SHCCF to the DEF power grid.

The SHCCF will sell its electric capacity, energy and ancillary services to Seminole pursuant to a tolling agreement. SHEC is a wholly-owned, indirect subsidiary of GE Capital US Holdings, Inc. ("GECUSH"), which is in turn a wholly-owned, indirect subsidiary of GE. GE Energy Financial Services ("GE EFS"), a business unit of GECUSH, will design, construct, own and operate SHEC. GE EFS has over 35 years of experience managing energy assets through multiple economic cycles, and a global portfolio that spans conventional and renewable power, and oil and gas infrastructure projects. GE EFS invests globally across the capital spectrum in essential, long-lived, and capital-intensive energy assets that meet the world's energy needs.

4.2.1 Proposed CC Technology

The SHCCF will consist of one CTG, one HRSG, and one STG, and one generator GSU. The CTG will be the advanced, large-frame GE Model 7HA.02.

4.2.2 Existing Infrastructure

The SHCCF will be located adjacent to the existing Shady Hills power plant, a three-unit simple cycle power plant using GE 7F-class technology, that is owned by Shady Hills Power Company, L.L.C. ("SHPC"), which is also a wholly-owned, indirect subsidiary of GECUSH. The new combustion turbine, steam turbine and heat recovery steam generator will be installed to the east of the existing power plant on land currently controlled by SHPC.

4.2.3 Other Facilities

Other facilities to be constructed include an approximately 1 mile generator tie-line to a new DEF substation, to be designated Hudson North, that will connect the SHCCF to the DEF 230kV high voltage transmission grid in Pasco County, Florida. Additional systems to connect the SHCCF to the Pasco County Master Reuse System, and water and wastewater treatment systems to enable use of reclaimed water, including a zero-liquid discharge ("ZLD") system will also be deployed. A new gas metering station will be provided to connect to the existing gas lateral owned by FGT to the SHCCF.

4.2.4 Air Emission Controls

The SHCCF will be designed with technologies to minimize air emissions. The CTG will be equipped with dry low-NOx combustors to control NOx emissions. The HRSG will be equipped with a SCR system, to further reduce NOx emissions. Emissions of other regulated air pollutants (SO2 and PM) will be controlled through use of pipeline-quality natural gas as the only fuel fired in the CTG, HRSG, and dew point fuel heaters, and good combustion practices. In addition, the new unit will minimize GHG emissions through the use of clean-burning natural gas along with the highly efficient, combined cycle electric generating technology.

4.2.5 Water Use & Supply

Process water for the SHCCF (cooling water, demineralized water, and service water) will be sourced in the form of wastewater treatment effluent from Pasco County's Master Reuse System, of which the Shady Hills Wastewater Treatment Plant is adjacent to the SHPC site. In addition, supplemental sources may be utilized on an emergency basis in the event reclaimed or treated wastewater is not available. An onsite water treatment system will reduce the concentrations of calcium, magnesium, alkalinity, silica and suspended solids by adding hydrated lime, soda ash, ferric chloride and polymer to reduce these constituents in clarifiers. The onsite water treatment system will also include granular media filters, ultrafiltration trains and reverse osmosis ("RO") trains. Finally,

RO reject and other concentrated process wastewater streams will be treated in brine concentrators and crystallizers. These treatment processes, and the reuse of process wastewater around the site, will be used to achieve zero liquid discharge from the site. The ZLD system will generate a solid waste byproduct that will be disposed offsite.

4.2.6 Stormwater Management

A new stormwater retention system will be provided to accommodate storm water collection, treatment, storage, and discharge from the SHCCF site.

4.2.7 Fuel Type & Supply

The SHCCF will burn only natural gas as its fuel. At peak operation, including duct-firing, the new unit will require approximately 89,000 MMBtus of natural gas per day. Seminole will be responsible for the procurement and delivery of natural gas to the SHCCF. Seminole will purchase the natural gas supply for the new unit as part of its natural gas portfolio procurement program, as discussed in Section 4.1.7 above. Natural gas supply will be transported to the SHCCF via the existing FGT pipeline system. A new interconnection with FGT will be constructed to supply fuel to the SHCCF.

Seminole is finalizing negotiations with multiple entities for natural gas transportation service and/or natural gas supply for delivery to various Seminole owned and purchased power resources, including the SHCCF. Seminole anticipates that these arrangements, combined with Seminole's existing gas transportation capacity, will provide for up to 130,000 MMBtus per day of gas transportation delivery rights to the SHCCF. Part of this transportation service will come from existing Seminole capacity that will be re-purposed for the SHCCF and some transportation will be through existing capacity on the FGT system.

Seminole is finalizing its contracts for gas transportation capacity that will provide a firm transportation path from geographic locations that are expected to have adequate natural gas supply available over the horizon of the Need Study. It is anticipated that

reliable gas supply from various production basins will continue to be transported to the areas at which Seminole will have transportation rights to purchase gas supply.

4.2.8 Transmission Interconnections

The SHCCF will be interconnected to the DEF transmission system via a planned Hudson North Switching Station. GE EFS has submitted a request for Network Resource Interconnection Service through DEF's OATT process. In 2016, DEF completed a System Impact Study and a Facilities Study to identify the necessary transmission improvements to integrate the SHCCF into the DEF transmission system.

4.2.9 Tolling Agreement

SHEC and Seminole have entered into a tolling agreement, which has a term of 30-years from the anticipated commercial operation date on December 1, 2021. Under the tolling agreement, Seminole will have the right to schedule the dispatch of the SHCCF, provide fuel for such scheduled operation, and receive the power produced. The terms of the tolling agreement provide Seminole with security of power supply at a competitive price for 30 years.

4.2.10 Construction Schedule & Projected In-Service Date

Construction activities for the SHCCF are scheduled to begin in mid 2019, with targeted commercial operation approximately 30 months later. The tolling agreement calls for an in-service date of December 1, 2021.

5.0 THE NEED FOR PROPOSED GENERATING UNITS

5.1 Overview of Need Assessment

Seminole's power supply planning process begins with the development of its nine Members' load forecasts, which are aggregated to represent the Seminole load forecast. The aggregated peak demand forecasts are used to determine Member capacity requirements and an additional 15 percent of demand is added to satisfy Seminole's Reserve Margin requirement. A gap analysis is then used to identify deficiencies between forecasted requirements and current available capacity. When a deficiency is identified, Seminole evaluates all available purchased power, acquisition, and self-build alternatives to establish a portfolio that provides a cost-effective, risk-managed, and reliable generation mix to meet the needs of Seminole's Members.

5.2 The Load Forecast

Seminole's load forecast is an annual assessment of a range of information influencing electricity demand and energy growth in the nine-Member system. Seminole and its Members coordinate throughout the year to discuss forecast assumptions, past performance and ongoing developments. Each Member service territory is forecasted individually based on the unique growth characteristics of the region. The Seminole-system forecast is the aggregate of the Member system forecasts. Seminole's peak demand is the aggregate of all Member demands that maximizes the peak of the system.

Seminole produces a load forecast study which is sumitted annually to the Rural Utilities Service ("RUS") for approval. Seminole, its Members, and the RUS have consistently relied on Seminole's forecasts as the basis for power supply planning, rate development, and financial planning. The most recent load forecast study was approved by the RUS in October 2017.

5.2.1 Consumer Base

The combined service area of Seminole Members is primarily rural and extends into 42 of Florida's 67 counties. Seminole Members provide electricity to over 763,000

member-consumers, serving a population of approximately 1.6 million people and businesses. The combined service area encompasses a variety of geographic and weather conditions, as well as a diverse mix of economic activity and demographic characteristics.

The Members' member-consumer mix is approximately 89% residential, 10% commercial/industrial, and 1% "other." Residential member-consumers represent approximately 68% of total energy sales, with commercial/industrial sales representing 31%, and "other" representing 1% of sales. The commercial sector is primarily small to medium sized retail businesses, while the industrial sector is primarily manufacturing, mining and forestry. The "other" class consists of irrigation, street and highway lighting, public buildings, and sales for resale.

5.2.2 Load Forecast Methodology & Assumptions

Seminole adheres to generally accepted load forecasting methodologies currently employed in the electric utility industry. Energy and demand is forecasted by Member-system total and the Seminole forecast is the aggregate of all Member forecasts.

Model inputs and assumptions are collected from Members, government agencies, universities, and other third party providers. The primary resource for forecasting load growth is population and Seminole primarily relies on the University of Florida's Bureau of Economic and Business Research for population forecasts. Additional economic and demographic data employed in the forecast models are collected from Moody's Analytics, Inc. Weather data is collected from AccuWeather for 25 stations and normalized weather assumptions are based on 30 years of historical observations. Seminole implements statistically adjusted end-use methods to reflect historical and forecasted trends in appliance stock saturation and efficiency for all rate class sectors.

5.2.3 Energy and Demand Models

Seminole forecasts monthly energy sales at the Member-total and Member-rate class level with econometric models. Delivery point billing load and Member-rate class

sales to end-use member-consumers grossed up for distribution losses are trained with a variety of explanatory variables in order to estimate future growth.

Maximum demand by Member by month and by season are modeled using econometric models. Winter seasonal peak models regress the highest peak during November through March of each year against contemporaneous explanatory variables. Summer seasonal peak models regress the highest peak from April through September of each year against contemporaneous explanatory variables. Seasonal peak forecasts replace monthly model forecast results for the month each seasonal peak is most likely to occur.

Seminole's maximum demand is the aggregate of the one-hour simultaneous demands of all Members that maximizes the peak of the system by month. Forecasts of Seminole maximum demand are derived by applying coincident factors to Member-maximum demand forecasts. Member demand coincident with Seminole represents Seminole's planning capacity.

5.2.4 Historical Trends and Forecast Results

Tables 6 through 13 provide Seminole's history and forecast of number of consumers, usage-per consumer and end-use sales by rate class and in total. Tables 14 and 15 provide historical and forecasted net energy for load, summer peak demand, and winter peak demand. These figures update the projections presented in Seminole's 2017 Ten Year Site Plan, which is provided as Appendix A to this Need Study. For comparison purposes, these tables are presented with and without Lee County Electric Cooperative ("LCEC") included in historical data. Prior to 2014, Seminole Electric Cooperative was a ten-Member system, which included LCEC. Tables 6 through 15 also include five and ten-year historical and forecasted average annual growth rates ("AAGR").

Seminole also prepared "high" and "low" load forecasts for use in sensivity analyses as part of the economic evaluations discussed in Section 6.5 below. These "high" and "low" load forecasts are also provided in Tables 14 and 15.

Table 6

Residential Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	803,957	-	-	14,235	-	-	11,444	-	-
2008	808,926	*4,969*	*0.6*	13,727	*-508*	*-3.6*	11,104	*-340*	*-3.0*
2009	811,767	*2,841*	*0.4*	13,912	*185*	*1.4*	11,293	*190*	*1.7*
2010	761,993	*-49,774*	*-6.1*	14,920	*1,008*	*7.2*	11,369	*75*	*0.7*
2011	765,279	*3,286*	*0.4*	13,605	*-1,315*	*-8.8*	10,412	*-957*	*-8.4*
2012	769,591	*4,312*	*0.6*	12,967	*-638*	*-4.7*	9,979	*-433*	*-4.2*
2013	777,493	*7,902*	*1.0*	12,885	*-82*	*-0.6*	10,018	*39*	*0.4*
2014	662,626	*-114,867*	*-14.8*	13,293	*408*	*3.2*	8,808	*-1,210*	*-12.1*
2015	673,215	*10,589*	*1.6*	13,470	*177*	*1.3*	9,068	*260*	*3.0*
2016	683,672	*10,458*	*1.6*	13,618	*149*	*1.1*	9,310	*242*	*2.7*
Forecast									
2017	692,985	*9,313*	*1.4*	13,034	*-585*	*-4.3*	9,032	*-278*	*-3.0*
2018	703,726	*10,741*	*1.5*	13,287	*253*	*1.9*	9,351	*318*	*3.5*
2019	715,007	*11,281*	*1.6*	13,283	*-4*	*0.0*	9,497	*147*	*1.6*
2020	726,600	*11,593*	*1.6*	13,120	*-162*	*-1.2*	9,533	*36*	*0.4*
2021	737,810	*11,209*	*1.5*	13,047	*-73*	*-0.6*	9,626	*93*	*1.0*
2022	748,714	*10,904*	*1.5*	13,031	*-16*	*-0.1*	9,757	*130*	*1.4*
2023	759,586	*10,872*	*1.5*	13,033	*2*	*0.0*	9,900	*143*	*1.5*
2024	770,385	*10,800*	*1.4*	13,029	*-5*	*0.0*	10,037	*137*	*1.4*
2025	780,806	*10,420*	*1.4*	13,018	*-11*	*-0.1*	10,164	*127*	*1.3*
2026	790,745	*9,939*	*1.3*	13,023	*5*	*0.0*	10,298	*134*	*1.3*
2027	800,299	*9,554*	*1.2*	13,037	*14*	*0.1*	10,433	*136*	*1.3*
AAGR '07-'16			*-1.8*			*-0.5*			*-2.3*
AAGR '12-'16			*-2.9*			*1.2*			*-1.7*
AAGR '18-'22			*1.6*			*-0.5*			*1.1*
AAGR '18-'27			*1.4*			*-0.2*			*1.2*

Note: Estimated-Actual data through February 2017

Table 7

Residential Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	627,934	-	-	14,329	-	-	8,998	-	-
2008	633,384	*5,450*	*0.9*	13,871	*-457*	*-3.2*	8,786	*-212*	*-2.4*
2009	635,862	*2,478*	*0.4*	14,043	*171*	*1.2*	8,929	*143*	*1.6*
2010	639,640	*3,778*	*0.6*	15,147	*1,105*	*7.9*	9,689	*760*	*8.5*
2011	642,853	*3,214*	*0.5*	13,653	*-1,494*	*-9.9*	8,777	*-912*	*-9.4*
2012	646,830	*3,976*	*0.6*	13,021	*-632*	*-4.6*	8,423	*-354*	*-4.0*
2013	653,820	*6,990*	*1.1*	12,929	*-93*	*-0.7*	8,453	*30*	*0.4*
2014	662,626	*8,806*	*1.3*	13,293	*364*	*2.8*	8,808	*355*	*4.2*
2015	673,215	*10,589*	*1.6*	13,470	*177*	*1.3*	9,068	*260*	*3.0*
2016	683,672	*10,458*	*1.6*	13,618	*149*	*1.1*	9,310	*242*	*2.7*
Forecast									
2017	692,985	*9,313*	*1.4*	13,034	*-585*	*-4.3*	9,032	*-278*	*-3.0*
2018	703,726	*10,741*	*1.5*	13,287	*253*	*1.9*	9,351	*318*	*3.5*
2019	715,007	*11,281*	*1.6*	13,283	*-4*	*0.0*	9,497	*147*	*1.6*
2020	726,600	*11,593*	*1.6*	13,120	*-162*	*-1.2*	9,533	*36*	*0.4*
2021	737,810	*11,209*	*1.5*	13,047	*-73*	*-0.6*	9,626	*93*	*1.0*
2022	748,714	*10,904*	*1.5*	13,031	*-16*	*-0.1*	9,757	*130*	*1.4*
2023	759,586	*10,872*	*1.5*	13,033	*2*	*0.0*	9,900	*143*	*1.5*
2024	770,385	*10,800*	*1.4*	13,029	*-5*	*0.0*	10,037	*137*	*1.4*
2025	780,806	*10,420*	*1.4*	13,018	*-11*	*-0.1*	10,164	*127*	*1.3*
2026	790,745	*9,939*	*1.3*	13,023	*5*	*0.0*	10,298	*134*	*1.3*
2027	800,299	*9,554*	*1.2*	13,037	*14*	*0.1*	10,433	*136*	*1.3*
AAGR '07-'16			*0.9*			*-0.6*			*0.4*
AAGR '12-'16			*1.4*			*1.1*			*2.5*
AAGR '18-'22			*1.6*			*-0.5*			*1.1*
AAGR '18-'27			*1.4*			*-0.2*			*1.2*

Note: Estimated-Actual data through February 2017

Table 8

Commercial Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	88,306	-	-	54,798	-	-	4,839	-	-
2008	86,121	*-2,185*	*-2.5*	56,827	*2,029*	*3.7*	4,894	*55*	*1.1*
2009	84,318	*-1,803*	*-2.1*	56,643	*-184*	*-0.3*	4,776	*-117*	*-2.4*
2010	78,788	*-5,530*	*-6.6*	57,433	*790*	*1.4*	4,525	*-252*	*-5.3*
2011	78,828	*40*	*0.1*	55,386	*-2,047*	*-3.6*	4,366	*-158*	*-3.5*
2012	80,598	*1,770*	*2.2*	55,287	*-99*	*-0.2*	4,456	*90*	*2.1*
2013	82,302	*1,704*	*2.1*	54,458	*-829*	*-1.5*	4,482	*26*	*0.6*
2014	72,632	*-9,670*	*-11.7*	55,086	*628*	*1.2*	4,001	*-481*	*-10.7*
2015	73,290	*658*	*0.9*	56,689	*1,603*	*2.9*	4,155	*154*	*3.8*
2016	74,411	*1,121*	*1.5*	57,940	*1,251*	*2.2*	4,311	*156*	*3.8*
Forecast									
2017	75,712	*1,301*	*1.7*	57,536	*-405*	*-0.7*	4,356	*45*	*1.0*
2018	76,926	*1,214*	*1.6*	57,406	*-130*	*-0.2*	4,416	*60*	*1.4*
2019	78,101	*1,176*	*1.5*	57,438	*32*	*0.1*	4,486	*70*	*1.6*
2020	79,168	*1,067*	*1.4*	57,737	*299*	*0.5*	4,571	*85*	*1.9*
2021	80,176	*1,008*	*1.3*	58,000	*263*	*0.5*	4,650	*79*	*1.7*
2022	81,283	*1,107*	*1.4*	58,295	*294*	*0.5*	4,738	*88*	*1.9*
2023	82,427	*1,144*	*1.4*	58,527	*232*	*0.4*	4,824	*86*	*1.8*
2024	83,450	*1,023*	*1.2*	58,766	*239*	*0.4*	4,904	*80*	*1.7*
2025	84,426	*975*	*1.2*	59,009	*243*	*0.4*	4,982	*78*	*1.6*
2026	85,366	*941*	*1.1*	59,302	*293*	*0.5*	5,062	*81*	*1.6*
2027	86,268	*902*	*1.1*	59,602	*300*	*0.5*	5,142	*79*	*1.6*
AAGR '07-'16			*-1.9*			*0.6*			*-1.3*
AAGR '12-'16			*-2.0*			*1.2*			*-0.8*
AAGR '18-'22			*1.4*			*0.4*			*1.8*
AAGR '18-'27			*1.3*			*0.4*			*1.7*

Note: Estimated-Actual data through February 2017

Table 9

Commercial Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	67,898	-	-	55,757	-	-	3,786	-	-
2008	68,703	*805*	*1.2*	55,814	*58*	*0.1*	3,835	*49*	*1.3*
2009	67,704	*-999*	*-1.5*	54,899	*-915*	*-1.6*	3,717	*-118*	*-3.1*
2010	67,552	*-151*	*-0.2*	57,588	*2,689*	*4.9*	3,890	*173*	*4.7*
2011	67,755	*202*	*0.3*	54,597	*-2,991*	*-5.2*	3,699	*-191*	*-4.9*
2012	69,287	*1,532*	*2.3*	55,154	*556*	*1.0*	3,821	*122*	*3.3*
2013	71,094	*1,807*	*2.6*	54,390	*-764*	*-1.4*	3,867	*45*	*1.2*
2014	72,632	*1,538*	*2.2*	55,086	*696*	*1.3*	4,001	*134*	*3.5*
2015	73,290	*658*	*0.9*	56,689	*1,603*	*2.9*	4,155	*154*	*3.8*
2016	74,411	*1,121*	*1.5*	57,940	*1,251*	*2.2*	4,311	*156*	*3.8*
Forecast									
2017	75,712	*1,301*	*1.7*	57,536	*-405*	*-0.7*	4,356	*45*	*1.0*
2018	76,926	*1,214*	*1.6*	57,406	*-130*	*-0.2*	4,416	*60*	*1.4*
2019	78,101	*1,176*	*1.5*	57,438	*32*	*0.1*	4,486	*70*	*1.6*
2020	79,168	*1,067*	*1.4*	57,737	*299*	*0.5*	4,571	*85*	*1.9*
2021	80,176	*1,008*	*1.3*	58,000	*263*	*0.5*	4,650	*79*	*1.7*
2022	81,283	*1,107*	*1.4*	58,295	*294*	*0.5*	4,738	*88*	*1.9*
2023	82,427	*1,144*	*1.4*	58,527	*232*	*0.4*	4,824	*86*	*1.8*
2024	83,450	*1,023*	*1.2*	58,766	*239*	*0.4*	4,904	*80*	*1.7*
2025	84,426	*975*	*1.2*	59,009	*243*	*0.4*	4,982	*78*	*1.6*
2026	85,366	*941*	*1.1*	59,302	*293*	*0.5*	5,062	*81*	*1.6*
2027	86,268	*902*	*1.1*	59,602	*300*	*0.5*	5,142	*79*	*1.6*
AAGR '07-'16			*1.0*			*0.4*			*1.5*
AAGR '12-'16			*1.8*			*1.2*			*3.1*
AAGR '18-'22			*1.4*			*0.4*			*1.8*
AAGR '18-'27			*1.3*			*0.4*			*1.7*

Note: Estimated-Actual data through February 2017

Table 10

Other Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	5,150	-	-	31,960	-	-	165	-	-
2008	5,075	-75	-1.5	32,098	138	0.4	163	-2	-1.0
2009	5,036	-39	-0.8	33,085	987	3.1	167	4	2.3
2010	4,956	-80	-1.6	31,896	-1,189	-3.6	158	-9	-5.1
2011	4,954	-2	0.0	32,255	359	1.1	160	2	1.1
2012	4,818	-136	-2.7	34,080	1,825	5.7	164	4	2.8
2013	5,185	367	7.6	32,022	-2,058	-6.0	166	2	1.1
2014	5,308	123	2.4	28,449	-3,573	-11.2	151	-15	-9.1
2015	5,343	35	0.7	28,262	-187	-0.7	151	0	0.0
2016	5,384	42	0.8	28,162	-100	-0.4	152	1	0.4
Forecast									
2017	5,428	44	0.8	25,357	-2,805	-10.0	138	-14	-9.2
2018	5,455	27	0.5	24,887	-470	-1.9	136	-2	-1.4
2019	5,475	20	0.4	24,534	-353	-1.4	134	-1	-1.1
2020	5,497	22	0.4	24,099	-435	-1.8	132	-2	-1.4
2021	5,524	27	0.5	23,855	-243	-1.0	132	-1	-0.5
2022	5,553	29	0.5	23,708	-147	-0.6	132	0	-0.1
2023	5,579	25	0.5	23,596	-112	-0.5	132	0	0.0
2024	5,603	25	0.4	23,492	-104	-0.4	132	0	0.0
2025	5,628	24	0.4	23,379	-113	-0.5	132	0	-0.1
2026	5,650	23	0.4	23,303	-76	-0.3	132	0	0.1
2027	5,671	21	0.4	23,247	-56	-0.2	132	0	0.1
AAGR '07-'16			0.5			-1.4			-0.9
AAGR '12-'16			2.8			-4.7			-2.0
AAGR '18-'22			0.4			-1.2			-0.8
AAGR '18-'27			0.4			-0.8			-0.3

Note: Estimated-Actual data through February 2017

Table 11

Other Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	5,098	-	-	26,761	-	-	136	-	-
2008	5,019	-79	-1.5	26,514	-247	-0.9	133	-3	-2.5
2009	4,982	-37	-0.7	27,465	951	3.6	137	4	2.8
2010	4,966	-16	-0.3	27,693	228	0.8	138	1	0.5
2011	4,878	-88	-1.8	28,442	749	2.7	139	1	0.9
2012	4,940	61	1.3	29,287	845	3.0	145	6	4.3
2013	5,047	107	2.2	29,044	-244	-0.8	147	2	1.3
2014	5,308	261	5.2	28,449	-595	-2.0	151	4	3.0
2015	5,343	35	0.7	28,262	-187	-0.7	151	0	0.0
2016	5,384	42	0.8	28,162	-100	-0.4	152	1	0.4
Forecast									
2017	5,428	44	0.8	25,357	-2,805	-10.0	138	-14	-9.2
2018	5,455	27	0.5	24,887	-470	-1.9	136	-2	-1.4
2019	5,475	20	0.4	24,534	-353	-1.4	134	-1	-1.1
2020	5,497	22	0.4	24,099	-435	-1.8	132	-2	-1.4
2021	5,524	27	0.5	23,855	-243	-1.0	132	-1	-0.5
2022	5,553	29	0.5	23,708	-147	-0.6	132	0	-0.1
2023	5,579	25	0.5	23,596	-112	-0.5	132	0	0.0
2024	5,603	25	0.4	23,492	-104	-0.4	132	0	0.0
2025	5,628	24	0.4	23,379	-113	-0.5	132	0	-0.1
2026	5,650	23	0.4	23,303	-76	-0.3	132	0	0.1
2027	5,671	21	0.4	23,247	-56	-0.2	132	0	0.1
AAGR '07-'16			0.6			0.6			1.2
AAGR '12-'16			2.2			-1.0			1.2
AAGR '18-'22			0.4			-1.2			-0.8
AAGR '18-'27			0.4			-0.8			-0.3

Note: Estimated-Actual data through February 2017

Table 12

Total Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	897,413	-	-	18,328	-	-	16,448	-	-
2008	900,122	*2,709*	*0.3*	17,954	*-374*	*-2.0*	16,161	*-287*	*-1.7*
2009	901,121	*999*	*0.1*	18,018	*64*	*0.4*	16,236	*75*	*0.5*
2010	845,737	*-55,384*	*-6.1*	18,979	*961*	*5.3*	16,052	*-185*	*-1.1*
2011	849,061	*3,324*	*0.4*	17,594	*-1,386*	*-7.3*	14,938	*-1,113*	*-6.9*
2012	855,007	*5,946*	*0.7*	17,074	*-519*	*-3.0*	14,599	*-339*	*-2.3*
2013	864,980	*9,973*	*1.2*	16,956	*-119*	*-0.7*	14,666	*67*	*0.5*
2014	740,566	*-124,414*	*-14.4*	17,500	*545*	*3.2*	12,960	*-1,706*	*-11.6*
2015	751,848	*11,282*	*1.5*	17,788	*288*	*1.6*	13,374	*414*	*3.2*
2016	763,467	*11,620*	*1.5*	18,041	*252*	*1.4*	13,773	*399*	*3.0*
Forecast									
2017	774,126	*10,658*	*1.4*	17,473	*-568*	*-3.1*	13,526	*-248*	*-1.8*
2018	786,107	*11,982*	*1.5*	17,685	*212*	*1.2*	13,902	*376*	*2.8*
2019	798,584	*12,476*	*1.6*	17,678	*-7*	*0.0*	14,118	*215*	*1.5*
2020	811,265	*12,682*	*1.6*	17,549	*-130*	*-0.7*	14,237	*119*	*0.8*
2021	823,510	*12,245*	*1.5*	17,496	*-53*	*-0.3*	14,408	*172*	*1.2*
2022	835,550	*12,040*	*1.5*	17,506	*9*	*0.1*	14,627	*218*	*1.5*
2023	847,591	*12,041*	*1.4*	17,527	*22*	*0.1*	14,856	*229*	*1.6*
2024	859,439	*11,848*	*1.4*	17,538	*11*	*0.1*	15,073	*217*	*1.5*
2025	870,859	*11,420*	*1.3*	17,543	*5*	*0.0*	15,278	*205*	*1.4*
2026	881,761	*10,902*	*1.3*	17,569	*26*	*0.1*	15,492	*214*	*1.4*
2027	892,238	*10,477*	*1.2*	17,604	*35*	*0.2*	15,707	*215*	*1.4*
AAGR '07-'16			*-1.8*			*-0.2*			*-2.0*
AAGR '12-'16			*-2.8*			*1.4*			*-1.4*
AAGR '18-'22			*1.5*			*-0.3*			*1.3*
AAGR '18-'27			*1.4*			*-0.1*			*1.4*

Note: Estimated-Actual data through February 2017

Table 13

Total Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	700,930	-	-	18,432	-	-	12,920	-	-
2008	707,106	*6,176*	*0.9*	18,036	*-396*	*-2.1*	12,754	*-166*	*-1.3*
2009	708,548	*1,442*	*0.2*	18,041	*5*	*0.0*	12,783	*29*	*0.2*
2010	712,159	*3,610*	*0.5*	19,260	*1,220*	*6.8*	13,716	*934*	*7.3*
2011	715,486	*3,328*	*0.5*	17,631	*-1,629*	*-8.5*	12,615	*-1,101*	*-8.0*
2012	721,056	*5,570*	*0.8*	17,181	*-450*	*-2.6*	12,389	*-226*	*-1.8*
2013	729,961	*8,905*	*1.2*	17,078	*-103*	*-0.6*	12,466	*78*	*0.6*
2014	740,566	*10,605*	*1.5*	17,500	*422*	*2.5*	12,960	*494*	*4.0*
2015	751,848	*11,282*	*1.5*	17,788	*288*	*1.6*	13,374	*414*	*3.2*
2016	763,467	*11,620*	*1.5*	18,041	*252*	*1.4*	13,773	*399*	*3.0*
Forecast									
2017	774,126	*10,658*	*1.4*	17,473	*-568*	*-3.1*	13,526	*-248*	*-1.8*
2018	786,107	*11,982*	*1.5*	17,685	*212*	*1.2*	13,902	*376*	*2.8*
2019	798,584	*12,476*	*1.6*	17,678	*-7*	*0.0*	14,118	*215*	*1.5*
2020	811,265	*12,682*	*1.6*	17,549	*-130*	*-0.7*	14,237	*119*	*0.8*
2021	823,510	*12,245*	*1.5*	17,496	*-53*	*-0.3*	14,408	*172*	*1.2*
2022	835,550	*12,040*	*1.5*	17,506	*9*	*0.1*	14,627	*218*	*1.5*
2023	847,591	*12,041*	*1.4*	17,527	*22*	*0.1*	14,856	*229*	*1.6*
2024	859,439	*11,848*	*1.4*	17,538	*11*	*0.1*	15,073	*217*	*1.5*
2025	870,859	*11,420*	*1.3*	17,543	*5*	*0.0*	15,278	*205*	*1.4*
2026	881,761	*10,902*	*1.3*	17,569	*26*	*0.1*	15,492	*214*	*1.4*
2027	892,238	*10,477*	*1.2*	17,604	*35*	*0.2*	15,707	*215*	*1.4*
AAGR '07-'16			*1.0*			*-0.2*			*0.7*
AAGR '12-'16			*1.4*			*1.2*			*2.7*
AAGR '18-'22			*1.5*			*-0.3*			*1.3*
AAGR '18-'27			*1.4*			*-0.1*			*1.4*

Note: Estimated-Actual data through February 2017

Table 14
Annual Net Energy for Load and Seasonal Net Firm Demand

Net Energy for Load				Summer Net Firm Demand				Winter Net Firm Demand			
Year	Base (GWh)	Low (GWh)	High (GWh)	Year	Base (MW)	Low (MW)	High (MW)	Year	Base (MW)	Low (MW)	High (MW)
History				*History*				*History*			
2007	17,669	-	-	2007	3,839	-	-	2007/2008	4,221	-	-
2008	17,332	-	-	2008	3,630	-	-	2008/2009	4,738	-	-
2009	17,453	-	-	2009	3,824	-	-	2009/2010	5,047	-	-
2010	17,346	-	-	2010	3,548	-	-	2010/2011	4,315	-	-
2011	16,037	-	-	2011	3,653	-	-	2011/2012	3,918	-	-
2012	15,769	-	-	2012	3,428	-	-	2012/2013	3,707	-	-
2013	15,812	-	-	2013	3,566	-	-	2013/2014	3,240	-	-
2014	13,854	-	-	2014	3,088	-	-	2014/2015	3,593	-	-
2015	14,104	-	-	2015	3,021	-	-	2015/2016	3,307	-	-
2016	14,471	-	-	2016	3,243	-	-	2016/2017	3,018	-	-
Forecast				*Forecast*				*Forecast*			
2017	14,125~~14,165~~	13,648~~13,814~~	14,770 ~~15,192~~	2017	3,090	2,974	3,176	2017/2018	3,398	3,063	3,856
2018	14,601~~14,655~~	13,903~~13,954~~	15,577 ~~15,635~~	2018	3,140	3,025	3,228	2018/2019	3,466	3,131	3,922
2019	14,820~~14,875~~	14,124~~14,176~~	15,795 ~~15,854~~	2019	3,187	3,074	3,274	2019/2020	3,531	3,200	3,985
2020	14,948~~15,023~~	14,252~~14,325~~	15,918 ~~15,997~~	2020	3,238	3,124	3,325	2020/2021	3,588	3,258	4,038
2021	15,094~~15,125~~	14,403~~14,432~~	16,064 ~~16,096~~	2021	3,251	3,153	3,354	2021/2022	3,643	3,314	4,091
2022	15,306~~15,337~~	14,615~~14,644~~	16,273 ~~16,306~~	2022	3,297	3,198	3,399	2022/2023	3,699	3,371	4,145
2023	15,543~~15,574~~	14,851~~14,881~~	16,508 ~~16,541~~	2023	3,343	3,245	3,446	2023/2024	3,749	3,422	4,194
2024	15,774~~15,805~~	15,081~~15,112~~	16,737 ~~16,770~~	2024	3,388	3,290	3,489	2024/2025	3,802	3,477	4,244
2025	15,990~~16,022~~	15,297~~15,328~~	16,950 ~~16,984~~	2025	3,430	3,333	3,533	2025/2026	3,857	3,532	4,298
2026	16,216~~16,249~~	15,524~~15,556~~	17,175 ~~17,209~~	2026	3,474	3,375	3,577	2026/2027	3,909	3,586	4,351
2027	16,437~~16,470~~	15,745~~15,777~~	17,394 ~~17,429~~	2027	3,516	3,417	3,619	2027/2028	3,955	3,633	4,397
AAGR '07-'16	*-2.2*	*-*	*-*	*AAGR '07-'16*	*-1.9*	*-*	*-*	*AAGR '08-'17*	*-3.7*	*-*	*-*
AAGR '12-'16	*-2.1*	*-*	*-*	*AAGR '12-'16*	*-1.4*	*-*	*-*	*AAGR '13-'17*	*-5.0*	*-*	*-*
AAGR '18-'22	*1.2~~1.1~~*	*1.3~~1.2~~*	*1.1*	*AAGR '18-'22*	*1.2*	*1.4*	*1.3*	*AAGR '18-'22*	*1.8*	*2.0*	*1.5*
AAGR '18-'27	*1.3*	*1.4*	*1.2*	*AAGR '18-'27*	*1.3*	*1.4*	*1.3*	*AAGR '18-'27*	*1.6*	*1.8*	*1.4*

Table 15
Annual Net Energy for Load and Seasonal Net Firm Demand
Excluding Lee County Electric Cooperative

Net Energy for Load				Summer Net Firm Demand				Winter Net Firm Demand			
Year	Base (GWh)	Low (GWh)	High (GWh)	Year	Base (MW)	Low (MW)	High (MW)	Year	Base (MW)	Low (MW)	High (MW)
History				*History*				*History*			
2007	13,729	-	-	2007	3,060	-	-	2007/2008	3,343	-	-
2008	13,567	-	-	2008	2,915	-	-	2008/2009	3,817	-	-
2009	13,659	-	-	2009	3,064	-	-	2009/2010	4,224	-	-
2010	14,658	-	-	2010	3,011	-	-	2010/2011	3,685	-	-
2011	13,502	-	-	2011	3,121	-	-	2011/2012	3,383	-	-
2012	13,256	-	-	2012	2,890	-	-	2012/2013	3,229	-	-
2013	13,302	-	-	2013	3,012	-	-	2013/2014	3,240	-	-
2014	13,854	-	-	2014	3,088	-	-	2014/2015	3,593	-	-
2015	14,104	-	-	2015	3,021	-	-	2015/2016	3,307	-	-
2016	14,471	-	-	2016	3,243	-	-	2016/2017	3,018	-	-
Forecast				*Forecast*				*Forecast*			
2017	14,125~~14,165~~	13,648~~13,814~~	14,770 ~~15,192~~	2017	3,090	2,974	3,176	2017/2018	3,398	3,063	3,856
2018	14,601~~14,655~~	13,903~~13,954~~	15,577 ~~15,635~~	2018	3,140	3,025	3,228	2018/2019	3,466	3,131	3,922
2019	14,820~~14,875~~	14,124~~14,176~~	15,795 ~~15,854~~	2019	3,187	3,074	3,274	2019/2020	3,531	3,200	3,985
2020	14,948~~15,023~~	14,252~~14,325~~	15,918 ~~15,997~~	2020	3,238	3,124	3,325	2020/2021	3,588	3,258	4,038
2021	15,094~~15,125~~	14,403~~14,432~~	16,064 ~~16,096~~	2021	3,251	3,153	3,354	2021/2022	3,643	3,314	4,091
2022	15,306~~15,337~~	14,615~~14,644~~	16,273 ~~16,306~~	2022	3,297	3,198	3,399	2022/2023	3,699	3,371	4,145
2023	15,543~~15,574~~	14,851~~14,881~~	16,508 ~~16,541~~	2023	3,343	3,245	3,446	2023/2024	3,749	3,422	4,194
2024	15,774~~15,805~~	15,081~~15,112~~	16,737 ~~16,770~~	2024	3,388	3,290	3,489	2024/2025	3,802	3,477	4,244
2025	15,990~~16,022~~	15,297~~15,328~~	16,950 ~~16,984~~	2025	3,430	3,333	3,533	2025/2026	3,857	3,532	4,298
2026	16,216~~16,249~~	15,524~~15,556~~	17,175 ~~17,209~~	2026	3,474	3,375	3,577	2026/2027	3,909	3,586	4,351
2027	16,437~~16,470~~	15,745~~15,777~~	17,394 ~~17,429~~	2027	3,516	3,417	3,619	2027/2028	3,955	3,633	4,397
AAGR '07-'16	*0.6*	*-*	*-*	*AAGR '07-'16*	*0.6*	*-*	*-*	*AAGR '08-'17*	*-1.1*	*-*	*-*
AAGR '12-'16	*2.2*	*-*	*-*	*AAGR '12-'16*	*2.9*	*-*	*-*	*AAGR '13-'17*	*-1.7*	*-*	*-*
AAGR '18-'22	*1.2~~1.1~~*	*1.3~~1.2~~*	*1.1*	*AAGR '18-'22*	*1.2*	*1.4*	*1.3*	*AAGR '18-'22*	*1.8*	*2.0*	*1.5*
AAGR '18-'27	*1.3*	*1.4*	*1.2*	*AAGR '18-'27*	*1.3*	*1.4*	*1.3*	*AAGR '18-'27*	*1.6*	*1.8*	*1.4*

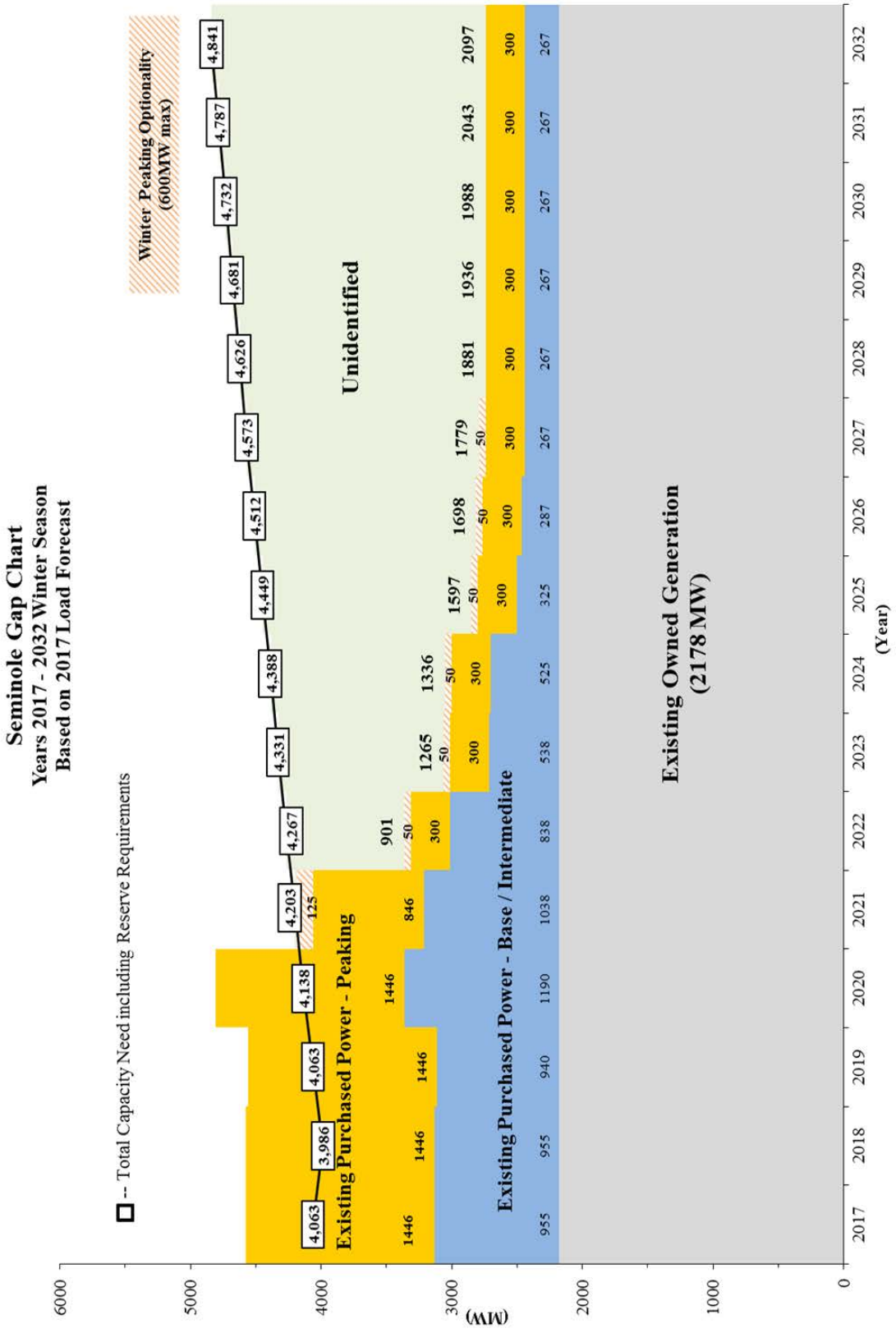
5.3 Seminole's Reliability Criteria

The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and its reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages; and to account for load forecast uncertainty. Seminole's reliability criteria include a Reserve Margin criterion of 15 percent and a Loss of Load Probability ("LOLP") criterion of one day in 10 years. The Reserve Margin is a percentage of the load forecast peak demand and is the additional amount of capacity that a utility maintains above the load forecast peak demand. The Reserve Margin considers only the peak demand versus the amount of generation resources, but the LOLP criterion takes into account load shape, unit sizes, unit availability, and capacity mix when calculating the probability of a utility not adequately meeting load. These reliability criteria help to ensure that Seminole has adequate generating capacity to provide reliable service to its Members and to limit Seminole's emergency purchases from interconnected, neighboring systems.

5.4 Seminole's Capacity Needs

By the end of 2021, Seminole will need 901 MW of generation to meet its Members' energy needs along with its Reserve Margin requirements. That need will grow to 1,265 MW by the end of 2022. Seminole's future capacity need results primarily from the expiration of PPAs, starting with the expiration of 150 MW from DEF on December 31, 2020, followed by expiration of 200 MW from FPL on May 31, 2021, and another for Southern Company's Oleander plant, which includes capacity ratings of 550 MW winter and 460 MW summer. In total, Seminole will lose 900 MW of purchased power resources by the end of 2021, followed by the loss of an additional 300 MW PPA with DEF in 2022. Figure 6 is a "gap chart" showing Seminole's projected winter season need through 2032.

Figure 6 "Gap Chart" summarizing Seminole's Projected Need



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6.0 EVALUATION OF MAJOR GENERATING ALTERNATIVES

6.1 Overview of Evaluation Process

Seminole conducted a multi-stage process for evaluating resource alternatives to meet its projected capacity need. The process began over two years ago when Seminole first determined which self-build alternatives would be evaluated. Seminole then issued an RFP into the market for firm capacity and received a robust response. Seminole then performed economic and risk evaluations on all available alternatives and developed portfolios of generation resources to fulfill Seminole's need. The recommended portfolio, which includes the SCCF and SHCCF, was submitted to Seminole's Board of Trustees and was unanimously approved on September 27, 2017.

6.2 Self-Build Alternatives Considered

6.2.1 Technology Assessment

Due to the high costs and regulatory uncertainties associated with new nuclear and coal-fired generation, Seminole limited its analysis of self-build alternatives to natural gas-fired generation. Seminole retained Black and Veatch, a global engineering, procurement and construction company, to help evaluate numerous power generation technologies as potential future resources prior to selecting the advanced class gas turbine technologies incorporated in the SCCF. Combined cycle technology was selected because the high fuel efficiency and flexible dispatch capability offered by these systems will allow the SCCF to match varying system load at a low cost and with limited environmental impact. Seminole selected state-of-the-art "advanced class" gas turbine technology coupled with flexible operation heat recovery steam generators and an associated steam turbine as the most cost-effective risk-managed self-build option. Seminole initiated a power island equipment purchase bidding process followed by an Engineer, Procure, Construct ("EPC") services bidding process to develop accurate self-build cost estimates which would then compete with market alternatives.

Seminole evaluated several different technologies from three different vendors, General Electric, Mitsubishi Hitachi, and Siemens. Upon completion of the initial screening, Seminole issued an RFP in February 2016 to three vendors; two of which, General Electric and Mitsubishi, responded with compliant bids. Both of these vendors submitted two proposals; one for a 1x1 unit and the second for a 2x1 unit. All four units were evaluated along with the market alternatives**.** Seminole ultimately determined that the GE technology was the most economic option.

6.2.2 Site Assessment

In order to fully evaluate potential self-build site location options, Seminole retained a third party environmental consultant to assess the environmental licensing considerations associated with locating new generation facilities at two potential sites owned by Seminole: the site adjacent to SGS in Putnam County and another 586-acre site in Gilchrist County. Informed by the results of that study and subsequent information, Seminole retained Black & Veatch, a global engineering firm, to evaluate the SGS site versus the Gilchrist site using a comparative analysis that utilized the following intangible criteria:

- Land Use/Ownership
- Site Development
- Electrical Transmission
- Fuel Supply
- Water Supply
- Waste Water
- Environmental Assessment
- Transportation
- Technology Selection
- Schedule

Based on the comparative analysis, the SGS site scored substantially better than the Gilchrist site for a combined cycle facility. In particular, the Gilchrist site posed

significant issues relative to water availability and wastewater discharge options. In addition, the SGS site is a brownfield site with capability of utilizing existing water intake, water discharge, and electrical transmission infrastructure. Overall, the SGS site has significant economic and strategic advantages for siting a combined cycle facility.

6.3 Purchase Power Alternatives Considered

6.3.1 The Requests for Proposals ("RFP")

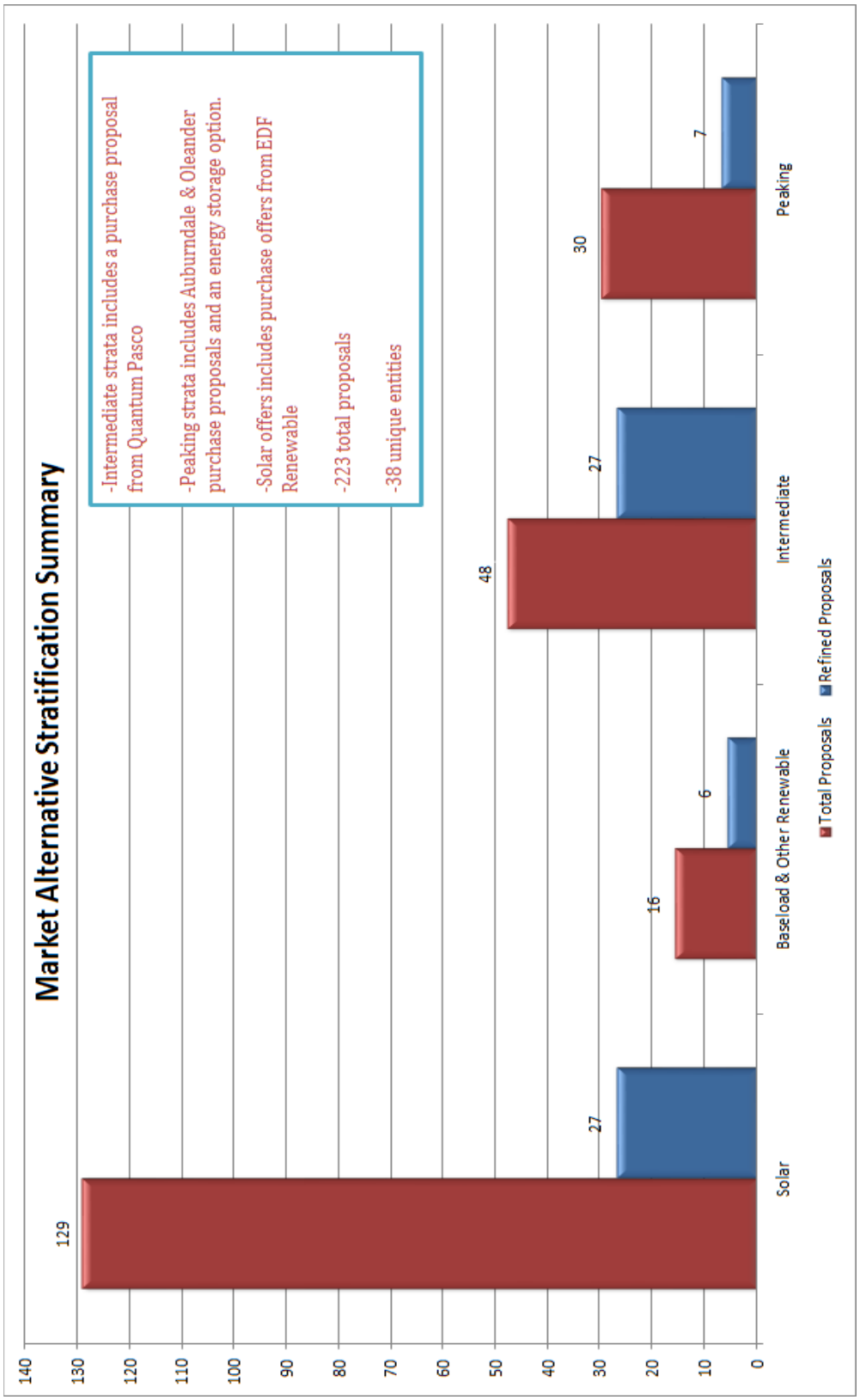
Seminole identified market alternatives by issuing an RFP in March 2016 for firm capacity up to 1,000 MW beginning as early as June 1, 2021. The RFP stated that the need for 600 MW of capacity would start in June 2021, with total needs increasing to 1,000 MW by June 2022. Seminole encouraged proposals of base, intermediate, and/or peaking capacity, as well as renewable resources. The RFP also stated that proposals providing demand side options would be considered, although no such proposals were received. A copy of the RFP is provided as Appendix A.

6.3.2 Proposals Received & Initial Economic Evaluation

In May 2016, Seminole received proposals for purchased power alternatives in response to its RFP. The response was robust, with Seminole receiving a total of 223 proposals from 38 counterparties. The proposals included offers providing generation from various renewable sources including solar, wind and energy storage; existing and new gas-fired facilities; and system offers for both intermediate and peaking generation.

Following receipt of the bids, Seminole reviewed the proposals for completeness along with technical and operational viability. Seminole also performed an initial economic screening using bus bar cost analysis (i.e., the total cost to operate a resource on a $/MWh basis) of all alternatives within a stratification (baseload and other renewables, intermediate, peaking or solar). Those with significantly higher operating cost based on a typical capacity factor within a stratification were eliminated. Figure 7 provides a summary of proposals received in response to the RFP, as well as the set of "refined proposals" that Seminole received after the intital economic screening.

Figure 7 Summary of Proposals Received in Response to RFP



6.4 Economic Evaluation of Generation Alternatives

6.4.1 Methodology

After the initial screening of proposals, Seminole evaluated all remaining alternatives, including self-build options, using System Optimizer. System Optimizer is an industry-recognized utility model developed by ABB and used to develop an optimal resource mix to satisfy future needs. The model simulates how each potential and existing resource will be used to serve the forecasted peak demand and energy requirements in the load forecast. System Optimizer's inputs include the demand and energy forecast, Reserve Margin requirements, fuel price forecast, plus the individual resource's cost and performance characteristics such as fixed cost, variable cost, heat rates, forced outage rates, and maintenance schedules.

Seminole ran multiple iterations through System Optimizer. The first iteration was used to develop a portfolio for Seminole's need starting in winter of 2022 with all resources available ("SGS 2x1 Portfolio"). Seminole also developed a limited build portfolio which allowed one 1x1 combined cycle unit to be built ("Limited Build Risk: Shady Hills Portfolio") as well as a "no build" portfolio consisting of only PPAs ("All PPA Portfolio"). Because the status of the Clean Power Plan and long-term economics for coal-fired generation were uncertain, Seminole also developed a portfolio taking into account the removal of one coal unit from service ("CPP/CC Portfolio").

Once the optimal portfolio candidates were identified via System Optimizer, Seminole used Planning and Risk ("PaR"), another industry-recognized utility model from ABB, to further evaluate the production cost. PaR is a detailed production cost model, which commits resources in each hour over the study period based on costs and operational constraints. The operational constraints are similar to those in System Optimizer but more extensive, including such constraints as minimum up and down times, must run requirements, and natural gas pipeline flow limits. The production costs from PaR along with any capital and transmission cost increases for network upgrades are loaded into the corporate financial model to develop the annual revenue requirements.

6.4.2 Economic Parameters

The primary drivers for the economic analysis among generation alternatives are plant fixed cost and fuel cost. Seminole's relatively low financing costs help mitigate the ultimate cost of self-build projects. Differences between the capital costs and fuel costs of competing technologies are the most significant factors affecting the economic comparisons among Seminole's generation altematives. Seminole's cost of debt projections for self-build alternatives assumed a financing rate of 5.96%.

The discount rate, which is used for present worth calculations, is equal to the average annual long term cost of debt. The construction cost of self-build alternatives includes a rate equal to the average annual long term debt rate on funds used during the construction period.

6.4.3 Fuel Price Forecast

Seminole's fuel price forecast is derived from a combination of published market indices, independent price forecasts, and escalators where necessary to extend the price forecast beyond the horizon of available values. For natural gas, Seminole uses the NYMEX futures forward market prices along with projected escalation of gas prices as provided by the Energy Information Administration ("EIA"). Seminole's coal price forecast is based on price projections obtained from Energy Research Company, LLC. Seminole's fuel oil price forecast is based on EIA's Annual Energy Outlook for distillate fuel oil. These sources of forward energy prices are commonly accepted in the utility industry.

The fuel price forecasts utilized in the original and updated economic analyses discussed below, including the alternative forecasts for natural gas, are summarized in Tables 16 and 17. Unless a firm fuel cost was included in an RFP proposal, Seminole used its fuel price forecast across all self-build and purchased power alternatives to ensure fairness in the evaluation.

Table 16 - Fuel Price Forecast

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.52	$4.34	$2.87	$3.53	$14.64
2018	$3.20	$4.43	$2.32	$3.59	$16.55
2019	$3.04	$4.30	$2.15	$3.41	$17.59
2020	$3.04	$4.34	$2.13	$3.53	$18.08
2021	$3.04	$4.43	$2.09	$3.62	$18.43
2022	$3.06	$4.53	$2.06	$3.70	$18.69
2023	$3.14	$4.71	$2.10	$3.78	$19.02
2024	$3.27	$4.94	$2.17	$3.86	$19.34
2025	$3.42	$5.25	$2.23	$3.95	$19.81
2026	$3.56	$5.55	$2.28	$4.03	$20.17
2027	$3.71	$5.86	$2.35	$4.13	$20.38
2028	$3.86	$6.16	$2.41	$4.22	$20.39
2029	$4.01	$6.48	$2.48	$4.32	$20.65
2030	$4.13	$6.74	$2.54	$4.42	$21.08
2031	$4.31	$7.07	$2.62	$4.52	$21.40
2032	$4.40	$7.27	$2.66	$4.62	$21.87
2033	$4.42	$7.35	$2.66	$4.73	$21.82
2034	$4.48	$7.49	$2.68	$4.83	$22.14
2035	$4.64	$7.79	$2.77	$4.94	$22.31
2036	$4.71	$7.93	$2.80	$5.05	$22.85
2037	$4.80	$8.10	$2.84	$5.17	$22.93
2038	$4.87	$8.24	$2.88	$5.29	$23.05
2039	$4.99	$8.46	$2.95	$5.41	$23.40
2040	$5.08	$8.60	$3.00	$5.53	$23.59
2041	$5.20	$8.81	$3.07	$5.66	$23.65
2042	$5.37	$9.10	$3.17	$5.78	$23.69
2043	$5.62	$9.51	$3.31	$5.92	$23.76
2044	$5.79	$9.80	$3.42	$6.05	$23.86
2045	$5.99	$10.13	$3.54	$6.19	$23.97
2046	$6.19	$10.45	$3.67	$6.33	$24.15
2047	$6.42	$10.81	$3.81	$6.47	$24.45
2048	$6.70	$11.26	$3.98	$6.61	$24.49
2049	$6.91	$11.59	$4.12	$6.76	$24.69
2050	$7.16	$11.97	$4.28	$6.92	$24.96
2051	$7.42	$12.37	$4.44	$7.07	$25.52

Table 17 - Fuel Price Forecast – Updated

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.32	$3.63	$2.90	$3.45	$14.64
2018	$3.20	$4.28	$3.06	$3.52	$16.55
2019	$2.94	$4.11	$2.39	$3.13	$17.59
2020	$2.92	$4.15	$2.11	$3.28	$18.08
2021	$2.94	$4.25	$2.06	$3.36	$18.43
2022	$3.03	$4.38	$2.04	$3.42	$18.69
2023	$3.09	$4.43	$2.10	$3.50	$19.02
2024	$3.16	$4.48	$2.15	$3.57	$19.34
2025	$3.24	$4.67	$2.23	$3.65	$19.81
2026	$3.33	$4.87	$2.25	$3.74	$20.17
2027	$3.42	$5.06	$2.28	$3.82	$20.38
2028	$3.51	$5.25	$2.31	$3.91	$20.39
2029	$3.60	$5.44	$2.34	$4.00	$20.65
2030	$3.71	$5.65	$2.38	$4.09	$21.08
2031	$3.86	$5.93	$2.43	$4.19	$21.40
2032	$3.94	$6.10	$2.52	$4.28	$21.87
2033	$3.96	$6.16	$2.55	$4.38	$21.82
2034	$4.02	$6.27	$2.55	$4.47	$22.14
2035	$4.16	$6.52	$2.58	$4.58	$22.31
2036	$4.23	$6.64	$2.66	$4.68	$22.85
2037	$4.30	$6.78	$2.69	$4.79	$22.93
2038	$4.37	$6.90	$2.73	$4.89	$23.05
2039	$4.48	$7.08	$2.77	$5.01	$23.40
2040	$4.55	$7.20	$2.83	$5.12	$23.59
2041	$4.66	$7.37	$2.88	$5.24	$23.65
2042	$4.84	$7.66	$2.94	$5.36	$23.69
2043	$5.06	$8.01	$3.06	$5.48	$23.76
2044	$5.22	$8.25	$3.20	$5.60	$23.86
2045	$5.40	$8.53	$3.30	$5.73	$23.97
2046	$5.58	$8.81	$3.42	$5.86	$24.15
2047	$5.78	$9.11	$3.54	$5.99	$24.45
2048	$6.04	$9.49	$3.67	$6.12	$24.49
2049	$6.22	$9.77	$3.84	$6.26	$24.69
2050	$6.45	$10.10	$3.97	$6.40	$24.96
2051	$6.68	$10.44	$4.12	$6.55	$25.52

6.4.4 Results

Ultimately, the net present value ("NPV") of the revenue requirements is the basis for comparing different portfolios in the economic evaluation. The CPP/CC Portfolio, which includes the SCCF, the SHCCF, and the removal from service of one SGS coal unit, was the least cost portfolio. The next portfolio in NPV revenue requirement terms was approximately $355 million more expensive over the study period. Figure 8 summarizes the results of Seminole's economic analyses of the various alternative portfolios.

Figure 8 Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	12,381	12,266	12,196	12,096
NPV @ 6.0%	9,008	8,936	8,885	8,797
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	61,264	60,244	62,185	61,695
NPV @ 6.0%	22,196	21,841	22,370	22,198

Figures 9 and 10 are "gap charts" showing how the selected portfolio would fill Seminole's projected need during the winter and summer seasons, respectively (the SHCCF is included within "new purchased power agreements").

Figure 9 "Gap Chart" Showing Effect of Selected Portfolio (Winter)

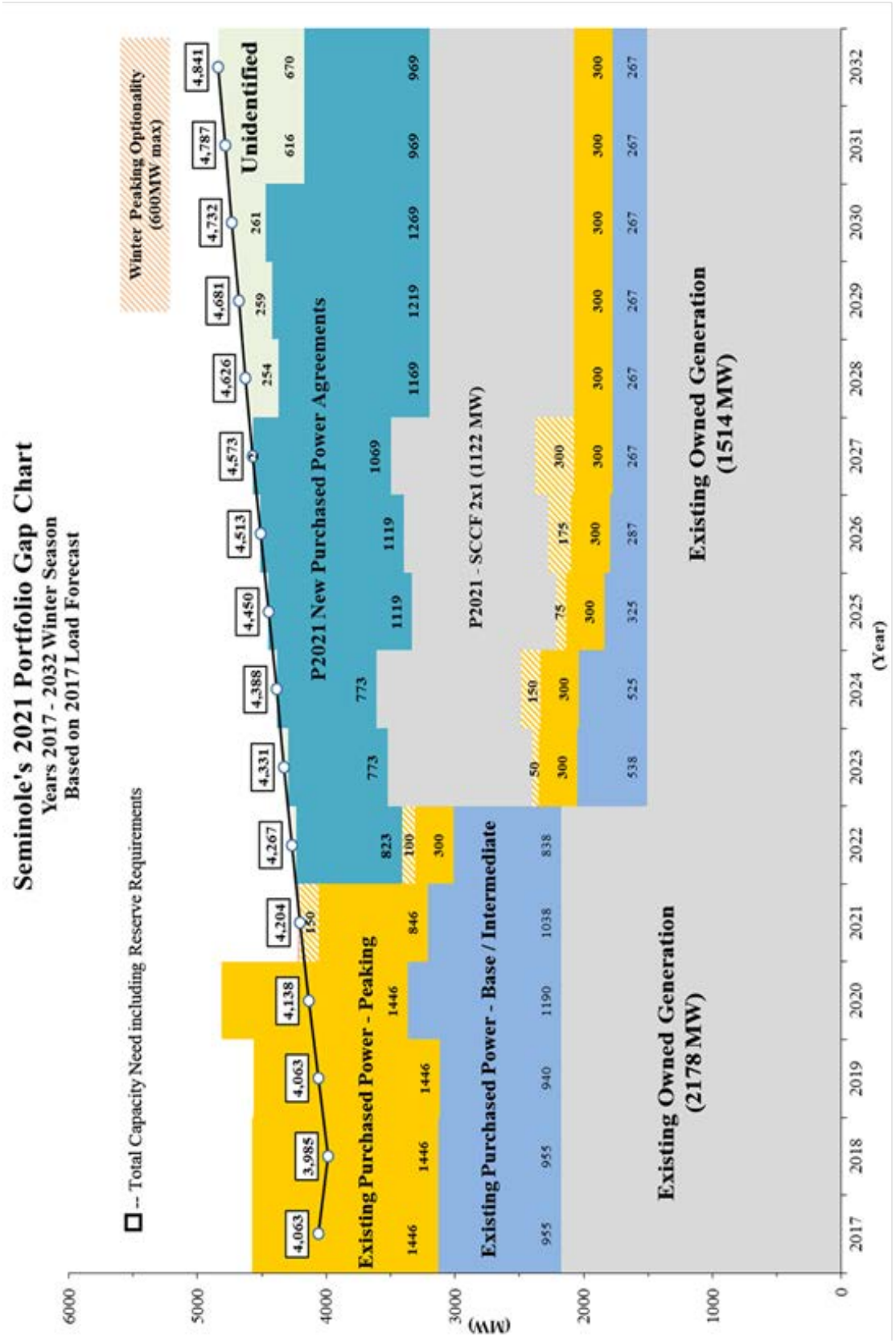
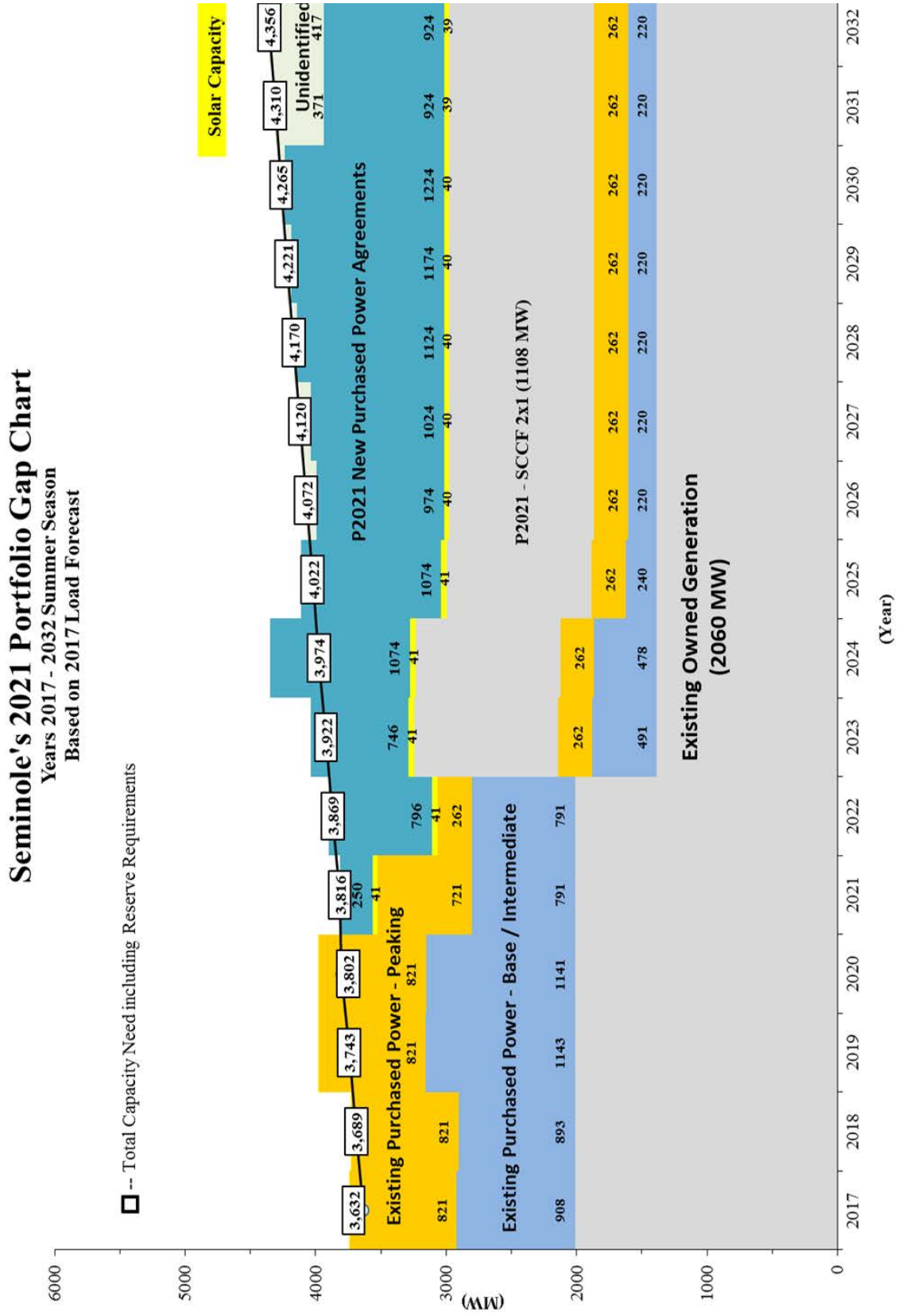


Figure 10 "Gap Chart" Showing Effect of Selected Portfolio (Summer)



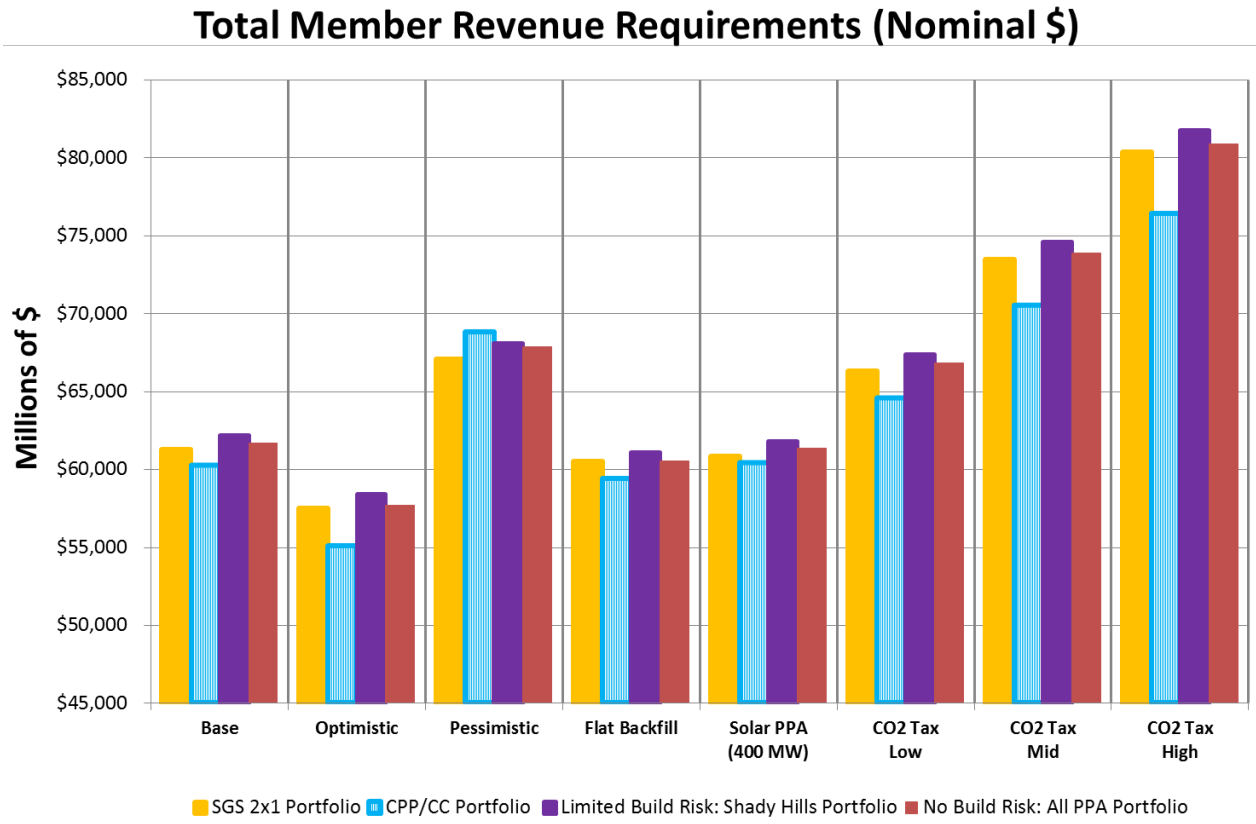
6.5 Sensitivity Analyses

Seminole also performed multiple sensitivity analyses to assess various uncertainties. The senstivity analyses include the following scenarios:

- **Optimistic (**High load growth with low gas prices)
- **Pessimistic** (Low load growth with high gas prices)
- **Flat Backfill** (No escalation of generic unit capacity costs)
- **Solar PPA 400 MW** (400 MW of additional solar PPA)
- **Various Carbon Tax** (based on Minnesota PSC Carbon tax assumptions)
    - Low – starting at $9.00/ton in 2019 and escalating
    - Mid – starting at $21.50/ton in 2019 and escalating
    - High – starting at $43.00/ton in 2019 and escalating

The results of these sensitivity analyses, which are summarized in Figure 11, support the conclusion that the CPP/CC Portfolio provides the most cost effective solution for Seminole's need.

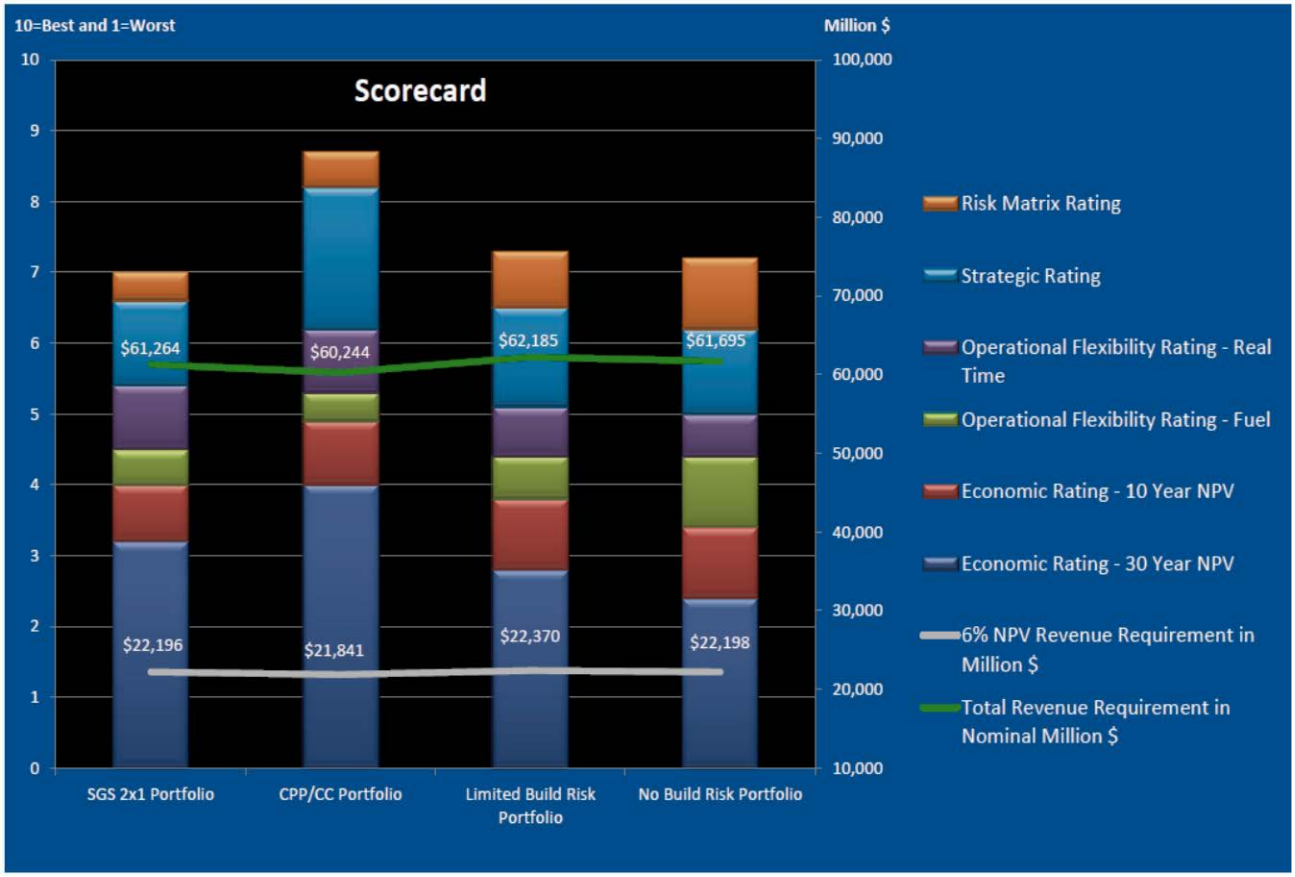
Figure 11 Results of Sensitivity Analyses



6.6 Consideration of Economic and Non-Economic Attributes

Once the production cost modeling was completed, Seminole's staff performed risk analysis for both individual alternatives and each of the remaining portfolios. Seminole produced scorecards for each portfolio which took into account a weighted risk rating, a strategic rating, operational flexibility ratings for fuel, real time operational flexibility, and an economic rating for a short-term (10 year) and long-term (30 year) net present value revenue requirement. These portfolio scorecard assessments are reflected in Figure 12.

Figure 12 Portfolio Scorecard Assessment



In addition to cost-effectiveness and risk impacts, Seminole considered the value of having optionality. One of the new PPAs included in the CPP/CC Portfolio provides Seminole with the advantage of optionality, giving Seminole the flexibility to modify its commitment up or down with relatively short notice. Given the vulnerability of load forecasts, the ability to modify resource commitments will give Seminole a hedge against economic acceleration/downturns or faster/slower load growth rates.

Seminole also considered the utilization of solar. However, Seminole is a winter-peaking utility that experiences its highest end-use demand on winter nights when solar energy is not a viable capacity source to offset peak demand. Nevertheless, in recognition of the energy value of solar, Seminole included 40 MW of new solar in the CPP/CC Portfolio.

Seminole also considered the potential impact of the resource plan on fuel diversity and supply reliability. The SCCF and SHCCF will be solely fueled by natural gas, but they will replace expiring purchased power resources that were also primarily natural gas-fired. Seminole's decision to maintain the operation of one SGS coal-fired generating unit will provide continued diversification in Seminole's fuel portfolio. Further, Seminole is implementing a natural gas transportation plan that includes contracts with four different counterparties for a variety of solutions to enhance the diversification and reliability of its delivered gas supply. For these reasons, the selected portfolio is not expected to significantly impact fuel diversity or supply reliability.

6.7 Selection of SCCF and SHCCF

Based on the analyses described above, Seminole determined that the most cost effective, risk-managed resource plan to meet its Members' future needs is a mix of resources consisting of existing generation resources, long-term PPAs, and the construction of two natural gas-fired combined cycle facilities. The first combined cycle unit would be a 573 MW (winter) one-on-one unit to be constructed, owned and operated by SHEC at the existing Shady Hills power plant site in Pasco County pursuant to a tolling agreement with Seminole. The second combined cycle plant would be a self-build 1,050 MW (nominal) two-on-one combined cycle plant adjacent to the existing SGS plant, along with the removal from service of one of the two existing 664 MW SGS coal units.

6.8 Updated Economic Assessment

Since the Board of Trustees' initial approval of the selected resource plan, Seminole conducted a present worth revenue requirements comparison for all four portfolios with the 2018 Budget assumptions approved in October 2017. While the total dollar values changed, the rankings between the portfolios did not. The CPP/CC Portfolio, which includes the SCCF and SHCCF along with the removal from service of one of the two existing 664 MW SGS coal units, remained the least cost portfolio. The

next portfolio in NPV revenue requirement terms was approximately $363 million more expensive over the study period. Figure 13 shows the differential between the portfolios.

Figure 13 Summary of Updated Economic Analysis

Portfolio Summaries Revised Economic Analysis Results (millions of $)				
	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	11,571
NPV @ 6.0%	8,641	8,568	8,549	8,432
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	56,465	58,312	58,289
NPV @ 6.0%	20,981	20,618	21,120	21,006

7.0 EVALUATION OF NON-GENERATING ALTERNATIVES

7.1 Current Conservation & Demand-Side Management Efforts

As a wholesale supplier of electric energy to its Member Cooperatives, Seminole is not directly responsible for DSM programs. However, Seminole's wholesale rate structure provides Members price signals that reflect Seminole's cost of supplying power in aggregate. Under this rate structure, Seminole's demand charge to each of its Members is applied to each Member's demand at the time of Seminole's peak. This encourages Members to concentrate their load management efforts on controlling Seminole's overall system peak rather than their separate peaks. In addition, Seminole's wholesale rate to its Members include time-of-use fuel charges to reflect the differences in fuel costs incurred by Seminole to serve its Members during the peak and off-peak periods. Each Member may use these price signals to evaluate the cost-effectiveness of DSM and conservation measures for its own circumstances. To ensure Members have the opportunity to achieve maximum load-management benefit, Seminole's system operators develop and implement a coordinated load management demand reduction strategy in real time to notify Members when Seminole's monthly billing peak is expected to occur.

Seminole also assists its Members in evaluating and implementing DSM measures. In 2008, Seminole and its Members jointly formed an Energy Efficiency Working Group to coordinate and further-promote energy conservation and efficiency initiatives. The function of this group is to promote conservation, efficiency and DSM programs through the sharing of information, member-consumer education, and joint assessment of energy efficiency technologies. In addition, Seminole has sponsored its own conservation/efficiency initiatives, which included giving light emitting diode light bulbs ("LEDs") to member-consumers during Member meetings and administering an LED bulk purchase program for Members. Seminole provides Members with materials that can be distributed to end-use member-consumers including educational brochures, manufactured housing weatherization brochures, videos on energy efficiency home

auditing, and a video on Cooperative Solar. Seminole also remains active in upgrading utility system efficiency at administration and generation facilities.

Because Seminole and its Members are not subject to the requirements of the Florida Energy Efficiency and Conservation Act ("FEECA"), they do not have Commission-approved DSM goals, programs or plans. However, Seminole's Members participate in a variety of utility system efficiency and DSM programs, including distribution system voltage reduction ("VR"), load management distributed generation and interruptible rate programs which help reduce Seminole's load during peak periods. Seminole's Members also offer a variety of programs and services to end-use member-consumers in order to promote energy conservation and cost savings. Member programs include:

- **Distribution System Voltage Reduction (VR):** Coordinated load management-demand reduction program where Member system operators lower voltage during critical peak billing periods, within allowable thresholds, on distribution feeders to reduce demand behind end-use meters during critical peak billing periods.
- **Commercial Coincident Peak Power (CPP) Rates:** Coordinated load management-demand reduction program where enrolled commercial and industrial member-consumers are signaled to shed load during critical peak billing periods.
- **Commercial Interruptible Rates:** Direct load control program where Seminole or the Member interrupts electrical service to enrolled commercial member-consumers during extreme peak demand, capacity shortage or emergency conditions.
- **Commercial Customer Load Generation:** Standby peak-shaving generators which Seminole and its Members may dispatch for purpose of load management and enhanced reliability. Members with standby generators under this program receive a billing credit.

- **Time-of-Use (TOU) Rates**: Residential, commercial, or industrial rates that encourage member-consumers to reduce power use during on-peak hours through price signals.
- **Residential Pre-Pay:** Residential member-consumers pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- **LED/CFL Efficient Bulb Giveaway:** This program provides participating end-use member-consumers with free energy-efficient 10 Watt (W) LED or 13W compact fluorescent light ("CFL") bulbs to replace their existing 60W incandescent bulbs.
- **LED Outdoor and Street Lighting:** Replacement of Member-owned outdoor and street lighting with lower wattage LEDs.
- **Residential Energy Smart Rebates:** A rebate is given to residential member-consumers to upgrade to more efficient equipment and/or improve the building envelope. Rebate opportunities include: air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation – batt or spray foam – and window film.
- **Energy Audits:** On-site energy audit program for residential, commercial and industrial member-consumers.

Table 18 shows the specific conservation and demand-side offerings of each of Seminole's Members.

Table 18 Conservation & Demand-Side Offerings of Seminole Members

	Distribution System Voltage Reduction	Commercial Coincident Peak Power Rates	Commercial Interruptible Rate	Commercial Customer Load Generation	TOU Rates	Residential Pre-Pay	Lighting Conservation	Energy Rebates	Energy Audits
Central Florida	X			X	X	X	X		X
Clay	X		X	X	X		X	X	X
Glades				X	X		X		X
Peace River	X			X	X		X		X
SECO Energy	X	X	X	X	X	X	X		X
Suwannee Valley	X		X	X	X	X	X		X
Talquin	X			X			X		X
Tri-County		X				X	X		X
Withlacoochee River	X			X		X	X		X

In 2016, Seminole engaged Advanced Energy and Tierra Resource Consultants (AE/Tierra), an energy and natural resource consulting firm, to help quantify the energy efficiency and DSM savings achieved by Seminole and its Members. As shown in Table 19, AE/Tierra estimated that Seminole and its Members are achieving approximately 12,353 MWh in annual savings and approximately 85 MW in peak savings.

Table 19 Annual Energy Savings

Program Type	Annual MWh Savings	Annual kW Savings
Residential Pre-Paid Energy Program	7,172	201
Bulb Giveaways (LED & CFL)	287	33
TOU/CPP Rates	170	18,258
Utility System Savings (inlcuding VR)	3,475	66,298
Energy Smart Rebates	946	236
LED Outdoor Lights/Street lighting	303	0
TOTAL	**12,353**	**85,026**

7.2 Potential for Conservation and DSM Savings to Mitigate Need

In order to help Seminole evaluate whether DSM measures may be reasonably available to mitigate the projected need, Seminole also engaged AE/Tierra to identify potential new programs and to evaluate their cost-effectiveness. None of the additional measures evaluated by AE/Tierra satsified the Rate Impact Measure ("RIM") test traditionally relied upon by the Commission in evaluating the cost-effectiveness of DSM measures. Nevertheless, Seminole is planning to implement one of the identified measures (Smart Thermostat) of particular interest to Members. Seminole also is committed to working with its Members to implement recommendations made by AE/Tierra to help improve program tracking and increase future savings by enhancing current efforts and adding new measures to existing programs when appropriate.

The DSM and conservation savings actually achieved by Seminole's Members are reflected in Seminole's load forecast, yet Seminole will still need 901 MW of additional capacity beginning in 2021. To put this in perspective, in Order No. PSC-14-0696-FOF-EU, the Commission established DSM goals for the utilites subject to FEECA. Based on those goals, the largest electric utility in the State of Florida, FPL, is expected to achieve Commission-Approved DSM Goals of approximately 526 MW in summer demand reduction and 324 MW in winter demand reduction, over the course of a ten-year period from 2015 through 2024. As an additional point of comparison, TECO, which is comparable in size to Seminole in terms of consumers and annual peak demand, is expected to achieve Commission-Approved DSM Goals of approximately 56 MW in summer demand reduction and 78 MW in winter demand reduction, over the course of the same ten-year period. Based on these Commission-approved DSM goals even large, vertically integrated utilities comparable to and larger than Seminole's size with centralized staff and resources to offer DSM programs directly to their customers cannot cost-effectively achieve 901 MW peak demand reductions through DSM and conservation programs over the course of the next four years.

Even if additional DSM savings were theoretically achievable, the selected CPP/CC Portfolio would still be Seminole's most cost-effective alternative based on the results of Seminole's "low load" senstivity analysis. The low load forecast sensitivity is intended to reflect reductions in loads due to a combination of potential factors as compared to the base case, including but not limited to changes in economic conditions, decreased customer counts, mild weather, increased utilization of customer-owned distributed generation resources, and increased energy efficiency. The low load forecast sensitivity may be considered as a proxy for Seminole's Members' member-consumers achieving increased levels of demand and energy reductions due to DSM or conservation as compared to the base case load forecast. Because the CPP/CC Portfolio is the most cost-effective alternative even considering the low load forecast, there is no reasonable basis to conclude that DSM or conservation measures are reasonably available to Seminole or its Members that would mitigate the need for SCCF and SHCCF.

8.0 ADVERSE CONSEQUENCES OF DENIAL

Non-approval would mean that Seminole's Members and the Members' retail member-consumers would be denied the most cost-effective, risk-managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021. While additional off-system purchases could perhaps be made to fulfill Member power requirements and maintain the target reserve margin, Seminole would not be able to remove a coal unit from service and the costs of the resulting resource plan would be substantially higher.

If the requested need determination for the SCCF were denied, Seminole would not be able to take an SGS coal unit out of service (664 MW) and the resulting resource plan would increase costs as compared to the resource plan that includes the SCCF. Seminole estimates that if only the SCCF were denied, the NPV revenue requirements impact would be approximately $502 million.

If the SHCCF was denied, then again Seminole could pursue one of two options. One option would be to leave the SGS coal unit in service which would cover our Members and their member-consumers' needs, but at a higher cost. The second option would be to go to the market to find replacement capacity, likely resulting in higher costs. Seminole estimates that if only the SHCCF were denied, the NPV revenue requirements impact would be approximately $363 million along with the continuation of service of the coal unit.

If both projects were to be denied, Seminole estimates that the NPV revenue requirements impact would be approximately $388 million, without consideration of transmission impacts which could be significant. Moreover, Seminole would need to continue operating both SGS coal units.

9.0 CONCLUSION

The analyses and other information described in this Need Study demonstrate that affirmative need determinations are warranted for the SCCF and SHCCF projects based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to the expiration of existing PPAs, Seminole will have a need for 901 MW of additional generating capacity by the end of 2021, and that need will grow to 1,265 MW by the end of 2022. The proposed SCCF and SHCCF are part of an integrated resource plan that will ensure that Seminole has an adequate supply of power to serve its Members' needs at a reasonable cost. The competitive RFP process, together with separate economic analyses and risk analyses presented in this Need Study demonstrate that the selected resource plan, including the two new combined cycle facilities, is the most cost-effective, risk-managed alternative to meet Seminole's power supply needs. Seminole and its Members already utilize reasonably available DSM programs and renewable resources and they are committed to implementing more. Even with potential demand and energy reductions that could be achieved from additional conservation and DSM initiatives, however, there is still a significant capacity need and the resource plan including the new SCCF and SHCCF is the least cost alternative to reliably meet that need.

APPENDIX A

Seminole Electric Cooperative

Ten Year Site Plan

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

April 1, 2016

Moniaishi Mtenga
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Mtenga:

In accordance with Section 186.801, Florida Statutes, Seminole Electric Cooperative, Inc. hereby submits our 2016 Ten Year Site Plan.

Please do not hesitate to call me if you have any questions or comments.

Sincerely,

Julia A Diazgranados

Julia A Diazgranados
Planning Manager
813-739-1538 (office)
jdiazgranados@seminole-electric.com

Enclosure

cc: M. Sherman
L. Johnson

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2016 - 2025
(Detail as of December 31, 2015)
April 1, 2016

Submitted To:
State of Florida
Public Service Commission

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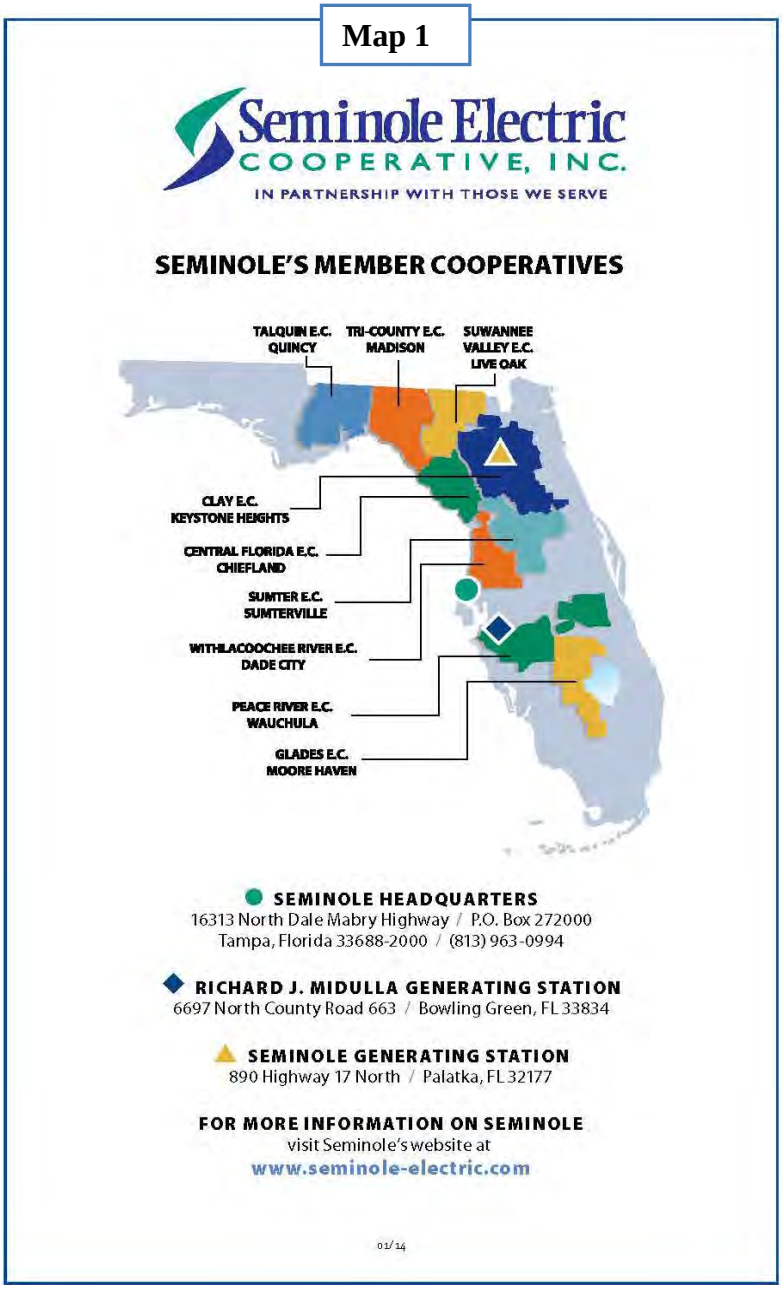
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1. DESCRIPTION OF EXISTING FACILITIES

1.1 Overview

Seminole Electric Cooperative, Inc. (Seminole) is a generation and transmission cooperative responsible for meeting the electric power and energy needs of its nine distribution cooperative members (Members). Member service areas are indicated on Map 1 below:

Map 1



Seminole provides full requirements service to all of its Members with the only exception relating to contracts between four Members with the Southeastern Power Administration (SEPA), which provides 26 MW or 1% of the total energy required by all Members. Seminole serves the aggregate loads of its Members with a combination of owned and purchased power resources. As of December 31, 2015, Seminole had total summer capacity resources of approximately 4,000 MW consisting of owned, installed net capacity of 2,012 MW and the remaining capacity in firm purchased power. Additional information on Seminole's existing resources can be found in Schedule 1 and Table 1.2 below.

1.2 Existing Facilities

1.2.1 Owned Generation

Seminole's existing generating facilities include:

1) Seminole Generating Station (SGS) Units 1 & 2 comprise a 1472 MW nameplate coal-fired plant located in Putnam County;
2) Midulla Generating Station (MGS) Units 1–3 comprise a 587 MW nameplate gas-fired combined cycle plant located in Hardee County; and,
3) MGS Units 4–8 comprise a 310 MW nameplate peaking plant.

Schedule 1
Existing Generating Facilities as of December 31, 2015

Plant	Unit No.	Location	Unit Type	Fuel		Fuel Transportation		Alt Fuel Days Use	Com In-Svc Date (Mo/Yr)	Expected Retirement (Mo/Yr)	Gen. Max Nameplate (MW)	Net Capability (MW)	
				Pri	Alt	Pri	Alt					Summer	Winter
SGS	1	Putnam County	ST	BIT	N/A	RR	N/A	N/A	02/84	Unk	736	626	664
SGS	2	Putnam County	ST	BIT	N/A	RR	N/A	N/A	12/84	Unk	736	634	665
MGS	1-3	Hardee County	CC	NG	DFO	PL	TK	Unk	01/02	Unk	587	482	539
MGS	4-8	Hardee County	CT	NG	DFO	PL	TK	Unk	12/06	Unk	310	270	310

Schedule Abbreviations:	General		
	Unit Type ST - Steam Turbine CC - Combined Cycle CT – Combustion Turbine PV – Photovoltaic	Fuel Type BIT - Bituminous Coal NG - Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy	Fuel Transportation PL – Pipeline RR – Railroad TK – Truck

Unk – Unknown
N/A – Not applicable

1.2.2 Transmission

Seminole serves its Members' load primarily in three transmission areas: Seminole Direct Serve (SDS) system, Duke Energy Florida (DEF) system, and Florida Power & Light (FPL) system. Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 141 circuit miles of 69 kV lines. Seminole's facilities are interconnected to the grid at twenty (20) 230 kV transmission interconnections with the utilities shown in Table 1.1.

Table 1.1

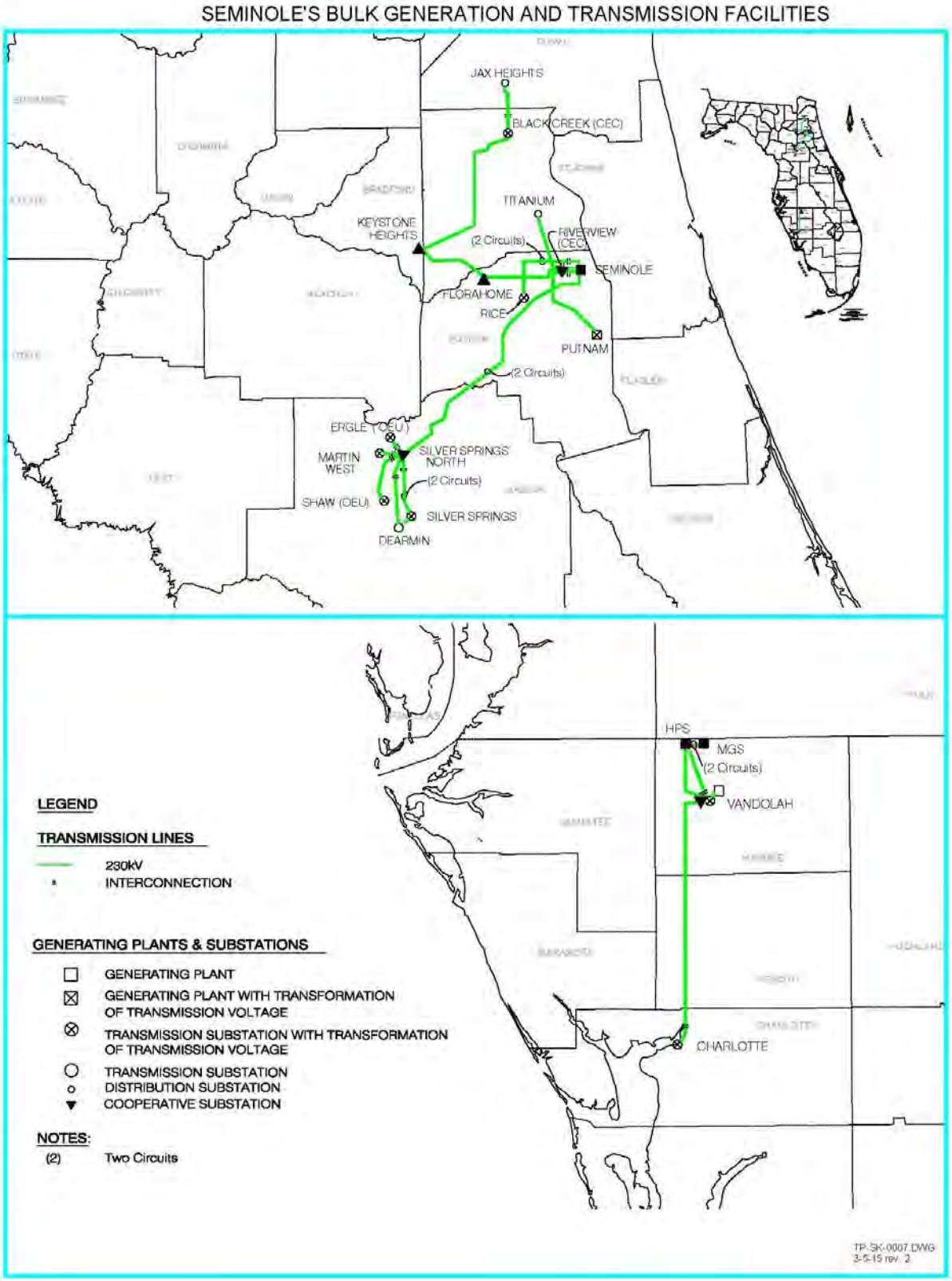
Transmission Grid Interconnections with Other Utilities

Utility	Voltage (kV)	Number of Interconnections
Florida Power & Light	230	6
Duke Energy Florida	230	7
JEA	230	1
City of Ocala	230	2
Tampa Electric Company	230	1
Hardee Power Partners	230	3

Note: This table describes physical facility interconnections, which do not necessarily constitute contractual interconnections for purposes of transmission service or interconnections between balancing areas.

Seminole contracts with other utilities for firm transmission service and interchange when required to serve loads. Map 2 below depicts Seminole's 230 kV transmission lines, including its interconnections with those entities identified in Table 1.1 above.

Map 2


SEMINOLE'S BULK GENERATION AND TRANSMISSION FACILITIES
JAX HEIGHTS
BLACK CREEK (CEC)
TITANIUM
KEYSTONE HEIGHTS
(2 Circuits)
RIVERVIEW (CEC)
SEMINOLE
FLORAHOME
RICE
PUTNAM
(2 Circuits)
ERGLE (OEU)
MARTIN WEST
SILVER SPRINGS NORTH
(2 Circuits)
SHAW (OEU)
SILVER SPRINGS
DEARMIN
HPS
MGS
(2 Circuits)
VANDOLAH
CHARLOTTE
LEGEND
TRANSMISSION LINES
230kV
INTERCONNECTION
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
DISTRIBUTION SUBSTATION
COOPERATIVE SUBSTATION
NOTES:
(2) Two Circuits
TP-SK-0007.DWG
3-5-15 rev. 2

1.3 Purchased Power Resources

Table 1.2 below sets forth Seminole's purchased power resources.

Table 1.2

2015				
SUPPLIER	**FUEL**	**MW (WINTER RATINGS)**	**IN SERVICE DATE**	**END DATE**
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	250	1/1/2014	5/31/2016
DEF	System	50	6/1/2016	12/31/2018
DEF	System	150	1/1/2014	5/31/2016
DEF	System	200-500	6/1/2016	12/31/2024
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026
Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.				

2. FORECAST OF ELECTRIC DEMAND AND ENERGY CONSUMPTION

2.1 Energy Consumption and Number of Customers

Residential consumer growth is projected to increase at an average annual rate of 1.6 percent from 2016 through 2025. Similarly, commercial consumer growth is projected to increase at an average annual rate of 1.4 percent during the same period. Residential energy sales are projected to grow at an average annual rate of 1.7 percent, and commercial energy sales are projected to grow at an average annual rate of 1.9 percent from 2016 through 2025.

Schedules 2.1, 2.2, and 2.3 below show the aggregate number of customers and energy consumption by customer classification of Seminole's nine Members, including other sales and purchases.

Schedule 2.1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Estimated Population Served by Members	Residential			
		Customers Per Household	GWh	Average Number of Customers	Average Consumption Per Customer (kWh)
2006	1,667,616	2.14	11,153	780,687	14,286
2007	1,716,841	2.14	11,444	803,957	14,235
2008	1,740,705	2.15	11,104	808,926	13,727
2009	1,748,408	2.15	11,293	811,767	13,912
2010	1,692,257	2.22	11,369	761,993	14,920
2011	1,716,516	2.24	10,412	765,279	13,605
2012	1,723,920	2.24	9,979	769,591	12,967
2013	1,749,359	2.25	10,018	777,493	12,885
2014	1,643,174	2.48	8,808	662,626	13,293
2015	1,666,850	2.48	9,068	673,215	13,470
2016	1,677,505	2.45	8,981	683,410	13,141
2017	1,697,061	2.44	9,177	695,982	13,185
2018	1,719,281	2.42	9,379	709,589	13,218
2019	1,746,279	2.42	9,555	722,026	13,234
2020	1,772,180	2.41	9,731	734,291	13,252
2021	1,795,824	2.41	9,892	745,826	13,263
2022	1,818,008	2.40	10,040	756,799	13,266
2023	1,839,569	2.40	10,183	767,621	13,266
2024	1,860,751	2.39	10,321	778,202	13,263
2025	1,881,770	2.39	10,452	788,493	13,256

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.
Estimated values for 2015.

Schedule 2.2

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Commercial[1]			Other Sales (GWh)[2]	Total Member Sales to Ultimate Consumers (GWh)[3]
	GWh	Average Number of Customers	Average Consumption Per Customer (kWh)		
2006	4,634	84,345	54,941	158	15,945
2007	4,839	88,306	54,798	165	16,448
2008	4,894	86,121	56,827	163	16,161
2009	4,776	84,318	56,643	167	16,236
2010	4,525	78,788	57,433	158	16,052
2011	4,366	78,828	55,386	160	14,938
2012	4,456	80,598	55,287	164	14,599
2013	4,482	82,302	54,458	166	14,666
2014	4,001	72,632	55,086	151	12,960
2015	4,155	73,290	56,689	151	13,374
2016	4,146	74,567	55,600	142	13,268
2017	4,262	75,722	56,282	140	13,579
2018	4,364	77,002	56,676	142	13,885
2019	4,478	78,212	57,249	143	14,176
2020	4,562	79,377	57,467	145	14,437
2021	4,640	80,508	57,636	146	14,679
2022	4,712	81,613	57,738	148	14,900
2023	4,781	82,694	57,816	149	15,114
2024	4,848	83,749	57,884	151	15,319
2025	4,912	84,790	57,928	152	15,516

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.
Estimated values for 2015

[1] Includes Industrial and Interruptible Customers.

[2] Includes Lighting Customers.

[3] Excludes Sales for Resale and includes SEPA.

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses, Less SEPA (GWh)*	Net Energy for Load (GWh)	Other Customers*	Total Number of Customers*
2006	0	1,288	17,233	5,101	870,133
2007	0	1,221	17,669	5,150	897,413
2008	0	1,171	17,332	5,075	900,122
2009	0	1,217	17,453	5,036	901,121
2010	0	1,294	17,346	4,956	845,737
2011	157	942	16,037	4,954	849,061
2012	134	1,036	15,769	4,818	855,007
2013	137	1,009	15,812	5,185	864,980
2014	170	724	13,854	5,308	740,566
2015	16	714	14,104	5,343	751,848
2016	5	651	13,925	5,332	763,309
2017	6	664	14,249	5,312	777,016
2018	6	675	14,566	5,335	791,927
2019	7	687	14,870	5,359	805,598
2020	9	687	15,133	5,392	819,060
2021	1	690	15,370	5,423	831,758
2022	0	702	15,602	5,455	843,868
2023	0	701	15,815	5,487	855,803
2024	0	707	16,026	5,517	867,467
2025	0	708	16,224	5,543	878,827

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative
* Estimated values for 2015.

2.2 Annual Peak Demand and Net Energy for Load

Schedules 3.1, 3.2, and 3.3 provide Seminole's summer peak demand, winter peak demand and net energy for load, respectively. Net firm peak demand reflects the energy reduction due to controllable interruptible load used in the historical years or made available for use in the forecasted years. Since population is the primary driver for Seminole's load growth, Seminole does not create high and low forecasts based upon alternative economic conditions.

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial[5]		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2006	3,813	3,813	0	0	51	130	N/A	N/A	N/A	3,632
2007	4,006	4,006	0	0	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	0	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	0	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	0	67	99	N/A	N/A	N/A	3,548
2011	3,829	3,829	0	0	79	97	N/A	N/A	N/A	3,653
2012	3,525	3,525	0	0	0	97	N/A	N/A	N/A	3,428
2013	3,665	3,665	0	0	0	99	N/A	N/A	N/A	3,566
2014	3,155	3,155	0	0	0	67	N/A	N/A	N/A	3,088
2015	3,092	3,092	0	0	0	71	N/A	N/A	N/A	3,021
2016	3,207	3,207	0	32	78	73	N/A	N/A	N/A	3,024
2017	3,275	3,275	0	41	78	74	N/A	N/A	N/A	3,082
2018	3,337	3,337	0	41	78	75	N/A	N/A	N/A	3,143
2019	3,396	3,396	0	41	78	76	N/A	N/A	N/A	3,201
2020	3,445	3,445	0	32	78	77	N/A	N/A	N/A	3,257
2021	3,480	3,480	0	32	78	78	N/A	N/A	N/A	3,291
2022	3,535	3,535	0	42	78	79	N/A	N/A	N/A	3,336
2023	3,576	3,576	0	41	78	80	N/A	N/A	N/A	3,377
2024	3,619	3,619	0	41	78	81	N/A	N/A	N/A	3,419
2025	3,657	3,657	0	41	78	82	N/A	N/A	N/A	3,457

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2005-06	4,349	4,349	0	0	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	0	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	0	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	0	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	0	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	0	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	0	66	134	N/A	N/A	N/A	3,918
2012-13	3,839	3,839	0	0	0	132	N/A	N/A	N/A	3,707
2013-14	3,333	3,333	0	0	0	93	N/A	N/A	N/A	3,240
2014-15	3,696	3,696	0	0	0	103	N/A	N/A	N/A	3,593
2015-16[5]	3,403	3,403	0	0	0	96	N/A	N/A	N/A	3,307
2016-17	3,696	3,696	0	36	78	101	N/A	N/A	N/A	3,481
2017-18	3,756	3,756	0	38	78	102	N/A	N/A	N/A	3,539
2018-19	3,815	3,815	0	38	78	103	N/A	N/A	N/A	3,596
2019-20	3,869	3,869	0	38	78	104	N/A	N/A	N/A	3,649
2020-21	3,919	3,919	0	38	78	106	N/A	N/A	N/A	3,698
2021-22	3,966	3,966	0	38	78	107	N/A	N/A	N/A	3,744
2022-23	4,010	4,010	0	38	78	108	N/A	N/A	N/A	3,787
2023-24	4,052	4,052	0	38	78	109	N/A	N/A	N/A	3,827
2024-25	4,091	4,091	0	38	78	110	N/A	N/A	N/A	3,866
2025-26	4,130	4,130	0	38	78	110	N/A	N/A	N/A	3,904

NOTE: Actual value for 2013-14 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)

Year	Total	Conservation		Retail	Total Sales Including Sales for Resale*	Utility Use & Losses, less SEPA*	Net Energy for Load	Load Factor %
		Residential	Commercial					
2006	17,233	N/A	N/A	0	15,945	1,288	17,233	48.9
2007	17,669	N/A	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	N/A	N/A	0	16,161	1,171	17,332	46.7
2009	17,453	N/A	N/A	0	16,236	1,217	17,453	42.1
2010	17,346	N/A	N/A	0	16,052	1,294	17,346	39.2
2011	16,037	N/A	N/A	0	15,095	942	16,037	46.7
2012	15,769	N/A	N/A	0	14,733	1,036	15,769	45.8
2013	15,812	N/A	N/A	0	14,803	1,009	15,812	45.7
2014	13,854	N/A	N/A	0	13,130	724	13,854	44.3
2015	14,104	N/A	N/A	0	13,390	714	14,104	48.7
2016	13,925	N/A	N/A	0	13,274	651	13,925	45.7
2017	14,249	N/A	N/A	0	13,585	664	14,249	46.0
2018	14,566	N/A	N/A	0	13,891	675	14,566	46.2
2019	14,870	N/A	N/A	0	14,183	687	14,870	46.5
2020	15,133	N/A	N/A	0	14,446	687	15,133	46.7
2021	15,370	N/A	N/A	0	14,680	690	15,370	46.9
2022	15,602	N/A	N/A	0	14,900	702	15,602	47.0
2023	15,815	N/A	N/A	0	15,114	701	15,815	47.2
2024	16,026	N/A	N/A	0	15,319	707	16,026	47.3
2025	16,224	N/A	N/A	0	15,516	708	16,224	47.4

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

* Estimated values for 2015

2.3 Monthly Peak Demand and Net Energy for Load

Schedule 4 shows peak demand and net energy for load by month for 2015 actuals and 2016 through 2017 forecasts.

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

Month	2015 Actual		2016 Forecast		2017 Forecast	
	Peak Demand (MW)[1]	NEL (GWh)	Peak Demand (MW)[2]	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	2,826	1,109	3,307	1,150	3,481	1,176
February	3,593	1,051	2,900	976	2,939	1,005
March	2,069	1,009	2,438	996	2,513	1,023
April	2,362	1,083	2,319	1,005	2,375	1,032
May	2,821	1,275	2,651	1,208	2,691	1,232
June	3,021	1,375	2,816	1,317	2,850	1,340
July	2,935	1,393	2,945	1,412	2,985	1,434
August	3,021	1,406	3,024	1,415	3,082	1,445
September	2,845	1,254	2,794	1,287	2,835	1,310
October	2,470	1,079	2,508	1,089	2,573	1,124
November	2,471	1,034	2,498	978	2,567	1,004
December	2,065	1,036	2,706	1,092	2,795	1,124
ANNUAL		**14,104**		**13,925**		**14,249**

[1] Peak Demand includes interruptible load; Excludes Distributed Generation, Load Management and SEPA allocations

[2] Peak Demand Excludes Interruptible Load, Distributed Generation, Load Management and SEPA allocations.

Note: Peak Demand for January 2016 is Actual.

2.4 Fuel Requirements

Seminole's coal, oil, and natural gas requirements for owned and future generating units are shown on Schedule 5 below.

Schedule 5
Fuel Requirements For Seminole Generating Resources

Fuel Requirements		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Nuclear		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-	-
Coal		1000 Tons	3,231	3,048	3,072	3,272	3,284	3,167	3,320	3,154	2,902	3,045	3,070	2,982
Residual	Total	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	Steam	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	CC	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	CT	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
Distillate	Total	1000 BBL	20	33	35	37	37	36	38	36	33	38	38	49
	Steam	1000 BBL	19	32	35	37	37	36	38	36	33	35	35	34
	CC	1000 BBL	1	1	-	-	-	-	-	-	-	3	3	14
	CT	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	1
Natural Gas	Total	1000 MCF	19,250	18,895	26,486	27,644	27,248	28,789	28,129	38,259	48,144	49,279	50,326	56,447
	Steam	1000 MCF	-	-	-	-	-	-	-	-	-	-	-	-
	CC	1000 MCF	18,346	17,529	25,567	26,844	26,263	28,189	27,628	37,913	47,815	47,736	48,275	51,098
	CT	1000 MCF	904	1,366	919	800	985	600	501	346	329	1,543	2,051	5,349

NOTE: Above fuel is for existing and future owned generating resources (excludes purchased power contracts).
Totals may not add due to rounding.

2.5 Energy Sources by Fuel Type

Seminole's total system energy sources in GWh and percent for each fuel type are shown on Schedules 6.1 and 6.2, respectively, on the following pages. Generation listed under renewable reflects the renewable units output but Seminole may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements. Seminole's additional requirements for capacity beyond 2021 are assumed to be from gas/oil resources. Due to concerns over proposed environmental regulations that would impact coal units negatively, future coal generation was not currently considered as a viable resource option.

Schedule 6.1
Energy Sources (GWh)

Energy Sources		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inter-Regional Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Coal		GWh	8,159	7,803	7,680	8,151	8,193	7,895	8,274	7,815	7,136	7,498	7,563	7,363
Residual	Total	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	Steam	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CC	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CT	GWh	-	-	-	-	-	-	-	-	-	-	-	-
Distillate	Total	GWh	35	36	37	39	43	42	37	38	29	35	35	50
	Steam	GWh	23	19	21	22	22	21	22	21	19	20	20	20
	CC	GWh	12	17	15	14	18	18	15	13	10	14	15	28
	CT	GWh	-	-	1	3	3	3	0	4	0	1	0	2
Natural Gas	Total	GWh	4,737	5,333	5,211	5,413	5,764	6,395	6,291	6,987	7,912	7,767	8,000	8,625
	Steam	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CC	GWh	4,570	5,052	5,093	5,294	5,579	6,256	6,200	6,901	7,875	7,603	7,787	8,086
	CT	GWh	167	281	118	119	185	139	91	86	37	164	213	539
NUG		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Renewables *		GWh	923	932	997	646	566	538	531	530	525	515	428	186
Other		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Net Energy for Load		GWh	13,854	14,104	13,925	14,249	14,566	14,870	15,133	15,370	15,602	15,815	16,026	16,224

NOTE: Net interchange, unit power purchases and DEF and FPL system purchases are included under source fuel categories.
Totals may not add due to rounding.
* Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

Schedule 6.2
Energy Sources (Percent)

Energy Sources		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inter-Regional Interchange		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Coal		%	58.89%	55.32%	55.15%	57.20%	56.25%	53.09%	54.67%	50.84%	45.74%	47.41%	47.19%	45.38%
Residual	Total	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Steam	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distillate	Total	%	0.25%	0.26%	0.27%	0.27%	0.30%	0.28%	0.24%	0.25%	0.19%	0.22%	0.22%	0.31%
	Steam	%	0.16%	0.14%	0.15%	0.15%	0.15%	0.14%	0.15%	0.14%	0.12%	0.13%	0.12%	0.12%
	CC	%	0.09%	0.12%	0.11%	0.10%	0.12%	0.12%	0.10%	0.08%	0.06%	0.09%	0.09%	0.17%
	CT	%	0.00%	0.00%	0.01%	0.02%	0.02%	0.02%	0.00%	0.03%	0.00%	0.01%	0.00%	0.01%
Natural Gas	Total	%	34.19%	37.81%	37.42%	37.99%	39.57%	43.01%	41.57%	45.46%	50.71%	49.11%	49.92%	53.16%
	Steam	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CC	%	32.99%	35.82%	36.57%	37.15%	38.30%	42.07%	40.97%	44.90%	50.47%	48.08%	48.59%	49.84%
	CT	%	1.20%	1.99%	0.85%	0.84%	1.27%	0.93%	0.60%	0.56%	0.24%	1.04%	1.33%	3.32%
NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Renewables		%	6.66%	6.61%	7.16%	4.53%	3.89%	3.62%	3.51%	3.45%	3.36%	3.26%	2.67%	1.15%
Other		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Net Energy for Load		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

NOTE: Net interchange, unit power purchases and DEF and FPL system purchases are included under source fuel categories.
Totals may not add due to rounding.
* Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements

3. FORECASTING METHODS AND PROCEDURES

3.1 Forecasting Methodology

Seminole adheres to generally accepted methodology and procedures currently employed in the electric utility industry to model number of consumers, energy and peak demand. Models are developed using regression and time series techniques and each Member Cooperative is modeled separately. Seminole produces monthly forecasts for each Member system and, when applicable, by multiple rate classifications. Seminole's system forecast is the aggregate of Member system forecasts.

3.1.1 Consumer Model

Numbers of consumers are modeled with regression and time-series techniques. Model input data sources include Member Rural Utilities Services Form-7 Financial and Statistical Reports (RUS Form-7), Moody's Economic Consumer and Credit Analytics (ECCA) and University of Florida's Bureau of Economic and Business Research (UF BEBR). Explanatory variables analyzed in these models include population, number of households, housing stock, gross county product and employment.

Consumers are modeled by Member total and by rate classification. Rate class forecasts are reconciled to match in aggregate the total consumer forecasts by each Member. Territorial agreements and information provided directly from Member representatives regarding anticipated changes in service territories are incorporated in forecast projections. The "other" consumer class represents a small portion of Member energy sales, including irrigation, street and highway lighting, public buildings and sales for resale.

3.1.2 Energy Model

Forecasts of Member energy purchases from Seminole are developed using regression

and time-series techniques. Model input data sources include Seminole's System Operations Power Billing System (PBS), RUS Form-7, Moody's ECCA, UF BEBR and AccuWeather. Explanatory variables analyzed in this model include heating and cooling degrees, population, number of households, housing stock and gross county product. The dependent variable, Member energy purchases from Seminole, is projected by aggregating hourly delivery point meter load to the monthly aggregate level.

Member rate class energy purchases from Seminole are projected by scaling RUS Form-7 energy sales to end-users by distribution loss factors. Rate class energy purchases forecasts are reconciled to match in aggregate the Member-total purchases forecasts. Historical reductions in energy consumption due to conservation and efficiency are reflected in historical sales and purchases data and are implied in forecasts.

3.1.3 Peak Demand Model

Maximum peak demand is modeled by month and by season for each Member system using regression and time-series techniques. Model input data sources include Seminole's PBS, Moody's ECCA, UF BEBR and AccuWeather. Explanatory variables analyzed in this model include heating and cooling degrees, minimum and maximum temperature, population, number of households, housing stock, gross county product and load factor.

Seasonal peak models are designed to predict winter and summer peaks based on a range of months when the highest peaks can be expected to occur in each season. Winter seasonal peak models regress the highest peak during November through March of each year against contemporaneous explanatory variables. Summer seasonal peak models regress the highest peak beginning as early as May and as late as September of each year against contemporaneous explanatory variables. Seasonal peak forecasts replace monthly model forecast results for the

month each seasonal peak is most likely to occur.

Seminole's maximum demand is the aggregate of the one-hour simultaneous demands of all Members that maximizes the peak of the system in a single month. Forecasts of Seminole maximum demand is derived by applying coincident factors to Member-maximum demand forecasts. Future peak demands coincident with Seminole may be equal to or less than Member non-coincident maximum peaks, if the Member peak is normally not coincident with Seminole.

Load factor forecasts are derived through regression analysis of monthly temperatures and daily temperatures leading up to the peak day. These models are also developed by month and by season.

3.1.4 Alternative-Scenario Models

In addition to the base forecasts, Seminole produces high and low forecasts based on population growth alternatives provided by UF BEBR. Seminole's system is primarily residential and population growth is the primary driver for load growth. Therefore, high and low population scenarios, rather than alternative economic growth scenarios, are developed for each Member system. Seminole also forecasts load conditions given mild and severe temperatures in a Member's geographical region. Last, we show a set of alternative projections associated with the statistical error of each model at the ninety-five percent prediction interval.

3.2 Load Forecast Data

The primary resources for load forecasting are weather data, economic data, Member retail data and delivery point meter data. Number of consumers and sales by consumer class are provided by Members through the Form-7 financial report. Hourly delivery point load data is provided monthly by Seminole's System Operations department. Independent source data for economic and demographic statistics are provided by government and credit rating agencies, as

well as local universities. A listing of load forecast data sources is provided below.

3.2.1 Materials Reviewed and/or Employed

Load Data by Delivery Point

- Seminole's System Operations' Power Billing System (PBS)

Retail Number of Consumers, Energy Sales by Rate Class:

- Rural Utilities Services Form-7 Financial and Statistical Reports (RUS Form-7)

Individual Large Consumer Loads Over 1000 kVA:

- Member provided

Demographic and Economic Indicators:

- Moody's Analytics Economic Consumer and Credit Analytics (ECCA)
- University of Florida Bureau of Economic and Business Research (UF BEBR)

Weather Data:

- AccuWeather

3.3 Significant Load Forecast Assumptions

3.3.1 Economic Assumptions

Seminole Members serve electricity to primarily rural areas within 42 counties in the north, central and south regions of Florida, which differ uniquely in geography, weather, and natural resources. These large, low-density land areas are largely undeveloped. Population growth in Seminole's territory is sensitive to national economic and demographic factors that influence population migration from other states and metropolitan areas within Florida.

This load forecast reflects expectations that the national economy, and Florida's economy in particular, will continue to recover from the Great Recession over the next several years. In

addition, Member territories will likely benefit from consumer growth due to "baby-boomer" retiree migration into Florida from other states. Improving economic conditions and expected net migration are leading indicators for overall load growth. Despite the potential growth opportunities however, electricity usage per residential consumer trends over the last decade for electric utilities in the state of Florida are on average flat to negative and Seminole projects this trend will generally continue into the future.

3.3.2 Weather Assumptions

Hourly temperature data for 25 weather stations in the proximity of Member service territories are provided by AccuWeather. Weather statistics for each Member's geographical area are derived from a set of weather stations that represent the optimal simple average combination of weather station temperature observations that best project Member aggregate load by date and time, using the lowest mean absolute percent error as an indicator of statistical efficiency.

Historical weather statistics input into forecast models include monthly average, minimum and maximum temperatures, as well as monthly heating and cooling degree days. Monthly heating degree days represent the sum of degrees each daily average temperatures falls below 61° Fahrenheit, which is an approximate temperature when consumers turn on heating devices. Alternatively, monthly cooling degree days represent the sum of degrees each daily average temperatures exceeds 72° Fahrenheit, which is an approximate temperature when consumers turn on A/C units.

Normal weather statistics are the thirty year median of historical observations by month. Seasonal weather statistics are the thirty year median of historical observations by month in which the highest peak demand occurred in a summer and winter season. Extreme weather used for alternative-scenario forecasts include the tenth and ninetieth percentile of historical

temperatures, representing mild and severe events, respectively.

4. FORECAST OF FACILITIES REQUIREMENTS

Seminole's forecasts of capacity and demand for the projected summer and winter peaks are in the following Schedules 7.1 and 7.2, respectively. The forecasts include the addition of approximately 1,700 MW of capacity by 2025. Such capacity is needed to replace expiring purchased power contracts and to serve increased Member load requirements while maintaining Seminole's reliability criteria.

Seminole's capacity expansion plan includes the need for four 224 MW class combustion turbine units and one 741 MW combined cycle plant, none of which are currently sited. The four combustion turbine units are scheduled to enter service in December 2021, December 2022, and two units in December 2024. In addition, by June 2021, Seminole also has a need for 741 MW of combined cycle capacity. A final decision as to whether Seminole will construct and own these additional facilities will be based upon future economic studies. The inclusion of these units in Seminole's capacity expansion plan does not represent at this time a commitment for construction by Seminole.

In March of 2015 Seminole issued a request for proposals for 2 MW of solar photovoltaic (PV) energy either through an Engineer, Procure, and Construct (EPC) contract or through a Purchase Power Agreement (PPA) to be in commercial operation on or before November 2, 2016. Seminole has incorporated a 2 MW solar photovoltaic facility into Seminole's ten year plan. On March 21 2016 Seminole finalized agreements for a 2.2 MW solar facility to be constructed at Seminole's MGS site in Hardee County.

Schedule 7.1
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak

Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)			Firm Capacity Export (MW)	QFs (MW)	Capacity Available (MW)		System Firm Summer Peak Demand (MW)		Reserve Margin Before Maintenance		Scheduled Maintenance (MW)	Reserve Margin After Maintenance	
		PR and FR	Other Purchases	Total			Total	Less PR and FR	Total	Obligation	MW	% of Pk		MW	% of Pk
2016	2,012	0	1,595	1,595	0	0	3,607	3,607	3,024	3,024	583	19%	0	583	19%
2017	2,012	0	1,650	1,650	0	0	3,662	3,662	3,082	3,082	580	19%	0	580	19%
2018	2,012	0	1,635	1,635	0	0	3,647	3,647	3,143	3,143	504	16%	0	504	16%
2019	2,012	0	1,885	1,885	0	0	3,897	3,897	3,201	3,201	696	22%	0	696	22%
2020	2,012	0	1,883	1,883	0	0	3,895	3,895	3,257	3,257	639	20%	0	639	20%
2021	2,661	0	1,135	1,135	0	0	3,796	3,796	3,291	3,291	505	15%	0	505	15%
2022	2,862	0	986	986	0	0	3,848	3,848	3,336	3,336	512	15%	0	512	15%
2023	3,063	0	833	833	0	0	3,896	3,896	3,377	3,377	519	15%	0	519	15%
2024	3,063	0	881	881	0	0	3,944	3,944	3,419	3,419	525	15%	0	525	15%
2025	3,465	0	522	522	0	0	3,987	3,987	3,457	3,457	530	15%	0	530	15%

NOTES: 1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.

2. Total Installed Capacity does not include SEPA or Solar.

3. Percent reserves are calculated at 15% of Seminole's obligation and include any surplus capacity.

Schedule 7.2
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak

Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)			Firm Capacity Export (MW)	QFs (MW)	Capacity Available (MW)		System Firm Winter Peak Demand (MW)		Reserve Margin Before Maintenance		Scheduled Maintenance (MW)	Reserve Margin After Maintenance	
		PR and FR	Other Purchases	Total			Total	Less PR and FR	Total	Obligation	MW	% of Pk		MW	% of Pk
2016/17	2,178	0	2,322	2,322	0	0	4,500	4,500	3,481	3,481	1,019	29%	0	1,019	29%
2017/18	2,178	0	2,322	2,322	0	0	4,500	4,500	3,539	3,539	960	27%	0	960	27%
2018/19	2,178	0	2,307	2,307	0	0	4,485	4,485	3,596	3,596	889	25%	0	889	25%
2019/20	2,178	0	2,557	2,557	0	0	4,735	4,735	3,649	3,649	1,086	30%	0	1,086	30%
2020/21	2,178	0	2,086	2,086	0	0	4,264	4,264	3,698	3,698	565	15%	0	565	15%
2021/22	3,143	0	1,174	1,174	0	0	4,317	4,317	3,744	3,744	573	15%	0	573	15%
2022/23	3,368	0	999	999	0	0	4,366	4,366	3,787	3,787	579	15%	0	579	15%
2023/24	3,368	0	1,046	1,046	0	0	4,413	4,413	3,827	3,827	586	15%	0	586	15%
2024/25	3,816	0	642	642	0	0	4,458	4,458	3,866	3,866	592	15%	0	592	15%
2025/26	3,816	0	685	685	0	0	4,501	4,501	3,904	3,904	597	15%	0	597	15%

NOTES: 1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.

2. Total Installed Capacity does not include SEPA or Solar.

3. Percent reserves are calculated at 15% of Seminole's obligation and include any surplus capacity.

4.1 Planned and Prospective Generating Facility Additions and Changes

Schedule 8 below shows Seminole's planned and prospective generating facility additions and changes.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No	Location	Unit Type	Fuel		Transportation		Const. Start Date	Comm. In-Service Date	Expected Retirement Date	Max Nameplate	Summer MW	Winter MW	Status
				Pri	Alt	Pri	Alt							
MGS Solar	1	Hardee County	PV	Sun		N/A		TBD	11/2016	Unk	2	2	2	P
Unnamed CC	1	TBA	CC	NG		PL		(1)	5/2021	Unk	741	649	741	P
Unnamed CT	1	TBA	CT	NG		PL		(1)	12/2021	Unk	224	201	224	P
Unnamed CT	2	TBA	CT	NG		PL		(1)	12/2022	Unk	224	201	224	P
Unnamed CT	3	TBA	CT	NG		PL		(1)	12/2024	Unk	224	201	224	P
Unnamed CT	4	TBA	CT	NG		PL		(1)	12/2024	Unk	224	201	224	P

NOTES:
(1) Future resource which may be existing or new as determined by future Request for Proposal results.
(2) Abbreviations – See Schedule 1
(3) MGS Solar is planned to be a leased facility

4.2 Proposed Generating Facilities

Schedule 9 below reports status and specifications of Seminole's proposed generating facilities.

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	MGS Solar Unit 1
2	Capacity a. Nameplate - AC (MW) b. Summer Firm - AC (MW): c. Winter Firm - AC (MW):	 2 0 0
3	Technology Type:	Photovoltaic
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 May 2016 November 2016
5	Fuel a. Primary fuel: b. Alternate fuel:	 Sun
6	Air Pollution Control Strategy	N/A
7	Cooling Method:	N/A
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 N/A N/A N/A 26.8% N/A
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 25 2,212 2,212 N/A N/A 0.02 N/A N/A N/A **NOTE:MGS Solar is planned to be a leased facility**

Schedule 9 **Status Report and Specifications of Proposed Generating Facilities**		
1	Plant Name & Unit Number	Unnamed Generating Station CC Unit 1
2	Capacity a. Summer (MW): b. Winter (MW):	 649 741
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 May 2018 May 2021
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	SCR
7	Cooling Method:	Wet Cooling Tower with Forced Air Draft Fans
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 4.50 2.50 93.00 50% 6684 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 30 808 742 66 Included in values above 12.72 1,728 0.08 N/A

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 1
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2019 December 2021
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.1 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2022) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 602 575 27 Included in values above 8.16 0.99* N/A *Variable O&M does not include start up charge of $7,301 per start

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 2
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2020 December 2022
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.11 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2023) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 613 588 25 Included in values above 8.40 1.01* N/A *Variable O&M does not include start up charge of $7,456 per start

Schedule 9 **Status Report and Specifications of Proposed Generating Facilities**		
1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 3 & 4
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2022 December 2024
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.11 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2024) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 639 612 27 Included in values above 8.64 1.05* N/A *Variable O&M does not include start up charge of $7,765 per start

4.3 Proposed Transmission Lines

Schedule 10 below reports status and specifications of Seminole's proposed directly associated transmission lines corresponding with proposed generating facilities.

Schedule 10 **Status Report and Specifications of Proposed Associated Transmission Lines**		
1	Point of Origin and Termination:	Unknown
2	Number of Lines:	To be determined
3	Right-of-Way	To be determined
4	Line Length:	To be determined
5	Voltage:	To be determined
6	Anticipated Construction Timing:	To be determined
7	Anticipated Capital Investment:	To be determined
8	Substation:	To be determined
9	Participation with Other Utilities:	N/A

5. OTHER PLANNING ASSUMPTIONS AND INFORMATION

5.1 Transmission Reliability

In general, Seminole models its transmission planning criteria after the Florida Reliability Coordinating Council's ("FRCC") planning guidelines. The FRCC has modeled its planning guidelines consistent with the North American Electric Reliability Corporation's ("NERC") Reliability Standards. In addition, Seminole uses the following voltage and thermal criteria as guidelines for all stations:

1. No station voltages generally above 1.05 per unit or below 0.90 per unit under normal or contingency conditions.
2. Transmission facilities shall not exceed their applicable facility rating under normal or contingency conditions.

Since sites for future generation have not been selected, Seminole has not yet modeled any associated transmission or evaluated constraints and/or plans for alleviating such constraints.

5.2 Plan Economics

Power supply alternatives are compared against a base case scenario which is developed using the most recent load forecast, fuel forecast, operational cost assumptions, and financial assumptions. Various power supply options are evaluated to determine the overall effect on the present worth of revenue requirements (PWRR). All other things being equal, the option with the lowest long-term PWRR is normally selected. Sensitivity analyses are done to test how robust the selected generation option is when various parameters change from the base study assumptions (e.g., load forecast, fuel price, and capital costs of new generation).

5.3 Fuel Price Forecast

5.3.1 Coal

Spot and long-term market commodity prices for coal (at the mine) and transportation rates have shown increased volatility in recent years. This condition is expected to continue into the future, as environmental rules/standards, generating station retirements, coal supply/demand imbalances, coal transportation availability/pricing and world energy markets all combine to affect U.S. coal prices. The underlying value of coal at the mine will continue to be driven by changing domestic demand, reductions to the number of available coal suppliers, planned coal unit retirements, export opportunities for U.S. coal and federal/state mine safety rules/legislation affecting the direct mining costs. Additional coal delivered price increases and volatility will come from the cost of transportation equipment (railcars), handling service contracts and freight transportation impacts. Railroads are also affected by federal rules and legislative changes and fuel oil markets, which are impacting the volatility of the cost of rail service in the U.S. As long-term rail transportation contracts come up for renewals, the railroads have placed upward pressure on delivered coal costs to increase revenues to overcome operating cost increases and reduced demand. However, since 2012, lower natural gas prices have created an opportunity for electric utilities to swap natural gas for coal-fired generation and this price arbitrage may have reduced the railroads' near-term ability to apply upward pricing pressure during contract renewals. CSX Transportation, Inc. is Seminole's sole coal transport provider and the parties are operating under a confidential multi-year rail transportation contract. Seminole also has a confidential multi-year coal contract with Alliance Coal, LLC providing a majority of our coal requirements from the Illinois Basin. Both of these existing relationships reduce Seminole's coal price volatility risk for the near term.

5.3.2 Fuel Oil

The domestic price for fuel oils will continue to reflect the price volatility of the world energy market for crude oil and refined products. In late 2014 and through 2015, the price for fuel oil moved down significantly across the globe. Seminole is currently only purchasing ultra-low sulfur fuel oil for its generating stations.

5.3.3 Natural Gas

At year-end 2015, natural gas prices were near $2.30 per mmBtu and nominal Henry Hub prices are projected to increase slowly over the next ten years nearing $4.00 per mmBtu at the end of the ten-year study period.

5.3.4 Modeling of Fuel Sensitivity

Given the uncertainty of future fuel prices, the historical volatility of natural gas prices, and Seminole's reliance on gas as a significant component of its fuel portfolio, it is prudent to evaluate the impact of various gas prices on its alternative resources for meeting future needs. For this, Seminole incorporates both a high and low natural gas price forecast as a complement to its base case price forecast to support resource planning. Calculated with available market information (e.g. projected volatility of gas prices), Seminole’s high/low gas price curves form a statistical confidence interval around its base case price forecast. Seminole's base fuel price forecast for this Ten Year Site Plan does not take into account potential federal carbon emission initiatives, such as the proposed Clean Power Plan, that if approved, would impact the market prices for all fuels. If legislation that penalizes carbon emissions is enacted in future years, Seminole’s costs to use all fossil fuels will rise since all fossil fuels emit carbon dioxide when burned. Further, the price of natural gas and fuel oil relative to coal may rise because of the associated carbon emissions penalty imposed on coal, the competing fuel.

5.4 Coal/Gas Price Differential

The current natural gas and coal markets continue to reflect a significant narrowing, and even inversion during some years, of the price spread that existed between the two fuels over the prior ten years primarily due to soft gas prices. This spread is expected to remain compressed throughout the study period given the projected slow rise in gas prices.

5.5 Modeling of Generation Unit Performance

Existing units are modeled with forced outage rates and heat rates for the near term based on recent historical data. The long-term rates are based on a weighting of industry average data or manufacturers' design performance data.

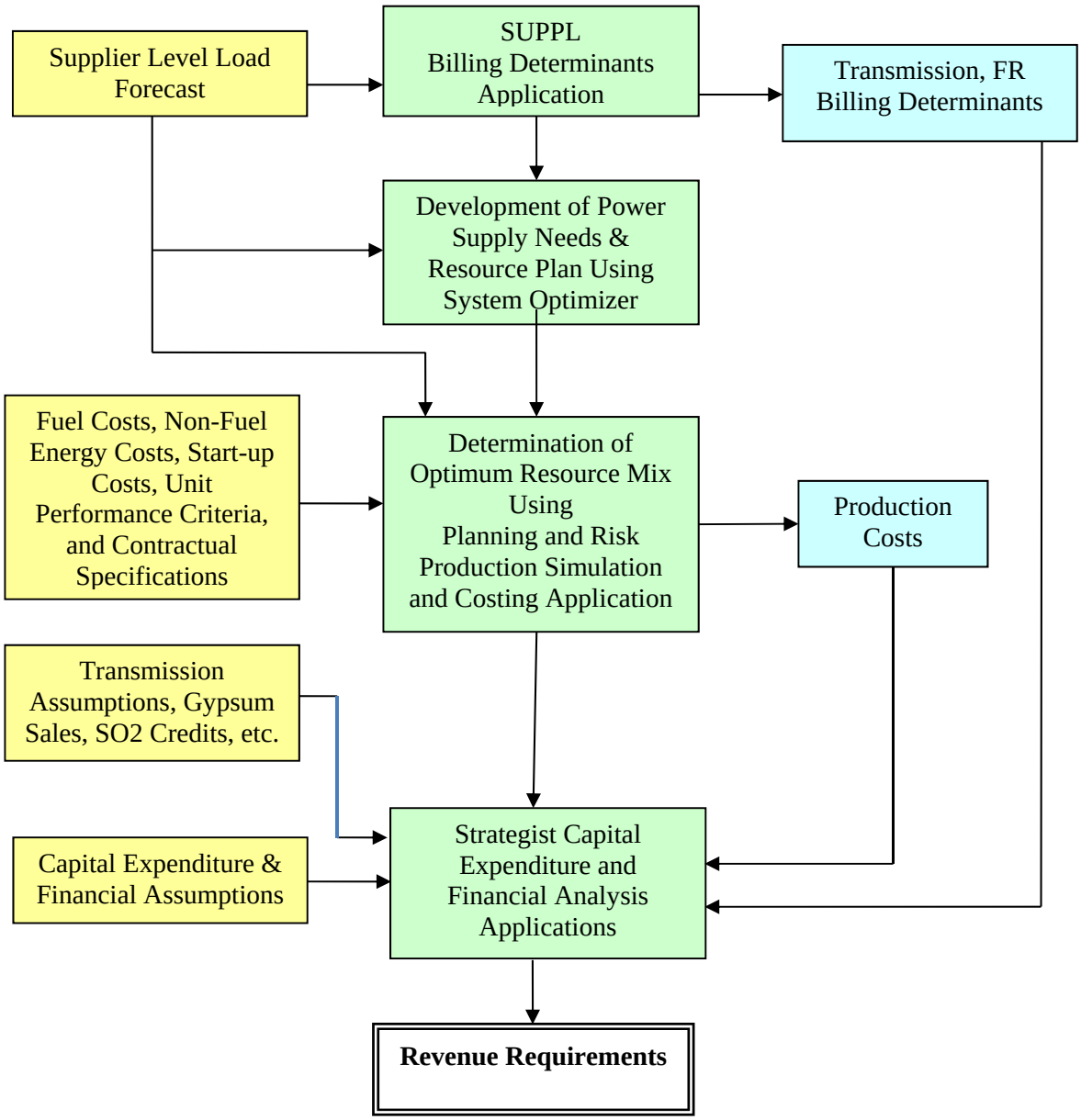
5.6 Financial Assumptions

Expansion plans are evaluated based on Seminole's forecast of market-based loan fund rates.

5.7 Resource Planning Process

Seminole's primary long-range planning goal is to develop the most cost-effective way to meet its Members' load requirements while maintaining high system reliability. Seminole's optimization process for resource selection is based primarily on total revenue requirements. As a not-for-profit cooperative, revenue requirements translate directly into rates to our Members. The plan with the lowest revenue requirements is generally selected, assuming that other factors such as reliability impact, initial rate impact, and strategic considerations are neutral. Seminole also recognizes that planning assumptions change over time, so planning decisions must be robust and are, therefore, tested over a variety of sensitivities. A flow chart of Seminole's planning process is shown below in Figure 5.1.

Figure 5.1
Resource Planning Process



5.8 Reliability Criteria

The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and its reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages; and to account for load forecast uncertainty. Seminole's primary reliability criteria is a minimum reserve margin of 15% during the peak season which ensures that Seminole has adequate generating capacity to provide reliable service to its Members and to limit Seminole's emergency purchases from interconnected, neighboring systems.

5.9 DSM Programs

Seminole promotes Member involvement in demand side management (DSM) through coincident peak billing and time-of-use energy rates as well as substation level conservation voltage reduction (CVR). The majority of Seminole's Members are active in managing their peak demand via one or more of these programs and several Members offer a time of use rate and a curtailable service rate to their commercial consumers for shifting energy usage from on-peak to off-peak periods.

Seminole's load management generation programs utilize standby generation on commercial consumer loads to lower demands at the time of the Seminole system peak demand. This program allows Seminole's Members to install distributed peaking generation resources on their system and/or to partner with their retail end-users to install "behind the meter" customer-based distributed generation (DG) to operate as dispatchable load management resources for Seminole's system, while providing load-center based generation to improve system reliability.

Seminole's load forecast accounts for reductions in peak demand resulting from DSM programs. Energy efficiency and energy conservation programs implemented by Seminole

Members have not been specifically quantified or estimated, but are both reflected in Seminole's load history and extrapolated into the future.

5.10 Strategic Concerns

In the rapidly changing utility industry, strategic and risk related issues are becoming increasingly important and will continue to play a companion role to economics in Seminole's power supply planning process. Seminole values resource diversity as a hedge against a variety of risks, as evidenced by our current generation portfolio. Long-term resources contribute stability while shorter term arrangements add flexibility. Seminole considers both system and unit-specific capacity when determining our reserve requirements. Resource location and transmission interconnection is also a consideration for Seminole in constructing its portfolio. Flexibility in fuel supply is another significant strategic concern. A portfolio that relies on a diverse number of fuel types is better protected against extreme price fluctuations, supply interruptions, and transportation constraints/instability. Seminole believes that the existing and future diversity in its power supply plan has significant strategic value, leaving Seminole in a good position to respond to both market and industry changes while remaining competitive.

The ongoing debate over the further need to regulate carbon emissions, mercury emissions and/or whether to establish renewable resource mandates has introduced new risks for electric utilities – among them is the risk of the most cost-effective fuels and associated technologies under current environmental regulations could change via new federal or state emissions rules. Using the best available information, Seminole is addressing these risks through its evaluation of a range of scenarios to assess what constitutes the best generation plan to ensure adequate and competitively priced electric service to its Members. Given the current regulatory environment, Seminole has assumed that all future large generation additions will be primarily

fueled with natural gas. Seminole is also reviewing the possibility of renewable generation additions, including solar.

5.11 Procurement of Supply-Side Resources

In making decisions on future procurement of power supply, Seminole compares self-build, acquisition and purchased power alternatives. Seminole solicits proposals from reliable counterparties. Seminole's evaluation of its options includes an assessment of economic life cycle cost, reliability, operational flexibility, strategic concerns and risk elements.

5.12 Transmission Construction and Upgrade Plans

Seminole is assessing future generation projects and needs for new, upgraded, or reconfigured transmission facilities over the ten-year planning horizon. At this time, Seminole has no specific transmission plans for future generating unit additions.

6. ENVIRONMENTAL AND LAND USE INFORMATION

6.1 Potential Sites

6.1.1 Gilchrist Site – Gilchrist County, Florida

Seminole owns land in Gilchrist County but has not made a final determination if or when the site will be used for any of Seminole's future resource requirements. The Gilchrist site is approximately five-hundred thirty (530) acres in size. The site is located in the central portion of Gilchrist County, approximately eight (8) miles north of the City of Trenton and may be suitable for installation of generation or transmission resources. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine communities. Few natural upland communities remain. Most of these large tracts have been

harvested, leaving xeric oak and pine remnants. A few wetland communities remain on the east side of the site with relatively minor disturbances due to adjacent silvicultural activities.

The initial site evaluation in 2007 included wetland occurrence information documented on National Wetland Inventory (NWI) map(s) from the U.S. Fish and Wildlife Service (USFWS), soils maps and information from the National Resource Conservation Service (NRCS), records of any listed plants or animals known from Gilchrist County that are available from online data and records maintained by the Florida Natural Areas Inventory (FNAI) and the Atlas of Florida Vascular Plants maintained by the University of South Florida Herbarium, lists of federally listed plants and animals maintained by USFWS, and records of eagle nest locations and wading bird rookeries that might occur within the site available on the Florida Fish and Wildlife Conservation Commission (FWC) website. At such time as Seminole has determined the Gilchrist site should be considered a preferred site for the construction of generation or transmission facilities, Seminole will update the site evaluation and will obtain approval of the site certification application.

6.1.2 Seminole Generating Station (SGS) - Putnam County, Florida

SGS is located in a rural unincorporated area of Putnam County approximately five (5) miles north of the City of Palatka. The site is one thousand nine-hundred seventy-eight (1,978) acres bordered by U.S. 17 on the west, and is primarily undeveloped land on the other sides. The site was certified in 1979 (PA78-10) for two 650 MW class coal-fired electric generating units, SGS Units 1 & 2.

The area around the SGS site includes mowed and maintained grass fields and upland pine flatwoods. Areas further away from the existing units include live oak hammocks, wetland conifer forest, wetland hardwood/conifer forest, and freshwater marsh. A small land parcel

located on the St. Johns River is the site for the water intake structure, wastewater discharge structure, and pumping station to supply the facility with cooling and service water.

The primary water uses for SGS Units 1 and 2 are for cooling water, wet flue gas desulfurization makeup, steam cycle makeup, and process service water. Cooling and service water is pumped from the St. Johns River and groundwater supplied from on-site wells is for steam cycle makeup and potable use. The site is not located in an area designated as a Priority Water Resource Caution Area by the St. Johns River Water Management District.

The local government future land use for the area where the existing units are located is designated as industrial use, and the site has not been listed as a natural resource of regional significance by the regional planning council.

Water conservation measures that are incorporated into the operation of SGS include the collection, treatment and recycling of plant process wastewater streams. This wastewater reuse minimizes groundwater and service water uses. A portion of recirculated condenser cooling water (cooling tower blowdown) is withdrawn from the closed cycle cooling tower and discharged to the St. Johns River. Site stormwater is reused to the maximum extent possible and any not reused is treated in wet detention ponds and released to onsite wetlands.

6.2 Preferred Sites

6.2.1 Midulla Generating Station (MGS) – Hardee County, Florida

MGS is located in Hardee and Polk Counties about nine (9) miles northwest of Wauchula. The site is bordered by County Road 663 on the east and by The Mosaic Company on the south, north and west. Payne Creek flows along the site's south and southwestern borders. The site was originally strip-mined for phosphate and was reclaimed as pine flatwoods, improved pasture, and a cooling reservoir with a marsh littoral zone. The proposed solar project

will be located on approximately 29-acres of land on the west side of the current plant entrance road and to the north of three onsite above ground storage tanks. A more detailed description of environmental, land use, as well as water use and supply, is available in the site certification application PA-89-25SA.

6.2.1.1 Land and Environmental Features

a. U.S. Geological Survey Map

   See Map 5

b. Proposed Facilities Layout

   The current proposed configuration of the single-axis tracking solar facility is attached. See Map 6

c. Map of Site and Adjacent Areas

   See Map 7

d. Existing Land Uses of Site and Adjacent Areas

   The existing land use for the majority of MGS is listed as utilities and zoned as industrial. There is a large reservoir and some wetlands located onsite as well. The solar PV area of the site will be located in an area that is currently active cattle pasture. The adjacent areas include reclaimed mine lands with both forested and non-forested uplands and wetlands interspersed, as well as industrial land use designations.

e. General Environmental Features On and In the Site Vicinity

   1. Natural Environment

      The majority of the site is currently made up of the MGS facilities, a 570-acre cooling reservoir, pastureland and some forested and non-forested

uplands and wetlands interspersed. The PV site is to be built completely on an area that is currently pastureland.

2. Listed Species

   A Florida Natural Areas Inventory (FNAI) database query was done for the site and indicated no documented occurrences of any state or federal listed species within 1-mile. Wildlife field surveys were performed on August 26 and 27, as well as December 8, 2015, and no listed species or signs of their presence were observed. Based on this information, no negative impacts to threatened or endangered species are anticipated as a result of the PV project.

3. Natural Resources of Regional Significance Status

   There are no natural resources of regional significance on or adjacent to the site.

4. Other Significant Features

   Seminole is not aware of any other significant site features.

f. Design Features and Mitigation Options

   The design includes construction of a single-axis tracking solar PV facility with approximately 2.2 MW of power generation.

g. Local Government Future Land Use Designations

   The Hardee County Future Land Use Map shows the entire site designated under the industrial category which should include solar PV.

h. Site Selection Criteria Process

   The Seminole Solar site at MGS has been selected as the location of the PV

facility based on various factors including system load, interconnection availability, and proximity to existing Seminole operations and maintenance personnel, as well as economics.

i. Water Resources

Minimal amounts of water, if any, would be required for cleaning the PV panels. The water would be provided by water trucks or obtained from existing onsite permitted water resources.

j. Geological Features of Site and Adjacent Areas

The soil types found on and adjacent to the site include Smyrna fine sand, Myakka fine sand, Basinger fine sand, Floridana muck fine sand (depressional), Ona fine sand, and Bradenton-Felda-Chobee Association (frequently flooded). The soils are disturbed in most areas since the site is on reclaimed mine lands.

k. Projected Water Quantities for Various Uses

The PV site requires minimal water, if any, for the cleaning of the panels in the absence of sufficient rainfall.

l. Water Supply Sources by Type

A water supply source is not required for this site. Any needed water may be brought to the site by water truck or obtained from existing onsite permitted water resources.

m. Water conservation Strategies Under Consideration

The PV site does not require a permanent water source. Water conservation strategies include minimizing water use by cleaning the panels with water only in the absence of sufficient rainfall and leaving the vegetation in and around the site

as is with no required watering.

n. Water Discharges and Pollution Control

Although no discharges of water are planned at the PV site, the facility will implement Best Management Practices (BMP) to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal and Pollution Control

No traditional fuel sources are required and no waste products will be generated at the site.

p. Air Emissions and Control Systems

Solar PV does not generate air emissions.

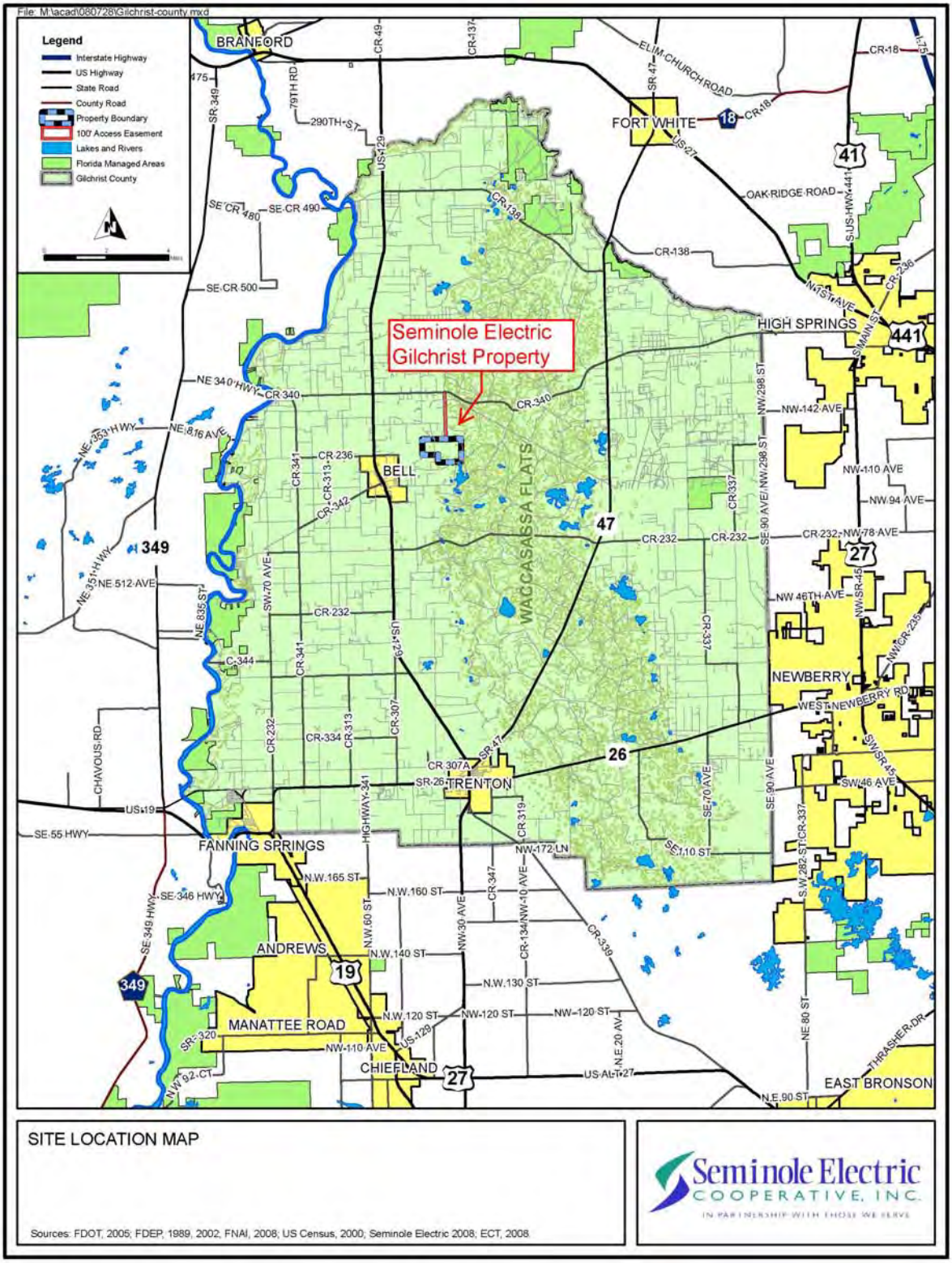
q. Noise Emissions and Control Systems

Solar PV does not generate noise.

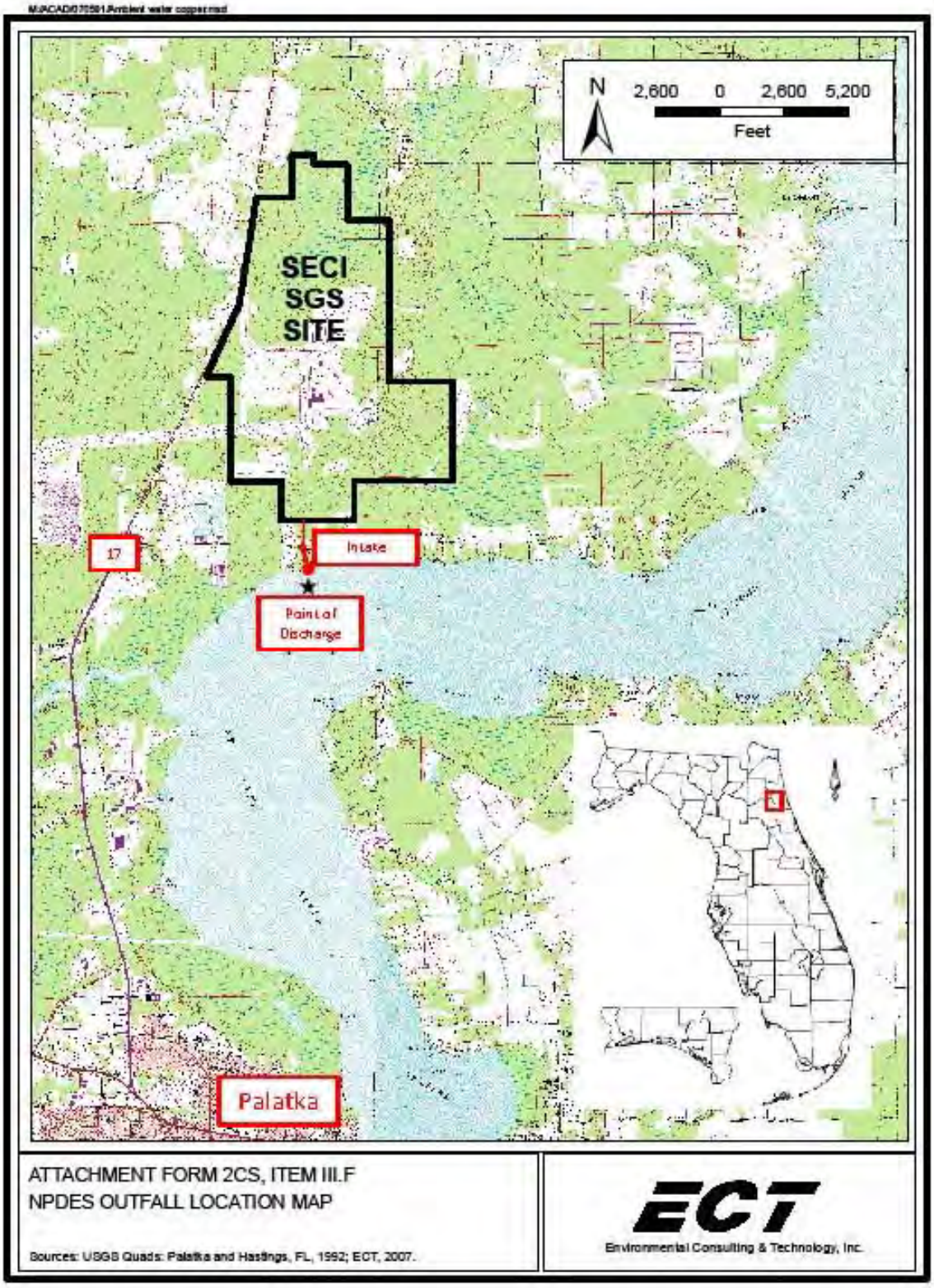
r. Status of Applications

Applications will be made to the Florida Department of Environmental Protection (FDEP) to amend the current Conditions of Certification for MGS. Hardee County will be contacted for local development approval.

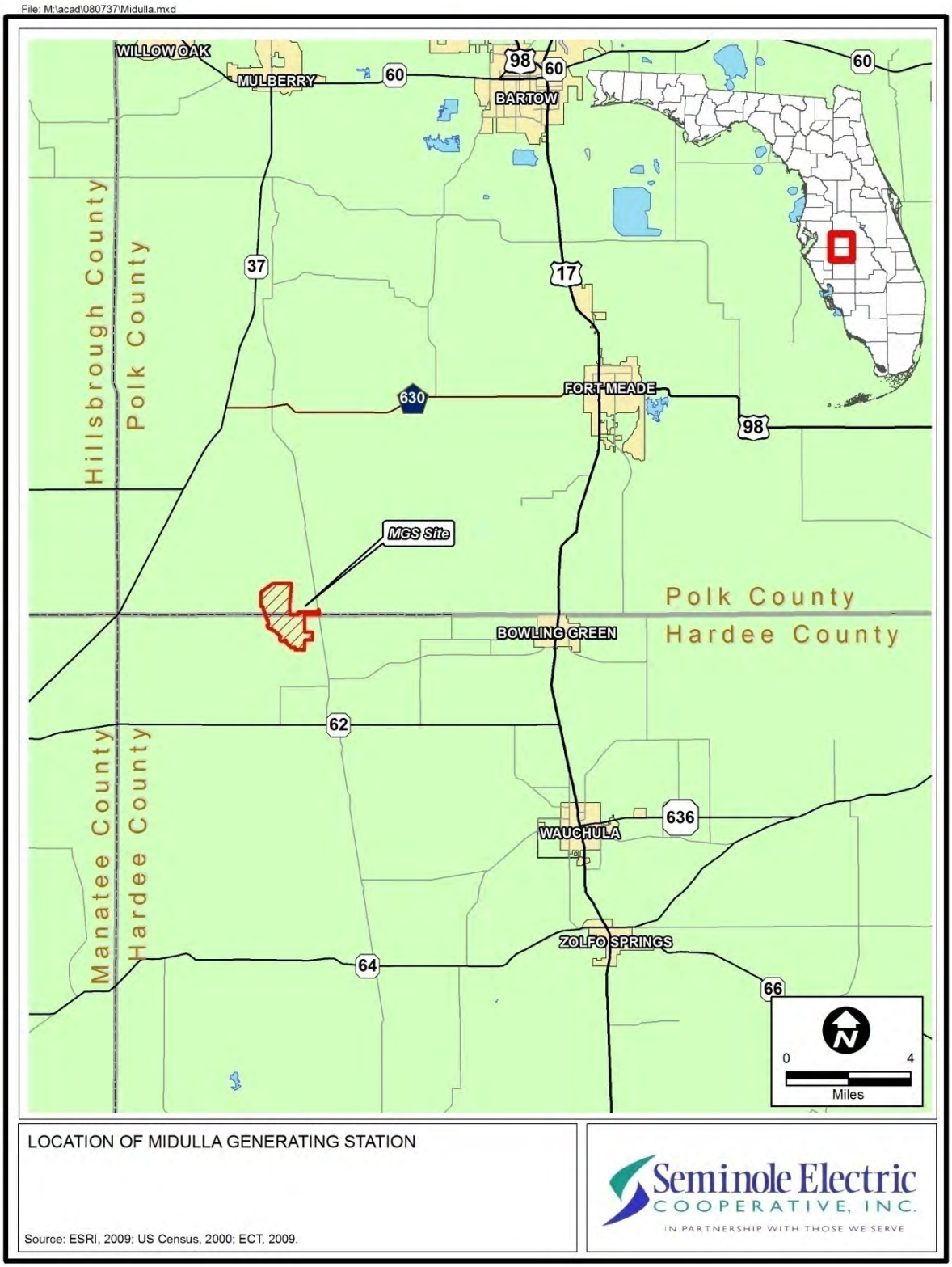
Map 3


File: M:\acad\080728\Gilchrist-county.mxd
Legend
Interstate Highway
US Highway
State Road
County Road
Property Boundary
100' Access Easement
Lakes and Rivers
Florida Managed Areas
Gilchrist County
Seminole Electric
Gilchrist Property
BRANFORD
FORT WHITE
HIGH SPRINGS
BELL
NEWBERRY
TRENTON
FANNING SPRINGS
ANDREWS
MANATTEE ROAD
CHIEFLAND
EAST BRONSON
WACCASASSA FLATS
SITE LOCATION MAP
Sources: FDOT, 2005; FDEP, 1989, 2002, FNAI, 2008; US Census, 2000; Seminole Electric 2008; ECT, 2008
Seminole Electric
COOPERATIVE, INC.

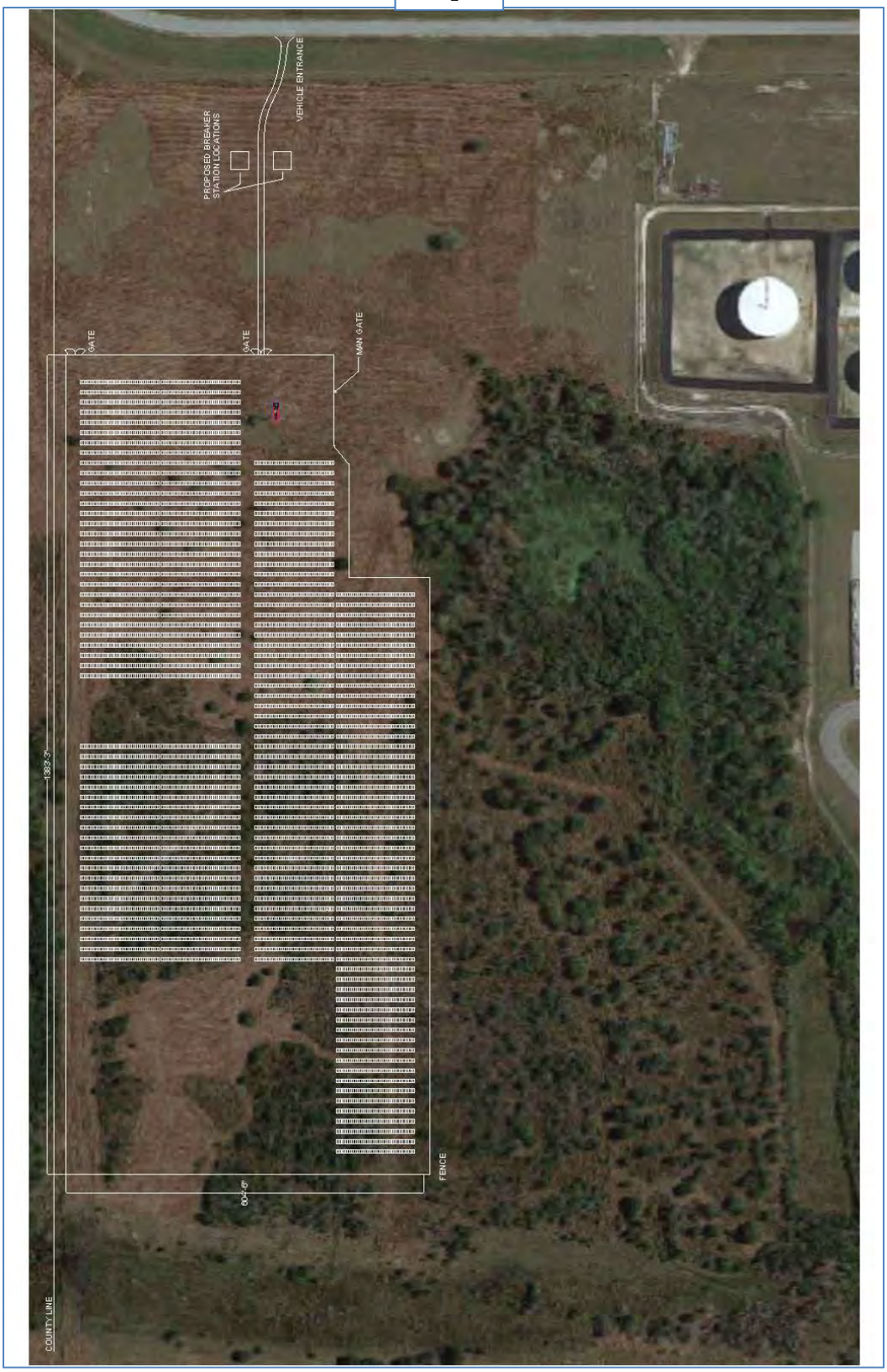
Map 4


N
2,600 0 2,600 5,200
Feet
SECI
SGS
SITE
17
Intake
Point of
Discharge
Palatka
ATTACHMENT FORM 2CS, ITEM III.F
NPDES OUTFALL LOCATION MAP
Sources: USGS Quads: Palatka and Hastings, FL, 1992; ECT, 2007.
ECT
Environmental Consulting & Technology, Inc.

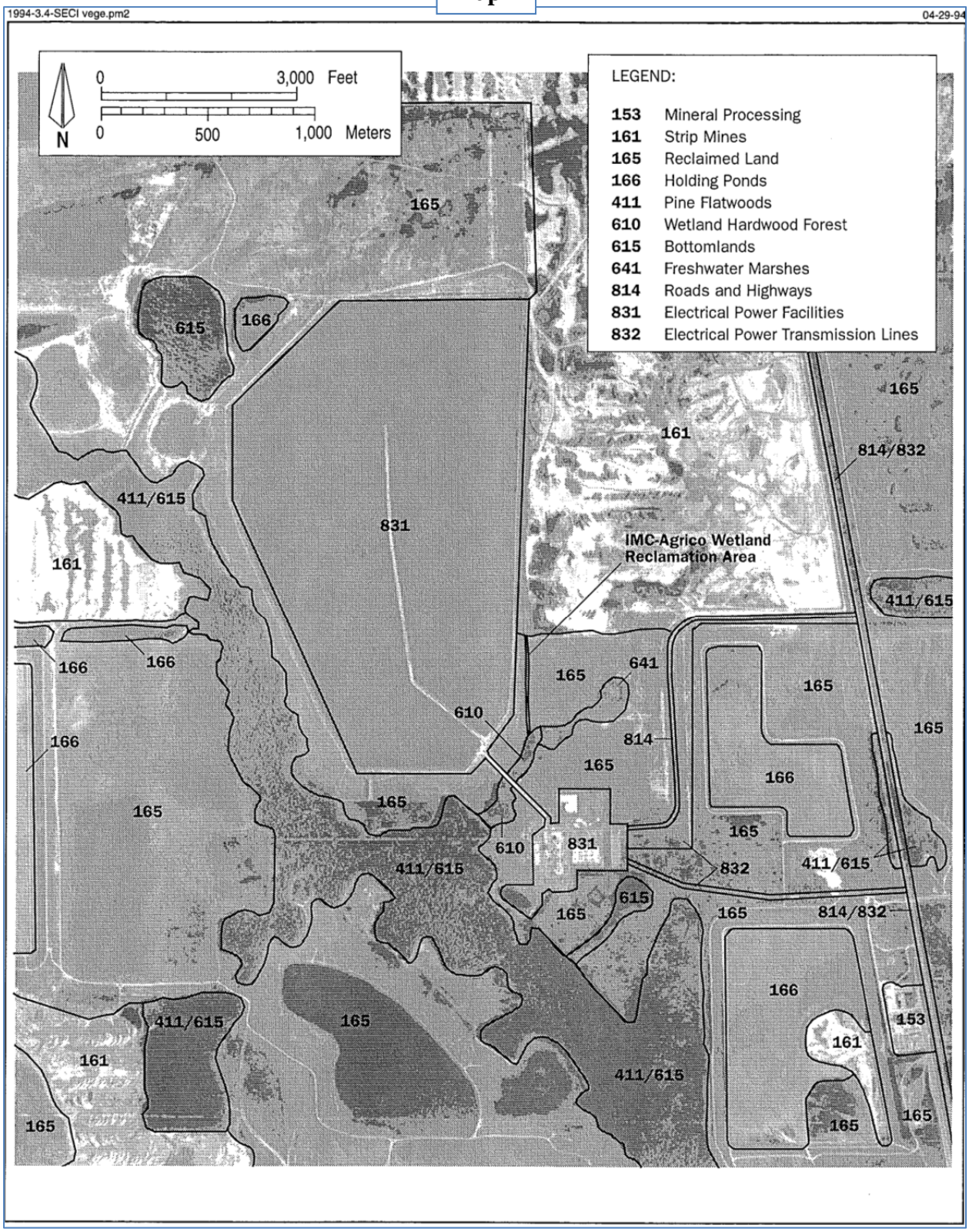
Map 5


File: M:\acad\080737\Midulla.mxd
WILLOW OAK
MULBERRY
BARTOW
FORT MEADE
BOWLING GREEN
WAUCHULA
ZOLFO SPRINGS
Hillsbrough County
Polk County
Manatee County
Hardee County
MGS Site
Polk County
Hardee County
60
98
37
17
630
62
636
64
66
0
4
Miles
LOCATION OF MIDULLA GENERATING STATION
Source: ESRI, 2009; US Census, 2000; ECT, 2009.
Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Map 6


PROPOSED BREAKER STATION LOCATIONS
VEHICLE ENTRANCE
GATE
GATE
MAIN GATE
1333'-3"
FENCE
COUNTY LINE

Map 7


1994-3.4-SECI vege.pm2
04-29-94
N
0 3,000 Feet
0 500 1,000 Meters
LEGEND:
153 Mineral Processing
161 Strip Mines
165 Reclaimed Land
166 Holding Ponds
411 Pine Flatwoods
610 Wetland Hardwood Forest
615 Bottomlands
641 Freshwater Marshes
814 Roads and Highways
831 Electrical Power Facilities
832 Electrical Power Transmission Lines
IMC-Agrico Wetland Reclamation Area

APPENDIX B

Seminole Electric Cooperative

Request for Proposal

& Addenda

Request for Proposals ("RFP")

Request for Firm Capacity
RFP No. FC 2021

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

March 1, 2016

Request for Proposals
RFP No. FC 2021

Table of Contents

1.0 Purpose
2.0 Description of Seminole Electric Cooperative, Inc.
3.0 RFP Provisions
4.0 Delivery to the Seminole System
5.0 Bidder Forms
6.0 Other Terms and Conditions
7.0 Reservation of Rights
8.0 Procedures for Application
9.0 Confidentiality
10.0 Bid Evaluation Process
11.0 Communication

Proposal Forms

All Bidders	Bidder Qualification Questionnaire
Schedule A	General Proposal Information
Schedule B	Firm Offer/Proposal Summary
Schedule C	Schedule for System Power Proposals
Schedule D	Schedules for New and Existing Unit Proposals

- Schedule D-1 Facility Information
- Schedule D-2 Pricing and Fuel Data
- Schedule D-3 Operating Performance Schedule
- Schedule D-4 Environmental and Regulatory Schedule
- Schedule D-5 Project Milestone Schedule
- Schedule D-6 Solar Energy Capacity Profile
- Schedule D-7 Air Emissions Schedule

Seminole Electric Cooperative, Inc.
RFP No. FC 2021

March 1, 2016
Request for Firm Capacity

1.0 Purpose

Seminole Electric Cooperative, Inc. ("Seminole") is seeking proposals from qualified and eligible bidders to provide up to 1,000 MW of firm capacity, beginning as early as June 1, 2021. Seminole has determined a need for capacity of 600 MW in June 2021, with total needs increasing to 1,000 MW in June 2022 and thereafter. Seminole encourages proposals of base, intermediate, and/or peaking capacity. Proposals providing demand side options will also be considered for evaluation. The evaluation among the proposals received will be seeking the least cost option, in consideration of all identified risks, when such resource(s) is operated as a part of Seminole's overall generation mix. Seminole is also evaluating self-build alternatives for the identified capacity needs.

2.0 Description of Seminole Electric Cooperative, Inc.

Seminole is an electric generation and transmission ("G&T") cooperative headquartered in Tampa Florida. Seminole provides wholesale electric service to nine (9) member electric distribution cooperatives ("Members"). The Members are located throughout peninsular Florida, serving loads located in 42 counties. More than 1,600,000 consumers rely on Seminole and its Members for electric service. Seminole has a current peak demand of approximately 3,500 MW, and continues to experience growth in its system.

Seminole supplies the Members' capacity and energy requirements from a mix of firm resources including both owned generation and purchased power agreements, supplemented by various interchange purchases. Seminole has an objective to continue to diversify its portfolio between resources it owns and purchased generation assets and is using this RFP to identify capacity and energy resources to help achieve this objective while meeting its future growth needs.

Seminole maintains "A" category investment grade credit ratings of A-/Stable with S&P and A3/Stable with Moody's. For additional information about Seminole, please see our website at **http://www.seminole-electric.com**.

3.0 RFP Provisions

3.1 This RFP is open to all parties, including, but not limited to: independent power producers, renewable energy providers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and electric utilities. Seminole will consider offers including purchased power proposals (system or tolling), generation proposals

that include Seminole taking an ownership/equity position in a portion of a facility, facility acquisitions, or proposals for firm energy.

3.2 Proposals received from specific units should be dispatchable and provide Seminole with scheduling flexibility (including real time control capability such as automatic generation control ("AGC")) and availability guarantees equivalent to the technical specifications of the units. Respondents should also indicate their ability to coordinate scheduled maintenance with Seminole.

3.3 Proposals sourced from a Seller's system of resources should be dispatchable and must offer intraday scheduling rights. Preference will be given to any proposals that can also provide contingency reserves, fast starts, and/or offer intra hour scheduling flexibility.

3.4 Seminole prefers the term of a proposal to be in the range of 2 years to 20 years, but may consider longer terms if proposed. Proposals longer than 30 years will not be considered.

3.5 Offers of capacity must be firm, from identifiable (either planned or existing) generating resources. Energy only products (such as Firm LD contracts) will be considered if adequate, reliable back-up capacity is specified and verifiable.

3.6 Proposals may be for less than the amount as shown in Section 1.0. However, proposals must be greater than a minimum of 25 MW.

3.7 Offers of capacity and energy may be from one or more resources. Such resources must be suitable to meet Seminole's firm load and/or reserve obligations Proposals based on system resources must provide Seminole with reliability equivalent to seller's firm native load customers.

3.8 Existing Seminole plant sites are not available for the addition of unit(s) to sell to Seminole.

3.9 Seminole also encourages the submission of proposals from renewable energy providers to meet its future power supply needs as defined in this RFP. Proposals from renewable resources do not have to be dispatchable, but must meet the 25 MW minimum stated in Section 3.6 above. Non-dispatchable renewable proposals of 75 MW or more will not be eligible to respond to this RFP and instead will need to pursue a standard offer agreement with Seminole, provided the facility has a Qualifying Facility certification under PURPA. Further details can be found on Seminole's website at **http://www.seminole-electric.com/index.php/S=0//site/qf**.

4.0 Delivery to the Seminole System

4.1 Seminole currently serves its load primarily through its own transmission system ("SSN") or through the transmission systems of Duke Energy Florida ("DEF") and Florida Power and Light Company ("FPL"). Wheeling and interconnection

arrangements and all costs to deliver the capacity and energy to the Seminole, DEF or FPL balancing authority areas are the responsibility of the bidder.

4.2 Proposed prices must include all integration and interconnection costs, and transmission network service upgrades to deliver the capacity and energy to one (or more) of the Seminole balancing authority areas.

4.3 All proposals must identify any wheeling and interconnection agreements with third parties that are required to deliver the capacity and energy to Seminole. Seminole requires that any transmission arrangements to deliver the offered capacity to the Seminole, DEF or FPL balancing authority areas to be firm. Seminole will accept and evaluate responses to the RFP in which arrangements of firm transmission for the delivery of energy to one of the Seminole balancing authority areas are in the process of being studied or finalized. In this case, the bidder should identify the underlying transmission service request, and provide Seminole with any existing studies and a summary of the study process and/or expected resolution.

4.4 For the benefit of the bidders in structuring their proposals, Seminole's forecasted peak loads in Winter 2022 in its three load serving balancing authority areas are as follows below. Bidders offering capacity amounts greater than the amounts listed in the SSN or FPL balancing authority areas will need to summarize their proposal to deliver the remainder of their offered capacity to one (or more) of the other balancing authority areas. Generally, Seminole does not want proposals for future generation resources to exceed the amount of its forecasted loads in any particular balancing authority area.

Balancing Authority Area	Winter Peak MW (2022)	Percentage (%) of Total Seminole Load
SSN	300	8
FPL	550	15
DEF	2,900	77
TOTAL	3,750	100

5.0 Bidder Forms

5.1 Bidders should complete and submit a Seminole Bidder Qualification Questionnaire ("BQQ") and Schedules A and B as part of each submittal. Schedules C through D will be completed by the bidders as required by the structure of their proposal. If

more than one submittal is made by a bidder, separate Schedules C through D must be prepared for each submittal.

5.2 All price quotes must be communicated on the attached Proposal Forms. Prices quoted shall always include all costs that Seminole would be expected to pay. Charges subject to change must be stated and estimates for the period provided along with their underlying assumptions.

6.0 Other Terms and Conditions

Each proposal must comply with all applicable federal and state laws. All permits, licenses, fees, emissions allowances, and environmental requirements are the responsibility of the bidder for the entire term of each proposal. If a resource detailed in a proposal is not yet in service, a detailed milestone schedule describing major project activities, including a permitting schedule, leading up to the commencement date for commercial service must also be provided. The minimum data required by Seminole to evaluate a bidder proposal is requested in Schedule D.

7.0 Reservation of Rights

Seminole expects to fulfill the capacity needs of this RFP through contracts resulting from this RFP, and/or from self-build options including joint ownership projects; however,

7.1 Seminole reserves the right to make resource commitments outside this RFP which result from (1) negotiated amendments to agreements with its current power suppliers, (2) negotiated arrangements with parties that Seminole is currently engaged in negotiations with for all or a portion of said capacity needs, or (3) negotiated arrangements for small power resources.

7.2 Seminole reserves the right, without qualification and at its sole discretion, to modify, supplement or withdraw this RFP and to reject any or all proposals or portions thereof or to waive irregularities or omissions. Those who submit proposals to Seminole do so without recourse against Seminole for either rejections by Seminole or failure to execute an agreement for any reason.

7.3 Seminole reserves the right to request further information, as necessary, to complete its evaluation of the proposals received.

7.4 No part of this RFP and no part of any subsequent communications with Seminole, its Members, trustees, employees, or officers shall be taken as providing legal, financial, or other advice, nor as establishing a commitment, promise or contractual obligation with a bidder.

7.5 Any negotiated contract shall be subject to the approval and award by the Seminole Board of Trustees.

8.0 Procedures for Application

8.1 A copy of this RFP, together with supporting forms, is on the Seminole website, "**www.seminole-electric.com**". The link to the RFP appears on the Seminole home page.

8.2 Bidders must submit their bid proposals via e-mail to the e-mail address below. Please note that an e-mail submission cannot exceed 20 MB in size. In addition, an **original bid proposal, signed by an authorized officer, plus two (2) copies must be mailed by either courier or U.S. Postal Service**. A separate point of contact for questions related to this RFP is defined in Section 11.4 below.

By Courier:
Seminole Electric Cooperative, Inc.
Attention: Mr. Timothy Nasello, Director of Supply Management
16313 North Dale Mabry Highway
Tampa, FL 33618

By U.S. Postal Service:
Seminole Electric Cooperative, Inc.
Attention: Mr. Timothy Nasello, Director of Supply Management
P.O. Box 272000
Tampa, FL 33688-2000

By E-Mail:
"**SeminolePowerRFP@seminole-electric.com**".

8.3 All proposals must arrive via e-mail by 5:00 PM Eastern Prevailing Time (EPT), **May 2, 2016**. Paper copies must arrive at Seminole's Tampa offices by 5:00 PM EPT on the next date (i.e., **May 3, 2016**). Seminole is not obliged to contact bidders concerning missing or incomplete forms. Only versions of the forms attached to this RFP may be used to submit proposals.

8.4 All bid packages should include any additional information required to support evaluation of the proposal, including a completed BQQ. Documents requested in support of the BQQ, including the applicant's most recent financial statements, must accompany the mailed versions of the proposals.

8.5 Seminole will not be assessing bidders a fee for any proposals submitted as a response to this RFP.

9.0 Confidentiality

9.1 Seminole recognizes that certain information contained in proposals submitted may be confidential and, as permitted by applicable law, will use reasonable efforts to maintain the information contained in the proposal as confidential. Seminole will not

treat submitted information as confidential if it already has the information, the information is clearly in the public domain or is readily available from public sources. However, Seminole reserves the right to submit the proposal to the Rural Utilities Service ("RUS") and to any other regulatory agency or judicial authority that may request it.

9.2 Seminole also reserves the right to disclose any or all of the information submitted in response to this request to any consultant(s) or attorney(s) retained by Seminole to assist with aspects of this process. Seminole will take reasonable steps to ensure that its consultant(s) or attorney(s) will also treat information received from bidders as confidential; however, Seminole will not be liable for any failure or for any damages of any consultant(s) or attorney(s) to do so. It is recommended that bidders clearly mark any response forms they desire to keep confidential as "Confidential".

10.0 Bid Evaluation Process

The procedures and criteria utilized to evaluate proposals will be as follows: first, to determine if the proposals are responsive to the RFP; second, to evaluate proposals from a technical, operational and commercial viewpoint, third, to evaluate proposals from an economic viewpoint, and fourth, if determined to be in the best interests of Seminole to develop a short-list for negotiations. Received proposals will be compared to Seminole's self-build alternatives as well as the other proposals. Seminole will use its planning and financial models to perform the analysis on the terms and conditions of each RFP proposal.

10.1 The economic evaluation of the RFP will use common economic assumptions for all proposals where appropriate.

10.2 Proposals may undergo a review from a technical and operational perspective on the following items:

- to ensure that the service offered is consistent with this RFP based upon the factors included herein, including, but not limited to:
  - a commercially viable term;
  - the reliability of the proposed power supply;
  - acceptable operational and scheduling characteristics;
  - acceptable fuel supply;
  - acceptable siting, construction and permitting plan (if applicable);
  - acceptable third party transmission arrangements (if applicable);
- to confirm that the capacity and energy will be delivered to the Seminole, DEF or FPL transmission systems, and can be delivered further to Seminole's member delivery points within the control areas of Seminole, DEF and/or the FPL; and if wheeling is required, that a firm transmission path will be available during the term;
- to evaluate the number and type of exceptions taken to the terms and

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 1
ISSUED MARCH 18, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 1 in response to general questions and inquiries applicable to all potential bidders.

1. **RFP Proposal Forms.** Seminole has modified Schedule D-1, Facility Information. Modifications were made to the "Average Heat Rate Curves" portion of the form based on bidder questions. The changes made are as follows: 1) winter values were eliminated from Seminole's data request, 2) specific data for certain percentages of capacity states/unit output (100%, 80% 60% and minimum output were requested), and 3) comments were added to individual cells to facilitate bidder use of the form. The remaining forms were unchanged from those issued with the RFP on March 1, 2016.

2. **Seminole Self-Build Option.** Several bidders have requested general information on Seminole's self-build alternative. Seminole is evaluating a self-build combined cycle option. Generally, Seminole is reviewing both a 1x1 and a 2x1 combined cycle option. The power island equipment for the self-build project has not yet been selected, and multiple sites are being assessed. MW output will range from about 550 MW to 1150 MW, and any constructed generation will be expected to be fully commercial by June 2021.

3. **Proposals Beginning Before June 2021.** Several bidders have asked if their proposals can start before June 1, 2021. The reason Seminole chose June 1, 2021 as a start date is because that is the first period of significant capacity need in Seminole's portfolio. Any proposal with a start date prior to June 2021 will be considered compliant with the RFP and will be evaluated by Seminole staff. However, any proposals with an earlier than requested start date will be evaluated against Seminole's existing portfolio to ascertain any potential energy benefits, and capacity will have a minimal value, if any.

4. **Hourly Loads in the FPL Balancing Authority Area.** Several bidders have asked if they can obtain historical hourly loads for Seminole in the FPL BAA. Seminole has provided these historical loads (by individual delivery point) for years 2013-2015 as part of this RFP addendum so that it is available for all bidders.

5. **Variable Generation/Non-Dispatchable Generation.** Several bidders have asked if they can provide proposals of greater than 75 MW of non-dispatchable generation in response to the RFP. Seminole has reviewed the cap (less than 75 MW) in Section 3.9 of RFP FC 2021 and still prefers proposals of less than 75 MW. However, any proposal of 75 MW or greater will be considered compliant with the RFP and will be evaluated by Seminole staff.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 2
ISSUED APRIL 7, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 2 in response to general questions and inquiries applicable to all potential bidders. A number of bidders have asked for further detail regarding distribution, transmission facilities and wheeling.

1. **Seminole Network Resources – Transmission Level Interconnection.** If the proposed resource interconnects with 69kV (or higher) voltage on the transmission system in either of the Duke Energy Florida ("DEF") or Florida Power and Light ("FPL") balancing authority areas, Seminole will request to designate the resource a "designated network resource" for the respective balancing authority area. If a proposed resource is approved as a designated network resource, that resource will serve Seminole's native load in that balancing area and no incremental wheeling costs will be assessed. Similarly, if the project interconnects with the Seminole transmission system, there will be no incremental wheeling costs for the bidder or Seminole.

2. **Seminole Network Resources – Distribution Level Interconnection.** If the proposed resource interconnects at the distribution level on the FPL or DEF systems (below 69kV) there will be additional wheeling charges and losses for the bidder. The bidder is responsible for the distribution wheeling charges and the related energy losses. Under the RFP requirements, the bidder's delivery of energy must be made to Seminole at transmission level.

3. **Resources from SERC.** Seminole will accept proposals delivering to the FL-GA interface on firm transmission. Seminole will then request that the resource be a designated network resource on either the FPL or DEF transmission system and there will be no incremental wheeling costs.

Below is a list of Frequently Asked Questions regarding Transmission Arrangements for Proposals to RFP FC 2021:

Question: For this RFP, would projects that are in an interconnection queue have a preference over those not in the queue?

Answer: Yes. Proposals that are submitted without any work on interconnection/transmission wheeling may be considered non-compliant with the RFP requirements (see section 4.3).

Question: At the time of submission of the bid proposal, the supplier would not have any interconnection studies back from the transmission provider. Would this be an issue?

Answer: No. Per section 4.3 of the RFP, it is acceptable for interconnection or wheeling arrangements to be in study status. Generally, it would be unusual for a proposal to have secured all of the necessary transmission prior to submitting a bid, simply due to the amount of time it takes to finalize such arrangements.

Question: For this RFP, is there a preference to direct connect to the Seminole Electric transmission system or to interconnect into the FPL or DEF balancing areas?

Answer: In terms of our economic evaluation, projects interconnecting with a) Seminole's balancing area, b) Seminole's distribution members, c) DEF's balancing area (@ 69kV or above), or d) FPL's balancing area (@ 69kV or above) will all be treated equally.

Question: Is site control for the project required to participate in this RFP?

Answer: Yes. Please see sections 4.1 and 4.2 of RFP FC 2021.

Question: What is the definition of firm and non-firm used in this RFP?

Answer: Firm transmission will be requested by the bidder as 7-FN from the relevant transmission provider. Any transmission arrangements designated in classes NS-1 through NM-5 are considered to be non-firm.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 3
ISSUED APRIL 19, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 3 in response to general questions and inquiries applicable to all potential bidders. A number of bidders have asked for relief on the bid due date. In addition, Seminole has clarified its "Procedures for Application" in section 8.0. The clarifications to section 8.0 are largely in response to our finalization of an independent evaluation process for the RFP. Sedway Consulting, Inc. (with Alan Taylor as the principal contact) will be providing an independent evaluation of Seminole's RFP process and will need to be copied on all RFP FC 2021 proposals. Please see the revised section 8.0 below.

8.0 Procedures for Application

8.1 A copy of this RFP, together with supporting forms, is on the Seminole website, "**www.seminole-electric.com/index.php/S=0/site/suppliers**". The link to the RFP documents appears on the bottom half of the page.

8.2 Bidders must submit their bid proposals via e-mail to the e-mail addresses below. Please note that an e-mail submission cannot exceed 7 MB in size. ".ZIP" files are acceptable if larger documents need to be submitted. If a Bidder finds that its proposal materials may still exceed the 7 MB limit, the Bidder should split its submission materials into two or more emails. In addition to the e-mail submittal, **an original bid proposal, signed by an authorized officer, plus two (2) copies must be mailed by either courier or U.S. Postal Service**. A separate point of contact for questions related to this RFP is defined in Section 11.4 below.

By Courier:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

16313 North Dale Mabry Highway

Tampa, FL 33618

By U.S. Postal Service:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

P.O. Box 272000

Tampa, FL 33688-2000

By E-Mail:

SeminolePowerRFP@seminole-electric.com

With a carbon copy to:

Alan.Taylor@sedwayconsulting.com

8.3 All proposals must arrive via e-mail by 5:00 PM Eastern Prevailing Time (EPT), **May 9, 2016**. Paper copies must arrive at Seminole's Tampa offices by 5:00 PM EPT on the next date (i.e., **May 10, 2016**). Seminole is not obliged to contact bidders concerning missing or incomplete forms. Only versions of the forms attached to this RFP may be used to submit proposals.

8.4 All bid packages should include any additional information required to support evaluation of the proposal, including a completed BQQ. Documents requested in support of the BQQ, including the applicant's most recent financial statements, must accompany the mailed versions of the proposals.

8.5 Seminole will not be assessing bidders a fee for any proposals submitted as a response to this RFP.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 4 - OPERATING PERFORMANCE
ISSUED JULY 13, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 4 to expand upon the information previously requested by Seminole in Schedule D-3 to RFP FC 2021. Please review the questions below and respond by COB Tuesday, July 19, 2016 to all questions applicable to your proposal. If a question is not applicable to your proposal, please add a response of "Not Applicable" in the answer section. Seminole's RFP Provisions 3.2 and 3.3 from RFP FC 2021 are also included below for your ease of reference.

> 3.2 Proposals received from specific units should be dispatchable and provide Seminole with scheduling flexibility (including real time control capability such as automatic generation control ("AGC")) and availability guarantees equivalent to the technical specifications of the units. Respondents should also indicate their ability to coordinate scheduled maintenance with Seminole.
>
> 3.3 Proposals sourced from a Seller's system of resources should be dispatchable and must offer intraday scheduling rights. Preference will be given to any proposals that can also provide contingency reserves, fast starts, and/or offer intra hour scheduling flexibility.

Seminole's additional questions regarding operational performance follow below:

1. Question: Please describe the desired next day scheduling requirements for your proposal. Your response should include information on the timing of scheduling notification, flexibility in regards to energy requested, delivery/nomination of fuel (if applicable), scheduling increments and requested method of communication.

   Answer:

2. Question: Please describe the desired intraday scheduling requirements for your proposal. Your response should include information on the timing of scheduling notification, flexibility in regards to energy requested, delivery/nomination of fuel (if applicable), scheduling increments and requested method of communication. Please distinctly note any desired differences between the next day and intraday processes. Are there any limits on the amount of schedule changes permitted in a single day?

   Answer:

3. Question: Regarding intraday scheduling rights, what is the minimum notice period (in minutes) that Seminole can provide for schedule adjustments? Please note that Seminole's preference would be to have the ability to call on energy from the resource within thirty (30) minutes at any point during a clock hour.

   Answer:

4. Question: Regarding intraday scheduling rights, would Seminole have any additional flexibility (beyond the intraday scheduling rights described in item 3 above) available in the event of an emergency situation (such as an unplanned transmission or generation outage) on its system? Seminole's preference for the availability of energy is notes in item 3 above.

   Answer:

5. Question: If your proposal is from a specific unit(s), would Seminole have available the full technical capability of the unit(s) for scheduling purposes? If not, what restrictions exist?

   Answer:

6. Question: If your proposal involves Seminole tolling the natural gas fuel for the requested energy, please note if Seminole will be the pipeline delivery point operator for the facility. Are the proposed units offered to Seminole on their own gas meter?

   Answer:

7. Question: If fuel supply for Seminole's energy requirements is included in your proposal, would Seminole have any optionality to bring its own fuel for its energy needs?

   Answer:

8. Question: Regarding the ramp in of energy schedules, please define a typical ramp in period for your proposal and any flexibility that may be available outside of ramping at the top and bottom of the hour. Seminole, as an FRCC entity, is accustomed to a 20-minute ramp schedule. Is dynamic scheduling available from your resource?

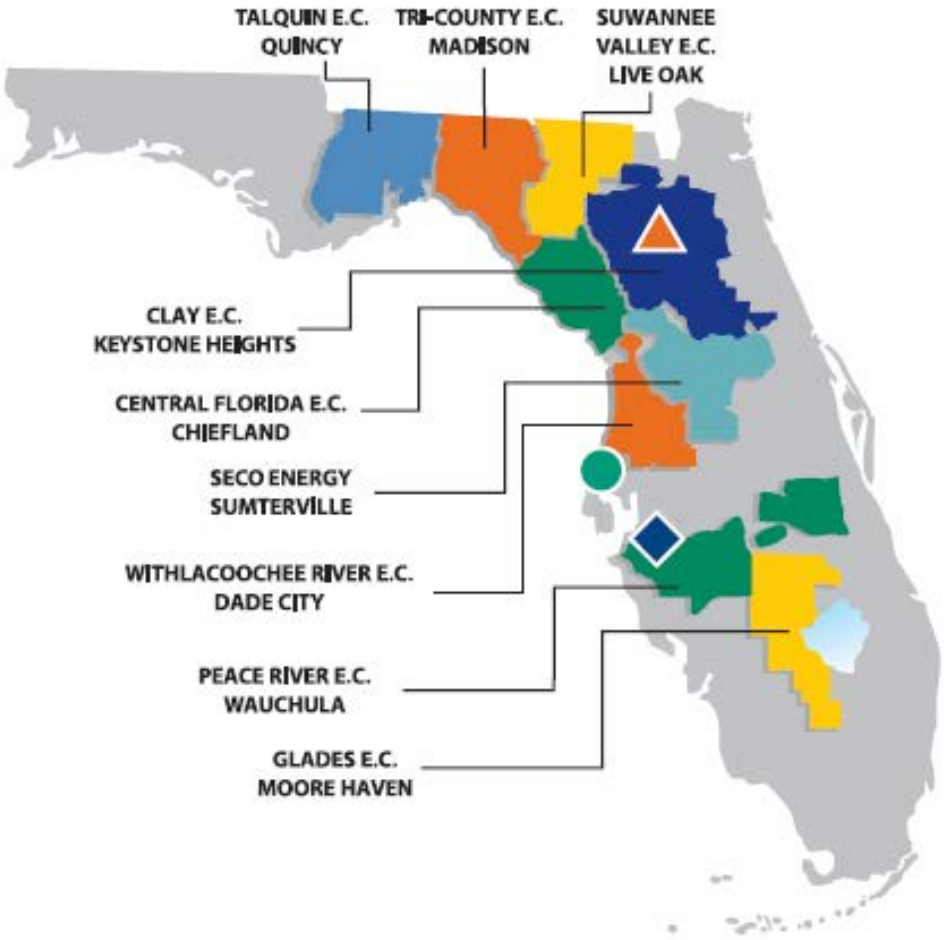
   Answer:

9. Question: Regarding availability, if your proposal is from a specific unit, please describe both the historical availability and capacity factor of the facility for each month during calendar years 2013-2015.

   Answer:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 4
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Michael P. Ward II MPW-3

SEMINOLE'S MEMBER COOPERATIVES



SEMINOLE HEADQUARTERS
16313 North Dale Mabry Highway / P.O. Box 272000
Tampa, Florida 33688-2000 / (813) 963-0994

RICHARD J. MIDULLA GENERATING STATION
6697 North County Road 663 / Bowling Green, FL 33834

SEMINOLE GENERATING STATION
890 Highway 17 North / Palatka, FL 32177

Seminole's Purchase Power Contracts
(as of December 31, 2016)

SUPPLIER	FUEL	MW (WINTER RATINGS)	IN SERVICE DATE	END DATE
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	50	6/1/2016	12/31/2018
DEF	System	200-500	6/1/2016	12/31/2024
DEF	System	50-600	1/1/2021	3/31/2027
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026

Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 5
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Michael P. Ward II MPW-4

Seminole's New Purchase Power Contracts

Supplier	Fuel	MW	In Service Date	End Date
Shady Hills Energy Center LLC	Gas	575*	12/1/2021	11/30/2051
Shady Hills Power Company LLC	Gas/Oil	364*	6/1/2024	5/31/2032
Oleander Power Project	Gas/OIl	546*	6/1/2021	12/31/2021
Southern Company Services	System	100-150*	6/1/2021	5/31/2026
DEF	System (IM)	50-400*	1/1/2021	12/31/2030
DEF	System (Peaking)	50-400*	1/1/2021	12/31/2035
Tillman Solar Center LLC	Solar/PV	40**	6/1/2021	5/31/2041

* Winter ratings
** Summer rating

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DOCKET: 20170266-EC EXHIBIT: 6
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Michael P. Ward II MPW-5

David L. Kezell, Seminole Electric Cooperative, Inc.

SUMMARY

Talented leader with more than 25 years of varied experience in general management, engineering management, construction management, power plant operations and maintenance, and environmental and engineering consulting roles. Currently responsible for all capital projects and future power resource development for a generation and transmission cooperative in Tampa, Florida.

EXPERIENCE

2013 – Present **Director of Engineering and Capital Development, Seminole Electric Cooperative, Tampa, FL**

Responsible for corporate engineering and development efforts. Developed a front-end planning system to evaluate and develop capital and large O&M projects in a multiple step, gated process intended to be used prior to finalizing budget-approved projects. Administer Seminole's multi-year Construction Work Plan (CWP) and the Cooperative's Capital Budget and Work Plan.

2010 - 2013 **General Manager, WorleyParsons, Chattanooga, TN**

Complete general manager responsibilities for all operations, including P&L, personnel, contracts and client relations, for WorleyParsons' Chattanooga, Tennessee office, which consisted of 150+ employees. Directed the management of power, mining and minerals, and chemical projects for Chattanooga Operations.

2006 - 2010 **Manager of Construction, WorleyParsons, Eastern Operations, Reading, PA**

Directed the management of power, mining and minerals, environmental, and chemical construction projects for the Eastern United States. Supported business development on proposals and client presentations. Recruited construction management personnel from internal and external sources. Managed staff of 40 geographically dispersed construction managers.

2005 - 2006 **Principal Mechanical Engineer and Project Manager, WorleyParsons, Reading, Pennsylvania**

Provided mechanical engineering and project management services on conceptual design, equipment layout, flow diagram, and cost estimating efforts.

2004 - 2005 **Plant Manager, GWF Power Systems, Inc., Pittsburg, California**

Managed daily operations of a 22 MW fluidized bed combustor Rankine cycle plant burning petroleum coke. Directly responsible for all on-going operations and maintenance activities required to achieve operational and financial objectives for the business unit as well as for compliance with all environmental permits.

2001 - 2004 **Engineering Supervisor, GWF Power Systems, Inc., Pittsburg, California**

Responsible for hiring and supervising engineering and support staff, as well as administering contracts for all contracted engineering and professional services. Responsible for the conceptual development, cost estimating, payback analysis, and justification of capital improvements and plant modifications.

2001 - 2002 **Project Manager, GWF Power Systems, Inc., Pittsburg, California**

Hanford Energy Park Peaker and Henrietta Peaker Plant Projects. Responsible for the execution of the conceptual development, engineering, procurement, construction, and start-up of

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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: David Kezell DK-1

two plants adding a total of 190 MW of peaking capacity to the California power grid during the critical summers of 2001 and 2002.

1997 - 2001 **Project Engineer/Construction Manager, GWF Power Systems, Inc., Pittsburg, CA**

Responsible for conceptual and detailed design, permitting, bidding, contracting, and construction management for various projects retrofitted into petroleum coke-fired power plants. Projects included retrofit of natural gas lines into five plants, replacement of oil-fired burners with low NOx natural gas burners, improvements to pneumatic flyash handling systems, fan upgrades, and replacement of CEM data acquisition systems.

1991 - 1997 **Engineering Roles, Duke Engineering & Services, Inc., San Ramon, California**

Served power, industrial, mining, institutional, and university clients in progressively responsible mechanical engineering, project engineering, and environmental compliance consulting roles.

1989 - 1991 **Research Assistant, The Center for Energy Systems Research, Tempe Arizona (An Energy Research Organization Associated with Arizona State University)**

Represented Arizona State University, in the absence of the center director, on The Advisory Committee on Energy Policy and Planning formed by the Arizona State Legislature. Presented a technical forum on the concept of energy sustainability to the committee. Researched environmental impacts of energy use.

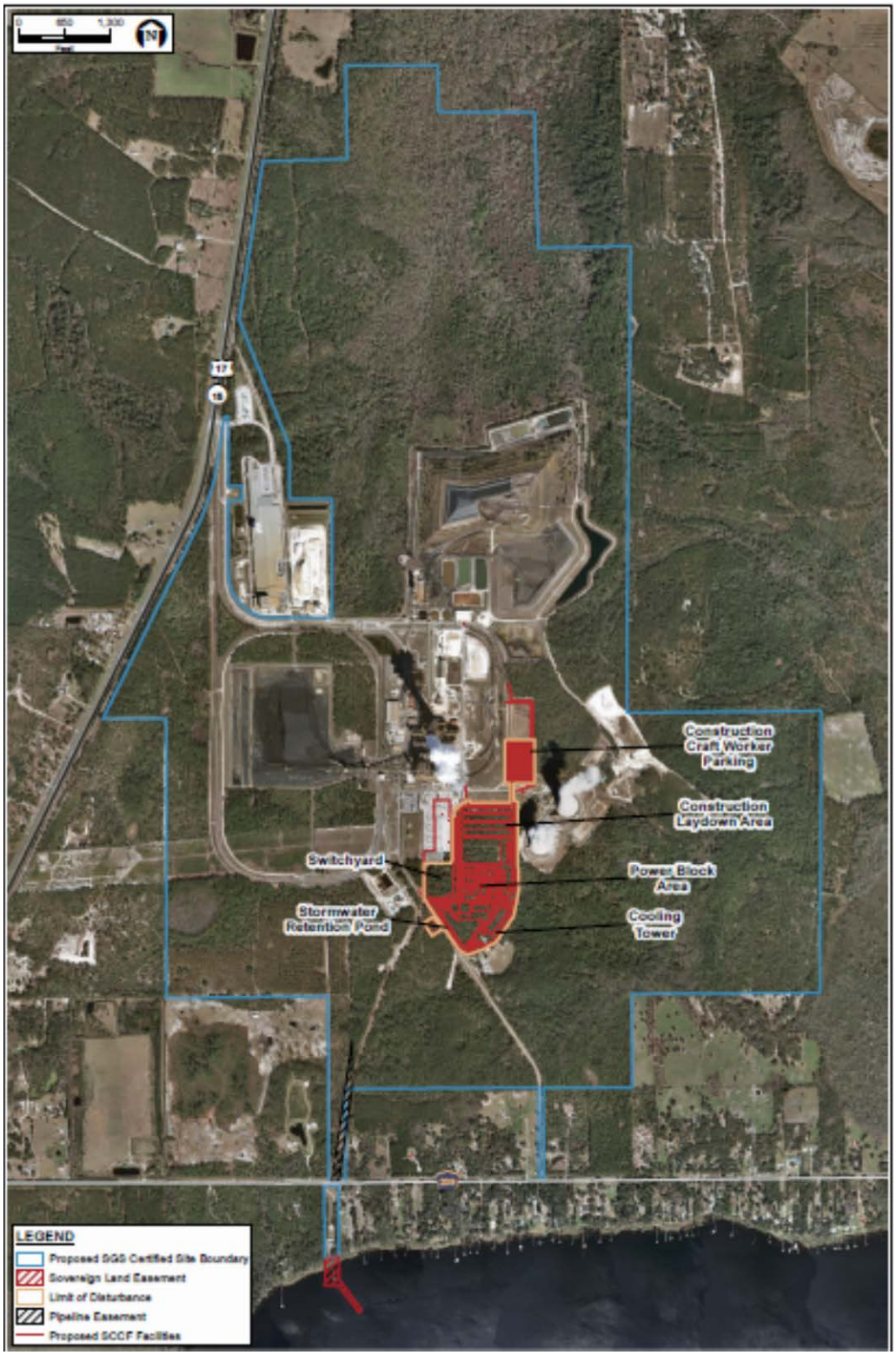
EDUCATION

- M.S., Mechanical Engineering, Arizona State University
- B.S., Mechanical Engineering, The Pennsylvania State University
- B.A., General Arts and Sciences, The Pennsylvania State University

REGISTRATIONS / AFFILIATIONS / PERSONAL

- Generation, Environment and Carbon Dioxide Membership Advisory Group Member, National Rural Electric Cooperative Association (NRECA) Business and Technology Strategy Unit, 2014 - Present
- Vistage CEO Group 3139 based in Knoxville, TN, member 2010 – 2013
- Registered Professional Mechanical Engineer, California, No. 28946, since 1994
- Facilitated Franklin-Covey 7 Habits of Highly Effective People Training Sessions 2003 - 2005
- Certificate, Air Quality Management, University of California, Berkeley Extension, 1995
- Fluent in Spanish

Preliminary Arrangement of the SCCF at the SGS site



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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: David Kezell DK-2

Seminole Combined Cycle Facility Capital Cost Estimate	
Equipment and Interconnection	$220,000,000
Development and EPC Contract	$381,000,000
Other Owner's Costs and Contingency	$ 63,000,000
Interest During Construction	$ 45,000,000
Financing	$ 1,000,000
Insurance	$ 17,000,000
TOTAL	$727,000,000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 9
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: David Kezell DK-3

P2021 SINGLE FUEL FACILITY ANALYSIS

BLACK & VEATCH PROJECT NO. 190285

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DOCKET: 20170266-EC EXHIBIT: 10
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: David Kezell DK-4

PREPARED FOR

SEMINOLE ELECTRIC COOPERATIVE, INC.

8 AUGUST 2016

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Black & Veatch Statement

This report was prepared for Seminole Electric Cooperative, Inc. ("Client") by Black & Veatch Management Consulting, LLC ("Black & Veatch") and is based on information not within the control of Black & Veatch. In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies Black & Veatch utilized in performing the analysis and making these projections follow generally accepted industry practices. While Black & Veatch believes that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this report are advised that any projected or forecast price levels and price impacts, reflects the reasonable judgment of Black & Veatch at the time of the preparation of such information and is based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, Black & Veatch recommends that periodic updates of the forecasts contained in this report should be conducted so recent historical trends can be recognized and taken into account.

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1.0 Executive Summary

Seminole Electric Cooperative, Inc. (SECI) is developing natural gas fired combined cycle self-build power plant options for its future energy resource needs. SECI's preliminary decision is to have this potential new facility be fired with natural gas only. In order to confirm or change that preliminary decision, SECI requested that Black & Veatch analyze the natural gas infrastructure, provide an estimate of the cost to add fuel oil firing capability to the proposed new facility, and review national and regional trends with respect to fuels in advanced class combined cycle facilities.

Florida has no native natural gas production. Two pipelines, the Florida Gas Transmission Pipeline ("FGT") and the Gulfstream Natural Gas System ("Gulfstream") provide more than 90% of the total natural gas supply capacity into the Florida Reliability Coordination Council ("FRCC"). These two pipelines have the capacity to deliver approximately 4.4 billion cubic feet per day ("Bcf/day") of natural gas into Florida. More than 80% of the natural gas supply from these two pipelines is dedicated to serving electric generation needs in Florida. A third pipeline, the Sabal Trail Transmission Pipeline ("Sabal Trail"), scheduled to be in service in May 2017, will add 1Bcf/day delivery capacity into Florida and greatly improve its gas supply diversification.

Historically, large scale natural gas pipeline failures with extended periods of supply disruptions have been rare incidents. In addition, most of the pipeline incidents can be partially mitigated by pipeline looping, storage withdrawals, and alternative supplies from interconnecting pipelines. For Florida, only the 1998 lightning strike on the FGT Perry compressor station was reported to have a significant impact on Florida's natural gas supplies, which was mitigated with backup fuels and demand side responses. Increasing shale gas productions in addition to supply and transportation diversification are likely to have muted the impact of supply disruptions such as Gulf of Mexico production curtailments caused by hurricanes. In its 2015 Reliability Assessment, FRCC concluded there will be sufficient back-up fuel capability to cover short-term natural gas supply interruptions.[1] Specifically, FRCC's Fuel Reliability Working Group (FRWG) studied the potential impact from the loss of key compressor stations and found that only some localized gas reductions would occur, which could be mitigated by dual-fuel capabilities.[2]

Based on the review the Pipeline and Hazardous Materials Safety Administration (PHMSA) data and the pipeline Operational Flow Order (OFO) notices, natural gas supplies into and through Florida are predominantly reliable. However, supply diversifications and dual-fuel capabilities are still critical to ensure resource adequacy during extreme events. With the increasing share of natural gas utilized in electricity generation, more emphasis is being placed on the interdependence between gas and power, and coordination strategies to address potential fuel supply interruptions due to unforeseeable conditions.

[1] FRCC 2015 Load & Resource Reliability Assessment Report, FRCC, July 7, 2015
[2] 2015 Long-Term Reliability Assessment, NERC, December 2015

Florida is well served with the existing dual-fuel generating units. Out of the total 40,788 MW of operating combined cycle and combustion turbine units, 31,506 MW or approximately 77% of the total capacity is equipped with dual fuel capabilities.[3] This is equivalent to approximately 5.3 Bcf/day of natural gas consumptions, if all the units are fired up simultaneously. An additional 2,764 MW of dual fuel units are proposed to be constructed before 2020, equivalent to approximately 0.5 Bcf/day of natural gas consumptions. At the State level, the dual fuel capability is expected to be relatively stable in the foreseeable future.

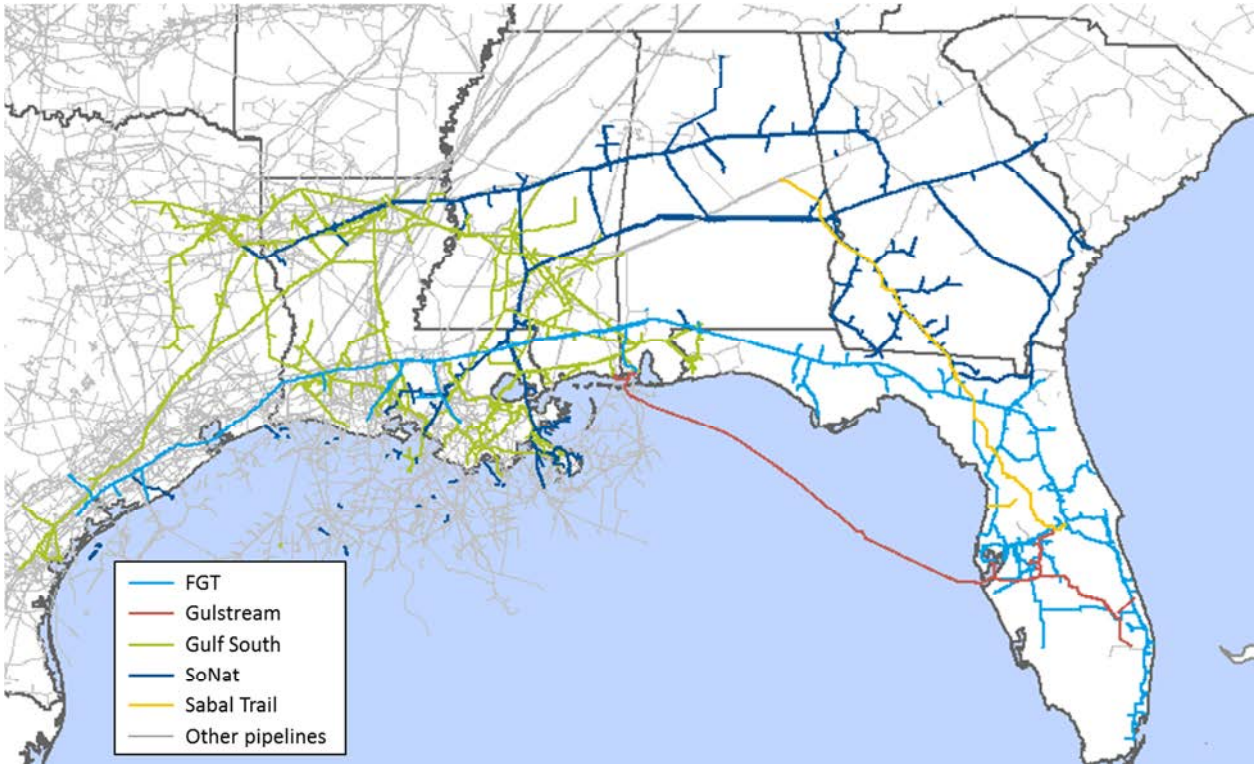
For SECI, this study will assume the addition of the 1,050 MW P2021 as a single fuel plant, and the retirement of SGS, approximately [49%] of its peak load will be met with owned generations. Within its own generation portfolio of approximately [1,860] MW, [44%] will have dual fuel capabilities, equivalent to a gas consumption of approximately 0.25 Bcf/day. Based on the high level review of the existing fuel oil capabilities within Florida and within the SECI fleet, it appears SECI will be adequately served without additional dual fuel capabilities at the portfolio level. However, we have not performed any site-specific fuel reliability analysis or cost/benefit projections. Considering the environmental and permitting impacts with dual fuel operation, and the reliable nature of the natural gas supply in Florida, the incremental benefit to add fuel oil as backup for P2021 may be limited.

[3] Black & Veatch research based on data provided through Velocity Suite, AGG Enterprise Software

2.0 Natural Gas Infrastructure Serving Florida

Florida has little to no natural gas production within the state; therefore it is reliant on supplies from four interstate natural gas pipelines to meet its annual demand for over 1,200 Bcf of natural gas.[4] These four pipelines are Florida Gas Transmission ("FGT"), Gulfstream Natural Gas System ("Gulfstream"), Southern Natural Gas ("SoNat"), and Gulf South Pipeline ("Gulf South"). SoNat and Gulf South do not directly supply Florida's power generation fleet, so the primary focus of this analysis will be on FGT, Gulfstream, and a proposed new interstate pipeline, Sabal Trail Transmission ("Sabal Trail"), which will also be used to serve the power generation load. The routing of all five pipelines is shown below in Figure 1.

Figure 1 Natural Gas Pipelines into Florida



Source: Velocity Suite, ABB Enterprise Software

Together, FGT and Gulfstream are capable of delivering up to approximately 4.4 Bcf/d of natural gas into FRCC. If Sabal Trail enters service, it will add another 1.0 Bcf/d to this capacity. A brief summary of the five pipelines is shown in

[4] EIA Natural Gas Consumption data

Table 1.

Table 1 Pipelines Supplying Florida: Summary Information

PIPELINE	LENGTH (MILES)	CAPACITY INTO FLORIDA (MMCF/D)	ANNUAL AVERAGE THROUGHPUT INTO FLORIDA, 2015-2016 GAS YEAR (MMCF/D)
Florida Gas Transmission	5,325	3,044	2,411
Gulfstream Natural Gas System	745	1,370	1,221
Southern Natural Gas Company	6,984	395*	231
Gulf South Pipeline Company	6,663	190**	104
Sabal Trail Transmission	516	1,000	0
Total Existing into FRCC	**—**	**4,414**	**3,632**
Total Existing into Florida	**—**	**4,999**	**3,863**

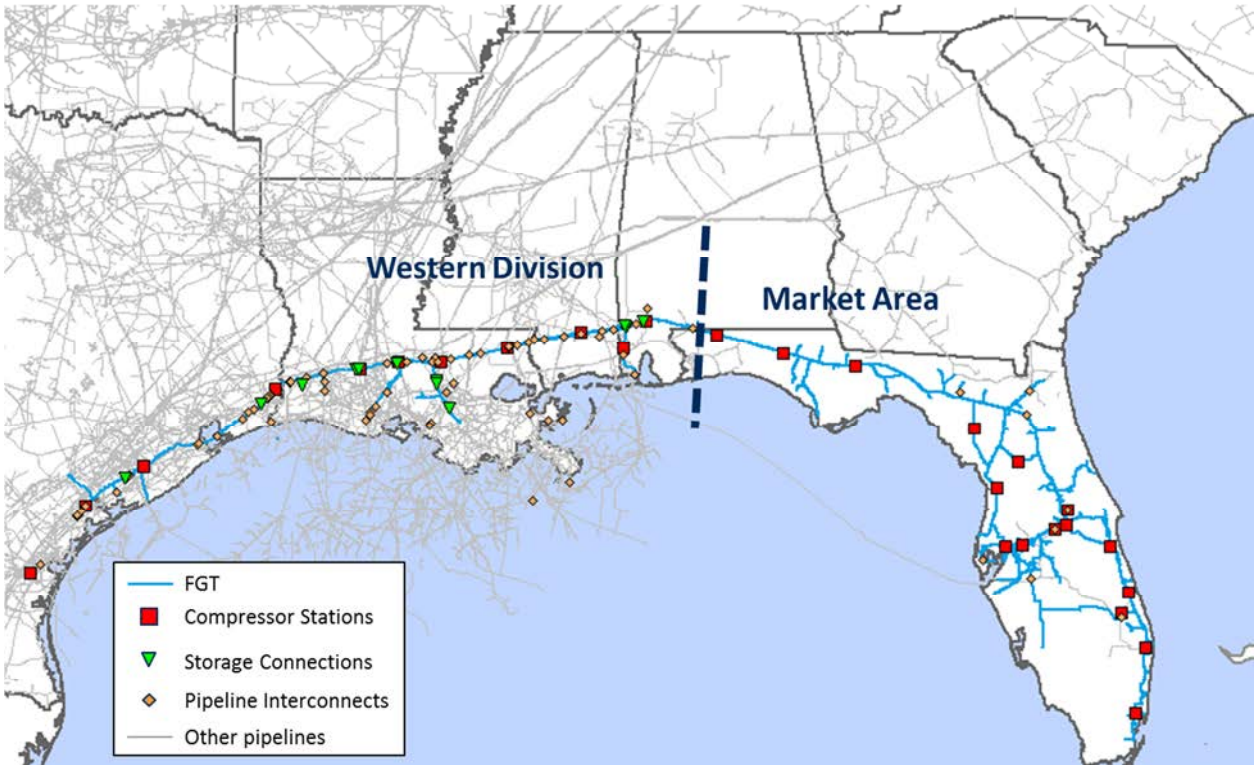
* Sum of three segments extending into Florida from Georgia, using highest recorded throughput as a proxy
** Excluding segment extending from Alabama that passes through Florida and back into Alabama
Source: PointLogic Energy

2.1 FLORIDA GAS TRANSMISSION

FGT is by far the largest pipeline delivering gas into Florida. FGT is a direct and wholly-owned subsidiary of Citrus Corp. The capital stock of Citrus is owned in a 50/50 partnership by El Paso Citrus Holdings, Inc. ("EPCH"), a wholly-owned indirect subsidiary of Kinder Morgan, Inc. and CrossCountry Citrus, LLC ("CCC"), a wholly-owned indirect subsidiary of Energy Transfer Partners, L.P., two large energy companies with a considerable portfolio of natural gas midstream assets in the U.S.[5] The pipeline stretches over 5,300 miles and is designed to receive gas from various Gulf Coast region production areas (originating in South Texas) and deliver gas throughout the Gulf Coast and Florida, with the terminus of the pipeline located in the Miami metro area. As shown in Figure 2, the pipeline is divided into a Western Division (comprised of its right-of-way in Texas, Louisiana, Mississippi, and Alabama) and a Market Division (which includes Florida). The pipeline includes several compressor stations, interconnections, and access to storage facilities which assist the pipeline in providing high quantities of reliable supply.

[5] Kinder Morgan website

Figure 2 Detailed FGT Infrastructure Map



Source: Velocity Suite, ABB Enterprise Software

Natural gas is a baseload power generation fuel in Florida, so electricity generators typically hold firm contracts on pipelines to ensure their facilities are supplied when distribution into the region is tight. FGT's capacity is currently fully contracted, meaning natural gas-fueled electric generators with contracts to meet the needs of their existing generation facilities may find it difficult to secure additional natural gas supplies via FGT if they plan to expand their gas-fired capacity in Florida.

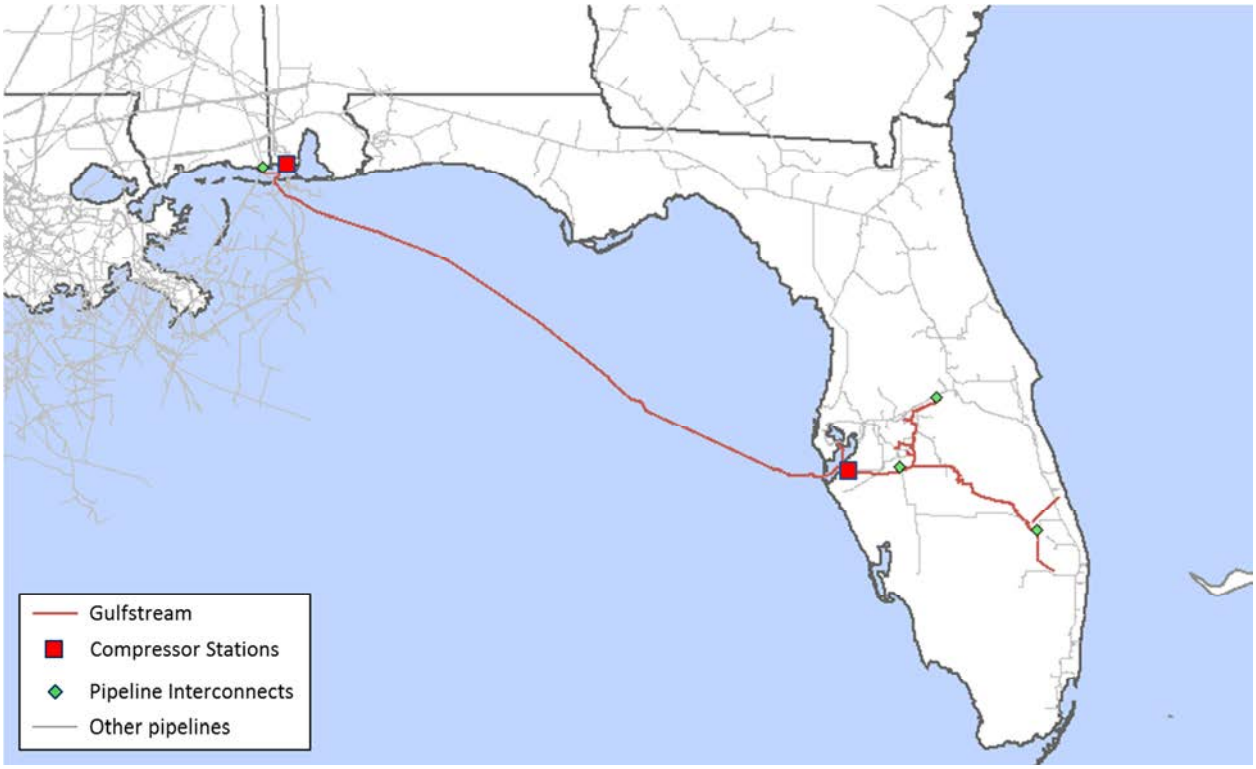
2.2 GULFSTREAM NATURAL GAS SYSTEM

Gulfstream is the only transmission pipeline in the U.S. which is routed mostly underwater. The pipeline receives gas on land near the Mississippi-Alabama border, crosses the Gulf of Mexico, and delivers gas near the Tampa Bay metro area. The routing extends beyond the Tampa Bay area into central and southeastern Florida, where it interconnects with FGT in three locations. Figure 3 shows the routing of the Gulfstream pipeline through the Gulf of Mexico and within Florida.

Gulfstream is operated by Williams Partners, and is owned by a 50/50 joint venture between Williams and Spectra Energy Partners.[6]

[6] Spectra Energy Website

Figure 3 Detailed Gulfstream Infrastructure Map



Source: Velocity Suite, ABB Enterprise Software

Williams is willing to contract for up to 1.30 Bcf/d on a firm basis through Gulfstream, which is currently 100% subscribed during the spring and summer months (and 99% subscribed during winter months).[7] Therefore, power generation customers will only be able to obtain capacity from Gulfstream under the contracts they currently hold.

2.3 SABAL TRAIL TRANSMISSION

Sabal Trail is a project proposed by Spectra Energy (59.5% stake), NextEra Energy (33%), and Duke Energy (7.5%) that would deliver natural gas from Alabama into central Florida. The pipeline would be supplied from an interconnect with the Transcontinental Gas Pipeline northeast of Station 85, between Stations 105 and 110. Sabal Trail is expected to require construction of five new compressor stations, three of which will be in Florida, and most of the pipeline will be 36-inches in diameter. Figure 4 shows the anticipated routing of the Sabal Trail pipeline.

[7] Williams EBB postings

Figure 4 Sabal Trail Proposed Project Infrastructure



Source: Velocity Suite, ABB Enterprise Software

Sabal Trail would provide 1.0 Bcf/d of incremental capacity into Florida, but it is nearly fully subscribed by affiliates of its owners, Florida Power & Light and Duke Energy Florida ("FPL" and "DEF," respectively). However, construction of Sabal Trail could alleviate market constraints into Florida by freeing up capacity on the two existing pipelines, provided FPL and DEF release FGT and Gulfstream capacity when Sabal Trail is commissioned.

2.4 INFRASTRUCTURE CONCLUSION

Natural gas demand for power generation in Florida is currently served by two pipelines which have reliably supplied Floridian power generators with firmly contracted capacity. However, these two pipelines, FGT and Gulfstream, are fully contracted meaning they will only be able to provide capacity to existing customers. The Sabal Trail Transmission project is proposed to meet the incremental gas demand of its project sponsors and to alleviate supply constraints. However, if and until Sabal Trail is constructed and commissioned, additional natural gas capacity in Florida will be limited.

3.0 Natural Gas Curtailment

3.1 OVERVIEW OF NATURAL GAS SUPPLY VULNERABILITIES

Historically, large curtailments of natural gas to pipeline customers ("shippers") are rare. Extreme winter weather conditions are primarily responsible for natural gas supply disruptions to electricity generation facilities, when supplies are disrupted by freezing conditions, pipeline capacity is strained by low line pack, firm customers are taking priorities in the gas deliveries, and electricity demand hits peak levels concurrently. Major hurricanes, such as Katrina and Rita, have significantly impacted natural gas production in the past due to a high percentage of gas production occurring off-shore (i.e., in the Gulf of Mexico). However, hurricane impacts are expected to be mitigated by increasing land-based shale gas productions. Other less significant incidents, caused by natural phenomenon, natural disasters or human errors, have also resulted in pipeline interruptions.

The most recent winter curtailment happened during the January of 2014 "Polar Vortex" event, during which many areas (such as MISO and PJM) reported record or near record winter peak electrical demand. The cold weather and resulting natural gas supply issues caused ~35,000 MW in generation outages.[8] FRCC was not impacted by the Polar Vortex and was able to export 1,500 MW to the Southeastern Electric Reliability Council (SERC) region.

The Polar Vortex experience raised the issue of spot-market and non-firm, interruptible gas supplies for power generators. As firm contracts are honored ahead of the interruptible contracts, several electric generation operators declared forced outages due to fuel unavailability. In the aftermath of the Polar Vortex, PJM implemented the Capacity Performance rules that require the generation resources to firm up their bids.[9]

Gas production in Texas is also susceptible to cold weather-related production disruptions and curtailments. In 2011, 14.8 Bcf was curtailed for five days; and in 2003, 5,500 MW of capacity was lost for three days.[10] Although there was no direct impact on Florida, such supply region interruptions could put stress on gas flow into Florida.

The share of total U.S. gas in the Gulf of Mexico has declined from 26% in 1997 to 5% in 2014. In its latest Gulf of Mexico production outage outlook, the U.S. Energy Information Administration (EIA) estimated the median outage impact to be approximately 18 Bcf for a normal hurricane season.[11] This is significantly lower than the 155 Bcf and 362 Bcf shut-in for Katrina and Rita in 2005,

[8] Polar Vortex Review, NERC, September 2014
[9] PJM Enhanced Liaison Committee - Capacity Performance http://www.pjm.com/committees-and-groups/committees/elc.aspx
[10] Outage and Curtailments During the Southwest Cold Weather Event of February 1,5, 2011, NERC, August 2011
[11] 2015 Outlook for Gulf of Mexico Hurricane-Related Production Outages, EIA, June 2015 (discontinued publication due to the declining risk)

respectively, and reduces the impact of hurricanes on the natural gas supplies to Gulf Coast pipeline operators.

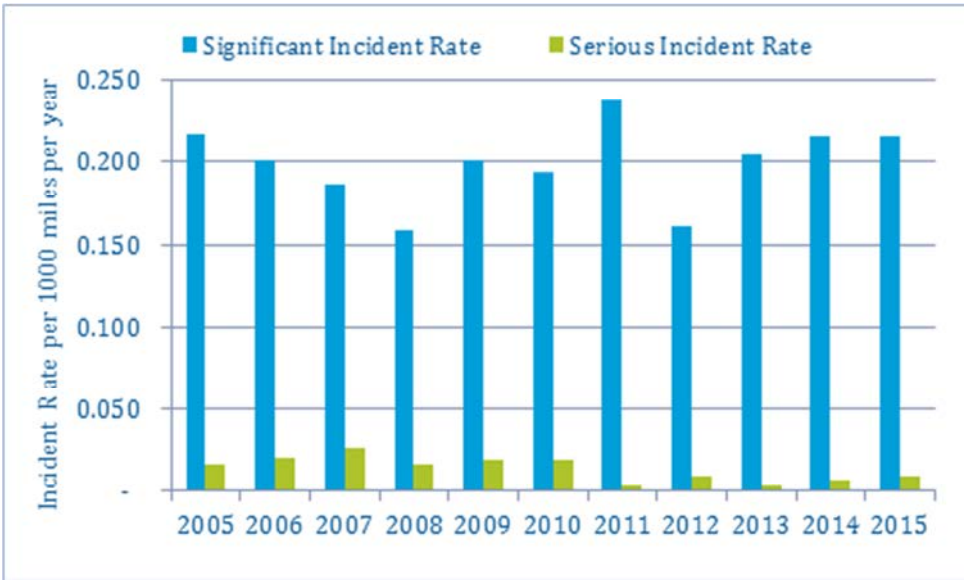
The North American Electric Reliability Corporation (NERC) special report also lists several notable historical incidents that have impacted gas supply reliability. A 1995 explosion on TransCanada's pipeline took out all six pipelines into New England, resulting in curtailment of 1.75 Bcf/day firm supplies and all interruptible supplies. A 1998 lightning strike at the Perry compressor station forced curtailment of 1.5 Bcf/day. A 2000 explosion on the El Paso Natural Gas pipeline forced curtailment of 500-700 MMcf/day for over two-weeks. In 2008, a mechanical failure at the Sable Offshore Energy Project resulted in significant loss of natural gas supply to New England and impacted 1,470MW of electricity generation. In 2010 and 2011, a series of pipeline ruptures on the PG&E system forced the utility to reduce the operating pressure and line packs.[12]

Figure 5 shows the historical incident rates per 1,000 miles per year for the approximately 300,000 miles of the transmission pipelines in the U.S. The significant incident rate has fluctuated since 2005 and is essentially flat, and serious incidents have declined sharply. Excavation damage (mostly by third parties) is the leading cause for incidents. Other causes include material/weld failures, corrosion, incorrect operation, and natural forces. During incidents, pipeline operators are also able to utilize storage facilities, looping, and interconnects with other systems to mitigate the curtailment impacts. Very rarely will a pipeline be completely out of service.

Despite the low incident rates, the increasing share of natural gas-fired generation facilities puts more emphasis on the study of the interdependence between gas and power. As an example, a recent technical report found reliability risks to the electric system associated with the loss of the Aliso Canyon natural gas storage facility in California. The western electric distribution system relies on natural gas to balance an increasing amount of renewable generation, and it is likely to experience 14-days of potential interruptions as a result of the unavailability of the Aliso Canyon storage.[13]

[12] 2013 Special Reliability Assessment, NERC, 2013
[13] Short-term Special Assessment, NERC, May 2016

Figure 5 US Gas Transmission System Incident Rates



Source: US DOT PHMSA; Significant Incidents include a fatality, or an injury requiring overnight, in-patient hospitalization, or $50,000 or more in total costs, measured in 1984 dollars; Serious Incidents include a fatality or injury requiring overnight, in-patient hospitalization.[14]

3.2 HISTORICAL FLORIDA GAS SUPPLIES INTERRUPTIONS

The most notable incident on FGT happened in 1998, when a lightning strike at the Perry compressor station damaged all three main lines and forced curtailment of 1.5 Bcf/day. The impact lasted 3-5 days, and the regional electric utilities were able to avoid rolling blackouts by switching from natural gas to fuel oil and requesting voluntary curtailments.[15]

Black & Veatch reviewed PHMSA data from 2002 through June 2016.[16] During this period, FGT reported 15 significant incidents, including 2 serious incidents. Most of the incidents resulted from gas leaks. No significant gas curtailment was reported as a result of the incidents.

No incidents were reported for Gulfstream in the PHMSA data during this period.

Black & Veatch also reviewed the pipeline posted notices and Operating Flow Orders ("OFO") regarding pipeline operating conditions and potential constraints on the capacities or flexibilities, for the period from January 2011 through June 2016.[17]

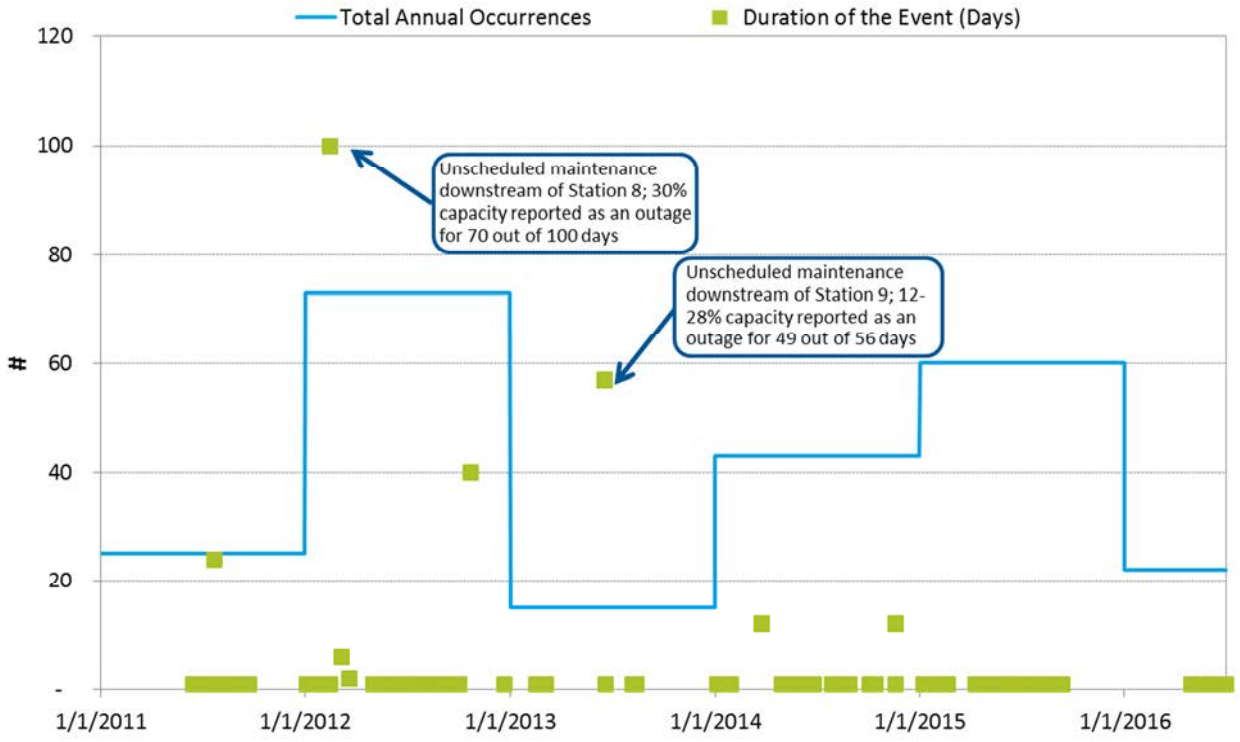
[14] US DOT Pipeline and Hazardous Materials Safety Administration, Gas Transmission Performance Measures, http://www.phmsa.dot.gov/pipeline/library/data-stats/performance-measures
[15] 2013 Special Reliability Assessment, NERC, 2013
[16] HMSA Pipeline Safety Flagged Incidents, http://www.phmsa.dot.gov/pipeline/library/data-stats
[17] Pipeline notices provided through PointLogic

FGT incurred a relatively frequent amount of critical notices regarding potential pipeline capacity constraints or weather alerts. Under these conditions, FGT would limit the amount of overtake (as a percentage of the nominated transportation quantities) that is typically allowed in the transportation tariff. Most of the notifications were in effect for one day, with very few extending to several days.

Maintenance outages may have longer-term impacts on FGT's capacity. For example, a 2012 unscheduled maintenance outage downstream of Station 8 resulted in a 30% capacity reduction for 70-days out of the 100-days the notice was in effect. A 2013 unscheduled maintenance outage downstream of Station 9 resulted in a 12-28% capacity reduction for 49-days out of the 56-days the notice was in effect.

There are also occasional scheduled or unscheduled maintenance outages on the upstream supply region pipelines and compressor stations that extend for periods of time. Such pipeline outages would have no material impact on the supplies into Florida, as they would be largely mitigated by alternative supplies.

Figure 6 FGT Critical Notices Occurrence and Duration

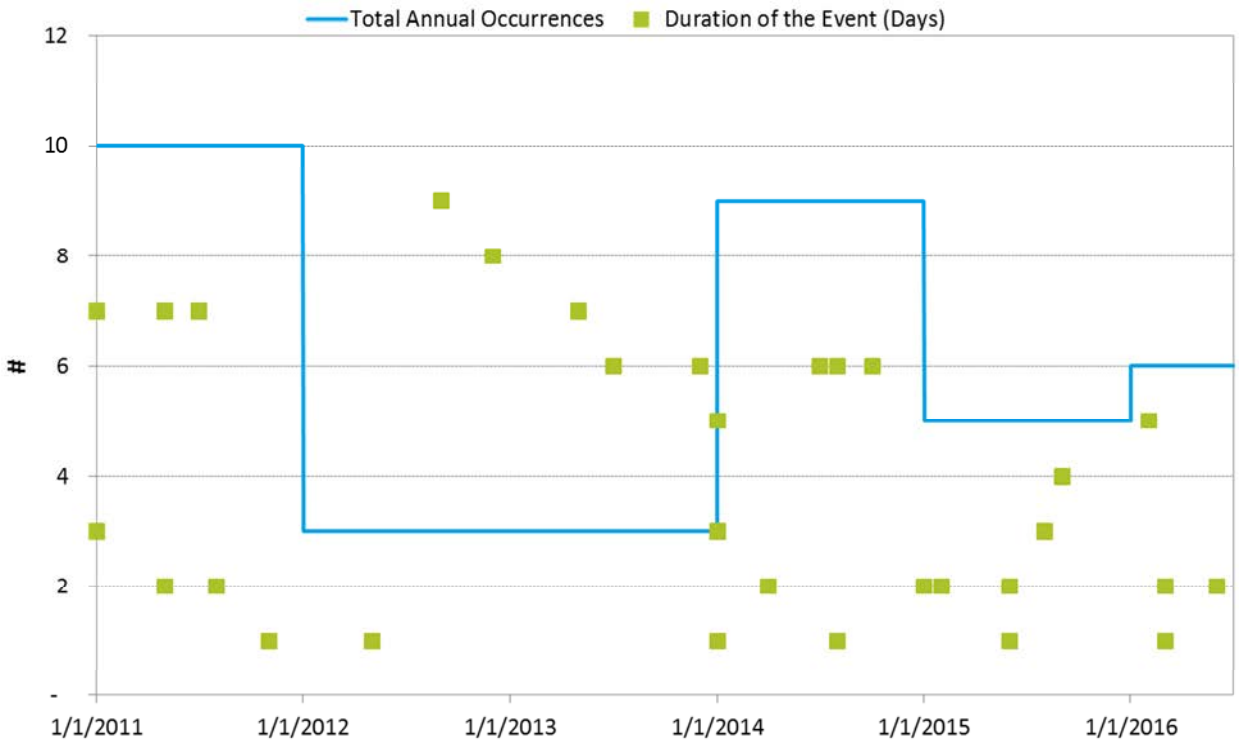


Source: Velocity Suite, ABB Enterprise Software (2011-2015); PointLogic Energy (2015-2016). Includes critical notices that could potentially impact system throughput.

There are similar types of operation advisories and weather alerts on the Gulfstream system, with fewer frequencies compared to FGT. Most of the notices regarded the line pack conditions limiting the flexibility available to shippers with durations lasting from one-day to several days.

For the period being examined, there were no extended times of maintenance outages on the Gulfstream system.

Figure 7 Gulfstream Critical Notices Occurrence and Duration



Source: Velocity Suite, ABB Enterprise Software (2011-2015); PointLogic Energy (2015-2016). Includes critical notices that could potentially impact system throughput.

3.3 FUTURE FLORIDA GAS SUPPLIES REALIBILITY ASSESSMENT

Natural gas is expected to account for 69.2% of the capacity and 64.7% of the electricity generation in Florida by 2024.[18] Gas supply reliability will be an important factor for the Florida electricity supply reliability with natural gas' increasing share in electricity generation.

In the 2015 Reliability Assessment, FRCC concluded there will be sufficient back-up fuel capability to cover short-term natural gas supply interruptions. Based on dual-fuel capabilities, increasing on-shore shale gas supplies, addition of a proposed third gas pipeline, and other contractual gas transportation diversifications, FRCC does not anticipate fuel-related reliability issues during extreme weather conditions in the near-term, absent long-term transportation outages.[19]

Furthermore, FRCC's Fuel Reliability Working Group (FRWG) provides oversight of the fuel reliability issues and coordinates responses to any emergencies. The FRWG recently evaluated the

[18] FRCC 2015 Load & Resource Reliability Assessment Report, FRCC, July 7, 2015
[19] Id.

potential impact from the loss of key compressor stations and found that only some localized gas reductions could occur, and these would be mitigated by dual-fuel capabilities.[20]

Based on the long-term PHMSA statistics and the more recent pipeline operating histories shown in OFO notices, large scale pipeline outages are extremely rare. Partial outages or maintenance needs can be mostly mitigated through alternative supplies and other flexibilities in the system. Pipeline operators also frequently monitor system flexibility and limit the customers' ability to overtake/undertake based on the established priorities in the tariff. Such restrictions are to the benefit of the system reliability and, for the most part, won't impact firm transportation shippers.

Dual-fuel capabilities will remain a critical component for supplies into peninsular Florida. Additional coordination may be required in the event of a long-term failure of the natural gas pipelines and related infrastructure, including purchasing replacement power from other dual fueled units, imports from other transmission areas and demand side responses.

[20] 2015 Long-Term Reliability Assessment, NERC, December 2015

4.0 Environmental Considerations for Dual Fuel Operation

Environmental Consulting & Technology, Inc. performed an evaluation of the environmental considerations for dual fuel operation. The analysis is included as Attachment A. The following is the Conclusion from this evaluation:

Obtaining a preconstruction air permit for a dual-fuel, i.e., natural gas with fuel oil backup, combined-cycle combustion turbine facility typically offers additional challenges as compared to a single-fuel, i.e., natural gas, facility. However, these challenges are rarely insurmountable and typically involve additional time and effort to demonstrate compliance with National Ambient Air Quality Standards (NAAQS). Some of the issues and challenges include:

- A BACT (best available control technology) analysis would be required for both natural gas and fuel oil combustion. Wet injection would be required as a control device to reduce nitrous oxide (NO_X) emissions during combustion of fuel oil.
- Annual hours of operation would need to be restricted when combusting fuel oil.
- Air dispersion modeling must be conducted for both natural gas combustion and fuel oil combustion cases. Results of the fuel oil combustion may lead to additional modeling for other pollutants and/or additional cumulative modeling as a result of a pollutant exceeding a significant impact level solely based on fuel oil combustion.
- Class I air dispersion modeling will be required for both natural gas and fuel oil combustion.

Dual-fuel, combined-cycle combustion turbine facilities can typically be permitted with some operational restrictions, such as annual hours of operation, and addition effort to demonstrate compliance with NAAQS for both fuels.

5.0 Evaluation of Fuel Oil Usage

5.1 DUAL FUEL PLANTS IN FRCC

As shown in Table 2 andTable 3, existing combined cycle dual-fuel capacity in FRCC is substantial, outnumbering the amount of capacity from combined cycle units without dual-fuel capability (reflected in Table 3). The total 31,506 MW generation capacity is equivalent to approximately 5.3 Bcf/day of natural gas consumptions, if all the units are fired up simultaneously. The actual duration of the running hours will be limited by the fuel oil supplies or the stored fuel onsite, and the units are often limited in the annual operating hours they are allowed to run on backup (non-natural gas) fuel under the environment permit.

Table 2 Currently Operating Natural Gas Fired Plants Utilizing Combined Cycle (CC) or Combustion Turbine (CT) Units in FRCC, with Backup Fuel Capability

PLANT	OPERATOR	NAMEPLATE CAPACITY (MW)	TECH	BACKUP FUEL
Auburndale Peaker Energy Center LLC	Auburndale Peaker Energy Center	130	CT	Diesel Fuel Oil (DFO)
Baptist Memorial Hospital	Baptist Medical Center	9	CT	DFO
City of Lake Worth - (FL)	Tom G Smith	31	CC	DFO
City of Lakeland - (FL)	C D McIntosh Jr	27	CT	DFO
City of Lakeland - (FL)	Larsen Memorial	109	CC	DFO
City of Tallahassee - (FL)	Arvah B Hopkins	362	CC	DFO
City of Tallahassee - (FL)	S O Purdom	277	CC	DFO
City of Vero Beach - (FL)	Vero Beach Municipal Power Plant	41	CT	DFO
Duke Energy Florida, Inc	Avon Park	34	CT	DFO
Duke Energy Florida, Inc	DeBary	345	CT	DFO
Duke Energy Florida, Inc	Higgins	153	CT	DFO
Duke Energy Florida, Inc	Hines Energy Complex	2,263	CC	DFO
Duke Energy Florida, Inc	Intercession City	805	CT	DFO
Duke Energy Florida, Inc	P L Bartow	1,364	CC	DFO
Duke Energy Florida, Inc	Suwannee River	122	CT	DFO
Florida Power & Light Co	Fort Myers	1,491	CC	DFO
Florida Power & Light Co	Manatee	753	CC	DFO

PLANT	OPERATOR	NAMEPLATE CAPACITY (MW)	TECH	BACKUP FUEL
Florida Power & Light Co	Sanford	1,506	CC	DFO
Florida Power & Light Co	Turkey Point	752	CC	DFO
Florida Power & Light Co	Cape Canaveral	1,295	CC	DFO
Florida Power & Light Co	Lauderdale	1,863	CC	DFO
Florida Power & Light Co	Martin	1,569	CC	DFO
Florida Power & Light Co	Port Everglades	1,762	CC	DFO
Florida Power & Light Co	Riviera	1,295	CC	DFO
Florida Power & Light Co	West County Energy Center	4,263	CC	DFO
Fort Pierce Utilities Authority	Treasure Coast Energy Center	220	CC	DFO
Gainesville Regional Utilities	Deerhaven Generating Station	145	CT	DFO
Gainesville Regional Utilities	John R Kelly	146	CC	DFO
Invenergy Services LLC	Hardee Power Station	432	CC	DFO
JEA	Brandy Branch	555	CC	DFO
JEA	Greenland Energy Center	381	CT	DFO
JEA	J D Kennedy	370	CT	DFO
Kissimmee Utility Authority	Cane Island	290	CC	DFO
LS Power Development LLC	DeSoto County Plant	399	CT	DFO
Northern Star Generation Services Co LLC	Mulberry Cogeneration Facility	125	CC	DFO
NRG Florida LP	Osceola (FL)	600	CT	DFO
Orlando Utilities Comm	Indian River Plant	343	CT	DFO
Orlando Utilities Comm	Stanton Energy Center	333	CC	DFO
Reedy Creek Improvement Dist	Central Energy Plant	62	CC	DFO
Seminole Electric Cooperative Inc	Midulla Generating Station	897	CC	DFO
Shady Hills Power Co LLC	Shady Hills Generating Station	541	CT	DFO
Southern Power Co	Curtis H Stanton Energy Center	688	CC	DFO
Southern Power Co	Oleander Power Project LP	994	CT	DFO
Tampa Electric Co	Polk	352	CT	DFO
Tampa Electric Co	Big Bend	62	CT	DFO
Vandolah Power Co LLC	Vandolah Power Station	728	CT	DFO

PLANT	OPERATOR	NAMEPLATE CAPACITY (MW)	TECH	BACKUP FUEL
Wood Group Power Plant Services Inc	Quantum Lake Power LP	108	CC	DFO
Wood Group Power Plant Services Inc	Quantum Pasco Power LP	115	CC	DFO
TOTAL		**31,506**		

Source: EIA 860, EIA 860M, Black & Veatch research

Table 3 Currently Operating Natural Gas Fired Plants Utilizing Combined Cycle or Combustion Turbine Units in FRCC, without Backup Fuel Capability

PLANT	OPERATOR	NAMEPLATE CAPACITY (MW)	TECH
Anheuser-Busch Jacksonville	Anheuser-Busch Inc	9	CT
Pensacola Florida Plant	Ascend Performance Materials LLC	86	CT
Florida's Natural Growers	Citrus World Inc	11	CT
C D McIntosh Jr	City of Lakeland - (FL)	369	CC
Vero Beach Municipal Power Plant	City of Vero Beach - (FL)	17	CC
Cutrale Citrus Juices USA I	Cutrale Citrus Juices USA Inc	4	CT
Cutrale Citrus Juices USA II	Cutrale Citrus Juices USA Inc	8	CT
Tiger Bay	Duke Energy Florida, Inc	278	CC
University of Florida	Duke Energy Florida, Inc	43	CT
Fort Myers	Florida Power & Light Co	593	CC
Manatee	Florida Power & Light Co	472	CC
Martin	Florida Power & Light Co	880	CC
Sanford	Florida Power & Light Co	872	CC
Turkey Point	Florida Power & Light Co	472	CC
Treasure Coast Energy Center	Fort Pierce Utilities Authority	191	CC
South Energy Center	Gainesville Regional Utilities	4	CT
Lansing Smith	Gulf Power Co	620	CC
Pea Ridge	Gulf Power Co	14	CT
Brandy Branch	JEA	228	CC
Cane Island	Kissimmee Utility Authority	180	CC
Orlando Cogen LP	Orlando CoGen Ltd LP	122	CC

PLANT	OPERATOR	NAMEPLATE CAPACITY (MW)	TECH
Orange Cogeneration Facility	Northern Star Generation Services Co LLC	137	CC
Osprey Energy Center Power Plant	Osprey Energy Center	644	CC
Central Energy Plant	Reedy Creek Improvement Dist	8	CC
Santa Rosa Energy Center	Santa Rosa Energy Center LLC	275	CC
H L Culbreath Bayside Power Station	Tampa Electric Co	2,294	CC
Polk	Tampa Electric Co	352	CT
Tropicana Products Bradent	Tropicana Products Inc	47	CT
Quantum Lake Power LP	Wood Group Power Plant Services Inc	26	CC
Quantum Pasco Power LP	Wood Group Power Plant Services Inc	26	CC
TOTAL		**9,282**	

Source: EIA 860, EIA 860M, Black & Veatch research

Out of the total current generation capacity of 40,788 MW for the natural gas CC and CT units in FRCC, 31,506 MW, or 77% of the total portfolio, are equipped with dual fuel capacity. As shown in Table 4, an additional 2,764 MW of dual fuel units might be added before 2020, representing 58% of the total capacity additions of 4,735 MW. The dual fuel capability at the State level, either in terms of nameplate capacity, or as a percentage of the total generation capacities, is expected to be relatively stable in the near future.

Table 4 Proposed Power Plants Utilizing Combined Cycle or Combustion Turbine Units in FRCC

PLANT	OPERATOR	YEAR	NAMEPLATE CAPACITY (MW)	TECH	BACKUP FUEL
Polk	Tampa Electric	2017	463	CC	DFO
Citrus County	Duke Energy Florida	2018	1,971	CC	None
Shady Hills Power	Shady Hills	2018	518	CT	DFO
Okeechobee	Florida Power & Light	2019	1,723	CC	DFO
Arvah B Hopkins	City of Tallahassee	2020	60	CT	DFO
Dual Fuel Capacity			**2,764**	**(58%)**	
Non-Dual Fuel Capacity			**1,971**	**(42%)**	
TOTAL			**4,735**		

Source: EIA 860, EIA 860M, Black & Veatch research

5.2 FUEL OIL USAGE – UNITED STATES

Fuel oil is typically used at combined cycle facilities only as a backup fuel. Relative to natural gas, fuel oil combustion results in higher emissions, higher heat rate, and higher expense. Natural gas has traditionally been, and is expected to remain, a better economic choice than fuel oil.

Plants with the greatest fuel oil usage are generally those that experience natural gas curtailments while being required to generate electricity. Such usage is common in the northeastern United States, where weather events such as the 2014 "Polar Vortex" can defer natural gas away from power generation facilities and towards residential heating users, without a reduction in electricity usage. When natural gas is curtailed, these facilities must have backup fuel available to support the grid load demand.

Florida is much less prone to severe cold weather events, but risks exist for a natural disaster from hurricanes. Hurricane events differ from incidents such as the Polar Vortex in that post-hurricane transmission systems are typically damaged and must be repaired before load demand can be delivered at normal levels. This helps to alleviate natural gas curtailments in the region as pipeline operators can develop mitigation plans while transmission line operators restore service to their distribution grids.

5.3 HISTORICAL FUEL OIL USAGE AT SECI FACILITIES

SECI evaluated data on dual fuel usage at Midulla Generating Station (MGS) and several facilities (Osceola, Oleander, and Hardee) with which SECI has or has had Power Purchase Agreements (PPAs).

Over the past six years, these facilities have negligible run time on fuel oil other than testing runs. These facilities last experienced significant run time on fuel oil in 2010 in response to a severe regional cold spell that restricted gas supply.

Prior to the 2010 event, these facilities experienced several significant fuel oil events due to reductions in gas supply resulting from hurricanes impacting off-shore gas supplies. SECI has not used fuel oil at any of their facilities over the evaluation period for economic reasons. Fuel oil use has been restricted solely to testing and weather events; natural gas has consistently been a better economic choice for fuel.

5.4 NEED FOR FUEL OIL AT THE SECI P2021 FACILITY

SECI's P2021 facility will most certainly experience natural disaster events similar to those experienced by SECI's fleet prior to 2010. However, the need for backup fuel should be evaluated on a total SECI fleet basis rather than on an individual plant basis. SECI should maintain enough fleet-wide backup fuel generation capability to support the post-disaster load demand until natural gas availability recovers after a fuel supply impact event.

As previously noted, natural gas supply impact events for SECI typically occur concurrently with transmission system impacts. During such events, SECI's fleet (both owned generation and purchased power) is anticipated to be capable of meeting the load the impacted transmission system can deliver with backup fuel until natural gas availability is restored to normal capabilities. In a significant number of storm events, it is anticipated the transmission and distribution system, rather than the gas supply, will be the limiting factor in SECI's ability to meet load demand.

[SECI currently has 650 MW in the coal-fired Seminole Generating Station (SGS), and 500 MW combined cycle plus 310 MW peaking capacity in the natural gas-fired Richard J Midulla Generating Station (MGS). The MGS facility is equipped with dual fuel capabilities. The generation portfolio is approximately 38% of the 3,818 MW peak load reached in Winter 2011/2012.[21] The rest of the electricity demand will be met through market purchases. If the SGS is retired and replaced by the 1,050 MW P2021 facility with single fuel capability, 44% of the SECI generation portfolio will have dual fuel capabilities.]

Based on analysis of previous of natural gas curtailment events, SECI expects to have sufficient fleet wide backup fuel generation capability to manage such events without adding fuel oil capability to the P2021 facility.

[21] Seminole Electric Cooperative Inc. 2015 Annual Report

6.0 Cost Evaluation

Table 5 lists the equipment and other components that will be impacted by the use of fuel oil in a combined cycle facility with an associated cost estimate. Each of the major combustion turbine suppliers (General Electric, Siemens, and Mitsubishi Hitachi Power Systems) were contacted by telephone and requested to provide costs of the equipment associated with fuel oil operation. The equipment costs and the equipment installation costs provided from General Electric and Mitsubishi Hitachi Power Systems are included in the table. Siemens did not respond to the inquiry, so their costs are estimated. The cost for the remaining equipment associated with fuel oil operation was estimated by Black & Veatch using historical internal estimates. The present worth Operation and Maintenance (O&M) costs are based on 750-hours of fuel oil operation per combustion turbine per year using 11.3¢/MWH for the O&M costs for a 30-year plant life. The cost of fuel and water for the life of the plant has not been included.

Table 5 Fuel Oil Price Adder

		2x1 GE 7HA.02 (nominal output 1000MW)	2x1 Siemens 8000H (nominal output 920MW)	2x1 MHI 501JAC (nominal output 1000MW)
1	CTG Equipment Vendor Cost	$ 2,100,000	$ 3,000,000	$ 4,000,000
2	CTG Equipment Installation	$ 500,000	$ 500,000	$ 600,000
3	Fuel Oil Storage Tank - 4M Gallon	$ 6,000,000	$ 6,000,000	$ 6,000,000
4	Fuel Oil Storage Tank, Pump Foundation	$ 550,000	$ 550,000	$ 550,000
5	Fuel Oil Storage Containment (liner & earth berm)	$ 500,000	$ 500,000	$ 500,000
6	Fuel Oil Unloading/Forwarding	$ 250,000	$ 250,000	$ 250,000
7	Piping & Electrical - FO Systems	$ 400,000	$ 400,000	$ 400,000
8	BOP Systems impacts (Demin, etc.)	$ 1,000,000	$ 1,000,000	$ 1,000,000
9	Start-up/Commissioning & Guarantee	$ 1,000,000	$ 1,000,000	$ 1,000,000
10	EPC Contingency	$ 1,230,000	$ 1,320,000	$ 1,430,000
11	EPC Markup (G&A/Fee)	$ 1,714,500	$ 1,728,000	$ 1,759,500
12	O&M(750 hours of operation/year, 0.113$/MWH, 30 year life, 2 CTs)	$ 5,085,000	$ 4,576,500	$ 5,085,000
	Total	$ 20,329,500	$ 20,824,500	$ 22,574,500
	Notes:			
	1. Owner cost of Fuel and Water are not included.			
	2. The CTG Equipment Vendor Cost and Equipment Installation are estimated for Siemens.			

The cost to include fuel oil at the SECI P2021 facility is projected to be greater than $20M.

7.0 Conclusion

Based on the review the Pipeline and Hazardous Materials Safety Administration (PHMSA) data and the pipeline Operational Flow Order (OFO) notices, natural gas supplies into and through Florida are predominantly reliable.

Florida is well served with the existing dual-fuel generating units. Out of the total 40,788 MW of operating combined cycle and combustion turbine units, 31,506 MW or approximately 77% of the total capacity is equipped with dual fuel capabilities.[22] This is equivalent to approximately 5.3 Bcf/day of natural gas consumptions, if all the units are fired up simultaneously. An additional 2,764 MW of dual fuel units are proposed to be constructed before 2020, equivalent to approximately 0.5 Bcf/day of natural gas consumptions. At the State level, the dual fuel capability is expected to be relatively stable in the foreseeable future.

For SECI, assume the addition of the 1,050 MW P2021 as a single fuel plant, and the retirement of SGS, approximately [49%] of its peak load will be met with owned generations. Within its own generation portfolio of approximately [1860] MW, [44%] will have dual fuel capabilities, equivalent to a gas consumption of approximately 0.25 Bcf/day.

Obtaining a preconstruction air permit for a dual-fuel, i.e., natural gas with fuel oil backup, combined-cycle combustion turbine facility typically offers additional challenges as compared to a single-fuel, i.e., natural gas, facility. However, these challenges are rarely insurmountable and typically involve additional time and effort to demonstrate compliance with NAAQS.

Based on the high level review of the existing fuel oil capabilities within Florida and within the SECI fleet, it appears SECI will be adequately served without additional dual fuel capabilities at the portfolio level. Considering the environmental and permitting impacts with dual fuel operation, the reliable nature of the natural gas supply in Florida, and the cost to add fuel oil to the facility, the incremental benefit to add fuel oil as backup for the P2021 facility would not result in a commensurate benefit to the SECI system.

[22] Black & Veatch research based on data provided through Velocity Suite, AGG Enterprise Software

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US DOT Pipeline and Hazardous Materials Safety Administration, annual report and incident data, http://www.phmsa.dot.gov/pipeline/library/data-stats

David Wagner

Experience

2010 – Current **Seminole Electric Cooperative, Inc.** Tampa, FL

Supervisor of Gas Supply; Manager of Gas Supply; Portfolio Director

- Revamped the natural gas procurement function at Seminole to make it an integral part of the organization's decision making processes leading to more reliable, lower cost fuel supply.
- Ensured competitive fuel costs through the implementation of modifications to Seminole's financial gas hedging program to create a more robust risk management tool.
- Lead a team of natural gas professionals to plan robust gas supply, transportation and storage strategies to meet Seminole's supply needs and support the execution of such activities.

2006 – 2010 **Florida Gas Utility** Gainesville, FL

Gas Buyer; Senior Trader

- Brought a trading/asset optimization mentality to the agency to lower gas supply costs and increase returns on gas pipeline assets.
- Led the operations team on the optimization of FGU's gas supply and transportation portfolio. Coordinated all daily and monthly activities including administrative and gas accounting functions.
- Obtained Board approval for and implemented a formal program for the optimization of a member's firm gas storage capacity.

2004 – 2006 **Florida Municipal Power Agency** Orlando, FL

Energy Risk Analyst

- Provided analysis to support the effective utilization of FMPA's generation resources and purchased power agreements.
- Administered the agency's fuel hedging program and developed the methodology used to forecast FMPA's total gas exposure to improve the effectiveness of the hedging program..
- Identified less arbitrage opportunities for FMPA's dual-fuel generation units designed to capture value, improve system reliability and reduce risk.

2002 – 2003 **Westar Energy, Inc.** Topeka, KS

Energy Market Analyst

- Performed analysis for the energy trading floor to identify emerging opportunities that maximized the value realized from the company's assets and returns from the trading book.
- Developed a natural gas storage model for projecting weekly withdrawals, built historical databases of physical power and gas prices for spread and volatility analysis, and performed volatility and pricing analysis of exotic gas and power options.

Education

University of Florida

- Master of Agri-Business
- Bachelor of Science – Food and Resource Economics

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 11
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DESCRIPTION: David Wagner DW-1

Fuel Price Forecast – Updated

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.32	$3.63	$2.90	$3.45	$14.64
2018	$3.20	$4.28	$3.06	$3.52	$16.55
2019	$2.94	$4.11	$2.39	$3.13	$17.59
2020	$2.92	$4.15	$2.11	$3.28	$18.08
2021	$2.94	$4.25	$2.06	$3.36	$18.43
2022	$3.03	$4.38	$2.04	$3.42	$18.69
2023	$3.09	$4.43	$2.10	$3.50	$19.02
2024	$3.16	$4.48	$2.15	$3.57	$19.34
2025	$3.24	$4.67	$2.23	$3.65	$19.81
2026	$3.33	$4.87	$2.25	$3.74	$20.17
2027	$3.42	$5.06	$2.28	$3.82	$20.38
2028	$3.51	$5.25	$2.31	$3.91	$20.39
2029	$3.60	$5.44	$2.34	$4.00	$20.65
2030	$3.71	$5.65	$2.38	$4.09	$21.08
2031	$3.86	$5.93	$2.43	$4.19	$21.40
2032	$3.94	$6.10	$2.52	$4.28	$21.87
2033	$3.96	$6.16	$2.55	$4.38	$21.82
2034	$4.02	$6.27	$2.55	$4.47	$22.14
2035	$4.16	$6.52	$2.58	$4.58	$22.31
2036	$4.23	$6.64	$2.66	$4.68	$22.85
2037	$4.30	$6.78	$2.69	$4.79	$22.93
2038	$4.37	$6.90	$2.73	$4.89	$23.05
2039	$4.48	$7.08	$2.77	$5.01	$23.40
2040	$4.55	$7.20	$2.83	$5.12	$23.59
2041	$4.66	$7.37	$2.88	$5.24	$23.65
2042	$4.84	$7.66	$2.94	$5.36	$23.69
2043	$5.06	$8.01	$3.06	$5.48	$23.76
2044	$5.22	$8.25	$3.20	$5.60	$23.86
2045	$5.40	$8.53	$3.30	$5.73	$23.97
2046	$5.58	$8.81	$3.42	$5.86	$24.15
2047	$5.78	$9.11	$3.54	$5.99	$24.45
2048	$6.04	$9.49	$3.67	$6.12	$24.49
2049	$6.22	$9.77	$3.84	$6.26	$24.69
2050	$6.45	$10.10	$3.97	$6.40	$24.96
2051	$6.68	$10.44	$4.12	$6.55	$25.52

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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: David Wagner DW-2

Fuel Price Forecast

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.52	$4.34	$2.87	$3.53	$14.64
2018	$3.20	$4.43	$2.32	$3.59	$16.55
2019	$3.04	$4.30	$2.15	$3.41	$17.59
2020	$3.04	$4.34	$2.13	$3.53	$18.08
2021	$3.04	$4.43	$2.09	$3.62	$18.43
2022	$3.06	$4.53	$2.06	$3.70	$18.69
2023	$3.14	$4.71	$2.10	$3.78	$19.02
2024	$3.27	$4.94	$2.17	$3.86	$19.34
2025	$3.42	$5.25	$2.23	$3.95	$19.81
2026	$3.56	$5.55	$2.28	$4.03	$20.17
2027	$3.71	$5.86	$2.35	$4.13	$20.38
2028	$3.86	$6.16	$2.41	$4.22	$20.39
2029	$4.01	$6.48	$2.48	$4.32	$20.65
2030	$4.13	$6.74	$2.54	$4.42	$21.08
2031	$4.31	$7.07	$2.62	$4.52	$21.40
2032	$4.40	$7.27	$2.66	$4.62	$21.87
2033	$4.42	$7.35	$2.66	$4.73	$21.82
2034	$4.48	$7.49	$2.68	$4.83	$22.14
2035	$4.64	$7.79	$2.77	$4.94	$22.31
2036	$4.71	$7.93	$2.80	$5.05	$22.85
2037	$4.80	$8.10	$2.84	$5.17	$22.93
2038	$4.87	$8.24	$2.88	$5.29	$23.05
2039	$4.99	$8.46	$2.95	$5.41	$23.40
2040	$5.08	$8.60	$3.00	$5.53	$23.59
2041	$5.20	$8.81	$3.07	$5.66	$23.65
2042	$5.37	$9.10	$3.17	$5.78	$23.69
2043	$5.62	$9.51	$3.31	$5.92	$23.76
2044	$5.79	$9.80	$3.42	$6.05	$23.86
2045	$5.99	$10.13	$3.54	$6.19	$23.97
2046	$6.19	$10.45	$3.67	$6.33	$24.15
2047	$6.42	$10.81	$3.81	$6.47	$24.45
2048	$6.70	$11.26	$3.98	$6.61	$24.49
2049	$6.91	$11.59	$4.12	$6.76	$24.69
2050	$7.16	$11.97	$4.28	$6.92	$24.96
2051	$7.42	$12.37	$4.44	$7.07	$25.52

ROBERT DEMELO

8334 Lagerfeld Drive, Land O' Lakes, FL 34637
Mobile: (813) 601-5805
Email: rdemelo@seminole-electric.com

Education

Bachelor of Science, Electrical Engineering — December 2007
University of South Florida (USF), Tampa, Florida
Awarded First Place in USF Senior Design Project Presentation

Ken Chapman and Associates Leadership Development — December 2013

Professional Experience

Seminole Electric Cooperative, Inc. Tampa, Florida
Manager, Transmission Planning & System (Power Delivery & Technical Services) — June 2014 to Present

Key Responsibilities
- Lead and develop a team of System Protection, Transmission Planning and Transmission Compliance Engineers
- Seminole's primary representative at the FRCC (Florida Reliability Coordinating Council) Order 1000 Steering Task Force, and Solar Task Force, Stability Analysis Subcommittee, and Vice-Chair of the Planning Committee (PC)
- Long-term strategy as it relates to transmission and generation (existing and planned)
- Evaluate economic options to increase transmission flexibility and lower rates to reduce dependence on third party transmission providers
- Plan and execute multiple capital projects to enhance reliability, adequacy, and security of Seminole's transmission system
- Work closely with Federal Energy Regulatory Commission (FERC) counsel to comment and/or incorporate new or modified FERC rules to Seminole practices and procedures
- Oversee Subject Matter Expert (SME) compliance assessment, evidence, processes and procedures associated with North American Reliability Corporation (NERC) Operations and Planning (O&P) Reliability Standards
- Manage budget and evaluate options to reduce Operations and Maintenance (O&M) expense and increase capital project work
- Evaluate asset acquisitions with risk assessment tools within cross-functional teams

Seminole Electric Cooperative, Inc. Tampa, Florida
Lead Transmission Planning (Power Delivery & Technical Services) — September 2011 to June 2014

Key Responsibilities/Projects
- Provided technical expertise and guidance to team members within Transmission Planning and NERC Compliance
- Seminole's primary representative at the FRCC Transmission Technical Subcommittee (TTS) and Stability Analysis Subcommittee (SAS)
- Vice-Chair of the FRCC TTS and provided training sessions for planning engineers within the region
- Seminole's SME for Transmission Planning (TPL), Facilities (FAC), and Modeling (MOD) NERC Reliability Standards
- Performed transmission optimization studies for Seminole Member systems
- Led efforts in the analysis/justification for the removal of two existing Seminole special protection systems and received regional approval
- Confirmed the use/need of Seminole's existing power system stabilizer
- Assisted in the technical due diligence surrounding the acquisition of an existing switching station
- Took on full responsibility/led all transient/stability modeling and analysis

Seminole Electric Cooperative, Inc. Tampa, Florida
Engineer III - Transmission Planning (Power Delivery & Technical Services) — July 2010 to September 2011

Key Responsibilities/Projects
- Took on responsibility as Seminole's alternate SME for NERC TPL, FAC and MOD Reliability Standards
- Assisted in the development of Seminole's long-term future transmission and generation expansion plan
- Seminole's alternate representative at the FRCC TTS and SAS
- Worked with Seminole's Protection and Control Group to evaluate single points of failure using steady-state and stability analysis
- Assisted in the development of Seminole's annual Ten-Year Site Plan for submission to the Florida Public Service Commission
- Performed a complete review and developed an inventory of Seminole's generation dynamic modeling
- Analyzed Seminole and its Member's system for transient/stability response
- Worked alongside Seminole Marketing staff to implement long-term unit designations via FRCC Interchange Transactions Database

Seminole Electric Cooperative, Inc. Tampa, Florida
Engineer II - Transmission Planning (Power Delivery & Technical Services) — June 2009 to July 2010

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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Roberto Demelo RD-1

Key Responsibilities/Projects
- Assumed a more active role at the FRCC TTS and assisted in drafting regional planning procedures
- Developed knowledge and experience surrounding short circuit and stability modeling and analysis
- Verified Seminole and Seminole Member transmission modeling data
- Worked with Seminole Member staff to develop ten-year load forecasts via Schedule A process
- Assisted Seminole Regulatory staff with various FERC related filing, e.g. Open Access Transmission Tariff, Direct Assignment of Radials, etc.
- Increased my knowledge of NERC and the TPL, FAC, and MOD Reliability Standards
- Worked with Seminole Member staff to ensure compliance with power factor/power quality requirements within provider contracts

Seminole Electric Cooperative, Inc. Tampa, Florida

Engineer I – Transmission Planning (Power Delivery & Technical Services) May 2007 to June 2009

Key Responsibilities/Projects
- Assisted senior team members with transmission planning analysis and modeling
- Developed my skills and abilities with transmission planning software tools
- Worked with the FRCC TTS on regional studies
- Coordinated Seminole Member delivery point projects (new substations, meter points, etc)
- Helped evaluate future generation expansion plans for new baseload and peaking generation
- Tracked transmission reliability for Seminole and its Members utilizing IEEE SAIDI, CAIDI, and SAIFI indices

Skills

Certified in Siemens PSSE® Power Flow and Steady State Analysis & Modeling
Certified in Siemens PSSE® Short Circuit Analysis & Modeling
Certified in Siemens PSSE® Dynamic Simulation & Modeling
Proficient in PowerGEM's TARA (Transmission Adequacy & Reliability Assessment) Software
System Protection & Control Schemes
Microsoft Office Suite

2016 IEEE Florida West Coast Section Young Engineer of the Year

Kyle D. Wood

Education

M.A. Economics, University of South Florida, Tampa, FL

B.A. International Business, University of South Florida, Tampa, FL

Professional Experience

Manager of Load Forecasting and Member Analytics, Seminole Electric Cooperative, Tampa FL, 2012-Present

Senior Economic Analyst, Deiter Consulting Group, Tampa, FL, 2008-2012

Intern to International Trade Director, Greater Tampa Chamber of Commerce, Tampa, FL, 2007

Academic Awards and Honors

Undergraduate Degree with Distinction

Executive Board Member, College of Business Student Leadership Council, University of South Florida

Director of Corporate Relations, International Business Board, University of South Florida

Study Abroad Student, Osnabrück University, Germany

Professional Association Membership

Utility Advisory Board, SAS

Energy Forecasting Group, Itron

Load Forecasting Working Group, FRCC

Electric Utility Forecasters Forum

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DOCKET: 20170266-EC EXHIBIT: 14
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Kyle D. Wood KDW-1

TOM HINES

TOM HINES
Program Design and Regulatory Specialist
Tierra Resource Consultants, LLC
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Email: Tom.Hines@tierrarc.com
Web: www.TierraRC.com

PROFESSIONAL HISTORY

- Principal, Tierra Resource Consultants, LLC
- President, Hines Consulting
- Analyst/Project Manager, EcoGroup (Aclara)

EDUCATION

- MS, Environnent Planning, Arizona State University, 1993
- BS, Psychology, Rutgers University, 1990

PROFESSIONAL ASSOCIATIONS

- Board of Directors, Energy and Environmental Building Alliance

BIOGRAPHY

Tom Hines is a demand side management expert with over 25 years of experience in program design, regulatory strategy, implementation and evaluation. Tom specializes in fully integrated distributed energy resource planning - working with utilty system planners and stakeholders to design comprehensive portfolios that meet the evolving needs of both the customer and the grid.

From 1997 to present, Tom has worked with Arizona Public Service Company (APS) as the lead designer in developing and managing the company's award-winning portfolio of residential energy efficiency programs, including: new homes, existing homes HVAC, home performance, consumer products lighting, pools, multi-family, behavioral conservation, commercial/industrial and energy efficiency financing programs. Throughout this time, Tom has worked closely with industry stakeholders to drive market transformation, including; builders, contractors, realtors, lenders, raters and other trade allies.

Mr. Hines has extensive experience working directly with the Arizona Corporation Commission (ACC) providing direct testimony, developing filings and working directly with ACC staff during energy efficiency proceedings. Recent work includes acting as a strategic advisor on the design and development of APS' entire portfolio of DSM programs, while integrating the next generations of technologies, including connected devices and storage. In this role, Tom prepares information and analysis on DSM program trends, technologies, opportunities, and challenges for senior executives and the utility's board of directors. His unique experience in policy, evaluation, and implemenation allows him to develop successful paths to compliance that maximize cost-effectiveness, deliver targeted load shapes, and meet the needs of customers and stakeholders.

Since joining Tierra, Tom has expanded his efforts to serve a wide range of investor owned utilities and co-ops across the country. Tom's experience extends beyond electric utilities, providing design assistance for national energy efficiency efforts for both the U.S. EPA and China. He has consulted for state/local governments and private sector manufactures developing grid-interactive products.

Mr. Hines holds a masters degree in Environmental Planning from Arizona State University and is a board member of "EEBA" the Energy and Environmental Building Alliance, an organization devoted to advancing building science and energy efficient building practices.

PROFESSIONAL EXPERIENCE

Integrated Distributed Energy Resource Planning and Design

Mr. Hines is currently a leading proponent of Distributed Energy Resource program design to address load shape challenges from high solar DG adoption on the grid, often referred to as the "duck curve." In this role at APS, Tom is tasked with coordinating with a wide range of utility disciplines, including; resource planning, technology assessment, system operations planning,

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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Thomas Hines TH-1

regulatory, smart grid, customer service, and rates to identify new and innovate approaches to distributed energy resource programs that support the continued growth of solar, while minimizing grid impacts. Mr. Hines has begun to expand this effort to other utilities, since 2016.

Energy Efficiency Portfolio Design for Commercial and Residential Programs

Mr. Hines oversees the annual energy efficiency portfolio design for Arizona Public Service. In this role, he has designed multiple award winning EE programs including new homes, home performance, HVAC, duct repair, quality install, pool pumps, and lighting. He works closely with program managers to review cost-effectiveness, calculated emission reductions, develop program budgets, design program modifications and manage annual compliance targets. Recently, Tom has completed similar tasks for multiple electric Co-ops.

Policy and Strategic Consulting Support

Mr. Hines has provided EE regulatory support and policy development, including: testimony at commission proceedings, meeting with commissioners and staff, developing filings and reports for APS. Tom was an integral player in the development of the Arizona EE Standards. He has extensive experience working with EE program cost effectiveness tests, stakeholder coordination, regulatory development, program implementation plans, EE savings forecasts, and integrating new technology options into existing compliance approaches. This expertise has extended to assisting in consulting with other utilities and the EPA ENERGY STAR program.

Distributed Storage Technology Evaluations and Pilot Design

Mr. Hines has assisted in multiple technology evaluations and pilot program designs for emerging battery, thermal storage, load management and demand response projects including APS' Solar Innovation Study, the APS Demand Response, Energy Storage and Load Management program, and Tucson Electric Power's Sustainable Communities Project. These efforts have included an evaluation of the technology, control systems, and build-out of the full program design.

Program Management and Implementation

Tom has directly managed a wide range of successful EE programs including residential lighting, HVAC, duct repair, pool pumps, and new homes. Tom has managed multi-million-dollar program budgets and consistently exceeded savings goals. As an industry leader in these roles, he has collaborated with or worked for over 30 electric, gas and water utilities nationwide sharing best practices and strategies for successful market transformation.

Distributed Energy Resource Education

In 2016, Mr. Hines was the project lead for the APS Qualified Solar Sales and Installations training, in which he authored innovative training on the integration of EE and DR devices into solar sales to help customers better manage both their energy and demand. Prior to this effort, Tom oversaw the development of training for local ENERGY STAR programs, low-income weatherization, high bill management, and other cross-cutting resource management activities.

Energy Efficiency Marketing and Communications.

Tom has designed and developed multiple award-winning EE advertising and marketing campaigns. Additionally, served as the primary EE spokesperson for APS for many years and has extensive media experience in all forms.

SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT SAVINGS REPORT

Program Year 2015

FLORIDA PUBLIC SERVICE COMMISSION
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PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Thomas Hines TH-2

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advanced energy

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Organizations

Advanced Energy
Tierra Resource Consultants

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EXECUTIVE SUMMARY

In Q1 2016, Seminole Electric Cooperative, Inc. (Seminole) engaged the Advanced Energy and Tierra Resource Consultants team to help prepare for a Needs Determination for new generation and to compile savings reports for EIA Form 861. The process required collecting and quantifying Seminole's and its Member Co-ops' 2015 energy efficiency (EE) and demand management programs and savings. The AE/Tierra team worked with Seminole and Member Co-ops to identify applicable EE efforts, collect program data, run engineering models to determine costs and savings, and analyze key findings. The results of this analysis show that, based on reported program participation and data in 2015, Seminole produced total estimated savings of 12,353 annual megawatt-hours (MWh), 34,479 lifetime MWh, and 85 peak demand megawatts (MW) (at generator including transmission and distribution losses). Reported savings were equal to about 0.09% of total Seminole member retail energy sales and 2.5% of the peak demand in 2015.

AE/Tierra found that Member Co-ops had significant programs in place to help their members save energy and manage energy costs. However, it was difficult to accurately quantify all savings due to a lack of consistent tracking and reporting of program activities and member participation. To optimize current EE programs, AE/Tierra has made recommendations to help Seminole and its Member Co-ops improve program tracking and increase future savings by enhancing current efforts and adding new measures to existing programs. These recommendations are described in this report.

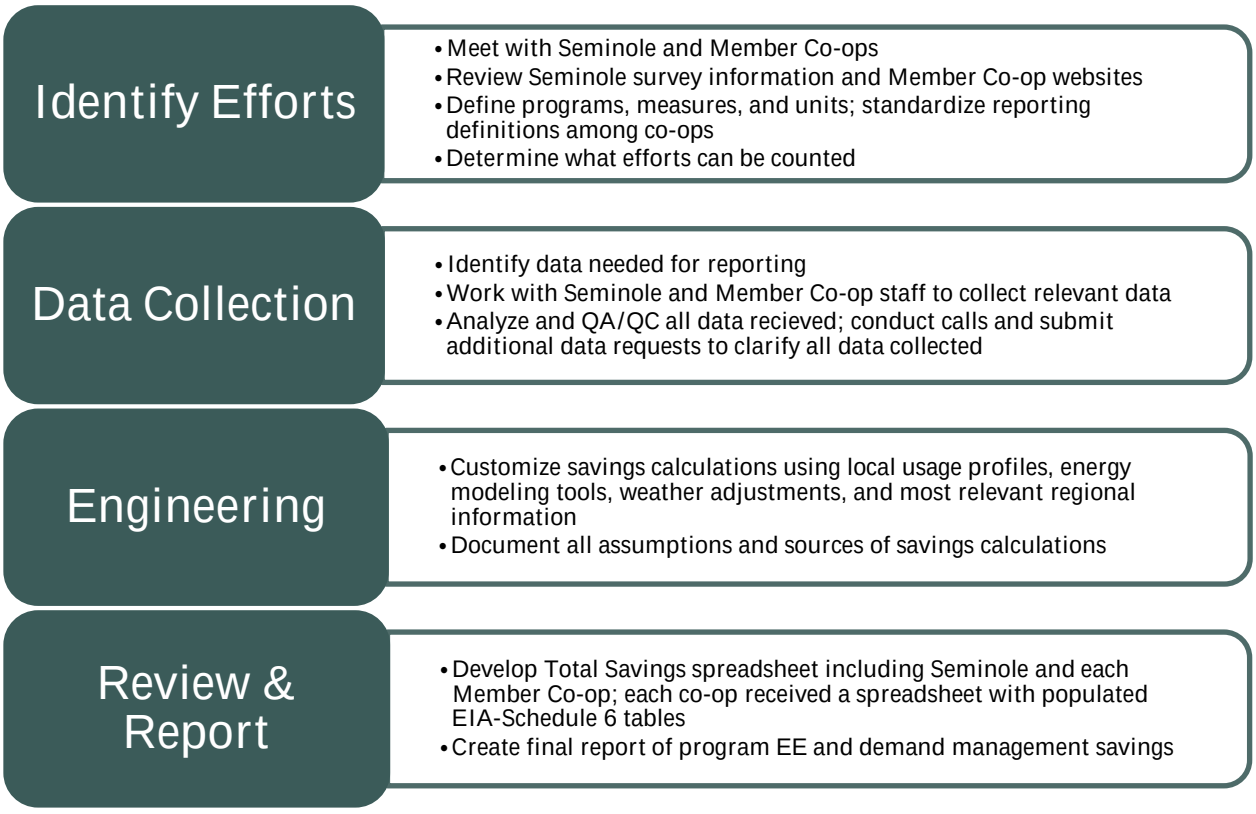
PROCESS FOR QUANTIFYING ENERGY EFFICIENCY RESULTS

To quantify Seminole and Member Co-ops' EE programs, AE/Tierra worked with Seminole and Member Co-ops through the following steps:

AE/Tierra researched all programs and EE measures currently offered by Seminole and Member Co-ops to collect cost and savings information. Seminole and Member Co-ops offer many programs and services to educate their members on ways to save energy, including web content, brochures, member outreach events, and on-site energy audits. Although it is expected that these efforts produce significant energy savings and market

transformation effects, it is difficult to accurately quantify and attribute these savings. Within the overall portfolio, the team identified a subset of EE measures and program activities where energy savings could be identified, quantified, and reported. The team also worked to standardize the program measures, units, and definitions across all Member Co-ops, ensuring consistent reporting. Per-unit energy savings estimates were developed using a variety of sources and custom energy-savings calculations, including regional technical reference manuals, national industry-recognized databases, custom energy modeling work using local weather and building characteristics, and engineering review of Seminole information submitted in response to data requests. Specific references are provided in the following section for each program type. Program participation, such as number of units or meters, and spending on incentives and labor were also collected and included in benefit/cost calculations for each measure. Finally, a tracking and reporting spreadsheet tool was developed for Seminole and each Member Co-op to document all data and summarize results.

EE Quantification Process:



PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

AE/Tierra identified a number of existing energy savings programs and initiatives offered by Seminole and/or Member Co-ops in 2015:

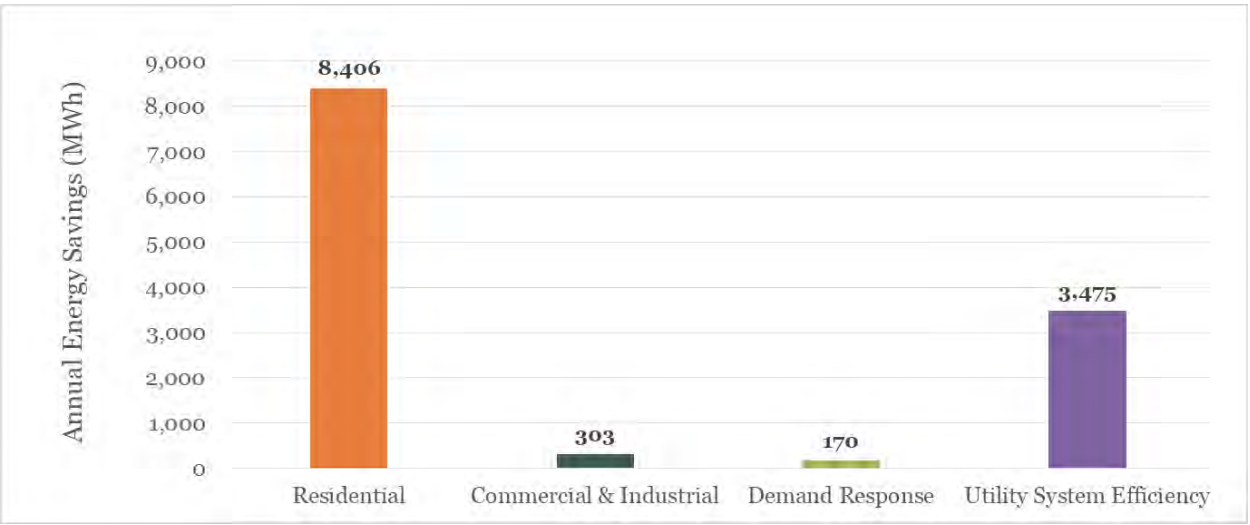
- Residential Pre-Pay Program: Residential members can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- LED/CFL Efficient Bulb Giveaway Lighting Programs: These Member Co-op programs provide participating members with free energy-efficient 10 Watt (W) LED or 13W CFL bulbs to replace their existing 60W incandescent bulbs.
- Energy Smart Rebate Programs: A rebate is given to residential members to upgrade to more efficient equipment and/or improve building envelope. Rebate measures include: air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation – batt or spray foam – and window film.
- LED Outdoor and Street Lighting: Replacement of utility-owned outdoor and street lighting with lower wattage LEDs. Each application was looked at separately: 100W high pressure sodium (HPS) to 40W, 48W, or 72W LED, 150W HPS to 70W LED, 250W HPS to 107W LED, 1000W metal halide (MH) to 283W or 316W LED
- Coincident Peak Power (CPP) Rates: Critical peak billing program where commercial members are signaled to initiate demand response to reduce short-term peak.
- Time-of-Use (TOU) Rates: Residential, commercial, or industrial rates that encourage members to use power during off-peak hours through less expensive prices. No demand or energy savings were claimed for these rates.
- Utility System EE Projects:
    - Lighting and HVAC upgrades at Seminole generation or administration facilities or Member Co-op facilities
    - Distribution System Voltage Reduction (VR): Reduction of voltage on certain distribution feeders during peak times

Sources of data for each program type are provided in the table below. Full references are provided in the last section of this report.

Program	Primary Data Sources
Residential Pre-Pay	Arizona Public Service, EPRI (2009), EPRI (2010), South Carolina Energy Office Budget and Control Board (2013)
LED/CFL Bulb Giveaways	Arkansas Public Service Commission (2015), Navigant Consulting (2012)
Energy Smart Rebates	Florida Department of Business and Professional Regulation (2014), National Renewable Energy Laboratory
LED Outdoor/Street Lights	Engineering Review of Utility Reported Data
TOU/CPP Rates	Utility reported
Utility System EE Projects	California Public Utilities Commission (2016), National Electric Manufacturers Association , Engineering Review

Total Annual Energy Savings by Program Type

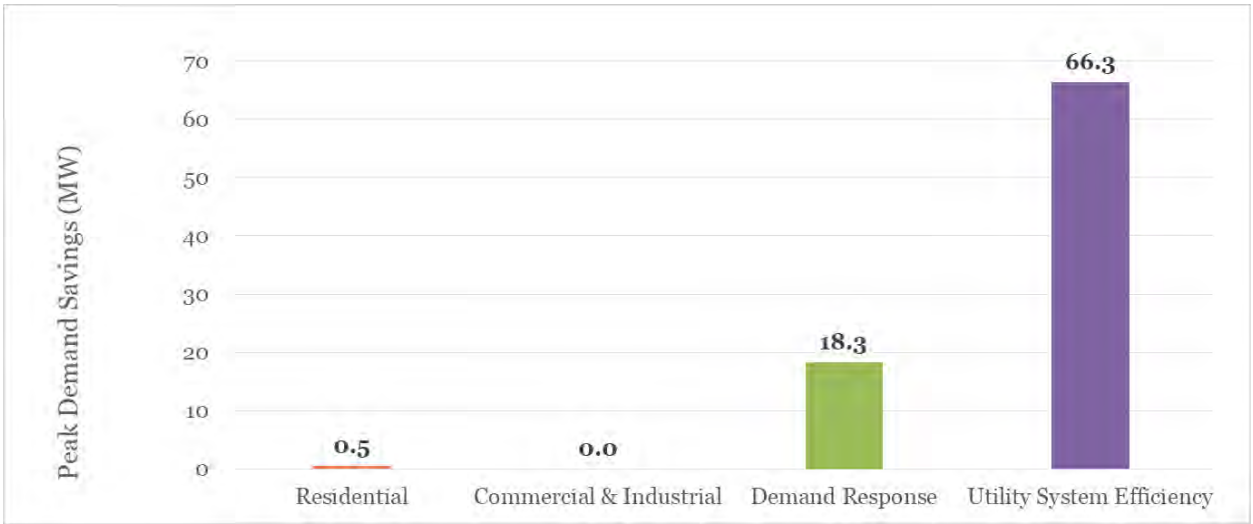
Total annual energy savings for Seminole in 2015 were 12,353 MWh and peak demand savings were 85 MW (at generator including transmission and distribution losses). Lifetime energy savings is 34,479 MWh. The chart below shows all Member Co-op program savings plus utility system savings projects. Residential programs accounted for 68.0% of savings, followed by utility system energy efficiency programs at 28.1%. The remaining 3.9% of savings came from commercial and industrial programs and demand response programs.



Sector	Annual MWh Savings	%
Residential	8,406	68.0%
Commercial & Industrial	303	2.5%
Demand Response	170	1.4%
Utility System Efficiency	3,475	28.1%
Total	**12,353**	**100%**

Total Annual Peak Demand Savings by Program Type

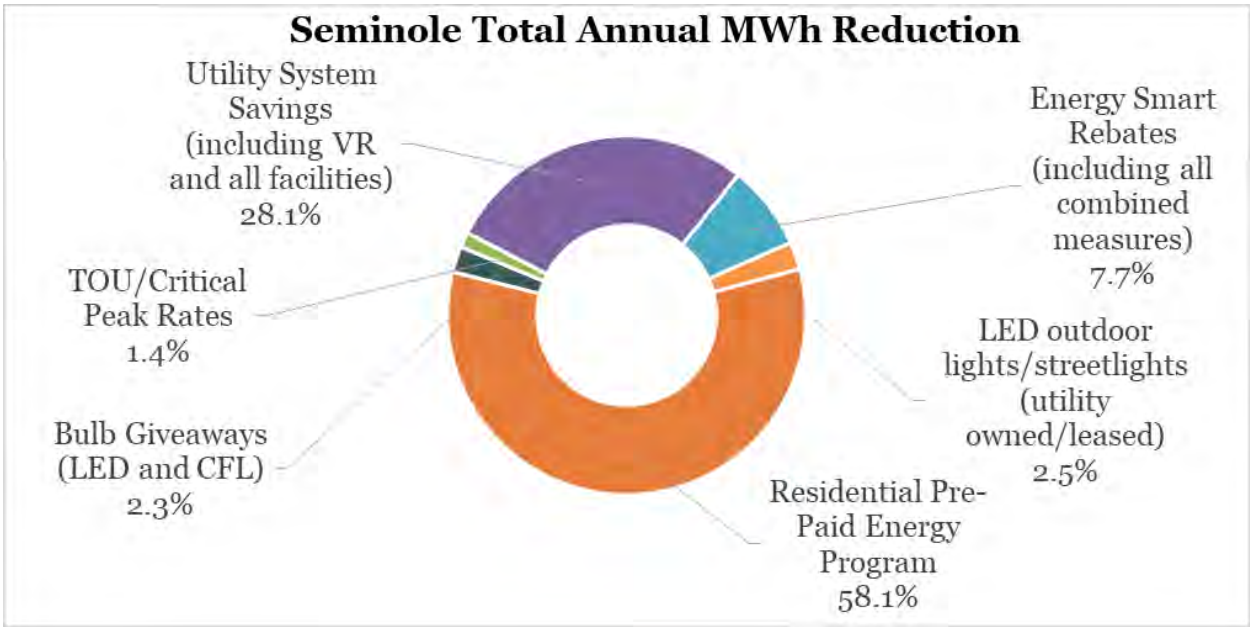
The majority of peak demand savings came from the utility system efficiency programs (78%) and demand response (21.5%). Residential Programs contributed less than 1% of annual demand savings.



Sector	Peak MW Savings	%
Residential	0.5	0.6%
Commercial & Industrial	0	0%
Demand Response	18.3	21.5%
Utility System Efficiency	66.3	78.0%
Total	**85.0**	**100%**

Percentage of Annual Savings by Program

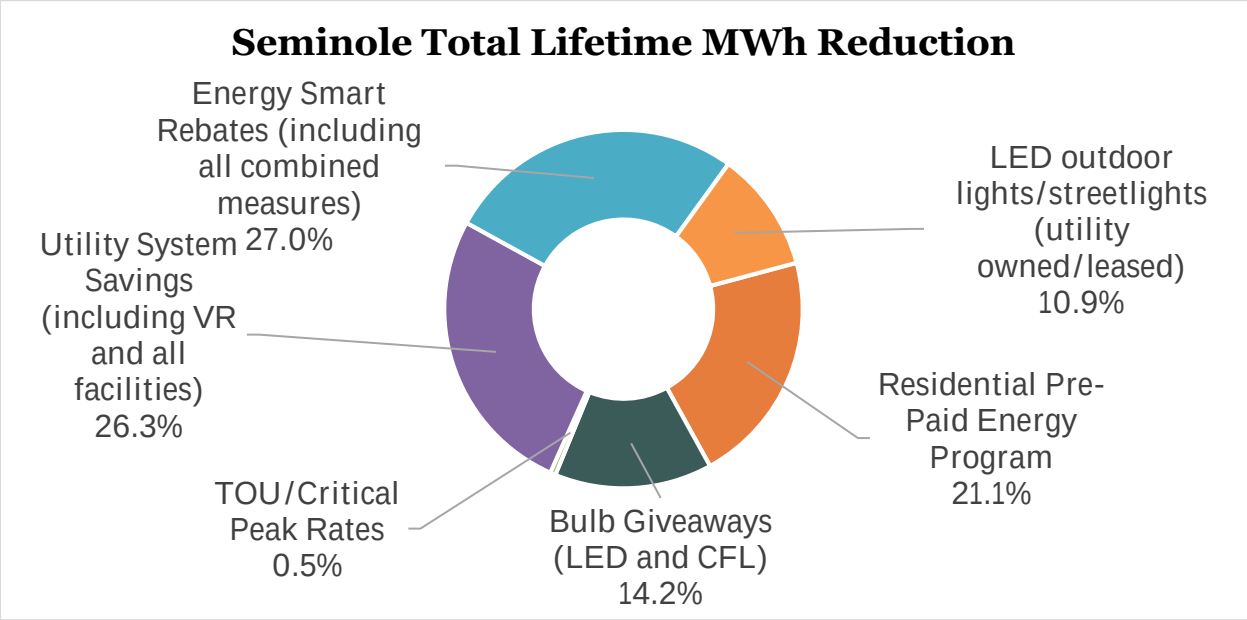
The majority of savings in 2015 came from three programs: pre-pay (58.1%), utility system savings projects (28.1%), and Energy Smart rebates (7.7%). The remaining 6% of savings came from bulb giveaways, TOU or CPP rates, and LED outdoor and street lights.



Program Type	Annual MWh Savings	%
Residential Pre-Paid Energy Program	7,172	58.1%
Bulb Giveaways (LED and CFL)	287	2.3%
TOU/CPP Rates	170	1.4%
Utility System Savings (including VR and all facilities)	3,475	28.1%
Energy Smart Rebates (including all combined measures)	946	7.7%
LED Outdoor Lights/Streetlights (utility owned/leased)	303	2.5%
Total	**12,353**	**100%**

Percentage of Lifetime Savings by Program

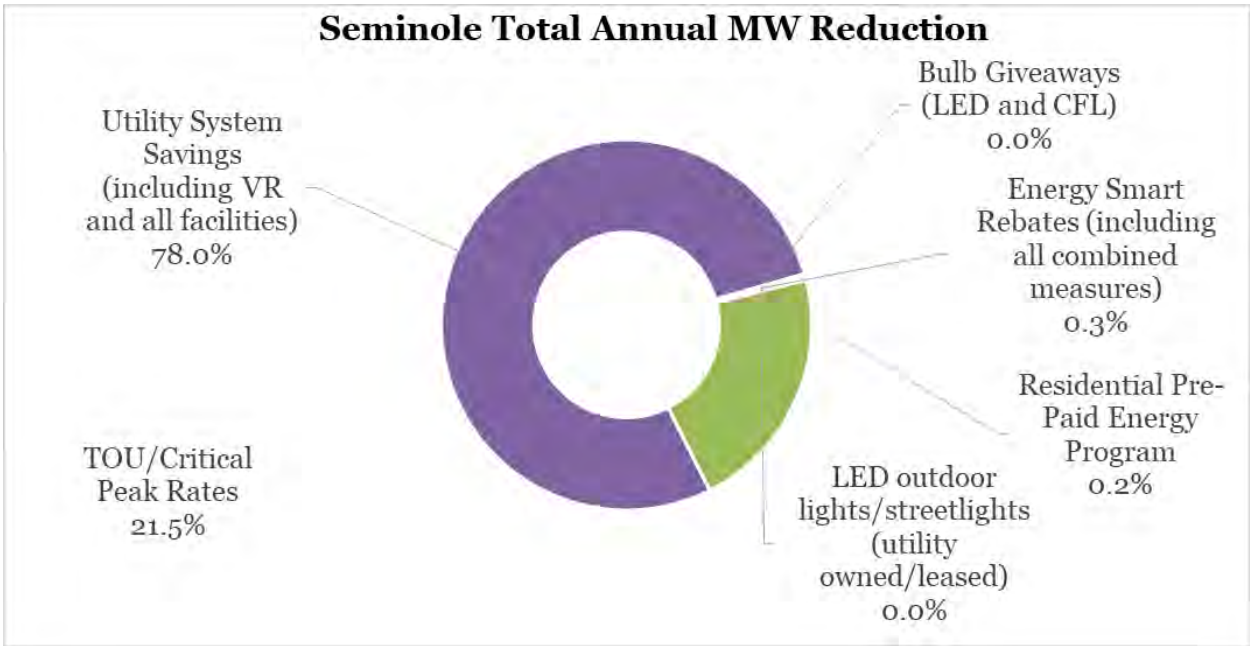
Lifetime savings refer to the cumulative EE savings over the expected lifetime of a measure. Energy Smart rebate measures consist of energy-efficient HVAC equipment and insulation that have much longer lives, so while they only contribute 8% of annual savings, they account for 27.0% of lifetime savings. In contrast, savings from the pre-pay program come from behavioral changes that participants make in response to receiving increased feedback on energy consumption and costs. These behavioral changes, while providing real energy savings, are generally considered to have a 1-year measure life and therefore this program goes from 58.1% of annual savings to only 21.1% of lifetime savings.



Program Type	Lifetime MWh Savings	%
Residential Pre-Paid Energy Program	7,290	21.1%
Bulb Giveaways (LED and CFL)	4,907	14.2%
TOU/CPP Rates	170	0.5%
Utility System Savings (including VR and all facilities)	9,068	26.3%
Energy Smart Rebates (including all combined measures)	9,296	27.0%
LED Outdoor Lights/Streetlights (utility owned/leased)	3,748	10.9%
Total	34,479	100%

Percentage of Annual Peak Demand Savings by Program

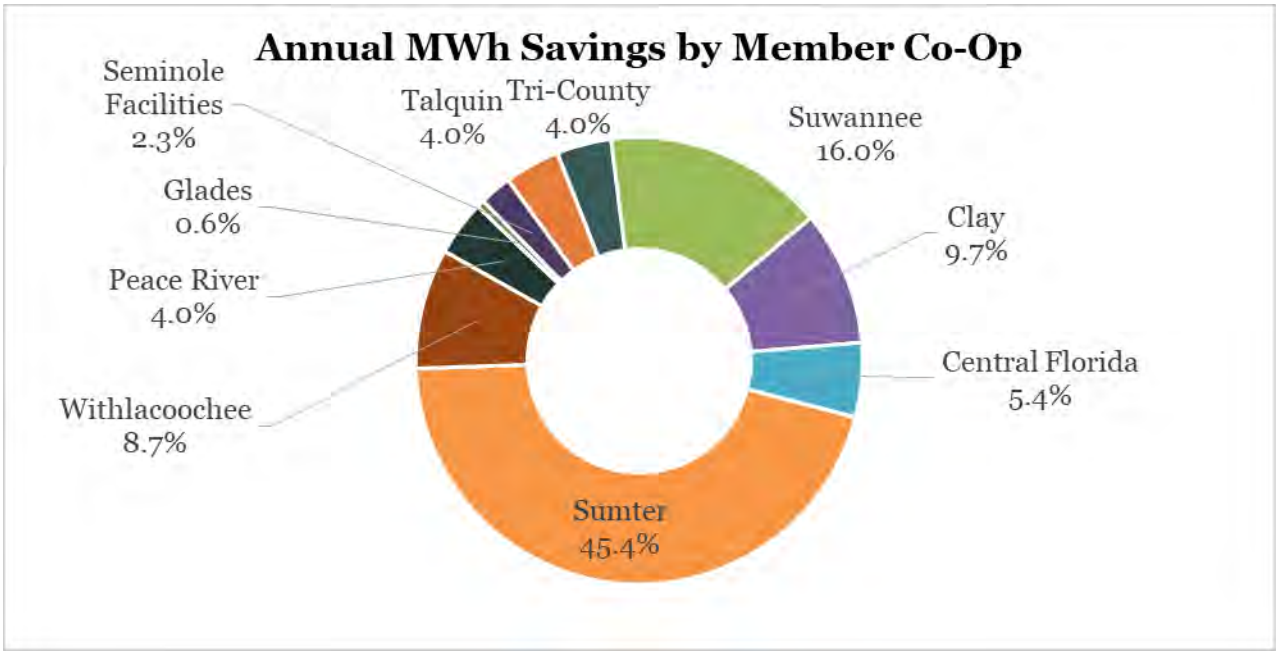
The majority of peak demand savings came from utility system savings projects (71.8%) and TOU/CPP rates (27.5%). Programs that are categorized as traditional customer EE programs contributed less than 1% of annual peak demand savings.



Program Type	Annual MW Savings	%
Residential Pre-Paid Energy Program	0.2	0.2%
Bulb Giveaways (LED and CFL)	0.03	0.0%
TOU/CPP Rates	18.3	21.5%
Utility System Savings (including VR and all facilities)	66.3	78.0%
Energy Smart Rebates (including all combined measures)	0.2	0.3%
LED Outdoor Lights/Streetlights (utility owned/leased)	0	0.0%
Total	85.0	100%

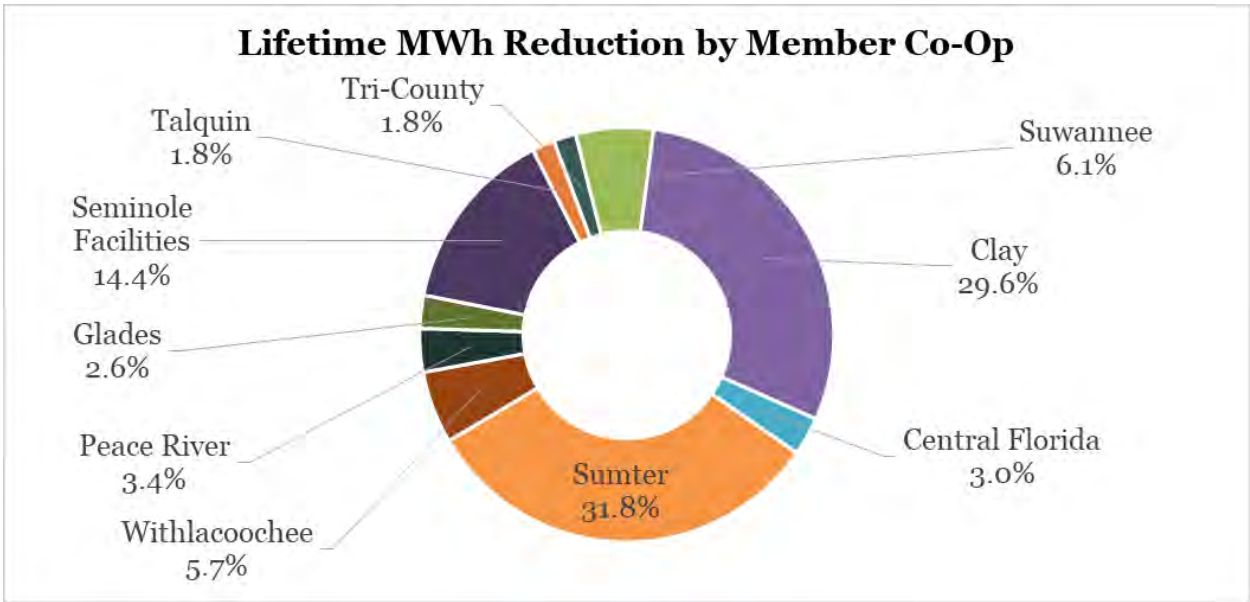
Percentage of Annual Savings by Member Co-op

When the overall savings were broken out by Member Co-op, almost half of the savings came from Sumter (45.4%), and 16.0% came from Suwannee. The remaining savings came from a combination of Clay (9.7%), Withlacoochee (8.7%), Talquin (4.0%), Central Florida (5.4%), Tri-County (4.0%), Peace River (4.0%), and Glades (0.6%).



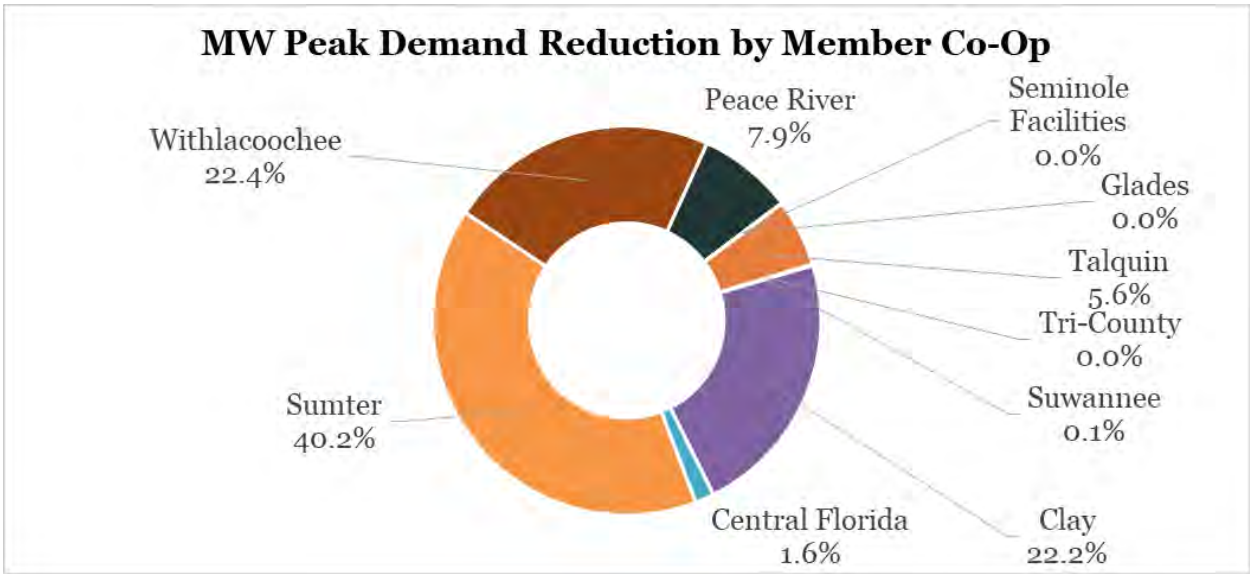
Percentage of Lifetime Savings by Member Co-op

Similar to Seminole's total lifetime savings results, the lifetime savings by Member Co-op differ significantly from annual savings due to the different types of EE programs and varying measure lives. Sumter's savings fell from 45.4% annual to 31.8% lifetime, while Clay's savings increased from 6.1% to 29.6%. Suwanee's savings fell from 16% to 6.1%. Co-ops implementing a pre-pay program will see lower lifetime savings results because of its 1-year measure life.



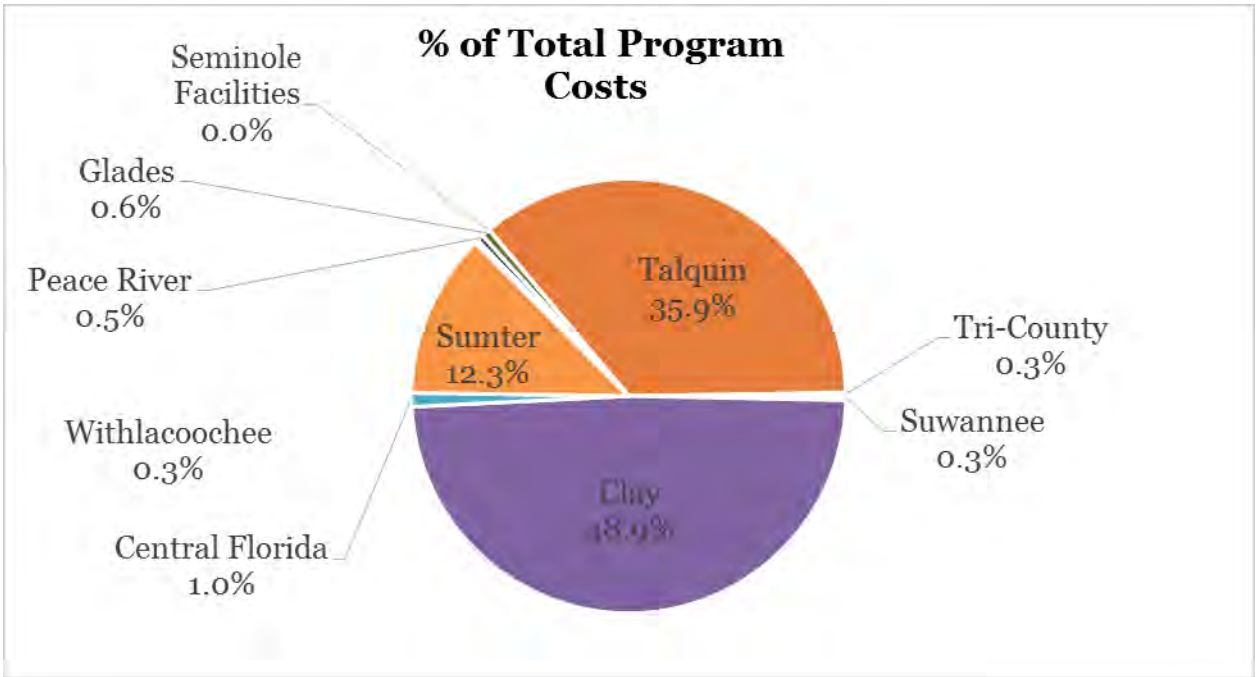
Percentage of Annual Peak Demand Savings by Member Co-op

The peak savings broken out by Member Co-op resulted in 40.2% of the savings coming from Sumter, 22.4% from Withlacoochee and 22.2% from Clay The remaining peak savings came primarily from Peace River (7.9%), Talquin (5.6%), and Central Florida (1.6%).



Percentage of Total Energy Efficiency Spending by Member Co-op

Energy efficiency spending does not necessarily correlate with savings. This outcome occurs partly because spending is not consistently tracked the same way across Member Co-ops, and partly because of differences in the energy efficiency programs and measures that each Member Co-op emphasizes. Clay spent 48.9% of Seminole's total, while Talquin spent 35.9%, and Sumter spent 12.3%. Together, these three Member Co-ops were responsible for 97.1% of all spending. Efforts to determine cost effectiveness were challenging due to incomplete and inconsistent tracking of program spending across Member Co-ops. Costs such as labor, program marketing, administration, training, and rebates/incentives must be separated and tracked consistently to accurately determine cost effectiveness.



Organization	Implementation Costs	Incentive Costs	Total Program Costs	% of Implementation Costs	% of Incentive Costs	% of Total Program Costs
Talquin	$ 251,160	$ 1,847	$ 253,007	53.13%	0.79%	35.88%
Tri-County	$ -	$ 1,847	$ 1,847	0.00%	0.79%	0.26%
Suwannee	$ 200	$ 1,847	$ 2,047	0.04%	0.79%	0.29%
Clay	$ 150,974	$ 193,808	$ 344,782	31.93%	83.39%	48.89%
Central Florida	$ 2,400	$ 4,817	$ 7,217	0.51%	2.07%	1.02%
Sumter	$ 65,187	$ 21,336	$ 86,523	13.79%	9.18%	12.27%
Withlacoochee	$ -	$ 1,847	$ 1,847	0.00%	0.79%	0.26%
Peace River	$ 166	$ 3,230	$ 3,395	0.04%	1.39%	0.48%
Glades	$ 2,677	$ 1,847	$ 4,524	0.57%	0.79%	0.64%
Seminole Facilities	$ -	$ -	$ -	0.00%	0.00%	0.00%
Seminole Total	**$ 472,764**	**$ 232,426**	**$ 705,189**	**100.00%**	**100.00%**	**100.00%**

Cost Effectiveness

To determine the cost effectiveness of EE programs, AE/Tierra looked at industry-accepted cost-effectiveness tests that are relevant to Florida, including

- Utility Cost Test (UCT) – Analyzes whether programs reduce utility revenue requirements and how energy efficiency compares to other resources
- Ratepayer Impact Measure (RIM) – Analyzes programs from the perspective of a non-participating member to determine if a program benefits all members or participants only

Each test shows a different perspective on the benefits versus costs of an EE program and is expressed as a benefit/cost (B/C) ratio.

To calculate cost effectiveness, the following information was collected from Seminole and Member Co-ops where available:

- Program Administrative Cost – The administrative costs associated with implementing energy efficiency and demand management programs by Seminole and Member Co-ops on a per-program basis
- Incentive Cost – The incentive costs paid by Seminole and its Member Co-ops to participants on a per-program basis
- Measure Incremental Cost ($/Unit) – The incremental cost of the measure (in excess of the standard costs for a non-energy-efficient device) used in cost-effectiveness calculations

- Billing Rate Escalation Rate – Co-op-specific expected escalation rate of retail rates - Default 0%
- Program Cost Escalation Rate – Co-op-specific expected escalation rate of program costs - Default 0%
- Avoided Costs Escalation Rate – Co-op-specific expected escalation rate of avoided costs - Default 0%
- IRP Discount Rate - The Weighted Average Cost of Capital (WACC) used in the integrated resource plan (IRP)
- Avoided Costs – The value of avoided costs of energy, capacity, and operations and maintenance (O&M)
- Retail Rates of Energy by Sector – The retail rates of energy by sector as used in cost-effectiveness testing to calculate the member cost savings per measure unit
- Transmission and Distribution Loss Factors – Includes total line losses from generation to member end-use meter

These data were combined with the energy savings and measure life to calculate UCT and RIM. The test results for all programs combined for Seminole were

- Utility Cost Test (utility's perspective) = 12.34 B/C ratio
- RIM Test (non-participant's perspective) = 1.12 B/C ratio

It is important to note that there are many limitations to these results due to the lack of available data. Specifically, AE/Tierra did not have a breakdown of accurate tracking of all program costs, including labor to deliver programs, an allocation of costs among programs, a separation of EE program- compared to non-program-related costs (e.g., pre-pay), and a distinction between incentive and non-incentive costs. Furthermore, for program benefits, Member Co-ops did not always accurately track the number of customers who participated in bulb giveaways and other programs. Therefore, it is expected that total program costs and program savings are higher than is reported.

KEY FINDINGS AND RECOMMENDATIONS

Through this research and analysis, AE/Tierra found that Seminole and its Member Co-ops currently offer a wide variety EE programs and demand management efforts to benefit their members. To maximize the benefits of these offerings, AE/Tierra has several recommendations:

Program Enhancement Recommendations

- Better program tracking
- Leverage what you are doing today
- Look at economies of scale
- Add targeted new programs and measures

1) Improve program tracking to ensure accurate accounting for all EE activities and expenses, which will allow for more comprehensive evaluation and verification of savings, costs, and benefits. This step includes aligning Member Co-ops around standardized program reporting and tracking and accounting procedures, including tracking program spending according to incentive and non-incentive costs.
2) Program administrative cost savings can be achieved through economies of scale, such as technology-enabled central services and partnering opportunities (within Seminole and/or with municipalities, water departments, and utilities). For example, simply partnering on bulk purchases of CFL and LED bulbs for giveaway programs among Member Co-ops can help save program costs. Aligning on centralized program tools, such as auditing software and tracking spreadsheets, is another opportunity to consider. By streamlining program delivery and driving down costs, Seminole can make these efforts even more cost effective and beneficial to members.
3) Increase the value of EE efforts by considering new measures that can be added to existing programs within the same delivery channels. This approach can leverage existing customer touch points to provide deeper energy savings per participant, which increases total program savings and cost effectiveness.
4) Investigate the costs and benefits of adding new cost-effective programs that meet the needs of the Member Co-ops and provide high value to their members. In this light, in the next phase of the project, the AE/Tierra team will be suggesting additional programs and measures for Seminole and its Member Co-ops to consider as smart additions to their current program portfolios.

A detailed list of key findings and recommendations by program type is shown in the table below.

Key Findings and Recommendations by Program Type

Program	Key Findings	Recommendations
Pre-Pay	• Large contributor to EE savings, producing 21% of total lifetime savings • Can provide utility operational savings (reduced collections and write offs) in addition to EE savings • Ideally, should be linked with enhanced program energy savings tips and information to bolster efficiency	• Explore opportunities to expand program participation • Expand energy savings tips and EE education for members to enhance EE benefits of the program • Improve tracking of EE costs to get a more accurate look at benefit/cost • Consider program evaluation and measurement and verification (EM&V) activities to better document savings for Seminole; this program is a large component of overall savings and relies on behavioral energy savings that can be difficult to document
Utility System Savings	• Represents 26% of total lifetime savings • Can be a very cost-effective savings opportunity that can reduce system losses and operating costs	• Look for opportunities to expand system savings • Institute better process for tracking utility system EE project data to better claim savings • Consider an in-depth opportunity assessment by feeder to determine savings potential. Voltage reduction savings can be a significant contributor to peak demand savings. They are also very specific to each feeder. For existing feeders with voltage reduction controls in place, consider conducting a metered measurement and evaluation study of voltage reduction savings to better document results.

Energy Smart HVAC	• Represent 27% of total lifetime savings • Savings from the HVAC rebates are reduced due to many cases of upsizing HVAC replacement equipment	• Consider updating the program design for Clay Energy Smart HVAC program to better capture savings (e.g., require sizing calculations or do not allow upsizing) • Offer HVAC quality installation training for local contractors to increase savings and impacts • Require proper sizing and quality installation • Consider multi-stage HVAC equipment and smart thermostats as emerging program opportunities
Energy Audits	• Most Member Co-ops have an on-site energy audit program for residential and/or commercial and industrial members • Bulb giveaways represent 14% of total lifetime savings	• Consider a standardized audit tool and/or set of audit data collected across all Member Co-ops • Leverage on-site audits to provide and track LED/CFL giveaways and claim additional EE savings • Combine efforts to make a bulk purchase at a lower cost per bulb

CONCLUSION

We thank Seminole and its Member Co-ops for their cooperation and assistance in preparing this report. The report contains the best available information from interviewing Seminole and Member Co-ops plus a variety of other sources: regional technical reference manuals, national industry-recognized databases, and custom energy modeling work using local weather and building characteristics. When necessary to make engineering judgements, the team chose conservative estimates. In the future, more consistent tracking and reporting of program activities and member participation could strengthen results and lead to greater savings.

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SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT PROGRAM ANALYSIS

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INTRODUCTION

Seminole Electric Cooperative Inc. (Seminole) is one of the largest generation and transmission cooperatives in the United States. Its mission is to provide reliable, competitively priced, wholesale electric power to its nine Member Cooperatives.

Recently, a pressing need for Seminole has been to secure additional resources to meet an upcoming shortfall in capacity in 2021 either through Power Purchase Agreements (PPAs) or by expanding generation. Seminole reached out to Advanced Energy (AE) and Tierra Resource Consultants LLC (Tierra) to help detail its energy efficiency (EE)/ demand-side management (DSM) portfolio to show the steps it has taken to reduce capacity and future generation needs. The AE/Tierra team assisted Seminole with determining and quantifying the EE/DSM efforts that it and its Member Cooperatives undertook in 2015 to reduce load. Together, they developed a short-term action plan for enhancing current and future EE/DSM efforts in as cost-effective a way as possible.

AE/Tierra found that Seminole and its Member Cooperatives have many programs in place to help their members save energy and manage energy costs. AE/Tierra also provided recommendations to help optimize the programs in the form of an Energy Efficiency and Demand Management Action Plan. This plan analyzes additional EE/DSM program concepts that Seminole and its Member could add to their portfolio in the future. However, none of the program concepts for the future pass the Rate Impact Measurement (RIM) test and may result in rate impacts to Member Cooperatives.

EXISTING PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

AE/Tierra found that Seminole and its Member Cooperatives offer many energy-saving programs, as well as services to educate their members about energy conservation. These services include web-based content, brochures, member outreach events, and on-site energy audits. Within Seminole's larger portfolio, AE/Tierra identified a subset of EE/DSM measures and programs where energy savings could be identified, quantified, and reported.

The existing EE/DSM programs and initiatives offered by Seminole and/or the Member Cooperatives include the following:

- Residential Pre-Pay Program: In this program, residential members can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness provided by this program produces behavioral changes that result in energy savings. Pre-Pay is limited to AMI customers only.
- LED/CFL Efficient Bulb Giveaway Lighting Programs: These Member Cooperative programs provide members with free energy-efficient 10 Watt (W) LED or 13W CFL bulbs to replace their existing 60W incandescent bulbs.
- Energy Smart Rebate Programs: These programs offer a rebate to residential members to upgrade to more efficient equipment and/or improve their building envelope. Rebate measures include air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation (batt or spray foam), and window film.
- LED Outdoor and Street Lighting: This initiative replaces utility-owned outdoor and street lighting with lower wattage LEDs. Each application was looked at separately: 100W high pressure sodium (HPS) to 40W, 48W, or 72W LED; 150W HPS to 70W LED; 250W HPS to 107W LED; and 1,000W metal halide (MH) to 283W or 316W LED.
- Coincident Peak Power (CPP) Rates: This billing program signals Members to signal commercial members to initiate demand response and reduce short-term peak. Members are offered an incentive of a Wholesale demand rate.
- Time-of-Use (TOU) Rates: These are residential, commercial, or industrial rates that encourage members to use power during off-peak hours through less expensive prices. No demand or energy savings were claimed for these rates.

- Utility System EE Projects
    - Example projects include lighting and HVAC upgrades at Seminole generation, administration facilities, or Member Cooperative facilities.
    - The Distribution System Voltage Reduction project reduces voltage on certain distribution feeders during peak times.

KEY FINDINGS AND RECOMMENDATIONS

Seminole and its Member Cooperatives currently offer a variety of EE/DSM programs and measures to benefit members. AE/Tierra Researched several other programs that ultimately did not meet the RIM test. However, there are some areas where Seminole could see marginal improvements on existing programs.

Program Enhancement Recommendations

- Improve program tracking
- Look at economies of scale
- Leverage what you are doing today
- Continue to evaluate new programs and measures

1) **Improve program tracking to ensure accurate accounting for all EE/DSM activities, savings impacts, and expenses.** The AE/Tierra team believes that Seminole is likely producing greater savings for members than is currently reported due to a lack of comprehensive program tracking. Improved tracking will allow for more comprehensive evaluation and verification of savings, costs, and benefits. This step includes aligning Member Cooperatives around standardized program reporting, tracking, and accounting procedures, including tracking program spending according to incentive and non-incentive costs.
2) **Program administrative cost savings can be achieved through economies of scale**, such as technology-enabled central services and partnering opportunities (within Seminole and/or with municipalities, water departments, and utilities). For example, partnering on bulk purchases of CFL and LED bulbs for giveaway programs can save program costs. Aligning on centralized program tools, including auditing software and tracking spreadsheets, is another opportunity to consider. By streamlining program delivery and driving down costs, Seminole can make these efforts even more cost effective and beneficial to members.
3) **Increase the value of EE/DSM efforts by considering new measures** that can be added to existing programs within the same delivery channels. This

approach can leverage existing member touch points to provide deeper energy savings per participant, which increases total program savings and cost effectiveness.

4) **Investigate the costs and benefits of adding new cost-effective programs** that meet the needs of Member Cooperatives and provide high value to their members. Below, the AE/Tierra team outlines five additional programs and measures for Seminole and its Member Cooperatives to consider.

Key Findings and Recommendations by Program Type

Program	Key Findings	Recommendations
Pre-Pay	• Produces 21% of total lifetime savings • Can provide utility operational savings (reduced collections and write-offs) in addition to EE savings • Ideally, should be linked with enhanced program energy savings tips and information to bolster efficiency • Available only to AMI customers	• Explore opportunities to expand participation • Target energy savings tips and education for members to enhance EE benefits • Improve tracking of EE costs to get a more accurate look at benefit/cost • Consider program evaluation, measurement, and verification (EM&V) activities to better document savings for Seminole; this program is a large component of overall savings and relies on behavioral energy savings that can be difficult to document
Utility System Savings	• Represents 25% of total lifetime savings • Can be a very cost-effective savings opportunity that can reduce system losses and operating costs	• Look for opportunities to expand system savings • Institute more thorough process for tracking utility system EE project data to better claim savings • Consider an in-depth opportunity assessment by feeder to determine savings potential. Voltage reduction savings can be a significant contributor to peak demand savings. They are also very specific to each feeder. For existing feeders with voltage reduction controls in place, consider conducting a metered measurement and evaluation study of voltage reduction savings to better document results. Also, consider working with a Conservation Voltage Reduction (CVR) vendor to assess potential feeders for a pilot

Program	Key Findings	Recommendations
Energy Smart HVAC	• Represents 27% of total lifetime savings • Savings from the HVAC rebates are reduced because of many cases of upsizing HVAC replacement equipment	• Consider updating the program design for Clay Energy Smart HVAC program to better capture savings (e.g., require sizing calculations or do not allow upsizing) • Offer HVAC quality installation training for local contractors to increase savings and impacts (see below) • Require proper sizing and quality installation • Consider multi-stage HVAC equipment and smart thermostats as emerging program opportunities (see below)
Energy Audits	• Bulb giveaways represent 14% of total lifetime savings • Most Member Cooperatives have an on-site energy audit program for residential, commercial, and industrial members	• Consider a standardized audit tool and/or set of audit data collected across all Member Cooperatives • Leverage on-site audits to provide and track LED/CFL giveaways and claim additional EE savings (see below) • Combine efforts to make a bulk purchase at a lower cost per bulb

NEW PROGRAM SUMMARIES

As noted above, in addition to offering recommendations for improving current EE/DSM offerings, AE/Tierra has proposed several new, program concepts for Seminole and its Member Cooperatives. The program concepts were selected based on AE/Tierra experience and feedback from Seminole on current activities in Member Cooperative territories. The focus of this report is on providing concepts that enhance existing programs or leverage current activities, improve the member experience, provide potential to shift peak demand, promote new technologies, and add value for members. At this time, none of the concepts for future programs meet the RIM test based on the information and assumptions used to analyze future program benefits and costs.

Seminole is not subject to the requirements and guidance of the Florida Energy Efficiency and Conservation Act (FEECA); however, it was interested in the cost effectiveness of potential EE/DSM programs. Specifically, Seminole requested information on the impact of implementing EE/DSM programs on rates for all member-consumers, as well as a comparison between the cost of EE/DSM programs and other resources, such as new generation. As such, the AE/Tierra team performed calculations

for two cost-effectiveness tests: the Ratepayer Impact Measure (RIM) test and the Utility Cost Test (UCT). (Note that the UCT is also called the Program Administrator Cost [PAC] test.) The team used the definitions of the tests provided in the California Standard Practice Manual. The RIM test was more strongly considered because of the desire for future program offerings to have a minimal impact on rates. It is noted that based on the information and assumptions used to analyze potential program opportunities, none of the future program offerings in this report pass the RIM test and may impact Member rates.

The RIM test analyzes programs from the perspective of a non-participating member to determine if a program benefits all members or participants only. The UCT analyzes whether programs reduce utility revenue requirements and how EE/DSM compares to other resources. The results for cost effectiveness are presented as a benefit to cost ratio. Higher values indicate that a program is more cost effective, and a value greater than one shows that the benefits outweigh the costs over the program life. Results for both tests are presented.

Performing cost-effectiveness tests requires estimating program participation, energy/demand savings, program implementation costs, incentive costs, and contributors to net-to-gross ratios, such as free-ridership. AE/Tierra considered numerous secondary sources for these inputs, including utility program filings in Florida, Arizona, Kentucky, and California, and made best estimates based on Seminole member demographics. We also consulted the Arkansas Technical Reference Manual (the closest regional manual) and used information from existing Seminole Member Cooperative programs. As part of this effort, AE/Tierra used the California Energy Data and Reporting System (CEDARS) database (https://cedars.sound-data.com/programs/list/) maintained by the California Public Utilities Commission (CPUC). This database was used because it contains a large amount of detailed program information.

Seminole also provided certain primary data based on the best available information at the time of analysis. This data included avoided energy, capacity, and transmission costs for the years 2017 to 2043, current average residential and commercial retail rates, and an escalation schedule for retail rates. For the avoided cost assumptions, we considered two scenarios. The first scenario (listed as (1) on all tables) included the total annual value of avoided capacity cost for a new generic unit coming online in May 2021. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest

contingency during four summer months only per year. The second scenario (listed as (2) on a tables) included the total value of avoided capacity cost based upon responses received in Seminole's March 1, 2016 Request for Firm Capacity for the period from June 2021 through December 2025. The total annual cost of a new generic unit coming online in year 2026 is reflected thereafter. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest contingency during four summer months only per year. Where the scenarios produced different values, we have noted them in the tables below with (1) and (2).

Below are five program concepts that we analyzed for the Seminole and Member Cooperative EE/DSM program portfolio, along with the results of cost-effectiveness calculations. Note that cost effectiveness calculations were based on the best information that could be collected on potential costs and benefits of each program concept within the project scope.

Commercial & Industrial Lighting Program

Currently, only a few programs, such as the coincident peak power rates, target commercial and industrial members.

Program Description

The Commercial & Industrial Lighting Program will incentivize non-residential members who have qualifying businesses for installing energy-efficient lighting equipment. Program delivery will involve rebates paid directly to participating contractors for replacement lamps and fixtures that meet or exceed program standards. Incentives may also be paid directly to members who self-install qualifying lighting equipment. Based on the assumptions applied here, the Commercial & Industrial Lighting Program is projected to result in average annual energy savings of 5,976 kWh per facility per year. This program recommendation received a 0.38 on the RIM test resulting in possible rate impacts for Member Cooperatives.

Target

Qualifying businesses must be current members of the cooperative and in good standing with regard to electricity payment.

Energy Efficiency Savings Measures

- LED direct replacement lamps for incandescent lamps
- LED replacement fixtures for T12 and T8 fluorescent fixtures
- LED replacement fixtures for indoor HID fixtures

- LED replacement fixtures for outdoor HID fixtures
- High performance T8 replacement lamps for standard T8 fluorescent lamps
- High performance T8 replacement kits for T12 fluorescent fixtures

Incentive Design

- Incentive basis
  - $0.08 per total annual kWh reduction
  - $150 per total peak kW reduction
- Specific incentive amounts will be developed based on the following:
  - Fixture wattage
  - Lamp wattage
  - Wattage reduction
  - Application

Implementation Plan

This program will be advertised through brochures and bill inserts to commercial and industrial members. Web-based tools will provide incentive applications and calculations. Training and certification will qualify electrical contractors and enroll them in the program, while in-house training will assist co-op energy auditors with facilitating the program.

Incentives in the form of rebates will be paid to members who have qualifying lighting technologies installed in their businesses by qualified installers. A percentage of installations will be inspected.

Marketing and Member Education

Outreach and education can help attract commercial and industrial members to the program. Seminole's larger distribution Member Cooperatives already provide energy audits to these members, and auditors can refer them to the lighting program to assist them with improving their lighting systems.

Brochures, web-based tools, and applications can be developed to assist with facilitating the program and educating members. Some tools will describe eligibility requirements, lighting product standards, and rebate amounts for qualifying lighting technologies. Others will provide information on accessing qualified lighting installers and how electrical contractors can become qualified installers.

Potential Results

Table 1 – Savings, Costs, and Cost-Effectiveness Summary Commercial & Industrial Lighting

Units & Savings		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
366	**2190**	**0.472**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$250,157	**$83,386**	**$333,543**
Cost Test Results		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**1.44 (1), 1.36 (2)**	
Ratepayer Impact Measure (RIM) Test	**0.38**	

Residential Audit Direct Install Kits

Numerous Seminole Member Cooperatives currently offer residential energy audit programs. These programs are traditionally expensive but are critical to address members' high-bill complaints. It is difficult to attribute savings to an audit alone, and adding direct install kits will allow for claiming savings with audits. In addition, it is recommended that Seminole consider using a standardized audit tool and/or set of audit data collected across all Member Cooperatives, as well as bulk purchasing for lower costs per bulb.

Program Description

This program will enhance existing residential energy audits by including free direct installation of light bulbs. Because auditors are already in the home during an audit, they can perform the installation without an additional trip. A maximum of 10 high use interior light bulbs will be changed from incandescent to LED. The program can also be run as a mail-out program; however, installation will be difficult to verify, and fewer savings will be realized. The LED direct install program is projected to result in average annual energy savings of 280 kWh per household (10 lamps) per year. This program received a 0.29 on the RIM test resulting in possible rate impacts for Member Cooperatives.

Target Audience

Members who receive a residential audit and have incandescent bulbs in high use areas.

Energy Efficiency Savings Measures

- 10 Energy Star LED light bulbs (downlights, standard bulbs, and/or mini bulbs)

Incentive Design

There is no monetary incentive paid to members; however, the LEDs will be free.

Implementation Plan

All members who receive an audit will receive direct install LEDs for high use areas. Auditors will use their discretion as to where and how many bulbs should be installed, up to a maximum of 10. These bulbs will be at no cost to the member and must be restricted to interior high use lights. This direct install of LEDs can be added to any visit by a cooperative staff member as long as the staff is trained on the correct documentation and safety. LED bulbs will be bulk purchased by Member Cooperatives to reduce costs.

Marketing and Member Education

There is no need to market the program because it is an addition to residential audits. Marketing the free direct install LEDs may increase the number of audits of homes interested only in this feature, which will reduce the cost effectiveness of the program as a whole because the audits may produce fewer savings.

Potential Results

For illustrative purposes, Table 2(a) presents the cost effectiveness of performing a residential audit with direct install kits, and Table 2(b) does the same for LED direct install alone, excluding residential audit costs. When the savings from light bulbs are added to an existing audit program, the program becomes slightly more cost effective but does not currently meet the RIM test.

Potential Results

Table 2(a) – Savings, Costs, and Cost-Effectiveness Summary LED Direct Install

Units & Savings		
Estimated Annual Projects (Homes)	**Annual MWhs Saved**	**Coincident MW Saved**
3,188	**891**	**0.09**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$206,104	**$68,095**	**$274,199**
Cost Test Results		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**0.99(1), 0.97(2)**	
Ratepayer Impact Measure (RIM) Test	**0.28(1), 0.29(2)**	

Table 2(b) – Savings, Costs, and Cost-Effectiveness Summary LED Direct Install Excluding Energy Audit Costs

Units & Savings		
Estimated Annual Projects (Homes)	**Annual MWhs Saved**	**Coincident MW Saved**
3,188	**891**	**0.09**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$143,460	**$68,095**	**$211,555**
Cost Test Results		
Cost Test		**Estimated Result**
Utility Cost Test (UCT)		**1.29(1), 1.26(2)**
Ratepayer Impact Measure (RIM) Test		**0.30(1), 0.31 (2)**

Direct Load Control or Grid-Enabled Water Heater Program

Seminole expressed interest in water heater programs. The AE/Tierra team investigated programs for both direct load control water heaters and grid-enabled water heaters. The former may provide a good first step into water heater programs, while the latter are a new technology that is gaining traction. These programs could meet the overall goal of Seminole to reduce coincident peak. Many utilities have started running grid-enabled water heater programs, and some are still in pilot phases or have not completed a full EM&V cycle. For these reasons, the AE/Tierra team was unable to complete the calculation of cost-effectiveness tests for grid-enabled water heaters.

Program Description

This program will incentivize homeowners to replace existing water heaters with direct load control or grid-enabled water heaters. It will also allow Member Cooperatives to manage how homeowners' tank water heaters use energy. The goal of this program is to

develop protocols for different types and sizes of water heaters that can shift peak demand loads using their thermal storage potential without negatively impacting homeowners' access to hot water. This program could use either direct load control or grid-enabled water heaters but will not use both. Depending on current infrastructure and insight from Member Cooperatives, direct load control water heaters may be more reasonable; however, grid-enabled heaters can produce maximum peak shifting. Program delivery will include an equipment incentive to homeowners when replacing water heaters or during new construction, and an annual rebate for load shifting using grid-enabled or demand response control. The demand response control will have a limit to the number of events that can take place in a year. Based on the inherent demand-reducing nature of the Direct Load Control Water Heater Program, it is projected to result in no household energy savings. This program received a 0.67 under scenario (1) and 0.60 under scenario (2) on the RIM test and may result in rate impacts on Member Cooperatives.

Target Audience

Residential members who use electric tank water heaters. Grid-enabled water heaters require 80-gallon storage tanks, whereas direct load control water heaters require only 50-gallon tanks. We learned from the Residential Energy Consumption Survey (RECS) and Seminole that many houses have water heaters of less than 50 gallons, which could affect program design and participation. Both heat pump and standard resistant water heaters are eligible for participation.

Energy Efficiency Savings Measures (Either/Or)

- Grid-enabled water heaters allow the utility to design a load-shifting water heating profile that preemptively shifts water heater load to off-peak hours by preheating the water. These heaters also allow for rapid response to intermittent load and voltage issues, which requires at least an 80-gallon water heater because the thermal mass is needed to maintain the hot water. This will raise the amount of electricity homeowners use to heat their water but has the most potential to preemptively shift loads.
- Direct load control water heaters allow Member Cooperatives to temporarily turn off water heaters as demand response to high-peak events. This technology acts like a switch and does not use preheating. Direct load control can be applied to existing water heaters as long as the tank is at least 50 gallons. Homeowners' energy bills will not rise to heat their water, and the demand response events should be limited to 10 annually.

Incentive Design

The incentive for participating members will be a flat rate per year. To reduce administrative costs, incentives will be directly added to participants' bills. If a member opts out, the rebate amount will be prorated for the year. The incentive design can be adjusted to ensure installation and administration costs are appropriately covered.

Implementation Plan

Appropriate infrastructure will need to be in place for either grid-enabled or direct load control heaters. Radio frequency and Wi-Fi can be used for both programs, and the choice of communication will depend on existing infrastructure, cost, and capability with current cooperative systems.

Grid-Enabled Water Heaters: A predetermined plan for pre-charging water heaters during off-peak hours must be developed to ensure the maximum potential for load shifting while minimizing the impact on members. The pre-charging plan will be based on standard water draw patterns, thermal storage potential of the water heaters, and high-peak times for the cooperative.

Direct Load Control Water Heaters: A protocol for using switches on water heaters enrolled in the program for demand response events will be developed for different water heater sizes, which will determine the maximum amount of time during peak hours that a water heater can be switched off.

Qualified contractors will install equipment and water heaters. Once installation is complete, homeowners will receive an equipment rebate and later an annual rebate as long as they are still participating in the program. A website portal will be available for members to report hot water issues and will inform participants of the switching or grid-enabled protocols.

Marketing and Member Education

The program will need to be marketed by Member Cooperatives using stock materials created by Seminole. Potential resources include bill inserts, social media, website links, and the call/billing center. There will be two main goals of the marketing: 1) to educate homeowners about the available incentive for having the demand control device installed on their water heater or a grid-enabled water heater, and 2) to inform them that they will not see any change in hot water availability. This second goal will be the primary challenge for implementing the program.

Potential Results

Table 3 – Savings, Costs, and Cost-Effectiveness Summary Direct Load Control Water Heaters

Units & Savings		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
5,677	0	3.3
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$2,012,524	$393,108	$2,405,632
Cost Test Results		
Cost Test		**Estimated Result**
Utility Cost Test (UCT)		0.70(1), 0.63(2)
Ratepayer Impact Measure (RIM) Test		0.67(1), 0.60(2)

HVAC Quality Install Program

The HVAC Quality Install Program complements an existing HVAC rebate program from one of Seminole's Member Cooperatives. The current program has erosion of savings because of the installation of larger equipment. The Quality Install Program approach increases savings and impacts. Offering this program could lead to numerous benefits because HVAC systems dominate energy use in homes and have a relatively long useful life.

Program Description

This program will incentivize quality installations of replacement heating and cooling equipment in existing single-family homes, which will result in a better performing system. The Quality Install Program will follow the ACCA Quality Installation 5 Manual to ensure that the system is sized correctly, the total airflow of the system is set to the manufacturer's specifications, the duct system is well sealed, the refrigerant is correctly charged, and the total static is within the manufacturer's specifications. These five steps

are often overlooked during equipment change out, which results in underperforming equipment. Program delivery will include rebates to contractors that will reduce or cover the cost of the extra work associated with quality installations, a robust quality control/quality assurance protocol, and training to ensure contractors are capable of participating. A complementary program can be rolled out simultaneously that will retro-commission existing equipment to address duct tightness and refrigerant charge. The AE/Tierra team concentrated on a replacement program in this report but included cost-effectiveness calculations for a retro-commissioning program as well. The HVAC Quality Install and HVAC Quality Retrofit Programs are projected to result in average annual energy savings of 451 kWh and 305 kWh, respectively, per household per year. Neither program passed the RIM test and may result in rate impacts to Member Cooperatives.

Target Audience

Single-family homeowners in need of a replacement heating and cooling system and contractors who perform equipment change outs.

Energy Efficiency Savings Measures

- Correctly Sized System – A load calculation will be completed on the home, and a heating/cooling system will be selected to match the load calculation within 6,000 BTUs.
- Airflow Across Coil/Heat Exchanger – Airflow will be tested at coil, and speed will be adjusted until it falls within the manufacturer's specifications.
- Duct Sealing – Ducts will be tested and sealed to reduce leakage by 50 percent; ducts that have less than 10 percent leakage will not need to be sealed.
- Refrigerant Charge to Manufacturer's Specifications – Superheat or sub-cooling measurements will be taken to ensure refrigerant is charged to manufacturer's requirements. The charge will be adjusted as necessary.
- Correct Static – Total static will be measured and ductwork will be reworked as necessary to meet manufacturer's specifications.

Incentive Design

To reduce administrative costs, incentives will be paid directly to participating contractors, and the value will be passed on to members. As participating contractors complete the installations, they will submit applications for incentive payments until the program has reached its funding limit.

The incentive will be paid directly to the contractor to cover the additional cost to perform start-up tests and quality control measures required for the Quality Install

Program. To receive the incentive, contractors will have to undergo a qualification process that shows their ability to perform the appropriate tests and meet the requirements of the program. Contractors will complete the appropriate paperwork and submit per job for the incentive.

Implementation Plan

A network of local trade ally participating contractors will be developed to help implement and market the HVAC Quality Install Program to eligible members. Each participating contractor will be required to attend program training and meet minimum eligibility requirements. The training will not only teach contractors the requirements of the program but also educate them on how to market quality installation to potential members.

Contractor requirements will include filling out a start-up worksheet and providing photo verification of measurements that will be submitted with job forms for processing the incentive. In addition, skilled co-op staff or a third-party inspector will conduct random quality assurance inspections. If quality assurance staff discovers discrepancies in the HVAC system, the participating contractor will be put on probation and required to fix all discrepancies before new jobs are submitted. The program staff will develop plans and procedures for dealing with delinquent contractors.

Marketing and Member Education

The Quality Install Program will require a base of approved HVAC contractors capable of meeting program standards. HVAC contractors will need to be made aware of the value proposition of participating in the program, which will include the incentive amount, potential marketing from the cooperative, market differentiation, and value to members. These benefits will have to be equal to or greater than the extra cost associated with the additional paperwork and testing. Approved contractors will also sign an agreement that all eligible jobs will be enrolled in the program and not treated as an up sale to the member.

The program will need to be co-marketed by both the qualified contractors and the Member Cooperatives. The Member Cooperatives will create tools that market the program and contractors to members. The main purpose of the marketing will be to educate homeowners about the additional value they will receive by using a contractor that participates in the program. The contractors will market the program through incorporating Quality Install Program benefits into their sales materials.

Potential Results

Table 4(a) – Savings, Costs, and Cost-Effectiveness Summary HVAC Quality Install

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
550	248	0.076
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$110,000	$86,260	$196,260
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	0.38(1), 0.36(2)	
Ratepayer Impact Measure (RIM) Test	0.22(1), 0.21(2)	

Table 4(b) – Savings, Costs, and Cost-Effectiveness Summary HVAC Quality Retrofit

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,282	391	0.217
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$192,300	$69,167	$261,467
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	0.48(1), 0.43(2)	
Ratepayer Impact Measure (RIM) Test	0.26(1), 0.23(2)	

Smart Thermostat Program

Smart thermostats are ever-evolving technologies that bring the documented savings of an advanced programmable thermostat with adaptive recovery to the potential for demand response. These thermostats are often difficult to initially set up; however, they learn occupants' behaviors and self-program set-backs. In addition, smart thermostats are already heavily marketed and appeal to early adopters of new technology.

Program Description

This program will incentivize new and existing single-family homeowners to install smart thermostats on their heating and cooling systems. Smart thermostats are used to improve HVAC system efficiency by creating automated behavior-based set-points for heating and cooling systems, limiting the use of heat strips in heat pumps, and offering utility-enabled demand response. Some smart thermostats can also alert homeowners to underperforming systems and remind them of preventative maintenance. Program delivery will include incentives paid directly to homeowners, and installation can be performed by homeowners or HVAC contractors. The Smart Thermostat Program is projected to result in average annual energy savings of 366 kWh per household per year. For this analysis, the demand savings projected are consistent with a programmable thermostat program (0.14 kW). If utility-enabled demand response is included in the program design, demand savings will go up significantly and should increase the cost-effectiveness. This program received a 0.37 on the RIM test and may result in rate impacts to Member Cooperatives.

Target Audience

Single-family homeowners who have heat pumps and/or air conditioners with furnaces capable of functioning with a smart thermostat. Homeowners must have Wi-Fi available in their home to participate.

Energy Efficiency Savings Measures

- Smart thermostats learn occupants' behavioral patterns and schedule set-backs when the home is not occupied and/or occupants are asleep.
- Smart thermostats limit the use of heat strips on heat pumps when in heating mode.
- Smart thermostats can be used for demand response.

Incentive Design

Incentives will be paid directly to the member because installation may be done by the member or a contractor. A one-time equipment incentive will be paid to the member for

installing up to two smart thermostats in a single home. If demand response is activated, the member will receive a set incentive rate per year. There will be a limit to the number of demand events that can happen annually. The cost effectiveness results presented here are not based on the use of the demand response features. Utilizing demand response will significantly increase demand savings and program costs, and will require additional planning to maximize benefits.

Implementation Plan

It is recommended that a single type of smart thermostat be selected to reduce administrative costs and simplify implementation. The incentive will not be paid to the member until the thermostat has enrolled in the program over the manufacturer's platform and the serial number is submitted to the Member Cooperative. The member will opt in or out of the demand response part of the program. The Member Cooperative will work with the smart thermostat manufacturer to design how demand response will occur. Members who participate in demand response will receive a set number of credits.

Marketing and Member Education

The program will be marketed by Member Cooperatives through bill inserts, retail store displays, and social media. Member Cooperatives will partner with big-box stores to prominently display information about the program. Marketing material will educate members on the user features, energy savings, and demand response capabilities of smart thermostats.

Social media can be used to spread awareness and create energy savings competitions. Most smart thermostats calculate users' savings, which can be shared on social media, and Member Cooperatives could hold a gift card drawing for members who participate. Such an incentive may help create energy competition that could generate even more savings.

Potential Results

Table 5 – Savings, Costs, and Cost-Effectiveness Summary Smart Thermostat

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,517	**555**	**0.212**
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$75,850	**$158,250**	**$234,100**
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**1.04 (1), 0.96(2)**	
Ratepayer Impact Measure (RIM) Test	**0.37(1), 0.36(2)**	

CONCLUSION

We thank Seminole and it's Member Cooperatives for their cooperation and assistance with preparing this report. The report summarizes information from AE/Tierra's work interviewing Seminole and Member Cooperatives about their current activities and member demographics. Seminole and its Member Cooperatives already have a number of effective energy-and demand-saving programs in place; and as programs become more cost effective, there could be opportunities for additional marginal savings.

Additional energy savings can be realized by implementing the new, program concepts outlined in this report: Commercial & Industrial Lighting, Residential Audit Direct Install Kits, Direct Load Control or Grid-Enabled Water Heaters, HVAC Quality Install, and Smart Thermostats. However, these programs do not meet the RIM test, and are not cost-effective.

To calculate the cost effectiveness of the new program ideas, we considered numerous secondary sources, such as utility program filings in Florida, Arizona, Kentucky, and California, and made best estimates based on Seminole member demographics. Each program concept was evaluated individually for cost effectiveness. As new programs move to implementation, it is beneficial to also evaluate cost effectiveness at the portfolio level including all programs offered.

No programs passed the RIM test due to the cost of lost revenues they produce. While additional DSM opportunities are available, they must be considered in the context of their impact on rates for non-participants.

JASON PETERS

Education:

Masters of Business Administration, University of South Florida — 1998–2000
Bachelor of Arts, Criminology, University of South Florida — 1992-1995

PROFESSIONAL EXPERIENCE

SEMINOLE ELECTRIC COOPERATIVE, INC. — **2001-Present**

Various titles, currently a Portfolio Director

- Plan, develop and implement both short and long term power marketing and fuel strategies to optimize the resources of a nine member, 3500 MW rural G&T cooperative with a portfolio of fuel diverse generation assets (coal, and natural gas) and multiple purchased power agreements.
- Administrate all long term coal, rail transportation, railcar fleet and purchased power agreements in Seminole's resource portfolio, which includes duties such as contract interpretation, scheduling of resources, review of invoices, and resolution of disputes.
- Lead, train, develop and provide work direction to three employees.
- Established policies for and monitor compliance with both internal and external risk management controls.

FLORIDA POWER CORPORATION — **1997 – 2001**

Power Trader

- Conducted buying and selling transactions of electric commodity in the near-term or spot market for a 9000 MW portfolio of nuclear, steam, coal, gas, and oil units in Florida and SERC regions.
- Utilized personal relationships, competitive nature, creativity and sales ability to assist real-time trading team in achieving over 200% of 2000 goal.
- Coordinated efforts with portfolio, generation, and long-term trading contacts to maximize profit potential of FPC's generation assets and assure system reliability.

Manager, Automated Payment Processes

- Designed and directed Automated Payment Systems for Florida Power's 32 county service territory, significantly improving customer perception of convenience and reliability of FPC customer service channels.
- Constructed and directly supervised a network of 53 Automated Agents to provide additional face-to-face venues for customer service.
- Recruited and contracted each Agent location, developing a system that accepted over 300,000 payments and collected $10 million in revenue yearly. Optimized placement of and increased Agent locations while reducing cost per payment by 23%.
- Implemented an automated multimedia kiosk for the acceptance of customer payments and service transactions. Led efforts involving external vendor and internal departments to custom build the kiosk and integrate to existing FPC software systems.

BARNETT BANK — **1993 - 1997**

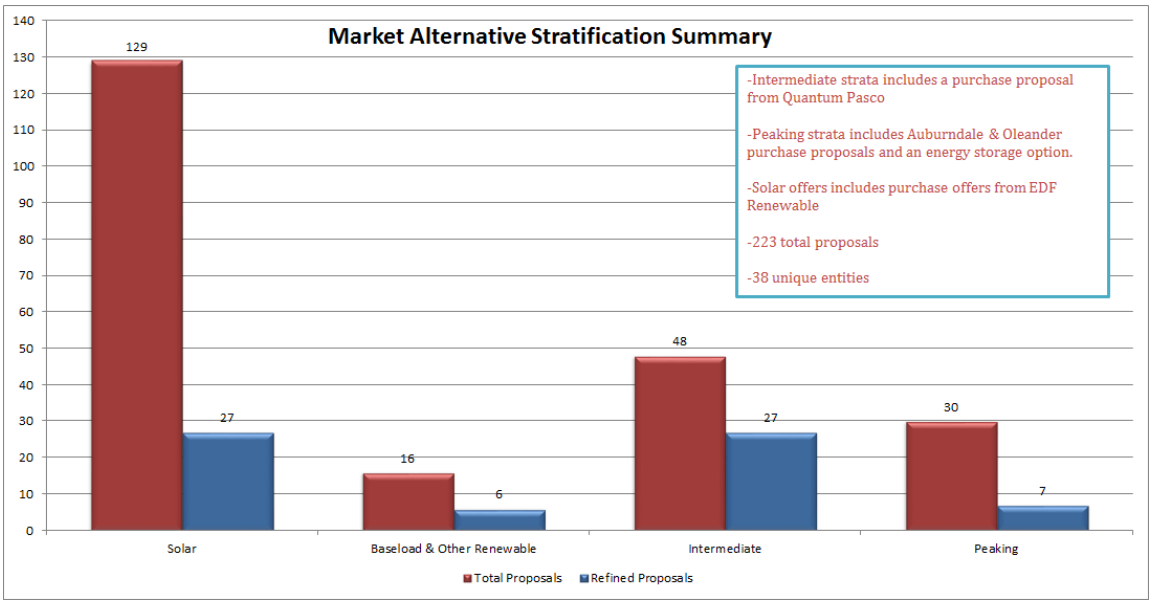
Business Banker

- Obtained new customer relationships and expanded existing customer relationships with Small Business customers (revenues of less than $5 million annually).

Sales and Service Coordinator

- Designed and implemented market plans for Barnett's Alternative Retail Delivery products to achieve affiliate level sales goals for each product line.
- Designed and conducted sales training for front-line sales personnel and designed sales incentive programs for a 35 branch network.
- Received 7 months centralized classroom and real time training focused on retails sales and management skills.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 18
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Jason Peters JP-1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 19
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Jason Peters JP-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 20
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-1

JULIA A. DIAZGRANADOS

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CAREER EXPERIENCE

SEMINOLE ELECTRIC COOPERATIVE INC.
16313 North Dale Mabry Highway, Tampa, Florida 33618

Director of Planning (2017-Present)
Leads budget and financial forecasting processes along with the planning and related analysis of Seminole's long range generating capacity needs including the evaluation of generation alternatives. Provides supervision and work direction to budget, financial forecast and generation planning personnel. Responsible for the application of production costing and corporate financial models in the performance of generation studies budgeting and financial forecasting. Enables integration of Seminole load forecasting into budget, financial and resource planning

Planning Manager (2013-2017)
Directs generation planning staff and cross-functional teams in order to develop studies used in establishing long-term rate projections; financial forecasts; and generation plans to meet future energy needs. Conducts risk assessment of power supply alternatives. Presents study results and recommendations to Executive Staff and Board of Directors. Seminole representative on the Florida Reliability Coordinating Council's Resource Subcommittee and the Generation & Transmission Resource Planning Association.

Generation Planning Supervisor (2010-2013)
Oversees the planning and related analysis of Seminole's long range generating capacity needs including the evaluation of generation alternatives. Provides supervision and work direction to generation planning personnel. Responsible for the application of production costing and corporate financial models in the performance of generation studies.

Lead Strategic Planning Analyst (2007-2009)
Coordinates and participates in the planning and related analysis of the long range generating capacity needs including evaluation of generation alternatives. Responsible for the application of production costing and system optimization models in the performance of generation planning studies.

Senior Strategic Planning Analyst (2005-2007)
Participates in the planning and related analysis of long range generation capacity needs including the evaluation of generation alternatives. Strategic plans included, but not limited to, the evaluation of proposed self-build generation units verses power purchase agreements, development of options for meeting renewable targets, and establishing financial strategies.

FUTURE SCOPE, INC.
400 WEST LAKE STREET, SUITE 306, ROSELLE, IL 60172

Principal – Utility Advisory (1999 – 2004)
Provided various utilities in the mid-west and east coast with situational assessments; resolution proposals; application design; project management including budgeting and resource requirements; implementation of systems; and development of user documentation. Created and conducted training courses of developed systems. Oversight of marketing campaigns; sales presentations; and implementation process of company's Capital Management and Cost of Service applications.

ALLEGHENY ENERGY SERVICE CORPORATION
800 CABIN HILL DRIVE, GREENSBURG, PA 15601

Financial Analyst 1996 -1999
Prepared assumptions and model runs to support operational decision-making, long-term forecasting, budgeting and strategic planning. Performed capital project evaluations/analysis on proposed investments to assist in the prioritizing/allocating of funds. Managed and coordinated the replacement of the Corporate Financial and Capital Management Systems with outside consultants.

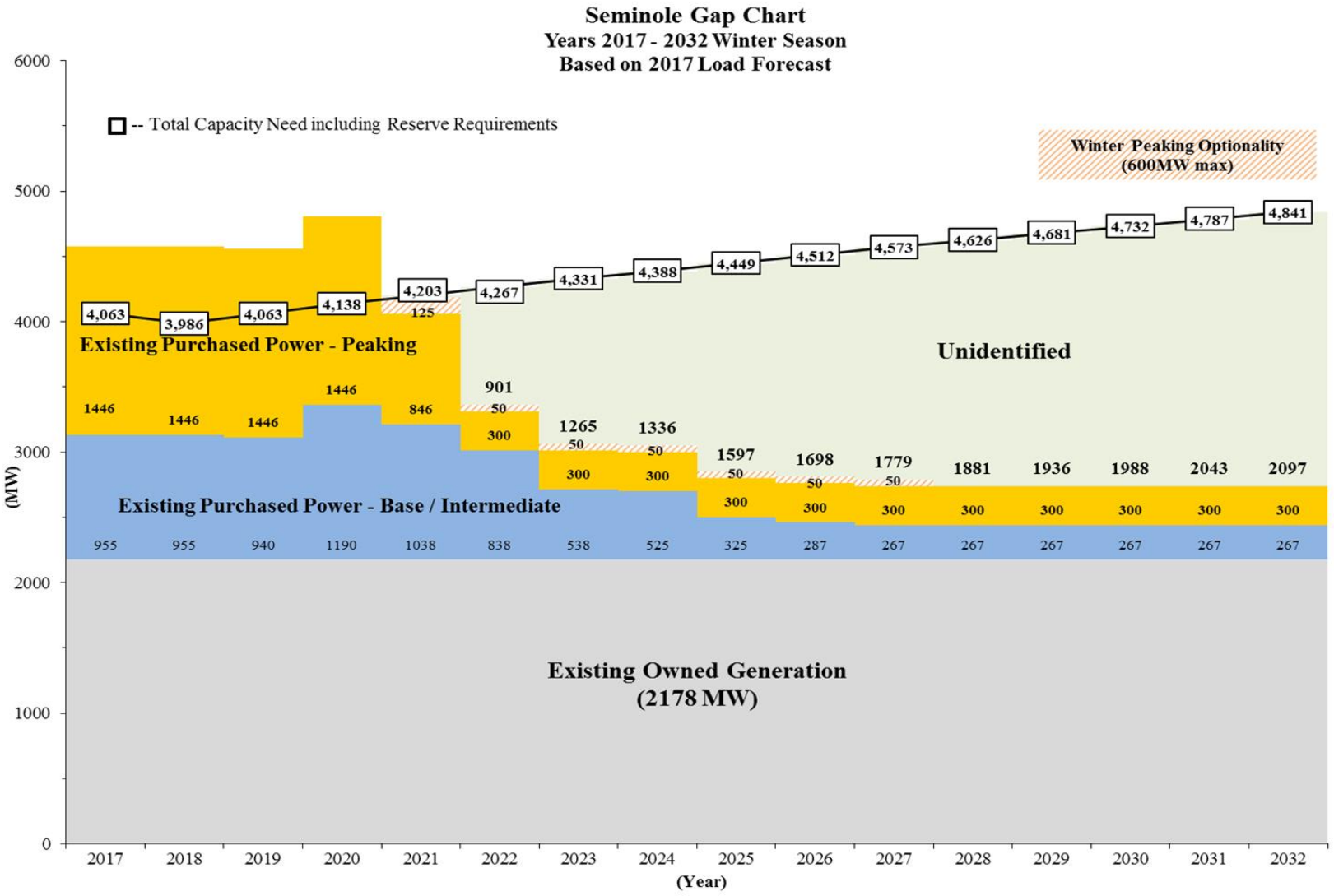
Financial Services Analyst 1991 -1996
Maintained and ran Corporate Financial Models. Responsible for the administrative duties of the Local Area Network (LAN) - setup servers, created backup/restore procedures, established user access rights, configured user workstations, and provided technical support for seven departments within Financial Service's area.

EDUCATION

Bachelors of Science Degree, Business Administration
Associate of Science Degree, Electronic Data Processing
FAIRMONT STATE UNIVERSITY
FAIRMONT, WV

- Awarded the Outstanding Electronic Data Processing Student Award

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 21
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC. (Direct)
DESCRIPTION: Julia A. Diazgranados JAD-2



Docket No. 2017_____-EC
Seminole Need Gap Chart
Exhibit No. __ (JAD-2), Page 1 of 1

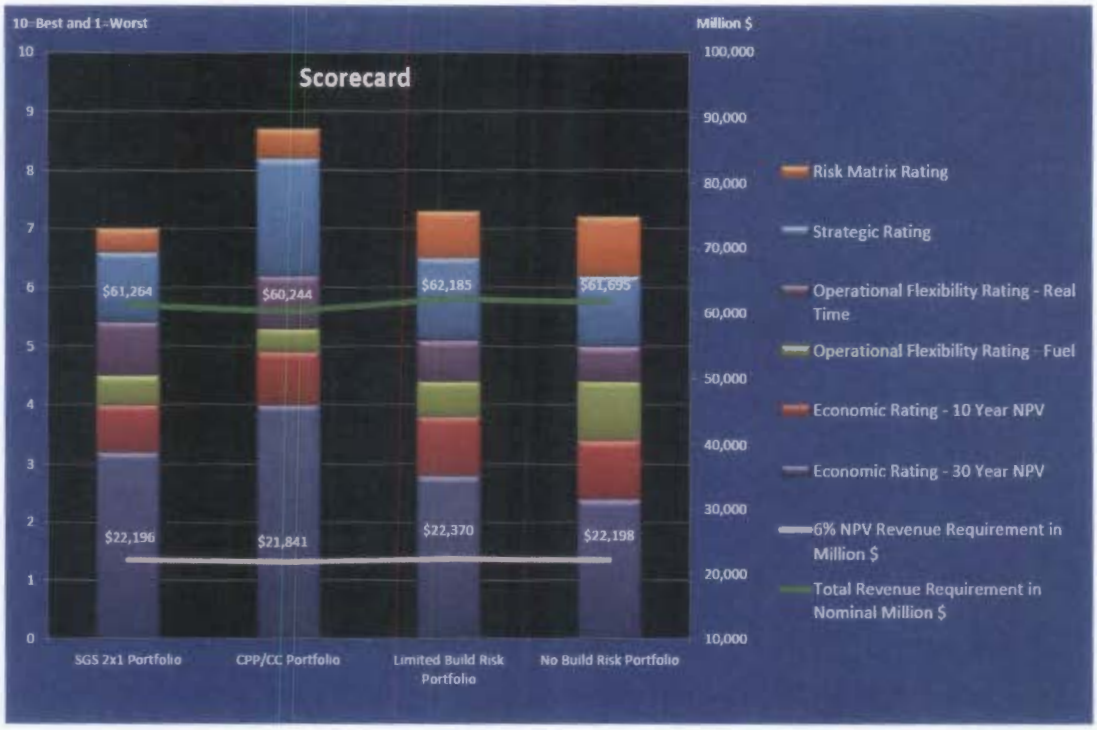
Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	12,381	12,266	12,196	12,096
NPV @ 6.0%	9,008	8,936	8,885	8,797
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	61,264	60,244	62,185	61,695
NPV @ 6.0%	22,196	21,841	22,370	22,198

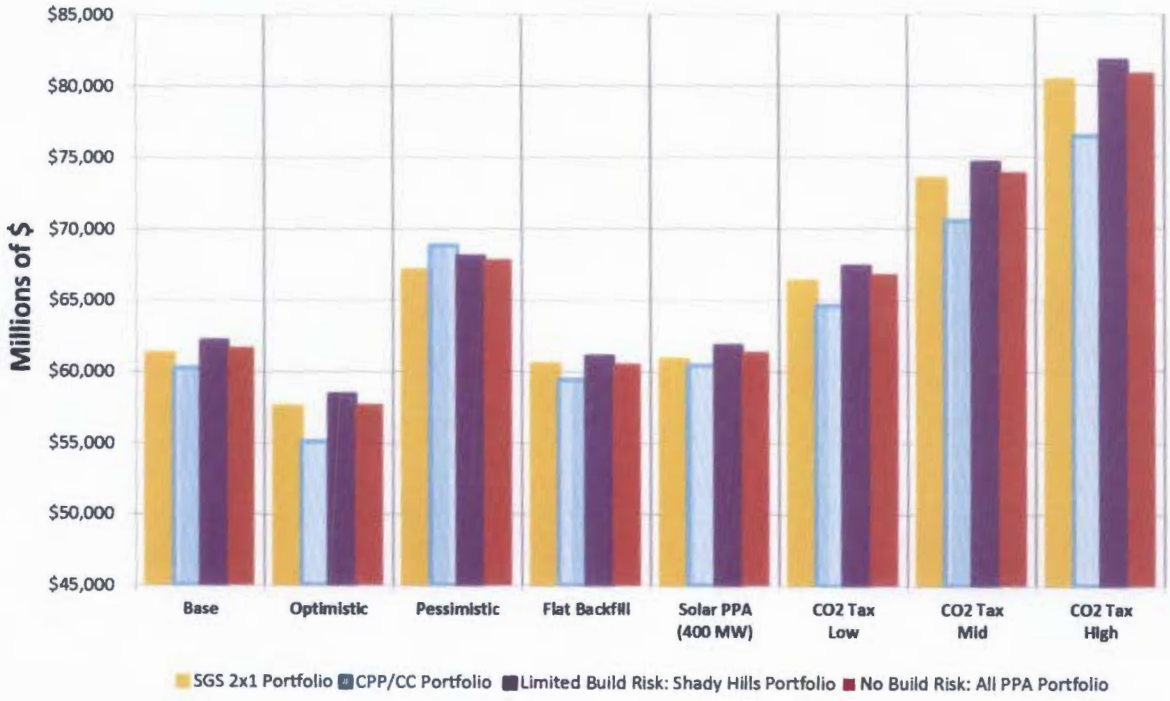
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 22
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-3

Portfolio Scorecard Assessment



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 23
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-4

Total Member Revenue Requirements (Nominal $)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 24
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-5

Portfolio Summaries
Revised Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	11,666
NPV @ 6.0%	8,641	8,568	8,549	8,499
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	56,465	58,312	58,616
NPV @ 6.0%	20,981	20,618	21,120	21,148

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 25
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 26
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Alan S. Taylor AST-1Doc 1

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, energy storage, energy efficiency projects, demand response, and off-system power purchases; analyzed thousands of such 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

2015- **Minnesota Solicitation for New Resources**
2017 Client: Minnesota Power Company

Provided independent evaluation services in five solicitations for new resources: up to 400 MW of gas-fired generation and up to 300 MW each of wind, solar, demand response, and customer cogeneration resources. Mr. Taylor reviewed the request for proposals (RFP), managed the Sedway Consulting team in performing a quantitative and qualitative evaluation of all proposals, monitored communications and negotiations with shortlisted bidders, and provided reports for filing with the Minnesota Public Utilities Commission regarding the results of the solicitations.

2014- **California Evaluation/Negotiation of Non-Conventional Resource Solicitation**
2017 Client: Southern California Edison

Provided independent evaluation services in several solicitations for new resources: two for up to 36 MW new energy storage resources, one for over 1,000 MW of near-term resource adequacy capacity, and one for a broad array of non-conventional resources to address over 100 MW of reliability needs in a local area. In that last project, solicited resource types included energy efficiency, demand response, in-front-of-meter and behind-the-meter energy storage, renewable resources, and hybrid transactions. For all four solicitations, Mr. Taylor managed the Sedway Consulting team in performing a parallel evaluation of offers and monitoring negotiations with shortlisted bidders.

2013- **Florida Solicitation for New Capacity**
2014 Client: Duke Energy Florida

Served as an independent evaluator in a solicitation for over 1,600 MW of new capacity in Florida. Resources had to be on-line by 2018. Proposals were compared to the utility's next planned generating unit – a natural-gas-fired combined-cycle generating 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.

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

Served as the independent evaluator 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 Wind 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 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

Served as the Independent Evaluator 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 the 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 Independent Evaluation 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 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.

2000-2001 **Solicitation for New Resources**
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.

REDACTED VERSION

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR SEMINOLE ELECTRIC'S POWER SUPPLY SOLICITATIONS FOR 2021 CAPACITY NEEDS

Submitted by:

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 27
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Direct)
DESCRIPTION: Alan S. Taylor AST-1Doc 2

December 21, 2017

Introduction and Background

In early 2016, Seminole Electric Cooperative, Inc. (Seminole) launched three solicitations to seek resources or transactions that would help the cooperative meet its forecasted capacity needs in 2021 and beyond. Two of those solicitations were associated with Seminole's efforts to explore the development of a self-build resource at its Seminole Generating Station (SGS) site; they involved Requests for Proposals (RFP) for 1) power island equipment (PIE) and an associated long-term service agreement (LTSA), and 2) engineering, procurement and construction (EPC) services to install the selected power island equipment and construct the balance of the facility. The third solicitation was for market alternatives (i.e., new build facilities that would be owned and operated by others, sales of power from existing facilities, and system sales from a portfolio of resources). Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent monitoring and evaluation services over all of these RFPs and provide a parallel economic evaluation of responses that might address Seminole's capacity needs. The primary focus of this report is the market alternative RFP, with the results of the PIE/LTSA and EPC solicitations incorporated in the form of finalized self-build alternatives that competed with the market alternatives.

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 Seminole's market alternatives 2021 RFP and the Seminole finalized self-build options,
- Sedway Consulting's proprietary Response Surface Model (RSM) and Revenue Requirements Model (RRM) which were used to conduct the parallel economic evaluation,
- fundamental assumptions that were applied,
- additional economic factors that affected the final cost of each resource, and
- the development and comparison of complete portfolios of resources that would meet Seminole's capacity needs.

Receipt of Market Alternative Proposals

In Seminole's market alternatives RFP, bidders were instructed to email their submission to Seminole (and cc Sedway Consulting) by May 9, 2016. On or before that date, Sedway Consulting received 265 proposals from 40 power suppliers. For organizational and ease of comparison purposes, Seminole segregated the submitted proposals into four categories (with offer count totals next to each label):

- solar photovoltaic (PV) – 127 offers,
- baseload – 16 offers,
- intermediate – 75 offers, and
- peaking – 47 offers.

These offer totals represent the overall numbers of proposals received, prior to any disqualification decisions or qualitative review that ultimately reduced the number of proposals that moved through the evaluation process. Sedway Consulting and Seminole reviewed their respective proposal counts and confirmed that any differences are due to some disqualifications and minor interpretation issues.

One rationale for segregating solar PV proposals into a separate category was the fact that Seminole is a winter-peaking entity, with its peak loads occurring during hours that solar resources provide little or no generation. Therefore, while these resources may provide some energy and fuel-diversity benefits throughout the year, they could not appreciably meet the need that Seminole was hoping to address with its RFPs.

Virtually all of the proposals in the last three categories could be modeled and evaluated on a side-by-side basis in Sedway Consulting's Response Surface Model (RSM). Therefore, the differentiation of proposals into baseload, intermediate, and peaking was less important from Sedway Consulting's perspective than another critical factor in the evaluation process – namely, the regional location of resources or power supplies. Essentially, Seminole's Member loads are electrically connected or located in either Duke Energy Florida's (DEF) balancing authority area (BAA) or Florida Power & Light's (FPL) BAA, with a third BAA as Seminole's north system (SSN). That third area has relatively little load; the majority of Seminole's load is in DEF's BAA. It was important to procure resources or transactions that would support Seminole's Members' needs in those areas and minimize the costs and reliance of inter-regional transfers. With its market alternatives RFP, Seminole provided historical load information for both of these load areas to provide bidders with important locational information. The FPL BAA has a long-term projected peak load of approximately 600 MW and an average load of approximately 400 MW. It was recognized that procuring more than those quantities in the FPL BAA would result in additional transmission wheeling/transfer costs to bring the power into the DEF BAA to serve Seminole's predominant needs there. Similarly, it was recognized that resources outside of Florida (e.g., in the Southeast Electric Reliability Council, SERC) would incur transmission-related costs – and potential reliability concerns, if Seminole relied too heavily on such resources. Thus, this report depicts and segregates much of the offer statistics into five different categories: solar PV, DEF BAA, FPL BAA, SSN BAA (which can reasonably provide capacity to either the FPL or DEF BAAs), and SERC.

Table A-1 depicts the number of non-solar offers by resource type and locations.

Table A-2 provides a summary of the solar PV proposals that Sedway Consulting received from each bidder. As has been Sedway Consulting's reporting approach in all solicitations, the identities of bidders and projects who were not selected for final contracts has been redacted as confidential. Thus, the actual bidder and project names in Tables A-2 through A-6 for these non-selected bidders and projects are redacted and the tables include a "Code" column that provides a counterparty letter and project number reference that is used throughout the remainder of the report.

Table A-1
Offer Count and Location of Summary of Non-Solar PV Proposals

	DEF BAA	FPL BAA	SSN BAA	SERC/Other	Total
Baseload	3	4	0	9	16
Intermediate	39	2	18	16	75
Peaking	21	7	12	7	47
Total	63	13	30	32	138

Note: One of the baseload offers in the DEF BAA column was actually a combination of small existing resources in both the DEF and FPL BAAs.

The tables include the number of proposals provided by each bidder. In many instances, bidders provided multiple mutually-exclusive proposals for the same resource (e.g., with flat or escalating pricing, different delivery period durations). Thus, the total number of offers was considerably more than the total number of projects.

The final column in Table A-2 provides the levelized solar PV energy price (in $/MWh) as calculated by Sedway Consulting for each project's best offer. Obviously, for offers with a flat, non-escalating price, the levelized price is that proposed price; but for offers with escalating prices, the levelized price is that flat, non-escalating price that would result in the same net present value over the term of the proposed agreement as the escalating price – and provides for a comparable metric for ranking the offers. In cases where there were multiple, mutually-exclusive offers for a project, the value in the final column represents the lowest levelized price among those offers. The ranking of the bidders in the table is based on each bidder's best project levelized price.

Table A-3 provides the number of proposals from each bidder for baseload, intermediate, and peaking resources that would provide power deliveries in the DEF BAA. Some of the proposals were for resources that would be connected to Tampa Electric Company's (TECO) system, where power could be transferred (with a wheeling cost) into the DEF system. Tables A-4 through A-6 provide similar summaries for the proposals offered in the FPL BAA, SSN BAA, and SERC regions, respectively. The tables include a "Type" column that identifies the proposed technology (CC=combined cycle, CT=combustion turbine, System=system sale, MSW=municipal solid waste). Similar to Table A-2, the identities of bidders and projects that were not selected for final contracts are confidential and hence redacted. The rankings of the bidders in the tables are roughly based on the economics of their best proposal in the initial evaluation phase.

Disqualification Decisions

Of the bidders/ proposals listed in Table A-2, bidders SolarU-1 and SolarV-1 were disqualified for lack of specificity (e.g., failure to provide specific prices).

Table A-2
Summary of Solar PV Proposals

	Bidder	Project	Code	Nameplate Capacity (MW)	Number of Proposals	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	1	[redacted]
2	[redacted]	[redacted]	SolarB-1	75	6	[redacted]
3	[redacted]	[redacted]	SolarB-2	50	6	[redacted]
4	[redacted]	[redacted]	SolarB-3	50	6	[redacted]
5	[redacted]	[redacted]	SolarB-4	75	6	[redacted]
6	[redacted]	[redacted]	SolarC-1	375	3	[redacted]
7	[redacted]	[redacted]	SolarD-1	25	1	[redacted]
8	[redacted]	Tillman	SolarD-2	50	1	[redacted]
9	[redacted]	[redacted]	SolarD-3	50	1	[redacted]
10	[redacted]	[redacted]	SolarD-4	50	1	[redacted]
11	[redacted]	[redacted]	SolarD-5	75	1	[redacted]
12	[redacted]	[redacted]	SolarD-6	75	1	[redacted]
13	[redacted]	[redacted]	SolarE-1	75	2	[redacted]
14	[redacted]	[redacted]	SolarE-2	65	2	[redacted]
15	[redacted]	[redacted]	SolarF-1	75	2	[redacted]
16	[redacted]	[redacted]	SolarF-2	75	2	[redacted]
17	[redacted]	[redacted]	SolarF-3	53	2	[redacted]
18	[redacted]	[redacted]	SolarG-1	65	12	[redacted]
19	[redacted]	[redacted]	SolarH-1	75	12	[redacted]
20	[redacted]	[redacted]	SolarH-2	75	12	[redacted]
21	[redacted]	[redacted]	SolarI-1	75	12	[redacted]
22	[redacted]	[redacted]	SolarJ-1	465	2	[redacted]
23	[redacted]	[redacted]	SolarJ-2	75	2	[redacted]
24	[redacted]	[redacted]	SolarJ-3	125	2	[redacted]
25	[redacted]	[redacted]	SolarK-1	75	4	[redacted]
26	[redacted]	[redacted]	SolarL-1	50	1	[redacted]
27	[redacted]	[redacted]	SolarM-1	65	4	[redacted]
28	[redacted]	[redacted]	SolarN-1	125	6	[redacted]
29	[redacted]	[redacted]	SolarO-1	65	2	[redacted]
30	[redacted]	[redacted]	SolarP-1	225	4	[redacted]
31	[redacted]	[redacted]	SolarQ-1	50	1	[redacted]
32	[redacted]	[redacted]	SolarR-1	80	3	[redacted]
33	[redacted]	[redacted]	SolarS-1	75	1	[redacted]
34	[redacted]	[redacted]	SolarT-1	75	1	[redacted]
35	[redacted]	[redacted]	SolarU-1	75	1	[redacted]
36	[redacted]	[redacted]	SolarV-1	25	1	[redacted]

Table A-3
Summary of DEF BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-1	1,064	6
2			CC	A-2	863	6
3			CC	A-3	599	6
4			CT	A-4	482	12
5	GE Shady Hills	Project 2	CC	B-1	573	4
6		[redacted]	CC	B-2	463	4
7			CT	B-3	519	2
8	[redacted]	[redacted]	CT	C-1	117	1
9	[redacted]		CT	D-1	484	2
10		[redacted]	CC	D-2	538	2
11	DEF	Peaking	System	E-3	50-300	1
12		Intermediate	System	E-4	50-300	1
13	[redacted]	[redacted]	CC	F-1	121	5
14	[redacted]	[redacted]	CC	G-1	557	4
15	[redacted]		Biomass	H-1	70	2
16	[redacted]		ES	I-1	75-225	3
17	[redacted]		Biogas	J-1	34	1
18	[redacted]		CC	K-1	N/A	1

Of the bidders/proposals in Table A-3, ten offers from Bidder A (two each associated with Projects A-1, A-2, and A-3 and four associated with A-4) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP. Also, Bidder K-1 was disqualified for lack of specificity.

Table A-4
Summary of FPL BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CT	L-1	515	5
2			System	A-5	100-1000	2
3	[redacted]	[redacted]	System	A-6	100-1000	2
4		[redacted]	System	A-7	All	1
5	[redacted]		MSW	M-1	25	1
6	[redacted]		MSW	N-1	40	2

No proposals were disqualified from the set that is depicted in Table A-4.

Table A-5
Summary of SSN BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-8	1,058	6
2			CC	A-9	859	6
3			CC	A-10	641	6
4			CT	A-11	480	12

Of the bidders/proposals in Table A-5, ten offers from Bidder A (two each associated with Projects A-8, A-9, and A-10 and four associated with A-11) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP.

Table A-6
Summary of SERC Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	L-2	500	4
2			CC	L-3	350	4
3			CC	L-4	200	4
4			System	L-5	138	4
5			CC	O-1	225	2
6			CC	P-1	350	1
7			System	Q-1	50-440	3
8			CT	R-1	280	4
9			CC	R-2	533	1
10			Call Option	S-1	200	3
11			System	T-1	50	1
12			Wind	C-2	200	1

No proposals were disqualified from the set that is depicted in Table A-6.

Evaluation and Selection Process

As noted earlier, Seminole is winter peaking cooperative and solar PV projects are not in a position to address this need. At the times that the winter peak might occur, there is little or no sunshine. Thus, the evaluation process was bifurcated into a review of the solar PV proposals for potential selection for environmental and diversification benefits and a full analysis of the non-solar PV proposals that offered firm capacity that could meet Seminole's capacity needs.

Solar PV Proposal Analysis

In the case of the solar PV analysis, Seminole and Sedway reviewed the proposals (especially pricing and qualifications) and decided to shortlist five of the top six bidders (i.e., SolarA, SolarB, SolarC, SolarD [Coronal, the firm that was ultimately awarded a final contract], and SolarF). The SolarE and SolarF bidders were very close in pricing and thus on the cusp of either being included or excluded from the short list. Seminole opted to shortlist SolarF because of slightly better qualitative considerations. Seminole held meetings and calls with the shortlisted bidders in which Sedway Consulting participated. After learning more about the qualifications of these bidders and the status of their projects, Seminole asked all shortlisted bidders to review their proposed pricing and provide "best-and-final-offers" (BAFO) by September 9, 2016; also, Seminole let each bidder know which of each bidder's projects were of greatest interest to Seminole. These were the following: SolarA-1, SolarB-1, SolarB-2, SolarB-3, SolarC-1 (with guidance that Seminole was not interested in procuring more than 75 MW), SolarD-1, SolarD-2 (the Coronal Tillman project that was ultimately selected), SolarD-4, SolarF-1 and SolarF-2. In several cases, bidders provided multiple options for each project (e.g., different terms, fixed or escalating prices). Table A-7 shows the lowest levelized BAFO price for each project. Seminole reviewed the BAFOs and decided to select bidders SolarB and SolarD with whom to commence negotiations and perform further due diligence. Although bidder SolarA had the lowest pricing, the bidder did not yet have a site or any interconnection information. The two final shortlisted bidders were much further along with the development of their projects. Sedway Consulting concurred with the selection of the two bidders for negotiations.

Solar PV Proposal Final Selection

Negotiations and due diligence discussions continued into 2017 with both bidders. In late May 2017, given the passage of time and the recognition that solar PV panel prices had continued to decline, Seminole encouraged both bidders to sharpen their pencils and provide final lower pricing, if they so chose. Both did, with a range of sizes and terms. Bidder SolarD (Coronal) came in with the lowest prices, as depicted in Table A-8 as levelized prices for those bids that were in the same size range and term.

Table A-7
September 2016 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	20	[redacted]
2	[redacted]	[redacted]	SolarB-2	50	30	[redacted]
3		[redacted]	SolarB-1	75	30	[redacted]
4		[redacted]	SolarB-3	75	30	[redacted]
5	Coronal	[redacted]	SolarD-1	75	20	[redacted]
6		Tillman	SolarD-2	75	20	[redacted]
7		[redacted]	SolarD-4	75	20	[redacted]
8	[redacted]		SolarC-1	75	25	[redacted]
9	[redacted]	[redacted]	SolarF-1	75	28	[redacted]
10		[redacted]	SolarF-2	75	28	[redacted]

The Coronal Tillman project had the lowest price and was selected for final negotiations. On October 16, 2017, Seminole and Tillman Solar Center, LLC (a subsidiary of Coronal Energy) executed a 20-year PPA for solar PV generation from a new facility to be built in Alachua County, Florida with an expected commercial operation date of June 1, 2021.

Table A-8
June 2017 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	Coronal	Tillman	SolarD-2	40	20	[redacted]
2		[redacted]	SolarD-4	40	20	[redacted]
3	[redacted]	[redacted]	SolarB-2	50	20	[redacted]
4		[redacted]	SolarB-3	50	20	[redacted]
5		[redacted]	SolarB-1	50	20	[redacted]

Non-Solar PV Proposal Analysis

As noted earlier, solar PV capacity provides little or no contribution to meeting Seminole's winter peak. Thus, the cooperative's 2021 RFP was essentially soliciting proposals for other types of generation. The analysis of proposals for this other generation was the primary focus for Sedway Consulting's independent evaluation

efforts. In this report, all references to proposals and proposal evaluation tasks from this point forward are entirely associated with Sedway Consulting's and Seminole's non-solar PV proposal analyses.

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 Seminole's self-build options):

- 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 surplus/deficit capacity assumptions to adjust for the slightly different annual or seasonal sizes of competing portfolios, and
- the process of developing final cost estimates for competing portfolios.

RSM Evaluation Process

The economic information for all outside proposals and Seminole's self-build option(s) was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each resource on Seminole's system production costs. The RSM calculated each proposal's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each proposal, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period.

A proposal'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), and transmission revenue requirements. These annual total fixed costs were discounted to mid-2017 dollars.

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

PaR (R·V·N)

The RSM then estimated Seminole's system production costs for each month and each proposal by interpolating between production costs estimates that were extracted from a set of runs from ~~EPM~~ – Seminole'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 Seminole system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated Seminole's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 13,000 Btu/kWh. Thus, for each proposal, the RSM yielded estimates of the annual production cost savings that Seminole 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 proposal'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 (2051). 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 Seminole 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 use a blend of the cost and benefit streams associated with the three top-ranked individual proposals for long-term power supplies. By doing so, Sedway Consulting was using direct market information as guidance for what future capacity might cost. All capacity-related costs were escalated by a modest rate of 1.0%/year (which was assumed to be a reasonable assumption for the rate of inflation minus future potential for technology cost reductions). 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 these three top-ranked offers (which were fairly large in capacity). In other words, if a 200 MW proposal ended in 2031, the RSM assumed that a 200 MW CC facility replaced it in 2032; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW plant, but rather, they were a prorated portion of the construction costs of a larger facilities.

It is worth noting that this development of a smoothly escalating cost and benefit stream and the scaling process differed from the future generation expansion assumptions and methodologies employed by Seminole. In the end, however, the approaches probably did not significantly alter either evaluation team's results, as they accomplish the same general goal of continuing to meet Seminole's future capacity needs with generic replacement capacity. However, this is one of several reasons that Seminole's and Sedway Consulting's final portfolio cost differential are different. Sedway Consulting retains the right to evaluate utility solicitations with its own methodologies and believes that using two different approaches reinforces a solicitation's evaluation process when both approaches yield results that support the same conclusion(s).

As noted above, depending on the "in-service date" for the back-fill resource, the back-filler's capital costs were escalated from a 2021 base-year value by 1.0%/year. This escalation assumption represented Sedway Consulting's estimate of how construction costs were likely to increase for generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using Seminole's declining revenue requirements profile for the recovery of capacity costs of future generic resources, 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 1.0%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the component top-ranked project cost streams, which include the Seminole's 2x1H self-build resource and its traditional declining revenue requirements profile.

Over the full 30 years, the restructuring of the back-fill resource's capacity costs made no difference to the present value of the blended top-ranked proposals' cost streams. 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. In effect, it assumed that, following the expiration of an outside proposal's term, Seminole would procure replacement power supplies at a trended price based on the best market resources. In reality, if 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 Seminole's customers would likely pay.

Figure A-1



Proposal/Resource Cost Computation

Sedway Consulting used its own proprietary Revenue Requirements Model (RRM) to develop estimates of the annual revenue requirements for Seminole' self-build option(s) and cross-checked them with those provided by Seminole. Both sets of values compared quite closely, and Sedway Consulting relied on its RRM results for use in the RSM.

Most of the input assumptions for the proposals and other cost and operational parameters for Seminole's self-build option(s) 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:

- Firm gas transportation
- Third-party transmission costs
- Network upgrade-related transmission costs.

Firm gas transportation. Seminole'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 Seminole to estimate the expected annual firm gas transportation (i.e., pipeline reservation) charges for each project. Sedway Consulting reviewed Seminole's calculations, compared Seminole's values to some of its own calculations and ultimately adopted the same or close approximations to Seminole's values for each applicable proposal.

In addition to the annual firm gas pipeline reservation charges, bidders provided and/or Seminole 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.

Third-party transmission costs. As noted above, Seminole members have load in three balancing areas in Florida, and the cooperative sought to procure power supplies in locations that would minimize excessive transfers between those areas (or from out-of-state). That said, proposals that entailed such transfers were allowed; they simply needed to include the necessary third-party transmission wheeling costs associated with such transfers. In fact, 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 Seminole for such transfers or for wheeling across third-party transmission systems.

Network-update-related transmission costs. With the addition of new generation to a utility system (and sometimes even for redirected sales of power from existing resources), 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 for new resources that would be located in the relevant balancing area authorities, bidders were responsible for recognizing that their resource might trigger the need for network upgrades on the DEF or FPL transmission systems. It was each bidder's responsibility to initiate, when appropriate, an interconnection request to study what those costs would be. Seminole, in turn, calculated what the effect would be on the DEF and FPL transmission rate tariffs and the costs that its members would need to pay on any on-going basis for its portion of such network upgrades. Where appropriate, estimates of such network upgrade investments were sought from bidders and/or calculated by Seminole's transmission subject matter experts for specific proposals. Sedway Consulting reviewed and adopted these annual cost estimates. However, Sedway Consulting employed a different methodology than Seminole for attributing these network-upgrade-related costs to projects. Sedway Consulting calculated Seminole's portion of the levelized annual transmission revenue requirements[1] 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). Seminole 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;

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

each was based on slightly different but defensible end-effects assumptions. In any case, as noted earlier, Sedway Consulting was free to employ its own evaluation methodologies that may differ from Seminole's; and although that contributed to somewhat different final quantitative results, the fact that different approaches supported the same final conclusions reinforces provides greater assurance in the results of the solicitation.

Surplus/Deficit Capacity Benefit/Cost – 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 Seminole's detailed model. In its final analysis, Sedway Consulting accounted for the different capacity of each resource by developing portfolios of resources that relatively closely met Seminole's project seasonal (i.e., summer and winter) capacity needs in 2021-2025. In instances where there was a small surplus or deficit of capacity in a season, Sedway Consulting used short-term capacity valuation assumptions that Seminole provided at the start of the RFP project and periodically updated with the latest market information for small short-term capacity transactions. For long-term portfolio capacity differences (i.e., past 2025), Sedway Consulting used its filler resource assumptions to determine the benefits of surplus capacity or the costs of being slightly short.

The inclusion of these costs or benefits of marginal capacity in the RSM results placed those results on a more comparable footing with the Seminole detailed production costing and generation expansion results.

RSM Evaluation Results

The evaluation process for the non-solar PV resources went through a series of "shortlistings" over the course of the RFP process, with uncompetitive projects being set aside and released from further consideration at various stages. For the first cut, Sedway Consulting and Seminole identified proposals that had high risks and/or high prices that made them outliers and undesirable candidates for selection. The following Tables A-8 through A-11 depict the RSM levelized $/kW-month net cost results for the initial review of the qualified offers, segmented into the same delivery zones as was depicted in Tables A-3 through A-6. The proposal ranking in each table is based on the levelized net cost, from lowest to highest.

In Table A-8 (for the DEF BAA proposals), it was decided that the bottom five proposals (H-1, G-1, D-2, I-1, and J-1) had net costs that were too high to warrant continued evaluation. Also, as far as competing peaking CT resources, the least cost-effective CT proposal (D-1) was seen as unnecessary for continued evaluation, given that there were better CT/peaking proposals in the BAA to consider.

Table A-8
Initial RSM Results – DEF BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	C-1	117	[redacted]
2	[redacted]	CT	A-4	482	[redacted]
3	GE Shady Hills CT	CT	B-3	519	[redacted]
4	DEF Peaking	System	E-3	50-300	[redacted]
5	[redacted]	CT	D-1	484	[redacted]
6	DEF Intermediate	System	E-4	50-300	[redacted]
7	GE Shady Hills CC2	CC	B-1	573	[redacted]
8	[redacted]	CC	B-2	463	[redacted]
9	[redacted]	CC	A-1	1,064	[redacted]
10	[redacted]	CC	A-2	863	[redacted]
11	[redacted]	CC	A-3	599	[redacted]
12	[redacted]	CC	F-1	121	[redacted]
13	[redacted]	Biomass	H-1	70	[redacted]
14	[redacted]	CC	G-1	557	[redacted]
15	[redacted]	CC	D-2	538	[redacted]
16	[redacted]	ES	I-1	75-225	[redacted]
17	[redacted]	Biogas	J-1	34	[redacted]

Later in the evaluation process, discussions with the bidder behind the Proposals A-1, A-2, A-3, and A-4 – all of which were associated with the same site – yielded the conclusion that the development efforts were in a rather early stage. Given that this translated into greater risks and uncertainty, these offers were removed from the later stages of the evaluation.

Proposal C-1 was for the purchase of an existing CT facility, with the proposed transfer to occur well before Seminole's 2021 need. More importantly, the CT's generation technology was an old non-standard, one-of-a-kind technology in the southeast U.S. that Seminole concluded would be hard to maintain and find spare parts. Sedway Consulting participated in several discussions with Seminole about the possible options if the cooperative were to buy this facility. However, both concluded that the technology risks were too high and the proposal was set aside.

Lastly, the Proposal B-2 was at the same site and mutually exclusive with a higher-ranked more attractive GE Shady Hills CC2 project, so that proposal was set aside. The remaining proposals continued to be included in the portfolio evaluation process, including Proposal F-1, which was sold by [redacted] to [redacted] during Seminole RFP process and is labeled as such in later tables.

For the Table A-9 proposals associated with resources in the FPL BAA, the last one in the table (Proposal A-7) was set aside because selecting it would cause Seminole to lose it ability to tap any other future power supply opportunities in the FPL BAA (e.g., short-term economic purchases). The bidder had two other proposals (A-5 and A-6) that did not have this drawback and included valuable optionality in the amount of capacity that Seminole could procure. That optionality value is not reflected in the RSM net cost metrics but was captured later in the portfolio development process. Thus, Seminole and Sedway Consulting agreed that those proposals should continue to be evaluated. The small Proposals M-1 and N-1 had net costs that were too high to warrant continued inclusion in the evaluation process and were set aside.

Table A-9
Initial RSM Results – FPL BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	L-1	515	2.25
2	[redacted]	System	A-5	100-1000	3.76
3	[redacted]	MSW	M-1	25	4.38
4	[redacted]	System	A-6	100-1000	5.70
5	[redacted]	MSW	N-1	40	9.09
6	[redacted]	System	A-7	All	N/A

Table A-10 depicts the four SSN market alternative proposals as well as Seminole's two self-build options at the cooperative's SGS site in the SSN BAA – the 2x1H CC (SCF) and a smaller 1x1H CC. Seminole and Sedway Consulting had several calls/meetings with the bidder of the four market alternative proposals (which were all at the same proposed site) and concluded that gas supply constraints (and the associated costs of remedying those constraints) made the larger Proposals A-8 and A-9 too risky and expensive; thus, the self-build options and the smaller Proposals A-11 and A-10 continued to be evaluated.

Table A-10
Initial RSM Results – SSN BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	Seminole 2x1H (SCCF)	CC		1,122	[redacted]
2	[redacted]	CT	A-11	479	[redacted]
3	[redacted]	CC	A-8	1,058	[redacted]
4	Seminole Self-Build 1x1H	CC		595	[redacted]
5	[redacted]	CC	A-9	859	[redacted]
6	[redacted]	CC	A-10	641	[redacted]

Table A-11 depicts the proposals associated with resources in SERC. Because of transmission constraints and the potential for curtailments of power deliveries from SERC into peninsular Florida, Seminole recognized that it would be unwise to rely too heavily on resources in SERC to meet the cooperative's firm capacity needs. Thus, early in the evaluation process, it reviewed the supply portfolios of other peninsular Florida utilities to assess what percentage of their total capacity needs those utilities procured from SERC resources. Based on that review, Seminole concluded that it should set a maximum of 350 MW as the limit for SERC-based supplies.

Table A-11
Initial RSM Results – SERC Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CC	L-2	500	3.16
2	[redacted]	CC	L-3	350	3.16
3	[redacted]	CC	L-4	200	3.22
4	[redacted]	CC	O-1	225	3.48
5	[redacted]	CC	P-1	350	3.49
6	Southern Company	System	Q-1	50-440	3.55
7	[redacted]	Call Option	S-1	200	3.67
8	[redacted]	System	L-5	138	3.81
9	[redacted]	CT	R-1	280	3.98
10	[redacted]	System	T-1	50	7.22
11	[redacted]	CC	R-2	533	8.67
12	[redacted]	Wind	C-2	200	N/A

Given the 350 MW limit, two proposals were eliminated (L-2 and R-2) and one (Q-1), after discussions with Southern Company regarding its system sale proposal, was revised to have a maximum capacity of 350 MW.

One proposal (C-2) was for long-term energy deliveries from a wind facility in Kansas via point-to-point transmission service across a yet-to-be-developed transmission line to the Tennessee Valley Authority (TVA), then across the Southern Company system into Florida. The expected transmission costs resulted in a rather high $/MWh price for a non-firm, non-dispatchable product that would consume a majority of Seminole's 350 MW SERC limit. Thus, the proposal was set aside.

Low-ranked Proposals S-1, L-5, R-1, T-1, and R-2 were removed from further evaluation because of their poor quantitative metrics. The remaining proposals had net costs that were in a fairly tight range. Of the Projects L, O, and P, only Proposal O-1 was for deliveries from a full facility. The Proposals L-3, L-4, and P-1 were partial plant proposals and had the scheduling and settlement complications of dealing with other

offtakers. Proposals O-1 and Q-1 (the Southern Company system sale) were seen as the best SERC proposals. Ultimately, the optionality associated with the Southern Company transaction (which could be set as low as 50 MW in a delivery year) made it the best fitting SERC resource in the final portfolio.

Final Proposal and Portfolio Analysis

Table A-12 depicts the final set of all of the resources that were modeled for the final selection decision in mid-2017. These were the results that Sedway Consulting presented to Seminole's Board of Trustees on July 12, 2017. The ranking is based on each resource's levelized and normalized $/kW-month net cost.

There are several 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, on an individual basis, do not necessary meet the capacity need. Total portfolio considerations 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 Seminole to select any of the resources.

Third, as noted earlier, Sedway Consulting calibrated the RSM with proxy run information from Seminole's detailed production cost model prior to the receipt of proposals. Because Seminole was procuring resources to replace a rather significant percentage of its overall supply portfolio and because it received so many qualified proposals, the evaluation process took longer than expected. By the spring of 2017, Seminole had developed new load, fuel price, and other planning-related forecasts and incorporated this new information into its modeling systems. Sedway Consulting reviewed the new forecasts and believed them to be better than the previous 2016 forecasts. Thus, Seminole and Sedway Consulting coordinated on a new set of proxy runs to recalibrate Sedway Consulting's RSM for the 2017 forecasts. Given that this occurred well after Seminole had received and reviewed the proposals in its RFP process, Sedway Consulting reviewed the final rankings under both RSM vintages. Thus, in Table A-12, levelized net costs are shown for each final proposal under "Old" and "New" forecast assumptions, and the table is ranked on the "Old" metric. The rankings were essentially unchanged, with some minor flipping of some proposals in the ranking as indicated with italicized values in the "New" column.

It is important to note that both of the DEF System Sales and the Southern Company Services (SCS) System had significant optionality (with annual delivered capacities as low as 50 MW); this optionality is not reflected in the net cost statistics and rankings.

Table A-12
Ranking of Final Proposals

	Proposal/Resource	Code	Type	Status	Start Date	Capacity (MW)	Term (years)	Levelized Net Cost ($/kW-month)	
								Old	New
1	Self-Build 2x1		CC	New	12/1/2022	1,122	30	[redacted]	[redacted]
2	[redacted]	L-1	CT	Existing	6/1/2021	172-515	5		
3	Shady Hills	B-3	CT	Existing	6/1/2024	173-519	23*		
4	DEF Peaking	E-3	System	Existing	6/1/2021	50-300	9		
5	[redacted]	O-1	CC	Existing	6/1/2021	235	10		
6	SCS System	Q-1	System	Existing	6/1/2021	50-350	3		
7	[redacted]	A-5	System	Existing	6/1/2021	100-1000	10		
8	DEF Intermediate	E-4	System	Existing	6/1/2021	50-300	5		
9	Self-Build 1x1		CC	New	6/1/2021	595	30		
10	Shady Hills 1x1	B-1	CC	New	12/1/2021	573	30		
11	[redacted]	A-10	CC	New	5/1/2021	641	20		
12	[redacted]	A-6	System	Existing	6/1/2021	100-1000	10		
13	[redacted]	F-1	CC	Existing	6/1/2021	121	20		

* This was the contemplated term of the Shady Hills CT contract at the time of the July 12, 2017 Board of Trustees meeting; during the subsequent negotiation process, the term was reduced to 15 years.

Portfolio Analysis

Seminole and Sedway Consulting reviewed their respective evaluation results and developed portfolios of proposals that would meet the cooperative's capacity needs. As this process was underway in early 2017, two important considerations came to light. First, Seminole began to explore potential savings that might be achieved by removing one of its SGS coal units from service and replacing that capacity with cost-effective resources and transactions that were available from its 2021 RFP. In the spring of 2017, Seminole retained an engineering firm to develop detailed estimates of the costs of the service removal process and the difference in the costs of continuing to operate one instead of two of its coal units. Second, it was recognized that each portfolio had certain expected portfolio transmission impacts that needed to be taken into consideration.

With these issues in mind, three specific optimal portfolios (i.e., optimal within the context of their purpose and constraints) rose to the top in terms of economic and strategic value and were labeled the following:

1. Clean Power Plan (CPP)
2. SGS 2x1
3. Limited Build

Tables A-13 through A-15 provide the component resources and additional economic factors of the three portfolios. Sedway Consulting found that the CPP portfolio was the least-cost option, yielding estimated total portfolio net costs that were $282 million less than the next best portfolio (which was the SGS 2x1 portfolio).

The first portfolio is depicted in Table A-13 and reflects the least-cost portfolio that entailed removing an SGS coal unit from service, achieving the cost savings associated with that removal, and replacing the coal unit's capacity with the most cost-effective resources that were available from Seminole's 2021 RFP.

Table A-13
Portfolio Net Cost - CPP

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	GE Shady Hills CC2	B-1	573	12/1/2021	30	
3	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	
4	Southern Company	Q-1	350	6/1/2021	5	
5	DEF-intermediate	E-4	300	6/1/2021	9.5	
6	DEF-peaking	E-3	300	6/1/2021	9.5	
7	[redacted]	L-1	172	6/1/2021	5	
8	DEF-Winter Extension					
9	Surplus Capacity Impacts					
10	Remove SGS 1 from service					
11	Portfolio Transmission Impacts					
12	TOTAL					**130**

Table A-14 depicts the SGS 2x1 portfolio which was the least-cost portfolio that did not entail removing an SGS coal unit from service.

Table A-14
Portfolio Net Cost - SGS 2x1

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	Southern Company-5yr	Q-1	350	6/1/2021	5	
3	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	
4	DEF-peaking	E-3	300	6/1/2021	9.5	
5	[redacted]	L-1	172	6/1/2021	5	
6	DEF-Winter Extension					
7	Surplus Capacity Impacts					
8	Portfolio Transmission Impacts					
9	TOTAL					**412**

Table A-15 depicts the least-cost portfolio that does not entail Seminole's development of any new self-build resources (nor the removal from service of any coal unit). Only one new build resource would be constructed if Seminole pursued this Limited Build portfolio – Shady Hill's CC (SHCCF).

Table A-15
Portfolio Net Cost – Limited Build

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	GE Shady Hills CC2	B-1	573	12/1/2021	30	[redacted]
2	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	
3	Southern Company-5yr	Q-1	350	6/1/2021	5	
4	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	
5	DEF-peaking	E-3	300	6/1/2021	9.5	
6	[redacted]	L-1	172	6/1/2021	10	
7	DEF-Winter Extension					
8	Surplus Capacity Impacts					
9	Portfolio Transmission Impacts					
10	TOTAL					**621**

Thus, on a CPVRR basis, the CPP Portfolio that Seminole selected 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 it is likely that the RSM results did not fully capture the production cost benefits associated with replacing coal generation with gas-fired generation.

Conclusions

Sedway Consulting performed an independent evaluation of Seminole's self-build option(s) and the market alternatives that were submitted in response to Seminole's 2021 RFP and concluded that the CPP portfolio represented the lowest-cost portfolio for meeting Seminole's 2021 resource need. That portfolio was found to be $282 million less expensive on a CPVRR basis than the next cheapest portfolio of alternatives.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 28
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Michael P. Ward II MPW-1

Michael P. Ward II

Experience

Vice President, Strategic Initiatives
2017-Present
SEMINOLE ELECTRIC COOPERATIVE INC.

- Executive management responsibility for identifying, analyzing, developing and implementing strategic opportunities that fulfill Seminole's strategic resource plan.
- Oversee, direct and manage Seminole's self-build combined cycle facility, tolling agreements, purchased power agreements, solar generation, coal unit retirement, headquarters building renovation and back-up control center/business continuity projects.

Director of System Operations **2014-2017**
SEMINOLE ELECTRIC COOPERATIVE INC.

- Managed operations, maintenance and engineering department responsible for all aspects of power systems engineering and energy delivery, including control center operations, planning, NERC compliance, member billing, and substation field operations.

Manager of Maintenance, Midulla Generating Station
2014-2014
SEMINOLE ELECTRIC COOPERATIVE INC.

- Managed Maintenance and Engineering department responsible for all preventative and corrective maintenance, as well as plant modifications.

Plant Engineer and Project Manager
2013-2014
SEMINOLE ELECTRIC COOPERATIVE INC.

- Plant Engineer for Combined Cycle facility.

Submarine Officer
1987-2014
UNITED STATES NAVY

- Progressive assignments on seven different nuclear submarines, up to and including commanding officer of a crew of 152 personnel. Six staff shore assignments with responsibility for national level policy-making, strategic planning, capital and operational budgeting, and expert technical advice.

Education

Bachelors of Science in Electrical Engineering, University of Florida **1994**
Masters of Business Administration, University of Maryland University College **2002**
Certificate in National Security Affairs, Naval War College and National Defense University **2011**

Skills

Previous Top Secret/SCI security clearance
Certified for Command and Supervision of Nuclear Powered Warships
Completed Prospective Commanding Officer course for Naval Nuclear Propulsion
Proficient in Microsoft Office Suite of applications, including Microsoft Project and Visio
Naval Nuclear Engineer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 29
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Michael P. Ward II MPW-2

Attachment "B"

ERRATA SHEET FOR
EXHIBIT NO. ___ (MPW-2)
SEMINOLE NEED STUDY
Filed in Docket Nos. 20170266-EC & 20170267-EC

Section	Page	Correction
1.5	8 of 153	Change "$363 million" to "$530 million"
6.8	65 of 153	Change Figure 13 to attached revised Figure 13 (Note: Figure 13 is the same as Exhibit (JAD-6)
8.0	72 of 153	Change "$388 million" to "$530 million"

Figure 13 Summary of Updated Economic Analysis

Portfolio Summaries
Revised Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	~~11,624~~ 11,686
NPV @ 6.0%	8,641	8,568	8,549	~~8,432~~ 8,499
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	**56,465**	58,312	~~58,289~~ 58,616
NPV @ 6.0%	20,981	**20,618**	21,120	~~21,006~~ 21,148



NEED STUDY

Submitted to the Florida Public Service Commission in support of Petitions to Determine Need for Electric Power Plants

December 2017

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APPENDICES

A. Seminole's 2017 Ten Year Site Plan
B. 2016 Request for Proposals

1.0 EXECUTIVE SUMMARY

Seminole Electric Cooperative, Inc. ("Seminole") submits this Need Study in support of two proposed natural gas-fired combined cycle ("CC") facilities, including: the Seminole Combined Cycle Facility ("SCCF"), a self-build 1,050 MW (nominal) two-on-one generating facility to be constructed adjacent to the existing Seminole Generation Station ("SGS") site in conjunction with the removal from service of one of the existing SGS coal-fired units; and the Shady Hills Combined Cycle Facility ("SHCCF"), a 573 MW (winter) one-on-one generating facility to be constructed by Shady Hills Energy Center, LLC ("SHEC"), an indirect subsidiary of General Electric Company ("GE"), at the existing Shady Hills power plant site in Pasco County pursuant to a tolling agreement with Seminole. The analyses discussed throughout this Need Study demonstrate that the two combined cycle facilities are needed to meet the electrical demands of Seminole and its Member Cooperatives.

1.1 The Primarily Affected Utilities

Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales; it does not make retail sales. Seminole's nine members ("Members" or "Member Cooperatives") are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use member-consumers in Florida. Seminole's Members are: Central Florida Electric Cooperative, Inc., Clay Electric Cooperative, Inc., Glades Electric Cooperative, Inc., Peace River Electric Cooperative, Inc., SECO Energy, Suwannee Valley Electric Cooperative, Inc., Talquin Electric Cooperative, Inc., Tri-County Electric Cooperative, Inc., and Withlacoochee River Electric Cooperative, Inc. Approximately 1.6 million people and businesses in parts of 42 of Florida's 67 counties rely on Seminole and its Member Cooperatives for electricity.

1.2 The Power Plant Siting Act and Need Determination Process

The Florida Electrical Power Plant Siting Act ("PPSA"), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection ("DEP") and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity;
- The need for adequate electricity at a reasonable cost;
- The need for fuel diversity and supply reliability;
- Whether the proposed plant is the most cost-effective alternative available;
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available; and
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

1.3 The Proposed New Facilities

Seminole has determined that the most cost effective, risk-managed resource plan to meet its projected capacity need is a mix of resources consisting of existing generation resources, PPAs, and the construction of two natural gas-fired combined cycle facilities, including: the self-build 1,050 MW SCCF along with the removal from service of one of the two existing 664 MW SGS coal units; and the 573 MW SHCCF to be constructed, owned and operated by SHEC under a tolling agreement with Seminole.

1.4 Seminole's Need for Generation Capacity

Based on its continuing evaluation of its Member Cooperatives' electricity needs, Seminole projects a need for 901 MW of additional generating capacity by the end of 2021. This projected need results primarily from the expiration of power purchase agreements ("PPAs"), including the expiration of a 150 MW PPA on December 31, 2020, followed by the expiration of two more PPAs totaling 750 MW of winter capacity in May, 2021. Because an additional 300 MW PPA expires the following year, along with load growth, Seminole's projected need increases to 1,265 MW by the end of 2022.

1.5 Major Generating Alternatives

Seminole's Board of Trustees selected the resource plan that includes the SCCF and the SHCCF facilities based on the results of a multi-stage resource planning process. That process included extensive economic analyses of self-build options and multiple power purchase alternatives, including numerous renewable energy proposals, identified during a robust Request for Proposal ("RFP") process, as well as careful consideration of non-economic attributes and risk factors. Seminole's analyses demonstrate that the resource plan containing the SCCF and the tolling agreement with SHEC for the SHCCF is the most cost-effective alternative to meet Seminole's capacity needs and would result in projected net present value ("NPV") savings of approximately $363 million as compared to the next ranked alternative over the study period. The selected resource plan also includes multiple PPAs with significant optionality in terms of available capacity. This provides Seminole a hedge against economic acceleration/downturns or faster/slower load growth rates.

1.6 Non-Generating Alternatives

As a wholesale supplier of electric energy to its Members, Seminole is not directly responsible for demand-side management ("DSM") programs. However, Seminole encourages conservation through its wholesale rate structure, which provides price signals that reflect Seminole's cost of supplying power in aggregate and thereby encourages Members to concentrate their load management efforts on controlling

Seminole's overall system peak. Seminole also assists its Members in the evaluation of potential DSM measures. Despite the DSM savings achieved by Seminole's Members, the need for additional capacity still exists and there is not a reasonable scenario in which sufficient DSM or conservation could be added to avoid the need for additional capacity.

1.7 Adverse Consequences of Denial

Non-approval of the requested need determination would mean that Seminole's Members and the Members' end-use member-consumers would be denied the most cost-effective, risk-managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021. While additional off-system purchases could perhaps be made to fulfill Member power requirements and maintain the target reserve margin, Seminole would not be able to remove a coal unit from service and the costs of the resulting resource plan would be substantially higher.

1.8 Conclusion

The analyses and other information described above demonstrate that affirmative need determinations are warranted for the new SCCF and SHCCF projects based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to the expiration of existing PPAs, Seminole will have a need for 901 MW of additional generating capacity by the end of 2021, and that need will grow to 1,265 MW by the end of 2022. Seminole's Board of Trustees selected the resource plan that includes the SCCF and SHCCF based on the results of a rigorous, multi-stage planning process that involved extensive economic analyses of generation alternatives, including numerous power purchase alternatives identified during a robust RFP process, as well as careful consideration of non-economic attributes and risk factors. In recognition of the energy value of solar, the selected resource plan also includes 40 MW from a new solar resource. Seminole and its Members continue to explore additional DSM/conservation measures even though there is no reasonable basis to conclude that such measures could offset Seminole's projected need.

2.0 PURPOSE AND OVERVIEW OF NEED STUDY

Seminole is submitting this Need Study in support of separate petitions for determination of need for the new SCCF and SHCCF pursuant to secton 403.519, Florida Statutes. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each petition for need determination must include to allow the Commission to address the statutory factors. This Need Study is organized as follows to provide the information required for such need determinations by Rule 25-22.081:

- Section 3 provides a general description of the utility or utilities primarily affected, including the load and electrical characteristics, generating capability, and interconnections;
- Section 4 provides a general description of the proposed electrical power plants, including the size, number of units, fuel type and supply modes, the approximate costs, and projected in-service date or dates;
- Section 5 provides a statement of the specific conditions, contingencies or other factors which indicate a need for the proposed electrical power plant including the general time within which the generating units will be needed;
- Section 6 provides a discussion of the major available generating alternatives (including renewable energy sources) which were examined and evaluated in arriving at the decision to pursue the proposed generating units;
- Section 7 provides a discussion of non-generating alternatives; and
- Section 8 provides an evaluation of the adverse consequences which will result if the proposed electrical power plants are not added in the approximate size sought or in the approximate time sought.

3.0 PRIMARILY AFFECTED UTILITIES

3.1 Seminole Electric Cooperative & its Member Cooperatives

Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales; it does not make retail sales. Seminole's nine Members are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use member-consumers in Florida. The names and headquarters locations of each of the Member cooperatives, along with the counties which each Member serves, are:

- Central Florida Electric Cooperative, Inc.
  Chiefland, Florida
  Counties: Alachua, Dixie, Gilchrist, Levy, Lafayette, Marion

- Clay Electric Cooperative, Inc.
  Keystone Heights, Florida
  Counties: Alachua, Baker, Bradford, Clay, Columbia, Duval, Gilchrist, Lake, Levy, Marion, Putnam, Suwannee, Union, Volusia

- Glades Electric Cooperative, Inc.
  Moore Haven, Florida
  Counties: Glades, Hendry, Highlands, Okeechobee

- Peace River Electric Cooperative, Inc.
  Wauchula, Florida
  Counties: Brevard, DeSoto, Hardee, Highlands, Hillsborough, Indian River, Manatee, Osceola, Polk, Sarasota

- SECO Energy
  Sumterville, Florida
  Counties: Citrus, Hernando, Lake, Levy, Marion, Pasco, Sumter

- Suwannee Valley Electric Cooperative, Inc.
  Live Oak, Florida
  Counties: Columbia, Hamilton, Lafayette, Suwannee

- Talquin Electric Cooperative, Inc.
  Quincy, Florida
  Counties: Gadsden, Leon, Liberty, Wakulla

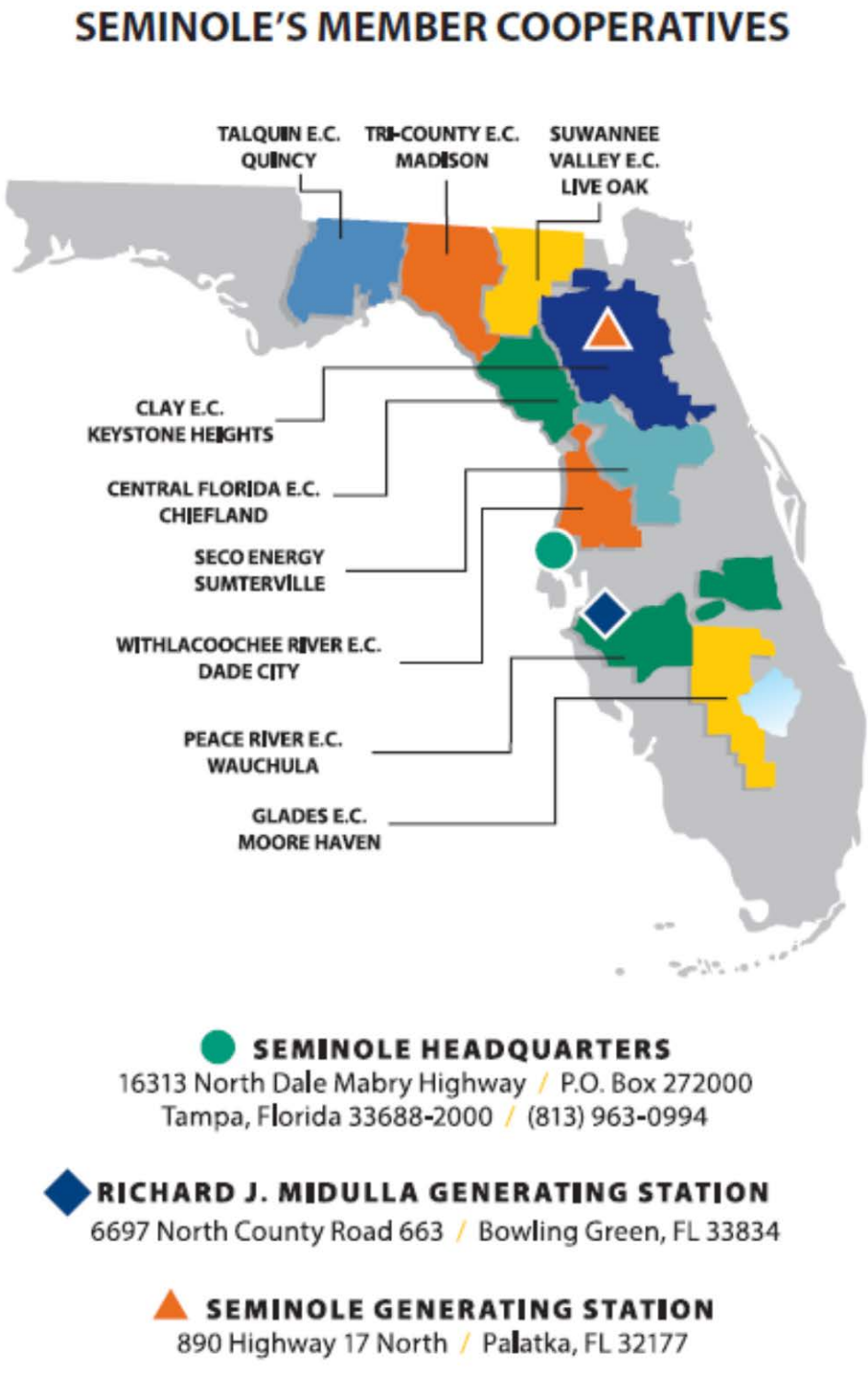
- Tri-County Electric Cooperative, Inc.
  Madison, Florida
  Counties: Dixie, Jefferson, Lafayette, Madison, Taylor

- Withlacoochee River Electric Cooperative, Inc.
  Dade City, Florida
  Counties: Citrus, Hernando, Pasco, Polk, Sumter

Seminole is owned by its Members and governed through a Board of Trustees, and it exists to provide reliable electric service at competitive rates to its Members. Seminole was organized in 1948, but remained relatively inactive until shortly after the 1973 oil embargo. In 1974, Seminole's Board determined that Seminole should develop independent power supplies for its Members. In 1975, each Member entered into a long term "All Requirements" contract with Seminole for the purchase of wholesale power. Under these contracts, each Member purchases from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts. Four of Seminole's Members had pre-existing contracts with the Southeastern Power Administration, which provides 26 MW of the total capacity required by these Members.

Seminole is one of the largest electric generation and transmission cooperatives in the country. Seminole and its Members serve approximately 1.6 million people and businesses in parts of 42 of Florida's 67 counties. Figure 1 shows the areas of the State serviced by Seminole's nine Member Cooperatives.

Figure 1 Seminole Member Service Areas



3.2 Load and electrical characteristics

Seminole Members serve electricity to primarily-rural areas within 42 counties in the north, central, and south regions of Florida, which differ uniquely in geography, weather, and natural resources. Seminole has historically been a winter-peaking utility and is expected to remain winter-peaking due to the concentration of service territory load in the north/central portion of peninsular Florida.

3.3 Generating Capability

Seminole meets the power supply needs of its Members and their member-consumers with Seminole-owned generation in combination with purchased power or tolling agreements with independent power producers, investor-owned and municipal utilities, and renewable energy providers. As of December 31, 2016, Seminole had total winter capacity resources of approximately 4,700 MW consisting of owned, installed net winter capacity of 2,178 MW and the remaining capacity in firm purchased power. As a result of the RFP process discussed in Section 6, Seminole recently extended its existing Oleander Power PPA through 2021 and entered into a new long-term PPA with Southern Company Services ("SCS") and two new long-term PPAs with Duke Energy Florida ("DEF").

3.3.1 Seminole's Owned/Leased Generation Facilities

Seminole's existing owned or leased generating resources are located at three generating facilities:

- SGS Units 1 and 2 comprise a 1,329 MW (winter) coal-fired power plant located in Putnam County near Palatka, Florida.
- Midulla Generating Station ("MGS") Units 1-3 comprise a 539 MW (winter) gas-fired two-on-one combined cycle plant located in Hardee County, Florida. MGS Units 4-8 comprise a 310 MW (winter) peaking plant consisting of five twin-pack gas turbines. The MGS units all have fuel oil capability.

- The 2.2 MWac (summer) Cooperative Solar facility is located in Hardee County, Florida adjacent to MGS.

Table 1 summarizes Seminole's existing owned generating facilities.

Table 1 Seminole's Existing Owned Generation Facilities

Plant	Unit No.	Location	Unit Type	Fuel		Fuel Transportation		Alt Fuel Days Use	Com In-Svc Date (Mo/Yr)	Expected Retirement (Mo/Yr)	Gen. Max Nameplate (MW)	Net Capability (MW)	
				Pri	Alt	Pri	Alt					Summer	Winter
SGS	1	Putnam County	ST	BIT	N/A	RR	N/A	N/A	02/84	Unk	736	626	664
SGS	2	Putnam County	ST	BIT	N/A	RR	N/A	N/A	12/84	Unk	736	634	665
MGS	1-3	Hardee County	CC	NG	DFO	PL	TK	Unk	01/02	Unk	587	482	539
MGS	4-8	Hardee County	CT	NG	DFO	PL	TK	Unk	12/06	Unk	310	270	310
Schedule Abbreviations:		General		Unk – Unknown N/A – Not applicable									
		Unit Type ST – Steam Turbine CC – Combined Cycle CT – Combustion Turbine PV – Photovoltaic		Fuel Type BIT – Bituminous Coal NG – Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy						Fuel Transportation PL – Pipeline RR – Railroad TK – Truck			

3.3.2 Power Purchase Agreements

Seminole uses wholesale market purchases to maintain competitive flexibility in its power supply portfolio. In 2016, approximately 26% of Seminole's energy and 54% of its capacity came from wholesale purchased power. Table 2 summarizes Seminole's purchased power and tolling contracts as of December 31, 2016. As a result of the RFP process discussed in Section 6, Seminole has extended the Oleander PPA through December 31, 2021, and has entered into additional system PPAs for intermediate and peaking power and a new PPA for solar resources. These new agreements are summarized in Table 3.

Table 2 Seminole's Power Purchase Contracts
(as of December 31, 2016)

SUPPLIER	FUEL	MW (WINTER RATINGS)	IN SERVICE DATE	END DATE
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	50	6/1/2016	12/31/2018
DEF	System	200-500	6/1/2016	12/31/2024
DEF	System	50-600	1/1/2021	3/31/2027
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026

Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

Table 3 Seminole's New Power Purchase Contracts

SUPPLIER	FUEL	MW	IN SERVICE DATE	END DATE
Shady Hills Energy Center LLC	Gas	575*	12/1/2021	11/30/2051
Oleander Power Project	Gas/Oil	546*	6/1/2021	12/31/2021
Southern Company Services	System	100-150*	6/1/2021	5/31/2026
DEF	System (IM)	50-400*	1/1/2021	12/31/2030
DEF	System (Peaking)	50-400*	1/1/2021	12/31/2035
Tillman Solar Center LLC	Solar/PV	40**	6/1/2021	5/31/2041

*Winter ratings
**Summer rating

3.3.3 Renewable Resources

Seminole's generation portfolio includes a mix of technologies and fuel types, including renewable energy. Seminole currently receives 87.8 MW from renewable

energy sources via PPAs, including 13 MW from Biomass, 16.8 MW from landfill gas-to-energy, and 58 MW from waste-to-energy. Additionally, as a result of the RFP process explained in Section 6, Seminole has entered into a new PPA for 40 MWac of solar capacity beginning in January, 2021. Seminole may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

In addition to renewable power purchases, Seminole operates a 2.2 MWac (summer) Cooperative Solar facility located in Hardee County, Florida. The Cooperative Solar project took shape in 2014, as the price of solar technology was declining and the abundance of government incentives for the industry provided the path to incorporate large-scale solar projects in Florida. Seminole's Members' end-use member-consumers were interested in utilizing solar power, but wanted to do so without large, personal financial commitments. Cooperative Solar provided the opportunity for Members and their member-consumers to participate and the project provides ongoing value to Seminole, as well. The information learned from designing and operating this solar facility will help inform future decisions as Seminole evaluates adding renewable resources to its energy mix.

Seminole's Members also operate small biomass facilities (1.6 MW) and wind turbines (7.4 kW), as well as small photovoltaic facilities connected to their administration buildings. Several Members are considering future community solar projects.

3.4 Transmission Interconnections

Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 127 circuit miles of 69 kV lines. However, Seminole's transmission facilities have limited direct interconnections with Seminole's Members' load. Seminole is therefore primarily a transmission dependent utility ("TDU") that relies mainly upon the transmission systems of DEF and Florida Power & Light Company ("FPL") for the delivery of Seminole's owned and/or contracted power supply resources to Seminole's

Members' load. Seminole is a Network Integration Transmission Service ("NITS") customer of DEF and FPL under each of their respective Open Access Transmission Tariffs ("OATT"). Approximately 76%, or 2,294 MW, (based on 2016-17 actual winter net firm peak demand) of Seminole's Members' load is served by DEF's transmission system, approximately 16%, or 483 MW, is served by FPL's transmission system, and approximately 8%, or 241 MW, is served directly by Seminole's transmission system.

Seminole's facilities are interconnected to Florida's electric grid at nineteen (19) 230 kV transmission interconnections with the entities shown in Table 4.

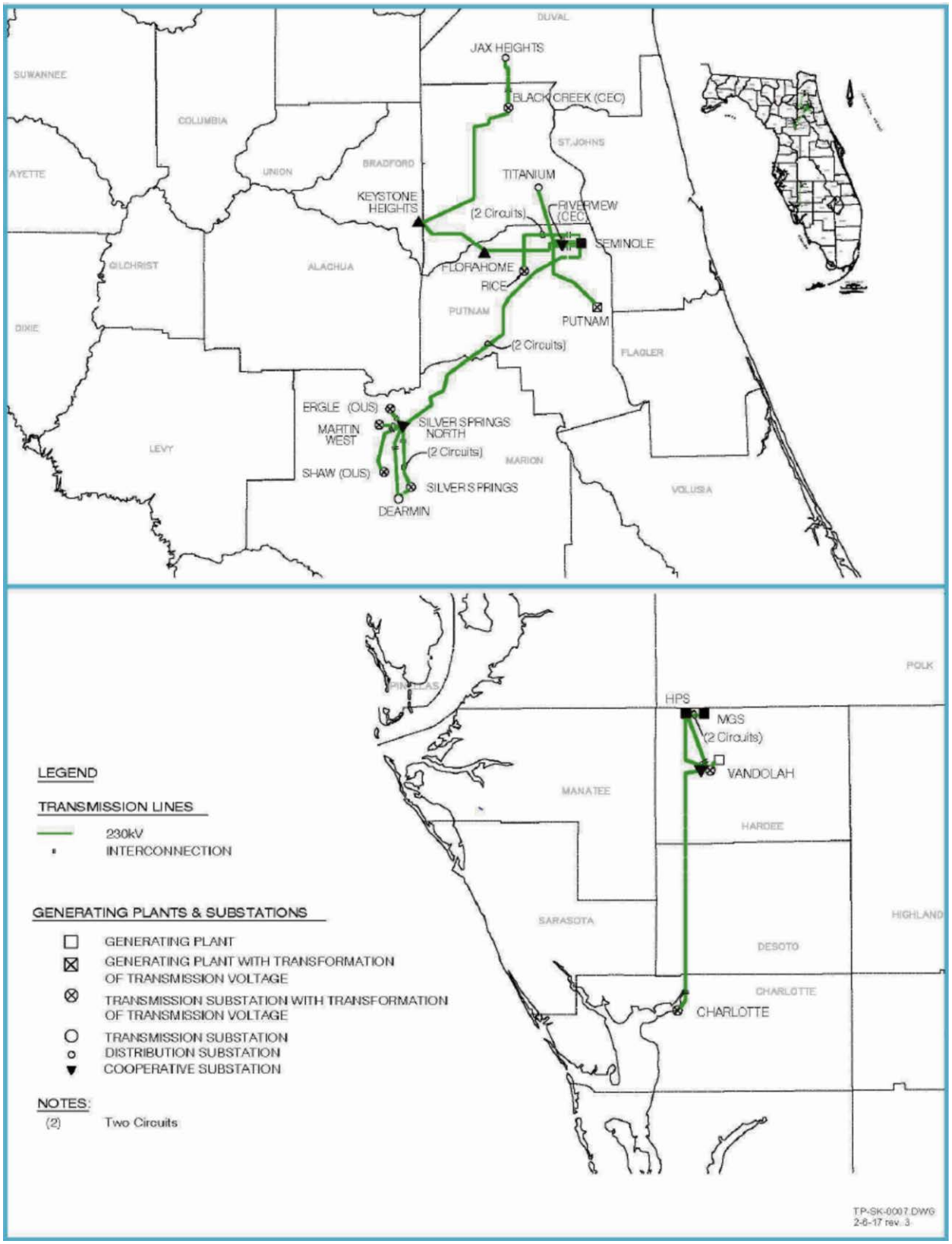
Table 4 Seminole's Transmission Interconnections

Entity	Voltage (kV)	Number of Interconnections
Florida Power & Light	230	5
Duke Energy Florida	230	7
JEA	230	1
City of Ocala (OUS)	230	2
Tampa Electric Company	230	1
Invenergy, LLC	230	3

Note: This table describes physical facility interconnections, which do not necessarily constitute contractual interconnections for purposes of transmission service or interconnections between balancing areas.

Figure 2 depicts Seminole's 230 kV transmission lines, including its interconnections with those entities identified in Table 4.

Figure 2 Seminole's Bulk Transmission Facilities



4.0 DESCRIPTION OF THE PROPOSED GENERATING UNITS

4.1 The Proposed Seminole Combined Cycle Facility ("SCCF")

The SCCF involves construction and operation of a new state-of-the-art natural gas-fired "two-on-one" combined cycle generating facility and onsite associated facilities on an approximately 32 acre parcel adjacent to the existing SGS plant. The SCCF will have a nominal net generating capacity of 1,050 MW and will be fired on natural gas only. The SGS site currently contains two 664 MW (net winter) coal-fired steam electric generating units (SGS Units 1 and 2) and associated facilities. One of the two existing SGS Units will be taken out of service coincident with the declared commercial operation of the SCCF. Figure 3 provides a conceptual rendering of the SCCF.

Figure 3 Conceptual Rendering of SCCF
(looking southwest to northeast)



4.1.1 The SGS Site

The SGS site is located 5.25 miles north-northeast of Palatka, Florida. As shown in Figure 4, the proposed SCCF site area is located southeast of the existing plant and southwest of the existing hyperbolic cooling towers.

Figure 4 Proposed Location of SCCF



4.1.2 Proposed Combined Cycle Technology

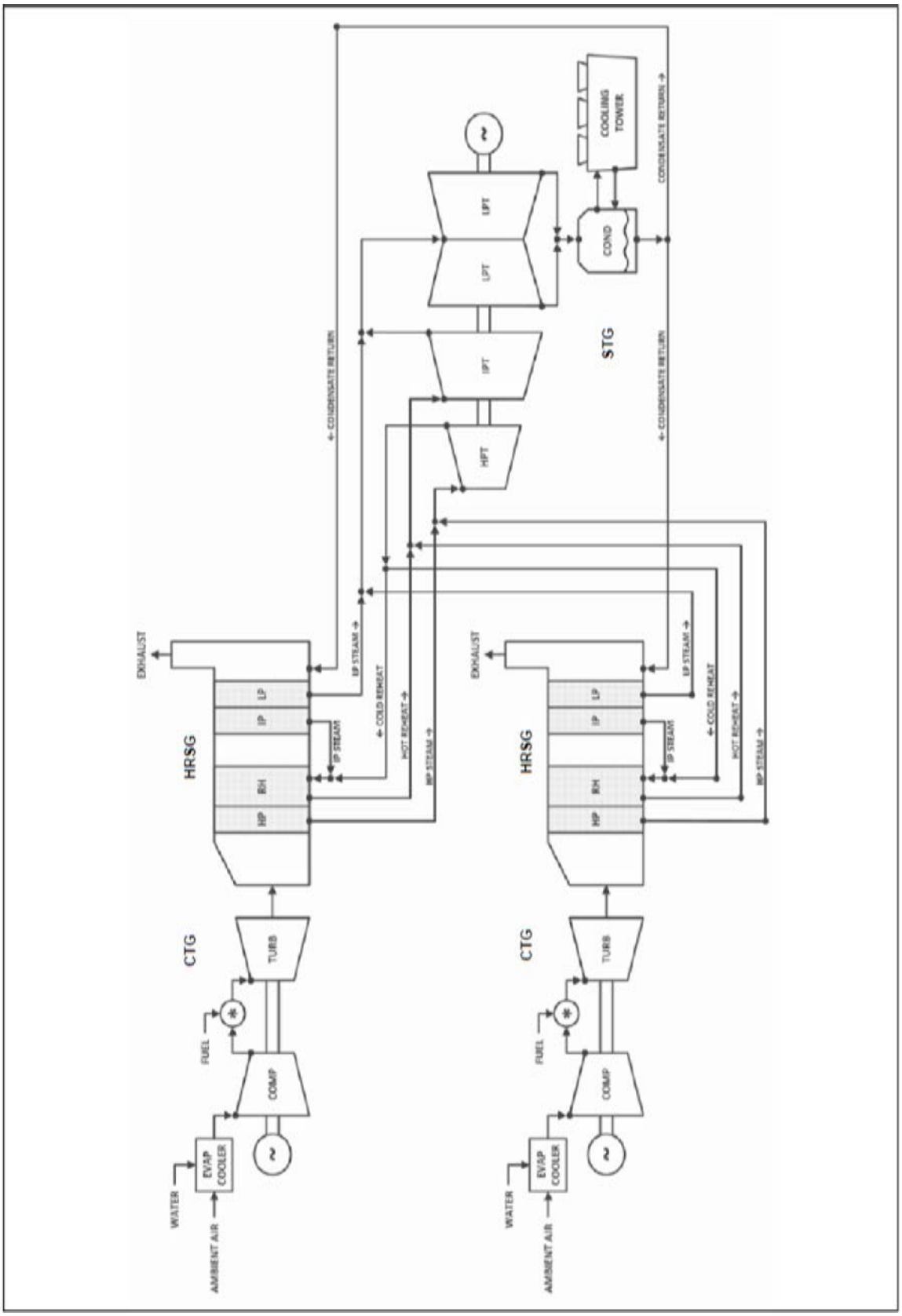
The SCCF will consist of two combustion turbine generators ("CTG"), two heat recovery steam generators ("HRSGs"), and one steam turbine generator ("STG"). Seminole has selected the advanced, large-frame GE Model 7HA.02 CTG for the SCCF. When operated in combined cycle mode, these large CTGs create the most efficient electric generating technology currently available for utility-scale power plants. These combined cycle plants can achieve an efficiency of up to 60 percent, compared to CTGs alone in simple-cycle mode at 35 to 38 percent and coal-fired steam plants at 32 to 42 percent. When a CTG is operated alone in simple-cycle mode, the hot exhaust gases from the CTG are released to the atmosphere. In combined cycle configuration, the hot exhaust gases from the CTG are used to produce steam in the HRSG, and the steam is used to drive an STG to generate additional electricity. Thus, a combined cycle power plant can generate 25 to 30 percent more electricity without burning more fuel or producing additional air emissions.

The facility is expected to have a "gross nominal" output of 1,183 MW and a "net nominal" output of 1,050 MW which it is anticipated to achieve across the entire range of ambient conditions typically experienced in Palatka, Florida. However, the facility will have significant flexibility in terms of its operational characteristics. During peak load periods, the SCCF will be able to fire supplemental natural gas in duct burners in the HRSGs to get additional generation out of the STG.

The 7HA.02 gas turbines have an extended "turndown" capability which will allow them to meet their required emissions levels while firing the turbines down to as low as 25 percent of their full-fire levels. This low turn-down capability is valuable as it will allow the SCCF to remain operational during low load periods typically experienced at night and avoid the thermal stresses, wear, and additional emissions associated with a shut-down / start-up cycle.

Figure 5 presents a conceptual schematic of a two-on-one combined cycle unit.

Figure 5 Schematic of Two-on-One Combined Cycle Unit



4.1.3 Existing Infrastructure

The SCCF will utilize existing infrastructure, including the cooling water supply and wastewater discharge pipelines to the St. Johns River and the intake and discharge structures in the river. The new electrical switchyard for the SCCF will be interconnected with the existing SGS switchyard and electricity generated by the SCCF will be transmitted to the Florida transmission network through the existing 230 kV transmission lines running west from the SGS site.

4.1.4 Associated Facilities

The SCCF also includes other associated facilities, such as electrical equipment enclosures, a mechanical draft cooling tower, exhaust stacks, an administration building that will include a control room and maintenance area, a warehouse, parking, fuel gas regulation station and heaters, diesel fired emergency fire water pump, aboveground service/fire water storage tank, aqueous ammonia tanks, a switchyard expansion, step-up transformers, potable water and sanitary wastewater treatment facilities, a stormwater management system/stormwater ponds, piping tie-ins, and other facilities necessary to integrate with existing intake and discharge water infrastructure.

4.1.5 Air Emission Controls

The SCCF will be designed with technologies to minimize air emissions. The two CTGs will be equipped with dry low-NOx combustors to control air emissions of nitrogen oxides ("NOx"). The HRSGs will be equipped with selective catalytic reduction ("SCR") systems to further reduce NOx emissions. Emissions of carbon monoxide ("CO") and volatile organic compounds ("VOCs") will be limited through use of oxidation catalyst systems. Emissions of other regulated air pollutants, such as sulfur dioxide ("SO2") and particulate matter (PM), will be controlled through use of pipeline-quality natural gas and good combustion practices. In addition, the SCCF will minimize greenhouse gas ("GHG") emissions through the use of clean-burning natural gas along with the highly efficient, combined cycle electric generating technology.

4.1.6 Water Use and Supply

The proposed SCCF is also designed to minimize the use of water. The condenser cooling system will be a closed-loop system consisting of a 16 cell mechanical draft cooling tower. Cooling tower makeup water for the SCCF will be provided from the St. Johns River through an interconnection with the existing water intake pipeline and structure. No in-water construction activities are expected for the SCCF.

Higher quality freshwater needs for plant service and potable uses for the SCCF will be provided through groundwater withdrawals from new wells within the SCCF area. Plant service water uses will include steam cycle makeup water, equipment wash water, pump seals, and emergency fire water. The service water will be filtered and treated in trailer-mounted demineralization systems, which will be regenerated offsite to avoid the need for onsite disposal of treatment wastewaters. Potable water for drinking, safety showers, eyewash stations, and other sanitary uses will be treated in a new potable water treatment facility within the SCCF site area.

Sanitary wastewater will be treated in a packaged treatment facility. The treated sanitary wastewater and other treated low-volume wastewaters will be collected in a wastewater collection sump and discharged in combination with the cooling tower blowdown through the existing water discharge pipeline and structure to the St. Johns River, similar to existing SGS operations. Any solids produced by the treatment system will be disposed offsite at the existing SGS landfill.

4.1.7 Stormwater Management

The stormwater management system for the SCCF is designed to handle and treat the 25 year, 24 hour storm event and is designed to meet all federal, state, regional, and local requirements. Potential contact stormwater runoff from the power block and equipment areas will be collected and treated through an oil/water separator and routed to the wastewater collection sump prior to discharge to the St. Johns River. Noncontact stormwater runoff from the facility area will be collected and routed to a stormwater retention pond. During construction, stormwater runoff from the construction

laydown and parking areas will also be collected and treated in swales and ponds, and best management practices will be utilized to minimize erosion from the disturbed areas during construction activities.

4.1.8 Fuel Type & Supply

The SCCF will burn natural gas as its fuel. At peak operation, including duct-firing, the SCCF will require approximately 173,000 million British thermal units ("MMBtu") of natural gas per day.

The natural gas supply for the SCCF will be purchased as a part of Seminole's procurement of its gas portfolio needs. Seminole's gas procurement process diversifies the timing and duration of such gas purchases. For example, when planning for the upcoming calendar year, Seminole will purchase a portion of its gas supply on an annual and/or seasonal basis, purchase incremental supply on a month-ahead basis, and then procure any remaining supply needs on a daily basis. Such supply is typically purchased at market based index prices. In addition, Seminole may contract for gas supply on a longer-term basis with a duration of up to five years or longer based on its projected needs and available supply.

Natural gas supply will be transported from the Florida Gas Transmission ("FGT") mainline to the SCCF via a new approximately 21-mile pipeline lateral that will be constructed, owned and operated by a third-party. Seminole will contract for firm transportation service on the pipeline lateral from FGT to the SCCF. This third-party will be an authorized natural gas transmission company in Florida as defined in section 368.103(4), Florida Statutes.

Seminole is finalizing negotiations with multiple entities for natural gas transportation service and/or natural gas supply for delivery to Putnam County, Florida and ultimately to the SCCF via the new gas pipeline lateral. These arrangements provide for up to 187,000 MMBtus per day of gas transportation rights to the lateral serving the SCCF. Some of this is existing capacity that will be re-purposed for the SCCF, some is existing capacity that will require additional facilities on FGT's system to provide the

incremental transportation capacity to Putnam County, Florida, and some of the capacity will be new transportation service into Florida enabled by additional facilities on existing pipeline(s).

Seminole is finalizing its contracts for adequate gas transportation capacity that will provide a firm transportation path from geographic locations that are expected to have adequate natural gas supply available over the horizon of the Need Study. More specifically, it is anticipated that reliable gas supply from various production basins will continue to be transported to the areas at which Seminole will have transportation rights to purchase gas supply.

4.1.9 Transmission Interconnections

The transmission interconnection process involves a System Impact Study that identifies potential impacts and mitigation plans for addressing such impacts on Seminole's transmission system as well as neighboring systems. The analysis is performed by Seminole in coordination with the Florida Reliability Coordinating Council ("FRCC") through the FRCC's Reliability Evaluation Process for Generator and Transmission Service Requests. The System Impact Study incorporates the use of steady-state load flow, short circuit, and stability analysis using industry standard tools and software programs to ensure that Seminole's transmission system operates reliably over a broad spectrum of system conditions and following a wide range of probable planning and extreme events.

In general, Seminole's transmission planning process includes the single contingency loss of any transmission circuit, transformer, bus section, shunt device, internal breaker fault, or generator. Such analysis is performed for multiple load levels, including but not limited to peak, off-peak, and high-import (Southern to Florida transfers) for select summer and winter conditions as modeled and made available by the FRCC. Additional analysis is performed to determine system response to credible, less probable extreme events, to assure the system meets Seminole, FRCC, and North American Electric Reliability Corporation ("NERC") transmission planning criteria. The

additional analysis includes the loss of multiple elements, including the loss of multiple transmission circuits, transformers, generators, or the combination of each. Seminole utilizes planned operational system adjustments, corrective action plans which can include projects that require construction of new facilities or upgrades to existing facilities, and load loss if permissible by Seminole, FRCC, and NERC transmission planning reliability criteria.

Seminole's transmission planning process also includes the evaluation of multiple fault types at various locations, consistent with the criteria of FRCC and NERC, to understand the magnitude of the resultant fault current that may be experienced by Seminole's interrupting devices and to ensure that such magnitude is safely mitigated. Lastly, Seminole's transmission interconnection process evaluates critical clearing time at multiple load levels to ensure that the system is able to respond to planning and extreme events to not compromise the existing transmission system and to ensure the system remains adequate, reliable, and secure.

Typically, new generation interconnections, such as for the SCCF, are evaluated for both interconnection and deliverability simultaneously. However, because Seminole is a TDU within the FRCC region, Seminole will be required to submit separate Transmission Service Requests ("TSR") to DEF and FPL after completion of the interconnection analyses, in accordance with their respective OATTs, for the deliverability of the SCCF to Seminole's Members' load in the respective control areas in order to determine transmission impacts on the systems of FPL and DEF, in addition to any impacts on neighboring systems that may result due to the SCCF. In order to request a TSR from DEF and FPL on their respective Open Access Same Time Information Systems ("OASIS"), via the designation of network resource ("DNR") process, Seminole is required to attest it either owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service, in accordance with FERC pro-forma OATT. Thus, Seminole could not submit the TSRs in advance of the interconnection process in order to obtain estimates of the costs for

delivery of the SCCF on DEF's or FPL's systems. Consequently, when evaluating alternatives to meet its projected 2021 need, Seminole did not have alternatives to evaluate deliverability of the resource into the respective areas to determine transmission impacts on DEF, FPL and neighboring systems. Instead, Seminole was limited to evaluating the SCCF interconnection for short circuit and stability impacts, including limited steady-state load flow analysis across Seminole's own transmission system emanating from the SGS Switchyard.

In late 2016, in order to evaluate the deliverability of the SCCF with a complete steady-state load flow analysis, Seminole and the members of the FRCC Transmission Technical Subcommittee ("TTS") agreed to perform a "quasi" study to evaluate the impacts of interconnection and deliverability simultaneously, with the recognition that deliverability would need to be studied again once TSRs were submitted after the completion of the interconnection process. In order to model the deliverability of the SCCF, the power output was modeled as being delivered to the DEF control area for ultimate delivery to Seminole's Members' load in DEF's area. The "quasi" study for deliverability of the SCCF included the assumption that the two existing SGS units, Unit 1 and Unit 2, were also running at full output in addition to the SCCF.

Seminole's original interconnection evaluation of the SCCF identified the required expansion of the existing SGS Switchyard, including the addition of ten (10) new 230 kV circuit breakers and associated relay protection, and twenty (20) new circuit breaker disconnect switches. Additionally, the FRCC deliverability steady-state load flow results identified the potential need for eight upgrade projects. However, the initial FRCC deliverability study assumed that both SGS unit 1 and unit 2 were at full output in addition to the SCCF, resulting in an aggregate net output emanating from the SGS Switchyard. As Seminole performed its economic analyses for this Need Study, the study assumptions changed to include the removal from service of one existing SGS unit. This resulted in a lower net incremental difference of ~~484~~ 386 RUN MW from the existing installed capacity. This change significantly reduces the magnitude of potential

overloads associated with four of the projects originally identified, leaving only three required to be evaluated further during the TSR process.

4.1.10 Approximate Capital Costs

The estimated capital cost of the SCCF is approximately $727 million. As summarized in Table 5, this estimate includes plant structures, equipment, construction, interest during construction, and other owner's costs.

Table 5 SCCF Capital Cost Estimate

Equipment and Interconnection	$220,000,000
Development and EPC Contract	$381,000,000
Other Owner's Costs and Contingency	$ 63,000,000
Interest During Construction	$ 45,000,000
Financing	$ 1,000,000
Insurance	$ 17,000,000
TOTAL	$727,000,000

4.1.11 Construction Schedule & Projected In-Service Date

Construction activities for the SCCF are scheduled to begin in mid to late 2019 or early 2020, with targeted commercial operation approximately 36 months later. Seminole currently projects an in-service date of December 1, 2022.

4.2 PROPOSED SHADY HILLS COMBINED CYCLE FACILITY

The new SHCCF will include a new state-of-the-art natural gas-fired 573 MW (winter), one-on-one, combined cycle generating unit and onsite associated facilities. The SHCCF will be designed, constructed, owned and operated by SHEC on a portion of the existing Shady Hills power plant site located in Shady Hills, Florida, approximately 30 miles north of Tampa, Florida. A new generator tie-line will be constructed as off-site facilities required to connect the SHCCF to the DEF power grid.

The SHCCF will sell its electric capacity, energy and ancillary services to Seminole pursuant to a tolling agreement. SHEC is a wholly-owned, indirect subsidiary of GE Capital US Holdings, Inc. ("GECUSH"), which is in turn a wholly-owned, indirect subsidiary of GE. GE Energy Financial Services ("GE EFS"), a business unit of GECUSH, will design, construct, own and operate SHEC. GE EFS has over 35 years of experience managing energy assets through multiple economic cycles, and a global portfolio that spans conventional and renewable power, and oil and gas infrastructure projects. GE EFS invests globally across the capital spectrum in essential, long-lived, and capital-intensive energy assets that meet the world's energy needs.

4.2.1 Proposed CC Technology

The SHCCF will consist of one CTG, one HRSG, and one STG, and one generator GSU. The CTG will be the advanced, large-frame GE Model 7HA.02.

4.2.2 Existing Infrastructure

The SHCCF will be located adjacent to the existing Shady Hills power plant, a three-unit simple cycle power plant using GE 7F-class technology, that is owned by Shady Hills Power Company, L.L.C. ("SHPC"), which is also a wholly-owned, indirect subsidiary of GECUSH. The new combustion turbine, steam turbine and heat recovery steam generator will be installed to the east of the existing power plant on land currently controlled by SHPC.

4.2.3 Other Facilities

Other facilities to be constructed include an approximately 1 mile generator tie-line to a new DEF substation, to be designated Hudson North, that will connect the SHCCF to the DEF 230kV high voltage transmission grid in Pasco County, Florida. Additional systems to connect the SHCCF to the Pasco County Master Reuse System, and water and wastewater treatment systems to enable use of reclaimed water, including a zero-liquid discharge ("ZLD") system will also be deployed. A new gas metering station will be provided to connect to the existing gas lateral owned by FGT to the SHCCF.

4.2.4 Air Emission Controls

The SHCCF will be designed with technologies to minimize air emissions. The CTG will be equipped with dry low-NOx combustors to control NOx emissions. The HRSG will be equipped with a SCR system, to further reduce NOx emissions. Emissions of other regulated air pollutants (SO2 and PM) will be controlled through use of pipeline-quality natural gas as the only fuel fired in the CTG, HRSG, and dew point fuel heaters, and good combustion practices. In addition, the new unit will minimize GHG emissions through the use of clean-burning natural gas along with the highly efficient, combined cycle electric generating technology.

4.2.5 Water Use & Supply

Process water for the SHCCF (cooling water, demineralized water, and service water) will be sourced in the form of wastewater treatment effluent from Pasco County's Master Reuse System, of which the Shady Hills Wastewater Treatment Plant is adjacent to the SHPC site. In addition, supplemental sources may be utilized on an emergency basis in the event reclaimed or treated wastewater is not available. An onsite water treatment system will reduce the concentrations of calcium, magnesium, alkalinity, silica and suspended solids by adding hydrated lime, soda ash, ferric chloride and polymer to reduce these constituents in clarifiers. The onsite water treatment system will also include granular media filters, ultrafiltration trains and reverse osmosis ("RO") trains. Finally,

RO reject and other concentrated process wastewater streams will be treated in brine concentrators and crystallizers. These treatment processes, and the reuse of process wastewater around the site, will be used to achieve zero liquid discharge from the site. The ZLD system will generate a solid waste byproduct that will be disposed offsite.

4.2.6 Stormwater Management

A new stormwater retention system will be provided to accommodate storm water collection, treatment, storage, and discharge from the SHCCF site.

4.2.7 Fuel Type & Supply

The SHCCF will burn only natural gas as its fuel. At peak operation, including duct-firing, the new unit will require approximately 89,000 MMBtus of natural gas per day. Seminole will be responsible for the procurement and delivery of natural gas to the SHCCF. Seminole will purchase the natural gas supply for the new unit as part of its natural gas portfolio procurement program, as discussed in Section 4.1.7 above. Natural gas supply will be transported to the SHCCF via the existing FGT pipeline system. A new interconnection with FGT will be constructed to supply fuel to the SHCCF.

Seminole is finalizing negotiations with multiple entities for natural gas transportation service and/or natural gas supply for delivery to various Seminole owned and purchased power resources, including the SHCCF. Seminole anticipates that these arrangements, combined with Seminole's existing gas transportation capacity, will provide for up to 130,000 MMBtus per day of gas transportation delivery rights to the SHCCF. Part of this transportation service will come from existing Seminole capacity that will be re-purposed for the SHCCF and some transportation will be through existing capacity on the FGT system.

Seminole is finalizing its contracts for gas transportation capacity that will provide a firm transportation path from geographic locations that are expected to have adequate natural gas supply available over the horizon of the Need Study. It is anticipated that

reliable gas supply from various production basins will continue to be transported to the areas at which Seminole will have transportation rights to purchase gas supply.

4.2.8 Transmission Interconnections

The SHCCF will be interconnected to the DEF transmission system via a planned Hudson North Switching Station. GE EFS has submitted a request for Network Resource Interconnection Service through DEF's OATT process. In 2016, DEF completed a System Impact Study and a Facilities Study to identify the necessary transmission improvements to integrate the SHCCF into the DEF transmission system.

4.2.9 Tolling Agreement

SHEC and Seminole have entered into a tolling agreement, which has a term of 30-years from the anticipated commercial operation date on December 1, 2021. Under the tolling agreement, Seminole will have the right to schedule the dispatch of the SHCCF, provide fuel for such scheduled operation, and receive the power produced. The terms of the tolling agreement provide Seminole with security of power supply at a competitive price for 30 years.

4.2.10 Construction Schedule & Projected In-Service Date

Construction activities for the SHCCF are scheduled to begin in mid 2019, with targeted commercial operation approximately 30 months later. The tolling agreement calls for an in-service date of December 1, 2021.

5.0 THE NEED FOR PROPOSED GENERATING UNITS

5.1 Overview of Need Assessment

Seminole's power supply planning process begins with the development of its nine Members' load forecasts, which are aggregated to represent the Seminole load forecast. The aggregated peak demand forecasts are used to determine Member capacity requirements and an additional 15 percent of demand is added to satisfy Seminole's Reserve Margin requirement. A gap analysis is then used to identify deficiencies between forecasted requirements and current available capacity. When a deficiency is identified, Seminole evaluates all available purchased power, acquisition, and self-build alternatives to establish a portfolio that provides a cost-effective, risk-managed, and reliable generation mix to meet the needs of Seminole's Members.

5.2 The Load Forecast

Seminole's load forecast is an annual assessment of a range of information influencing electricity demand and energy growth in the nine-Member system. Seminole and its Members coordinate throughout the year to discuss forecast assumptions, past performance and ongoing developments. Each Member service territory is forecasted individually based on the unique growth characteristics of the region. The Seminole-system forecast is the aggregate of the Member system forecasts. Seminole's peak demand is the aggregate of all Member demands that maximizes the peak of the system.

Seminole produces a load forecast study which is sumitted annually to the Rural Utilities Service ("RUS") for approval. Seminole, its Members, and the RUS have consistently relied on Seminole's forecasts as the basis for power supply planning, rate development, and financial planning. The most recent load forecast study was approved by the RUS in October 2017.

5.2.1 Consumer Base

The combined service area of Seminole Members is primarily rural and extends into 42 of Florida's 67 counties. Seminole Members provide electricity to over 763,000

member-consumers, serving a population of approximately 1.6 million people and businesses. The combined service area encompasses a variety of geographic and weather conditions, as well as a diverse mix of economic activity and demographic characteristics.

The Members' member-consumer mix is approximately 89% residential, 10% commercial/industrial, and 1% "other." Residential member-consumers represent approximately 68% of total energy sales, with commercial/industrial sales representing 31%, and "other" representing 1% of sales. The commercial sector is primarily small to medium sized retail businesses, while the industrial sector is primarily manufacturing, mining and forestry. The "other" class consists of irrigation, street and highway lighting, public buildings, and sales for resale.

5.2.2 Load Forecast Methodology & Assumptions

Seminole adheres to generally accepted load forecasting methodologies currently employed in the electric utility industry. Energy and demand is forecasted by Member-system total and the Seminole forecast is the aggregate of all Member forecasts.

Model inputs and assumptions are collected from Members, government agencies, universities, and other third party providers. The primary resource for forecasting load growth is population and Seminole primarily relies on the University of Florida's Bureau of Economic and Business Research for population forecasts. Additional economic and demographic data employed in the forecast models are collected from Moody's Analytics, Inc. Weather data is collected from AccuWeather for 25 stations and normalized weather assumptions are based on 30 years of historical observations. Seminole implements statistically adjusted end-use methods to reflect historical and forecasted trends in appliance stock saturation and efficiency for all rate class sectors.

5.2.3 Energy and Demand Models

Seminole forecasts monthly energy sales at the Member-total and Member-rate class level with econometric models. Delivery point billing load and Member-rate class

sales to end-use member-consumers grossed up for distribution losses are trained with a variety of explanatory variables in order to estimate future growth.

Maximum demand by Member by month and by season are modeled using econometric models. Winter seasonal peak models regress the highest peak during November through March of each year against contemporaneous explanatory variables. Summer seasonal peak models regress the highest peak from April through September of each year against contemporaneous explanatory variables. Seasonal peak forecasts replace monthly model forecast results for the month each seasonal peak is most likely to occur.

Seminole's maximum demand is the aggregate of the one-hour simultaneous demands of all Members that maximizes the peak of the system by month. Forecasts of Seminole maximum demand are derived by applying coincident factors to Member-maximum demand forecasts. Member demand coincident with Seminole represents Seminole's planning capacity.

5.2.4 Historical Trends and Forecast Results

Tables 6 through 13 provide Seminole's history and forecast of number of consumers, usage-per consumer and end-use sales by rate class and in total. Tables 14 and 15 provide historical and forecasted net energy for load, summer peak demand, and winter peak demand. These figures update the projections presented in Seminole's 2017 Ten Year Site Plan, which is provided as Appendix A to this Need Study. For comparison purposes, these tables are presented with and without Lee County Electric Cooperative ("LCEC") included in historical data. Prior to 2014, Seminole Electric Cooperative was a ten-Member system, which included LCEC. Tables 6 through 15 also include five and ten-year historical and forecasted average annual growth rates ("AAGR").

Seminole also prepared "high" and "low" load forecasts for use in sensivity analyses as part of the economic evaluations discussed in Section 6.5 below. These "high" and "low" load forecasts are also provided in Tables 14 and 15.

Table 6

Residential Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	803,957	-	-	14,235	-	-	11,444	-	-
2008	808,926	*4,969*	*0.6*	13,727	*-508*	*-3.6*	11,104	*-340*	*-3.0*
2009	811,767	*2,841*	*0.4*	13,912	*185*	*1.4*	11,293	*190*	*1.7*
2010	761,993	*-49,774*	*-6.1*	14,920	*1,008*	*7.2*	11,369	*75*	*0.7*
2011	765,279	*3,286*	*0.4*	13,605	*-1,315*	*-8.8*	10,412	*-957*	*-8.4*
2012	769,591	*4,312*	*0.6*	12,967	*-638*	*-4.7*	9,979	*-433*	*-4.2*
2013	777,493	*7,902*	*1.0*	12,885	*-82*	*-0.6*	10,018	*39*	*0.4*
2014	662,626	*-114,867*	*-14.8*	13,293	*408*	*3.2*	8,808	*-1,210*	*-12.1*
2015	673,215	*10,589*	*1.6*	13,470	*177*	*1.3*	9,068	*260*	*3.0*
2016	683,672	*10,458*	*1.6*	13,618	*149*	*1.1*	9,310	*242*	*2.7*
Forecast									
2017	692,985	*9,313*	*1.4*	13,034	*-585*	*-4.3*	9,032	*-278*	*-3.0*
2018	703,726	*10,741*	*1.5*	13,287	*253*	*1.9*	9,351	*318*	*3.5*
2019	715,007	*11,281*	*1.6*	13,283	*-4*	*0.0*	9,497	*147*	*1.6*
2020	726,600	*11,593*	*1.6*	13,120	*-162*	*-1.2*	9,533	*36*	*0.4*
2021	737,810	*11,209*	*1.5*	13,047	*-73*	*-0.6*	9,626	*93*	*1.0*
2022	748,714	*10,904*	*1.5*	13,031	*-16*	*-0.1*	9,757	*130*	*1.4*
2023	759,586	*10,872*	*1.5*	13,033	*2*	*0.0*	9,900	*143*	*1.5*
2024	770,385	*10,800*	*1.4*	13,029	*-5*	*0.0*	10,037	*137*	*1.4*
2025	780,806	*10,420*	*1.4*	13,018	*-11*	*-0.1*	10,164	*127*	*1.3*
2026	790,745	*9,939*	*1.3*	13,023	*5*	*0.0*	10,298	*134*	*1.3*
2027	800,299	*9,554*	*1.2*	13,037	*14*	*0.1*	10,433	*136*	*1.3*
AAGR '07-'16			*-1.8*			*-0.5*			*-2.3*
AAGR '12-'16			*-2.9*			*1.2*			*-1.7*
AAGR '18-'22			*1.6*			*-0.5*			*1.1*
AAGR '18-'27			*1.4*			*-0.2*			*1.2*

Note: Estimated-Actual data through February 2017

Table 7

Residential Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	627,934	-	-	14,329	-	-	8,998	-	-
2008	633,384	*5,450*	*0.9*	13,871	*-457*	*-3.2*	8,786	*-212*	*-2.4*
2009	635,862	*2,478*	*0.4*	14,043	*171*	*1.2*	8,929	*143*	*1.6*
2010	639,640	*3,778*	*0.6*	15,147	*1,105*	*7.9*	9,689	*760*	*8.5*
2011	642,853	*3,214*	*0.5*	13,653	*-1,494*	*-9.9*	8,777	*-912*	*-9.4*
2012	646,830	*3,976*	*0.6*	13,021	*-632*	*-4.6*	8,423	*-354*	*-4.0*
2013	653,820	*6,990*	*1.1*	12,929	*-93*	*-0.7*	8,453	*30*	*0.4*
2014	662,626	*8,806*	*1.3*	13,293	*364*	*2.8*	8,808	*355*	*4.2*
2015	673,215	*10,589*	*1.6*	13,470	*177*	*1.3*	9,068	*260*	*3.0*
2016	683,672	*10,458*	*1.6*	13,618	*149*	*1.1*	9,310	*242*	*2.7*
Forecast									
2017	692,985	*9,313*	*1.4*	13,034	*-585*	*-4.3*	9,032	*-278*	*-3.0*
2018	703,726	*10,741*	*1.5*	13,287	*253*	*1.9*	9,351	*318*	*3.5*
2019	715,007	*11,281*	*1.6*	13,283	*-4*	*0.0*	9,497	*147*	*1.6*
2020	726,600	*11,593*	*1.6*	13,120	*-162*	*-1.2*	9,533	*36*	*0.4*
2021	737,810	*11,209*	*1.5*	13,047	*-73*	*-0.6*	9,626	*93*	*1.0*
2022	748,714	*10,904*	*1.5*	13,031	*-16*	*-0.1*	9,757	*130*	*1.4*
2023	759,586	*10,872*	*1.5*	13,033	*2*	*0.0*	9,900	*143*	*1.5*
2024	770,385	*10,800*	*1.4*	13,029	*-5*	*0.0*	10,037	*137*	*1.4*
2025	780,806	*10,420*	*1.4*	13,018	*-11*	*-0.1*	10,164	*127*	*1.3*
2026	790,745	*9,939*	*1.3*	13,023	*5*	*0.0*	10,298	*134*	*1.3*
2027	800,299	*9,554*	*1.2*	13,037	*14*	*0.1*	10,433	*136*	*1.3*
AAGR '07-'16			*0.9*			*-0.6*			*0.4*
AAGR '12-'16			*1.4*			*1.1*			*2.5*
AAGR '18-'22			*1.6*			*-0.5*			*1.1*
AAGR '18-'27			*1.4*			*-0.2*			*1.2*

Note: Estimated-Actual data through February 2017

Table 8

Commercial Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	88,306	-	-	54,798	-	-	4,839	-	-
2008	86,121	*-2,185*	*-2.5*	56,827	*2,029*	*3.7*	4,894	*55*	*1.1*
2009	84,318	*-1,803*	*-2.1*	56,643	*-184*	*-0.3*	4,776	*-117*	*-2.4*
2010	78,788	*-5,530*	*-6.6*	57,433	*790*	*1.4*	4,525	*-252*	*-5.3*
2011	78,828	*40*	*0.1*	55,386	*-2,047*	*-3.6*	4,366	*-158*	*-3.5*
2012	80,598	*1,770*	*2.2*	55,287	*-99*	*-0.2*	4,456	*90*	*2.1*
2013	82,302	*1,704*	*2.1*	54,458	*-829*	*-1.5*	4,482	*26*	*0.6*
2014	72,632	*-9,670*	*-11.7*	55,086	*628*	*1.2*	4,001	*-481*	*-10.7*
2015	73,290	*658*	*0.9*	56,689	*1,603*	*2.9*	4,155	*154*	*3.8*
2016	74,411	*1,121*	*1.5*	57,940	*1,251*	*2.2*	4,311	*156*	*3.8*
Forecast									
2017	75,712	*1,301*	*1.7*	57,536	*-405*	*-0.7*	4,356	*45*	*1.0*
2018	76,926	*1,214*	*1.6*	57,406	*-130*	*-0.2*	4,416	*60*	*1.4*
2019	78,101	*1,176*	*1.5*	57,438	*32*	*0.1*	4,486	*70*	*1.6*
2020	79,168	*1,067*	*1.4*	57,737	*299*	*0.5*	4,571	*85*	*1.9*
2021	80,176	*1,008*	*1.3*	58,000	*263*	*0.5*	4,650	*79*	*1.7*
2022	81,283	*1,107*	*1.4*	58,295	*294*	*0.5*	4,738	*88*	*1.9*
2023	82,427	*1,144*	*1.4*	58,527	*232*	*0.4*	4,824	*86*	*1.8*
2024	83,450	*1,023*	*1.2*	58,766	*239*	*0.4*	4,904	*80*	*1.7*
2025	84,426	*975*	*1.2*	59,009	*243*	*0.4*	4,982	*78*	*1.6*
2026	85,366	*941*	*1.1*	59,302	*293*	*0.5*	5,062	*81*	*1.6*
2027	86,268	*902*	*1.1*	59,602	*300*	*0.5*	5,142	*79*	*1.6*
AAGR '07-'16			*-1.9*			*0.6*			*-1.3*
AAGR '12-'16			*-2.0*			*1.2*			*-0.8*
AAGR '18-'22			*1.4*			*0.4*			*1.8*
AAGR '18-'27			*1.3*			*0.4*			*1.7*

Note: Estimated-Actual data through February 2017

Table 9

Commercial Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	67,898	-	-	55,757	-	-	3,786	-	-
2008	68,703	*805*	*1.2*	55,814	*58*	*0.1*	3,835	*49*	*1.3*
2009	67,704	*-999*	*-1.5*	54,899	*-915*	*-1.6*	3,717	*-118*	*-3.1*
2010	67,552	*-151*	*-0.2*	57,588	*2,689*	*4.9*	3,890	*173*	*4.7*
2011	67,755	*202*	*0.3*	54,597	*-2,991*	*-5.2*	3,699	*-191*	*-4.9*
2012	69,287	*1,532*	*2.3*	55,154	*556*	*1.0*	3,821	*122*	*3.3*
2013	71,094	*1,807*	*2.6*	54,390	*-764*	*-1.4*	3,867	*45*	*1.2*
2014	72,632	*1,538*	*2.2*	55,086	*696*	*1.3*	4,001	*134*	*3.5*
2015	73,290	*658*	*0.9*	56,689	*1,603*	*2.9*	4,155	*154*	*3.8*
2016	74,411	*1,121*	*1.5*	57,940	*1,251*	*2.2*	4,311	*156*	*3.8*
Forecast									
2017	75,712	*1,301*	*1.7*	57,536	*-405*	*-0.7*	4,356	*45*	*1.0*
2018	76,926	*1,214*	*1.6*	57,406	*-130*	*-0.2*	4,416	*60*	*1.4*
2019	78,101	*1,176*	*1.5*	57,438	*32*	*0.1*	4,486	*70*	*1.6*
2020	79,168	*1,067*	*1.4*	57,737	*299*	*0.5*	4,571	*85*	*1.9*
2021	80,176	*1,008*	*1.3*	58,000	*263*	*0.5*	4,650	*79*	*1.7*
2022	81,283	*1,107*	*1.4*	58,295	*294*	*0.5*	4,738	*88*	*1.9*
2023	82,427	*1,144*	*1.4*	58,527	*232*	*0.4*	4,824	*86*	*1.8*
2024	83,450	*1,023*	*1.2*	58,766	*239*	*0.4*	4,904	*80*	*1.7*
2025	84,426	*975*	*1.2*	59,009	*243*	*0.4*	4,982	*78*	*1.6*
2026	85,366	*941*	*1.1*	59,302	*293*	*0.5*	5,062	*81*	*1.6*
2027	86,268	*902*	*1.1*	59,602	*300*	*0.5*	5,142	*79*	*1.6*
AAGR '07-'16			*1.0*			*0.4*			*1.5*
AAGR '12-'16			*1.8*			*1.2*			*3.1*
AAGR '18-'22			*1.4*			*0.4*			*1.8*
AAGR '18-'27			*1.3*			*0.4*			*1.7*

Note: Estimated-Actual data through February 2017

Table 10

Other Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	5,150	-	-	31,960	-	-	165	-	-
2008	5,075	-75	-1.5	32,098	138	0.4	163	-2	-1.0
2009	5,036	-39	-0.8	33,085	987	3.1	167	4	2.3
2010	4,956	-80	-1.6	31,896	-1,189	-3.6	158	-9	-5.1
2011	4,954	-2	0.0	32,255	359	1.1	160	2	1.1
2012	4,818	-136	-2.7	34,080	1,825	5.7	164	4	2.8
2013	5,185	367	7.6	32,022	-2,058	-6.0	166	2	1.1
2014	5,308	123	2.4	28,449	-3,573	-11.2	151	-15	-9.1
2015	5,343	35	0.7	28,262	-187	-0.7	151	0	0.0
2016	5,384	42	0.8	28,162	-100	-0.4	152	1	0.4
Forecast									
2017	5,428	44	0.8	25,357	-2,805	-10.0	138	-14	-9.2
2018	5,455	27	0.5	24,887	-470	-1.9	136	-2	-1.4
2019	5,475	20	0.4	24,534	-353	-1.4	134	-1	-1.1
2020	5,497	22	0.4	24,099	-435	-1.8	132	-2	-1.4
2021	5,524	27	0.5	23,855	-243	-1.0	132	-1	-0.5
2022	5,553	29	0.5	23,708	-147	-0.6	132	0	-0.1
2023	5,579	25	0.5	23,596	-112	-0.5	132	0	0.0
2024	5,603	25	0.4	23,492	-104	-0.4	132	0	0.0
2025	5,628	24	0.4	23,379	-113	-0.5	132	0	-0.1
2026	5,650	23	0.4	23,303	-76	-0.3	132	0	0.1
2027	5,671	21	0.4	23,247	-56	-0.2	132	0	0.1
AAGR '07-'16			0.5			-1.4			-0.9
AAGR '12-'16			2.8			-4.7			-2.0
AAGR '18-'22			0.4			-1.2			-0.8
AAGR '18-'27			0.4			-0.8			-0.3

Note: Estimated-Actual data through February 2017

Table 11

Other Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	5,098	-	-	26,761	-	-	136	-	-
2008	5,019	-79	-1.5	26,514	-247	-0.9	133	-3	-2.5
2009	4,982	-37	-0.7	27,465	951	3.6	137	4	2.8
2010	4,966	-16	-0.3	27,693	228	0.8	138	1	0.5
2011	4,878	-88	-1.8	28,442	749	2.7	139	1	0.9
2012	4,940	61	1.3	29,287	845	3.0	145	6	4.3
2013	5,047	107	2.2	29,044	-244	-0.8	147	2	1.3
2014	5,308	261	5.2	28,449	-595	-2.0	151	4	3.0
2015	5,343	35	0.7	28,262	-187	-0.7	151	0	0.0
2016	5,384	42	0.8	28,162	-100	-0.4	152	1	0.4
Forecast									
2017	5,428	44	0.8	25,357	-2,805	-10.0	138	-14	-9.2
2018	5,455	27	0.5	24,887	-470	-1.9	136	-2	-1.4
2019	5,475	20	0.4	24,534	-353	-1.4	134	-1	-1.1
2020	5,497	22	0.4	24,099	-435	-1.8	132	-2	-1.4
2021	5,524	27	0.5	23,855	-243	-1.0	132	-1	-0.5
2022	5,553	29	0.5	23,708	-147	-0.6	132	0	-0.1
2023	5,579	25	0.5	23,596	-112	-0.5	132	0	0.0
2024	5,603	25	0.4	23,492	-104	-0.4	132	0	0.0
2025	5,628	24	0.4	23,379	-113	-0.5	132	0	-0.1
2026	5,650	23	0.4	23,303	-76	-0.3	132	0	0.1
2027	5,671	21	0.4	23,247	-56	-0.2	132	0	0.1
AAGR '07-'16			0.6			0.6			1.2
AAGR '12-'16			2.2			-1.0			1.2
AAGR '18-'22			0.4			-1.2			-0.8
AAGR '18-'27			0.4			-0.8			-0.3

Note: Estimated-Actual data through February 2017

Table 12

Total Consumers & Sales

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	897,413	-	-	18,328	-	-	16,448	-	-
2008	900,122	*2,709*	*0.3*	17,954	*-374*	*-2.0*	16,161	*-287*	*-1.7*
2009	901,121	*999*	*0.1*	18,018	*64*	*0.4*	16,236	*75*	*0.5*
2010	845,737	*-55,384*	*-6.1*	18,979	*961*	*5.3*	16,052	*-185*	*-1.1*
2011	849,061	*3,324*	*0.4*	17,594	*-1,386*	*-7.3*	14,938	*-1,113*	*-6.9*
2012	855,007	*5,946*	*0.7*	17,074	*-519*	*-3.0*	14,599	*-339*	*-2.3*
2013	864,980	*9,973*	*1.2*	16,956	*-119*	*-0.7*	14,666	*67*	*0.5*
2014	740,566	*-124,414*	*-14.4*	17,500	*545*	*3.2*	12,960	*-1,706*	*-11.6*
2015	751,848	*11,282*	*1.5*	17,788	*288*	*1.6*	13,374	*414*	*3.2*
2016	763,467	*11,620*	*1.5*	18,041	*252*	*1.4*	13,773	*399*	*3.0*
Forecast									
2017	774,126	*10,658*	*1.4*	17,473	*-568*	*-3.1*	13,526	*-248*	*-1.8*
2018	786,107	*11,982*	*1.5*	17,685	*212*	*1.2*	13,902	*376*	*2.8*
2019	798,584	*12,476*	*1.6*	17,678	*-7*	*0.0*	14,118	*215*	*1.5*
2020	811,265	*12,682*	*1.6*	17,549	*-130*	*-0.7*	14,237	*119*	*0.8*
2021	823,510	*12,245*	*1.5*	17,496	*-53*	*-0.3*	14,408	*172*	*1.2*
2022	835,550	*12,040*	*1.5*	17,506	*9*	*0.1*	14,627	*218*	*1.5*
2023	847,591	*12,041*	*1.4*	17,527	*22*	*0.1*	14,856	*229*	*1.6*
2024	859,439	*11,848*	*1.4*	17,538	*11*	*0.1*	15,073	*217*	*1.5*
2025	870,859	*11,420*	*1.3*	17,543	*5*	*0.0*	15,278	*205*	*1.4*
2026	881,761	*10,902*	*1.3*	17,569	*26*	*0.1*	15,492	*214*	*1.4*
2027	892,238	*10,477*	*1.2*	17,604	*35*	*0.2*	15,707	*215*	*1.4*
AAGR '07-'16			*-1.8*			*-0.2*			*-2.0*
AAGR '12-'16			*-2.8*			*1.4*			*-1.4*
AAGR '18-'22			*1.5*			*-0.3*			*1.3*
AAGR '18-'27			*1.4*			*-0.1*			*1.4*

Note: Estimated-Actual data through February 2017

Table 13

Total Consumers & Sales

Excluding Lee County Electric Cooperative

Year	Average Number of Customers	Change	Growth (%)	Average Consumption Per Customer (kWh)	Change	Growth (%)	Sales (GWh)	Change	Growth (%)
History									
2007	700,930	-	-	18,432	-	-	12,920	-	-
2008	707,106	*6,176*	*0.9*	18,036	*-396*	*-2.1*	12,754	*-166*	*-1.3*
2009	708,548	*1,442*	*0.2*	18,041	*5*	*0.0*	12,783	*29*	*0.2*
2010	712,159	*3,610*	*0.5*	19,260	*1,220*	*6.8*	13,716	*934*	*7.3*
2011	715,486	*3,328*	*0.5*	17,631	*-1,629*	*-8.5*	12,615	*-1,101*	*-8.0*
2012	721,056	*5,570*	*0.8*	17,181	*-450*	*-2.6*	12,389	*-226*	*-1.8*
2013	729,961	*8,905*	*1.2*	17,078	*-103*	*-0.6*	12,466	*78*	*0.6*
2014	740,566	*10,605*	*1.5*	17,500	*422*	*2.5*	12,960	*494*	*4.0*
2015	751,848	*11,282*	*1.5*	17,788	*288*	*1.6*	13,374	*414*	*3.2*
2016	763,467	*11,620*	*1.5*	18,041	*252*	*1.4*	13,773	*399*	*3.0*
Forecast									
2017	774,126	*10,658*	*1.4*	17,473	*-568*	*-3.1*	13,526	*-248*	*-1.8*
2018	786,107	*11,982*	*1.5*	17,685	*212*	*1.2*	13,902	*376*	*2.8*
2019	798,584	*12,476*	*1.6*	17,678	*-7*	*0.0*	14,118	*215*	*1.5*
2020	811,265	*12,682*	*1.6*	17,549	*-130*	*-0.7*	14,237	*119*	*0.8*
2021	823,510	*12,245*	*1.5*	17,496	*-53*	*-0.3*	14,408	*172*	*1.2*
2022	835,550	*12,040*	*1.5*	17,506	*9*	*0.1*	14,627	*218*	*1.5*
2023	847,591	*12,041*	*1.4*	17,527	*22*	*0.1*	14,856	*229*	*1.6*
2024	859,439	*11,848*	*1.4*	17,538	*11*	*0.1*	15,073	*217*	*1.5*
2025	870,859	*11,420*	*1.3*	17,543	*5*	*0.0*	15,278	*205*	*1.4*
2026	881,761	*10,902*	*1.3*	17,569	*26*	*0.1*	15,492	*214*	*1.4*
2027	892,238	*10,477*	*1.2*	17,604	*35*	*0.2*	15,707	*215*	*1.4*
AAGR '07-'16			*1.0*			*-0.2*			*0.7*
AAGR '12-'16			*1.4*			*1.2*			*2.7*
AAGR '18-'22			*1.5*			*-0.3*			*1.3*
AAGR '18-'27			*1.4*			*-0.1*			*1.4*

Note: Estimated-Actual data through February 2017

Table 14
Annual Net Energy for Load and Seasonal Net Firm Demand

Net Energy for Load				Summer Net Firm Demand				Winter Net Firm Demand			
Year	Base (GWh)	Low (GWh)	High (GWh)	Year	Base (MW)	Low (MW)	High (MW)	Year	Base (MW)	Low (MW)	High (MW)
History				*History*				*History*			
2007	17,669	-	-	2007	3,839	-	-	2007/2008	4,221	-	-
2008	17,332	-	-	2008	3,630	-	-	2008/2009	4,738	-	-
2009	17,453	-	-	2009	3,824	-	-	2009/2010	5,047	-	-
2010	17,346	-	-	2010	3,548	-	-	2010/2011	4,315	-	-
2011	16,037	-	-	2011	3,653	-	-	2011/2012	3,918	-	-
2012	15,769	-	-	2012	3,428	-	-	2012/2013	3,707	-	-
2013	15,812	-	-	2013	3,566	-	-	2013/2014	3,240	-	-
2014	13,854	-	-	2014	3,088	-	-	2014/2015	3,593	-	-
2015	14,104	-	-	2015	3,021	-	-	2015/2016	3,307	-	-
2016	14,471	-	-	2016	3,243	-	-	2016/2017	3,018	-	-
Forecast				*Forecast*				*Forecast*			
2017	14,125~~14,165~~	13,648~~13,814~~	14,770 ~~15,192~~	2017	3,090	2,974	3,176	2017/2018	3,398	3,063	3,856
2018	14,601~~14,655~~	13,903~~13,954~~	15,577 ~~15,635~~	2018	3,140	3,025	3,228	2018/2019	3,466	3,131	3,922
2019	14,820~~14,875~~	14,124~~14,176~~	15,795 ~~15,854~~	2019	3,187	3,074	3,274	2019/2020	3,531	3,200	3,985
2020	14,948~~15,023~~	14,252~~14,325~~	15,918 ~~15,997~~	2020	3,238	3,124	3,325	2020/2021	3,588	3,258	4,038
2021	15,094~~15,125~~	14,403~~14,432~~	16,064 ~~16,096~~	2021	3,251	3,153	3,354	2021/2022	3,643	3,314	4,091
2022	15,306~~15,337~~	14,615~~14,644~~	16,273 ~~16,306~~	2022	3,297	3,198	3,399	2022/2023	3,699	3,371	4,145
2023	15,543~~15,574~~	14,851~~14,881~~	16,508 ~~16,541~~	2023	3,343	3,245	3,446	2023/2024	3,749	3,422	4,194
2024	15,774~~15,805~~	15,081~~15,112~~	16,737 ~~16,770~~	2024	3,388	3,290	3,489	2024/2025	3,802	3,477	4,244
2025	15,990~~16,022~~	15,297~~15,328~~	16,950 ~~16,984~~	2025	3,430	3,333	3,533	2025/2026	3,857	3,532	4,298
2026	16,216~~16,249~~	15,524~~15,556~~	17,175 ~~17,209~~	2026	3,474	3,375	3,577	2026/2027	3,909	3,586	4,351
2027	16,437~~16,470~~	15,745~~15,777~~	17,394 ~~17,429~~	2027	3,516	3,417	3,619	2027/2028	3,955	3,633	4,397
AAGR '07-'16	*-2.2*	*-*	*-*	*AAGR '07-'16*	*-1.9*	*-*	*-*	*AAGR '08-'17*	*-3.7*	*-*	*-*
AAGR '12-'16	*-2.1*	*-*	*-*	*AAGR '12-'16*	*-1.4*	*-*	*-*	*AAGR '13-'17*	*-5.0*	*-*	*-*
AAGR '18-'22	*1.2~~1.1~~*	*1.3~~1.2~~*	*1.1*	*AAGR '18-'22*	*1.2*	*1.4*	*1.3*	*AAGR '18-'22*	*1.8*	*2.0*	*1.5*
AAGR '18-'27	*1.3*	*1.4*	*1.2*	*AAGR '18-'27*	*1.3*	*1.4*	*1.3*	*AAGR '18-'27*	*1.6*	*1.8*	*1.4*

Table 15
Annual Net Energy for Load and Seasonal Net Firm Demand
Excluding Lee County Electric Cooperative

Net Energy for Load				Summer Net Firm Demand				Winter Net Firm Demand			
Year	Base (GWh)	Low (GWh)	High (GWh)	Year	Base (MW)	Low (MW)	High (MW)	Year	Base (MW)	Low (MW)	High (MW)
History				*History*				*History*			
2007	13,729	-	-	2007	3,060	-	-	2007/2008	3,343	-	-
2008	13,567	-	-	2008	2,915	-	-	2008/2009	3,817	-	-
2009	13,659	-	-	2009	3,064	-	-	2009/2010	4,224	-	-
2010	14,658	-	-	2010	3,011	-	-	2010/2011	3,685	-	-
2011	13,502	-	-	2011	3,121	-	-	2011/2012	3,383	-	-
2012	13,256	-	-	2012	2,890	-	-	2012/2013	3,229	-	-
2013	13,302	-	-	2013	3,012	-	-	2013/2014	3,240	-	-
2014	13,854	-	-	2014	3,088	-	-	2014/2015	3,593	-	-
2015	14,104	-	-	2015	3,021	-	-	2015/2016	3,307	-	-
2016	14,471	-	-	2016	3,243	-	-	2016/2017	3,018	-	-
Forecast				*Forecast*				*Forecast*			
2017	14,125~~14,165~~	13,648~~13,814~~	14,770 ~~15,192~~	2017	3,090	2,974	3,176	2017/2018	3,398	3,063	3,856
2018	14,601~~14,655~~	13,903~~13,954~~	15,577 ~~15,635~~	2018	3,140	3,025	3,228	2018/2019	3,466	3,131	3,922
2019	14,820~~14,875~~	14,124~~14,176~~	15,795 ~~15,854~~	2019	3,187	3,074	3,274	2019/2020	3,531	3,200	3,985
2020	14,948~~15,023~~	14,252~~14,325~~	15,918 ~~15,997~~	2020	3,238	3,124	3,325	2020/2021	3,588	3,258	4,038
2021	15,094~~15,125~~	14,403~~14,432~~	16,064 ~~16,096~~	2021	3,251	3,153	3,354	2021/2022	3,643	3,314	4,091
2022	15,306~~15,337~~	14,615~~14,644~~	16,273 ~~16,306~~	2022	3,297	3,198	3,399	2022/2023	3,699	3,371	4,145
2023	15,543~~15,574~~	14,851~~14,881~~	16,508 ~~16,541~~	2023	3,343	3,245	3,446	2023/2024	3,749	3,422	4,194
2024	15,774~~15,805~~	15,081~~15,112~~	16,737 ~~16,770~~	2024	3,388	3,290	3,489	2024/2025	3,802	3,477	4,244
2025	15,990~~16,022~~	15,297~~15,328~~	16,950 ~~16,984~~	2025	3,430	3,333	3,533	2025/2026	3,857	3,532	4,298
2026	16,216~~16,249~~	15,524~~15,556~~	17,175 ~~17,209~~	2026	3,474	3,375	3,577	2026/2027	3,909	3,586	4,351
2027	16,437~~16,470~~	15,745~~15,777~~	17,394 ~~17,429~~	2027	3,516	3,417	3,619	2027/2028	3,955	3,633	4,397
AAGR '07-'16	*0.6*	*-*	*-*	*AAGR '07-'16*	*0.6*	*-*	*-*	*AAGR '08-'17*	*-1.1*	*-*	*-*
AAGR '12-'16	*2.2*	*-*	*-*	*AAGR '12-'16*	*2.9*	*-*	*-*	*AAGR '13-'17*	*-1.7*	*-*	*-*
AAGR '18-'22	*1.2~~1.1~~*	*1.3~~1.2~~*	*1.1*	*AAGR '18-'22*	*1.2*	*1.4*	*1.3*	*AAGR '18-'22*	*1.8*	*2.0*	*1.5*
AAGR '18-'27	*1.3*	*1.4*	*1.2*	*AAGR '18-'27*	*1.3*	*1.4*	*1.3*	*AAGR '18-'27*	*1.6*	*1.8*	*1.4*

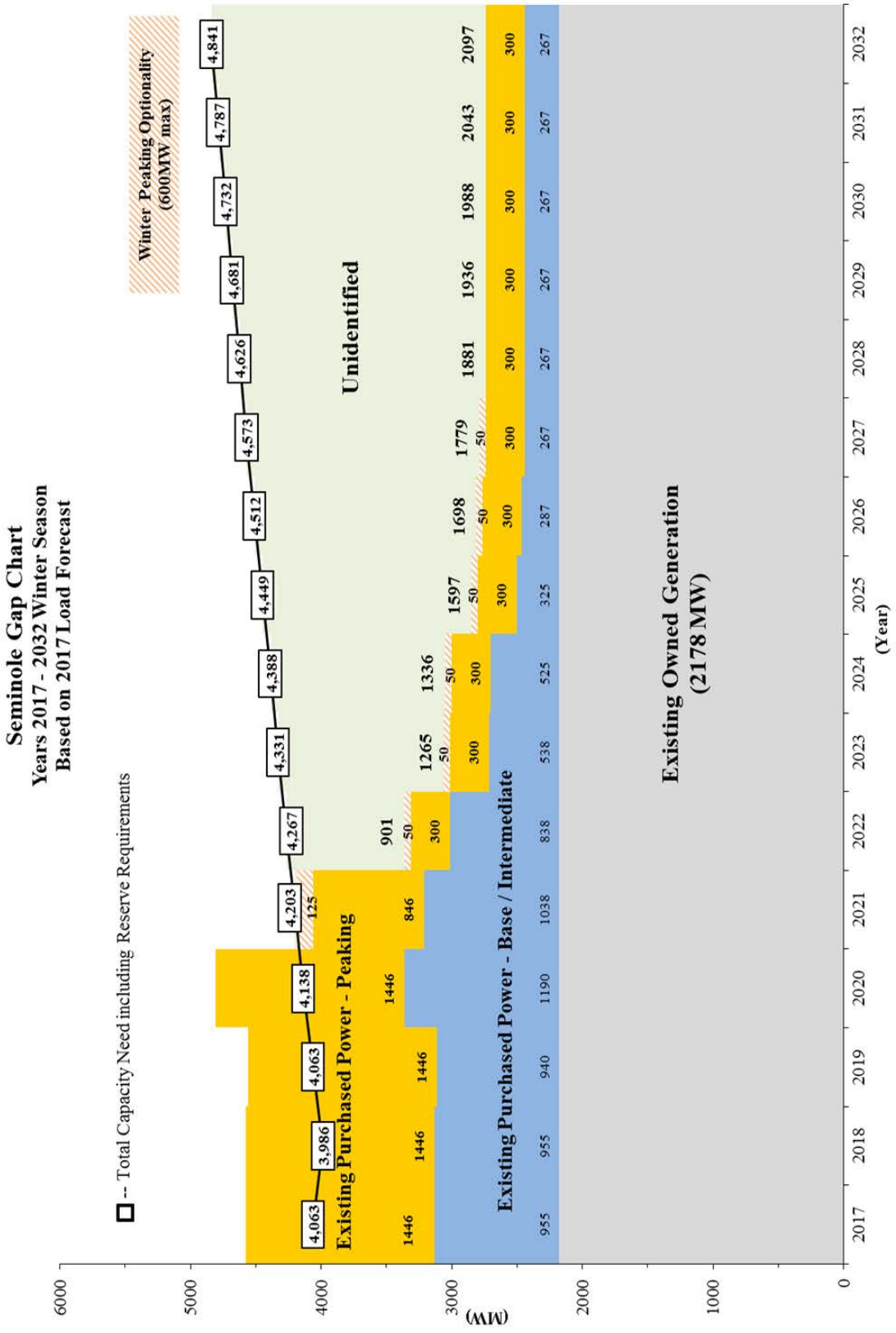
5.3 Seminole's Reliability Criteria

The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and its reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages; and to account for load forecast uncertainty. Seminole's reliability criteria include a Reserve Margin criterion of 15 percent and a Loss of Load Probability ("LOLP") criterion of one day in 10 years. The Reserve Margin is a percentage of the load forecast peak demand and is the additional amount of capacity that a utility maintains above the load forecast peak demand. The Reserve Margin considers only the peak demand versus the amount of generation resources, but the LOLP criterion takes into account load shape, unit sizes, unit availability, and capacity mix when calculating the probability of a utility not adequately meeting load. These reliability criteria help to ensure that Seminole has adequate generating capacity to provide reliable service to its Members and to limit Seminole's emergency purchases from interconnected, neighboring systems.

5.4 Seminole's Capacity Needs

By the end of 2021, Seminole will need 901 MW of generation to meet its Members' energy needs along with its Reserve Margin requirements. That need will grow to 1,265 MW by the end of 2022. Seminole's future capacity need results primarily from the expiration of PPAs, starting with the expiration of 150 MW from DEF on December 31, 2020, followed by expiration of 200 MW from FPL on May 31, 2021, and another for Southern Company's Oleander plant, which includes capacity ratings of 550 MW winter and 460 MW summer. In total, Seminole will lose 900 MW of purchased power resources by the end of 2021, followed by the loss of an additional 300 MW PPA with DEF in 2022. Figure 6 is a "gap chart" showing Seminole's projected winter season need through 2032.

Figure 6 "Gap Chart" summarizing Seminole's Projected Need



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6.0 EVALUATION OF MAJOR GENERATING ALTERNATIVES

6.1 Overview of Evaluation Process

Seminole conducted a multi-stage process for evaluating resource alternatives to meet its projected capacity need. The process began over two years ago when Seminole first determined which self-build alternatives would be evaluated. Seminole then issued an RFP into the market for firm capacity and received a robust response. Seminole then performed economic and risk evaluations on all available alternatives and developed portfolios of generation resources to fulfill Seminole's need. The recommended portfolio, which includes the SCCF and SHCCF, was submitted to Seminole's Board of Trustees and was unanimously approved on September 27, 2017.

6.2 Self-Build Alternatives Considered

6.2.1 Technology Assessment

Due to the high costs and regulatory uncertainties associated with new nuclear and coal-fired generation, Seminole limited its analysis of self-build alternatives to natural gas-fired generation. Seminole retained Black and Veatch, a global engineering, procurement and construction company, to help evaluate numerous power generation technologies as potential future resources prior to selecting the advanced class gas turbine technologies incorporated in the SCCF. Combined cycle technology was selected because the high fuel efficiency and flexible dispatch capability offered by these systems will allow the SCCF to match varying system load at a low cost and with limited environmental impact. Seminole selected state-of-the-art "advanced class" gas turbine technology coupled with flexible operation heat recovery steam generators and an associated steam turbine as the most cost-effective risk-managed self-build option. Seminole initiated a power island equipment purchase bidding process followed by an Engineer, Procure, Construct ("EPC") services bidding process to develop accurate self-build cost estimates which would then compete with market alternatives.

Seminole evaluated several different technologies from three different vendors, General Electric, Mitsubishi Hitachi, and Siemens. Upon completion of the initial screening, Seminole issued an RFP in February 2016 to three vendors; two of which, General Electric and Mitsubishi, responded with compliant bids. Both of these vendors submitted two proposals; one for a 1x1 unit and the second for a 2x1 unit. All four units were evaluated along with the market alternatives**.** Seminole ultimately determined that the GE technology was the most economic option.

6.2.2 Site Assessment

In order to fully evaluate potential self-build site location options, Seminole retained a third party environmental consultant to assess the environmental licensing considerations associated with locating new generation facilities at two potential sites owned by Seminole: the site adjacent to SGS in Putnam County and another 586-acre site in Gilchrist County. Informed by the results of that study and subsequent information, Seminole retained Black & Veatch, a global engineering firm, to evaluate the SGS site versus the Gilchrist site using a comparative analysis that utilized the following intangible criteria:

- Land Use/Ownership
- Site Development
- Electrical Transmission
- Fuel Supply
- Water Supply
- Waste Water
- Environmental Assessment
- Transportation
- Technology Selection
- Schedule

Based on the comparative analysis, the SGS site scored substantially better than the Gilchrist site for a combined cycle facility. In particular, the Gilchrist site posed

significant issues relative to water availability and wastewater discharge options. In addition, the SGS site is a brownfield site with capability of utilizing existing water intake, water discharge, and electrical transmission infrastructure. Overall, the SGS site has significant economic and strategic advantages for siting a combined cycle facility.

6.3 Purchase Power Alternatives Considered

6.3.1 The Requests for Proposals ("RFP")

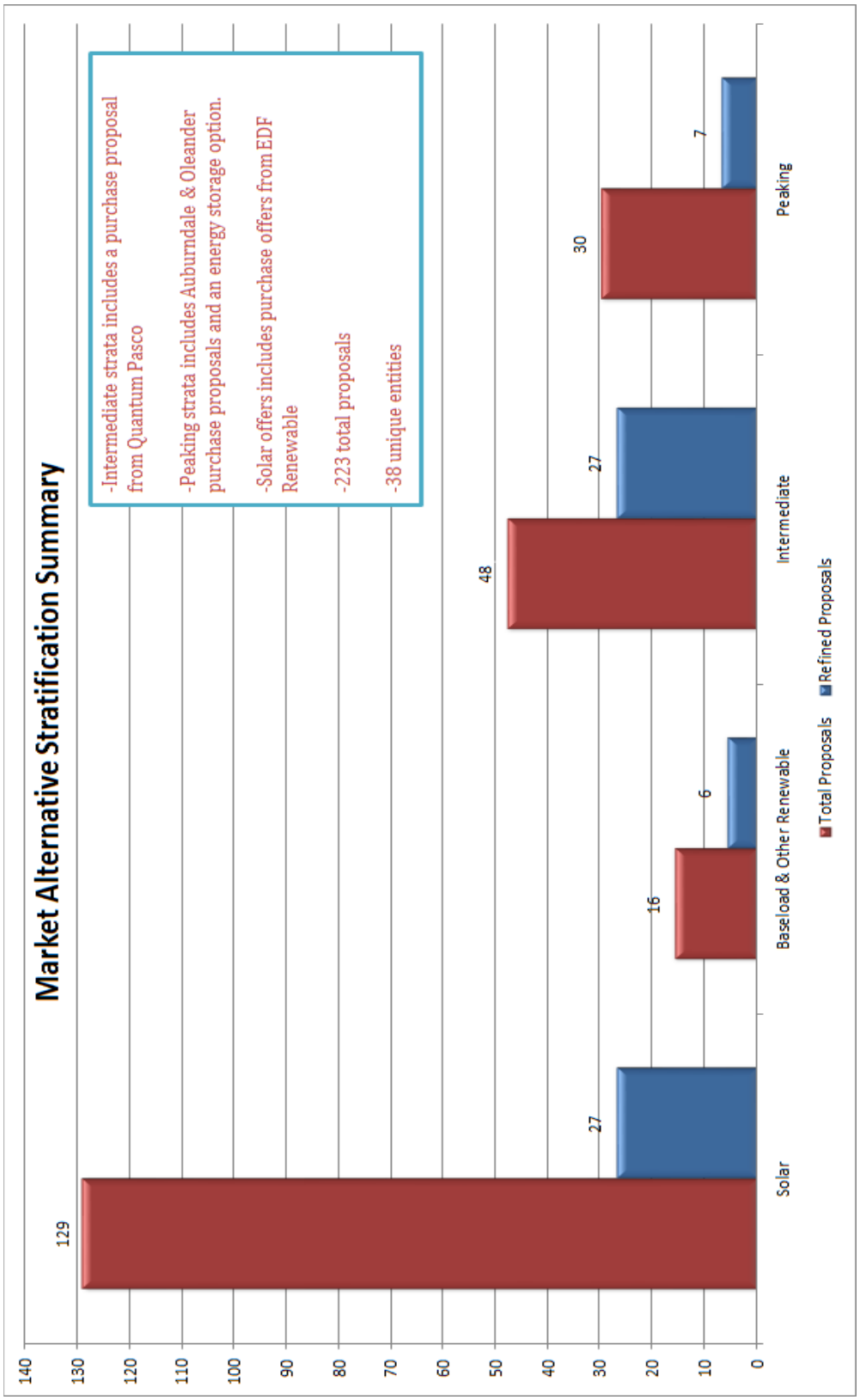
Seminole identified market alternatives by issuing an RFP in March 2016 for firm capacity up to 1,000 MW beginning as early as June 1, 2021. The RFP stated that the need for 600 MW of capacity would start in June 2021, with total needs increasing to 1,000 MW by June 2022. Seminole encouraged proposals of base, intermediate, and/or peaking capacity, as well as renewable resources. The RFP also stated that proposals providing demand side options would be considered, although no such proposals were received. A copy of the RFP is provided as Appendix A.

6.3.2 Proposals Received & Initial Economic Evaluation

In May 2016, Seminole received proposals for purchased power alternatives in response to its RFP. The response was robust, with Seminole receiving a total of 223 proposals from 38 counterparties. The proposals included offers providing generation from various renewable sources including solar, wind and energy storage; existing and new gas-fired facilities; and system offers for both intermediate and peaking generation.

Following receipt of the bids, Seminole reviewed the proposals for completeness along with technical and operational viability. Seminole also performed an initial economic screening using bus bar cost analysis (i.e., the total cost to operate a resource on a $/MWh basis) of all alternatives within a stratification (baseload and other renewables, intermediate, peaking or solar). Those with significantly higher operating cost based on a typical capacity factor within a stratification were eliminated. Figure 7 provides a summary of proposals received in response to the RFP, as well as the set of "refined proposals" that Seminole received after the intital economic screening.

Figure 7 Summary of Proposals Received in Response to RFP



6.4 Economic Evaluation of Generation Alternatives

6.4.1 Methodology

After the initial screening of proposals, Seminole evaluated all remaining alternatives, including self-build options, using System Optimizer. System Optimizer is an industry-recognized utility model developed by ABB and used to develop an optimal resource mix to satisfy future needs. The model simulates how each potential and existing resource will be used to serve the forecasted peak demand and energy requirements in the load forecast. System Optimizer's inputs include the demand and energy forecast, Reserve Margin requirements, fuel price forecast, plus the individual resource's cost and performance characteristics such as fixed cost, variable cost, heat rates, forced outage rates, and maintenance schedules.

Seminole ran multiple iterations through System Optimizer. The first iteration was used to develop a portfolio for Seminole's need starting in winter of 2022 with all resources available ("SGS 2x1 Portfolio"). Seminole also developed a limited build portfolio which allowed one 1x1 combined cycle unit to be built ("Limited Build Risk: Shady Hills Portfolio") as well as a "no build" portfolio consisting of only PPAs ("All PPA Portfolio"). Because the status of the Clean Power Plan and long-term economics for coal-fired generation were uncertain, Seminole also developed a portfolio taking into account the removal of one coal unit from service ("CPP/CC Portfolio").

Once the optimal portfolio candidates were identified via System Optimizer, Seminole used Planning and Risk ("PaR"), another industry-recognized utility model from ABB, to further evaluate the production cost. PaR is a detailed production cost model, which commits resources in each hour over the study period based on costs and operational constraints. The operational constraints are similar to those in System Optimizer but more extensive, including such constraints as minimum up and down times, must run requirements, and natural gas pipeline flow limits. The production costs from PaR along with any capital and transmission cost increases for network upgrades are loaded into the corporate financial model to develop the annual revenue requirements.

6.4.2 Economic Parameters

The primary drivers for the economic analysis among generation alternatives are plant fixed cost and fuel cost. Seminole's relatively low financing costs help mitigate the ultimate cost of self-build projects. Differences between the capital costs and fuel costs of competing technologies are the most significant factors affecting the economic comparisons among Seminole's generation altematives. Seminole's cost of debt projections for self-build alternatives assumed a financing rate of 5.96%.

The discount rate, which is used for present worth calculations, is equal to the average annual long term cost of debt. The construction cost of self-build alternatives includes a rate equal to the average annual long term debt rate on funds used during the construction period.

6.4.3 Fuel Price Forecast

Seminole's fuel price forecast is derived from a combination of published market indices, independent price forecasts, and escalators where necessary to extend the price forecast beyond the horizon of available values. For natural gas, Seminole uses the NYMEX futures forward market prices along with projected escalation of gas prices as provided by the Energy Information Administration ("EIA"). Seminole's coal price forecast is based on price projections obtained from Energy Research Company, LLC. Seminole's fuel oil price forecast is based on EIA's Annual Energy Outlook for distillate fuel oil. These sources of forward energy prices are commonly accepted in the utility industry.

The fuel price forecasts utilized in the original and updated economic analyses discussed below, including the alternative forecasts for natural gas, are summarized in Tables 16 and 17. Unless a firm fuel cost was included in an RFP proposal, Seminole used its fuel price forecast across all self-build and purchased power alternatives to ensure fairness in the evaluation.

Table 16 - Fuel Price Forecast

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.52	$4.34	$2.87	$3.53	$14.64
2018	$3.20	$4.43	$2.32	$3.59	$16.55
2019	$3.04	$4.30	$2.15	$3.41	$17.59
2020	$3.04	$4.34	$2.13	$3.53	$18.08
2021	$3.04	$4.43	$2.09	$3.62	$18.43
2022	$3.06	$4.53	$2.06	$3.70	$18.69
2023	$3.14	$4.71	$2.10	$3.78	$19.02
2024	$3.27	$4.94	$2.17	$3.86	$19.34
2025	$3.42	$5.25	$2.23	$3.95	$19.81
2026	$3.56	$5.55	$2.28	$4.03	$20.17
2027	$3.71	$5.86	$2.35	$4.13	$20.38
2028	$3.86	$6.16	$2.41	$4.22	$20.39
2029	$4.01	$6.48	$2.48	$4.32	$20.65
2030	$4.13	$6.74	$2.54	$4.42	$21.08
2031	$4.31	$7.07	$2.62	$4.52	$21.40
2032	$4.40	$7.27	$2.66	$4.62	$21.87
2033	$4.42	$7.35	$2.66	$4.73	$21.82
2034	$4.48	$7.49	$2.68	$4.83	$22.14
2035	$4.64	$7.79	$2.77	$4.94	$22.31
2036	$4.71	$7.93	$2.80	$5.05	$22.85
2037	$4.80	$8.10	$2.84	$5.17	$22.93
2038	$4.87	$8.24	$2.88	$5.29	$23.05
2039	$4.99	$8.46	$2.95	$5.41	$23.40
2040	$5.08	$8.60	$3.00	$5.53	$23.59
2041	$5.20	$8.81	$3.07	$5.66	$23.65
2042	$5.37	$9.10	$3.17	$5.78	$23.69
2043	$5.62	$9.51	$3.31	$5.92	$23.76
2044	$5.79	$9.80	$3.42	$6.05	$23.86
2045	$5.99	$10.13	$3.54	$6.19	$23.97
2046	$6.19	$10.45	$3.67	$6.33	$24.15
2047	$6.42	$10.81	$3.81	$6.47	$24.45
2048	$6.70	$11.26	$3.98	$6.61	$24.49
2049	$6.91	$11.59	$4.12	$6.76	$24.69
2050	$7.16	$11.97	$4.28	$6.92	$24.96
2051	$7.42	$12.37	$4.44	$7.07	$25.52

Table 17 - Fuel Price Forecast – Updated

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.32	$3.63	$2.90	$3.45	$14.64
2018	$3.20	$4.28	$3.06	$3.52	$16.55
2019	$2.94	$4.11	$2.39	$3.13	$17.59
2020	$2.92	$4.15	$2.11	$3.28	$18.08
2021	$2.94	$4.25	$2.06	$3.36	$18.43
2022	$3.03	$4.38	$2.04	$3.42	$18.69
2023	$3.09	$4.43	$2.10	$3.50	$19.02
2024	$3.16	$4.48	$2.15	$3.57	$19.34
2025	$3.24	$4.67	$2.23	$3.65	$19.81
2026	$3.33	$4.87	$2.25	$3.74	$20.17
2027	$3.42	$5.06	$2.28	$3.82	$20.38
2028	$3.51	$5.25	$2.31	$3.91	$20.39
2029	$3.60	$5.44	$2.34	$4.00	$20.65
2030	$3.71	$5.65	$2.38	$4.09	$21.08
2031	$3.86	$5.93	$2.43	$4.19	$21.40
2032	$3.94	$6.10	$2.52	$4.28	$21.87
2033	$3.96	$6.16	$2.55	$4.38	$21.82
2034	$4.02	$6.27	$2.55	$4.47	$22.14
2035	$4.16	$6.52	$2.58	$4.58	$22.31
2036	$4.23	$6.64	$2.66	$4.68	$22.85
2037	$4.30	$6.78	$2.69	$4.79	$22.93
2038	$4.37	$6.90	$2.73	$4.89	$23.05
2039	$4.48	$7.08	$2.77	$5.01	$23.40
2040	$4.55	$7.20	$2.83	$5.12	$23.59
2041	$4.66	$7.37	$2.88	$5.24	$23.65
2042	$4.84	$7.66	$2.94	$5.36	$23.69
2043	$5.06	$8.01	$3.06	$5.48	$23.76
2044	$5.22	$8.25	$3.20	$5.60	$23.86
2045	$5.40	$8.53	$3.30	$5.73	$23.97
2046	$5.58	$8.81	$3.42	$5.86	$24.15
2047	$5.78	$9.11	$3.54	$5.99	$24.45
2048	$6.04	$9.49	$3.67	$6.12	$24.49
2049	$6.22	$9.77	$3.84	$6.26	$24.69
2050	$6.45	$10.10	$3.97	$6.40	$24.96
2051	$6.68	$10.44	$4.12	$6.55	$25.52

6.4.4 Results

Ultimately, the net present value ("NPV") of the revenue requirements is the basis for comparing different portfolios in the economic evaluation. The CPP/CC Portfolio, which includes the SCCF, the SHCCF, and the removal from service of one SGS coal unit, was the least cost portfolio. The next portfolio in NPV revenue requirement terms was approximately $355 million more expensive over the study period. Figure 8 summarizes the results of Seminole's economic analyses of the various alternative portfolios.

Figure 8 Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	12,381	12,266	12,196	12,096
NPV @ 6.0%	9,008	8,936	8,885	8,797
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	61,264	60,244	62,185	61,695
NPV @ 6.0%	22,196	21,841	22,370	22,198

Figures 9 and 10 are "gap charts" showing how the selected portfolio would fill Seminole's projected need during the winter and summer seasons, respectively (the SHCCF is included within "new purchased power agreements").

Figure 9 "Gap Chart" Showing Effect of Selected Portfolio (Winter)

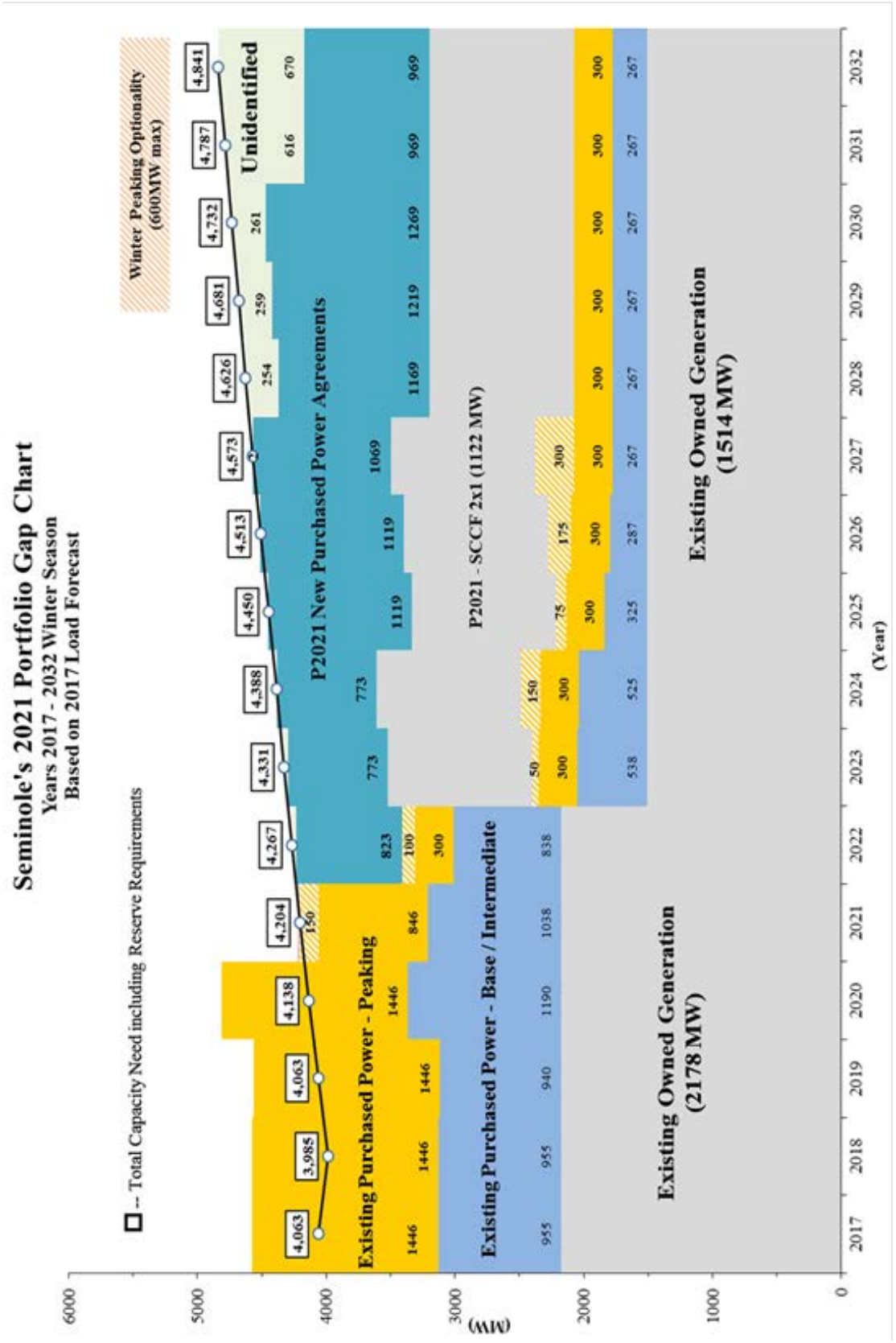
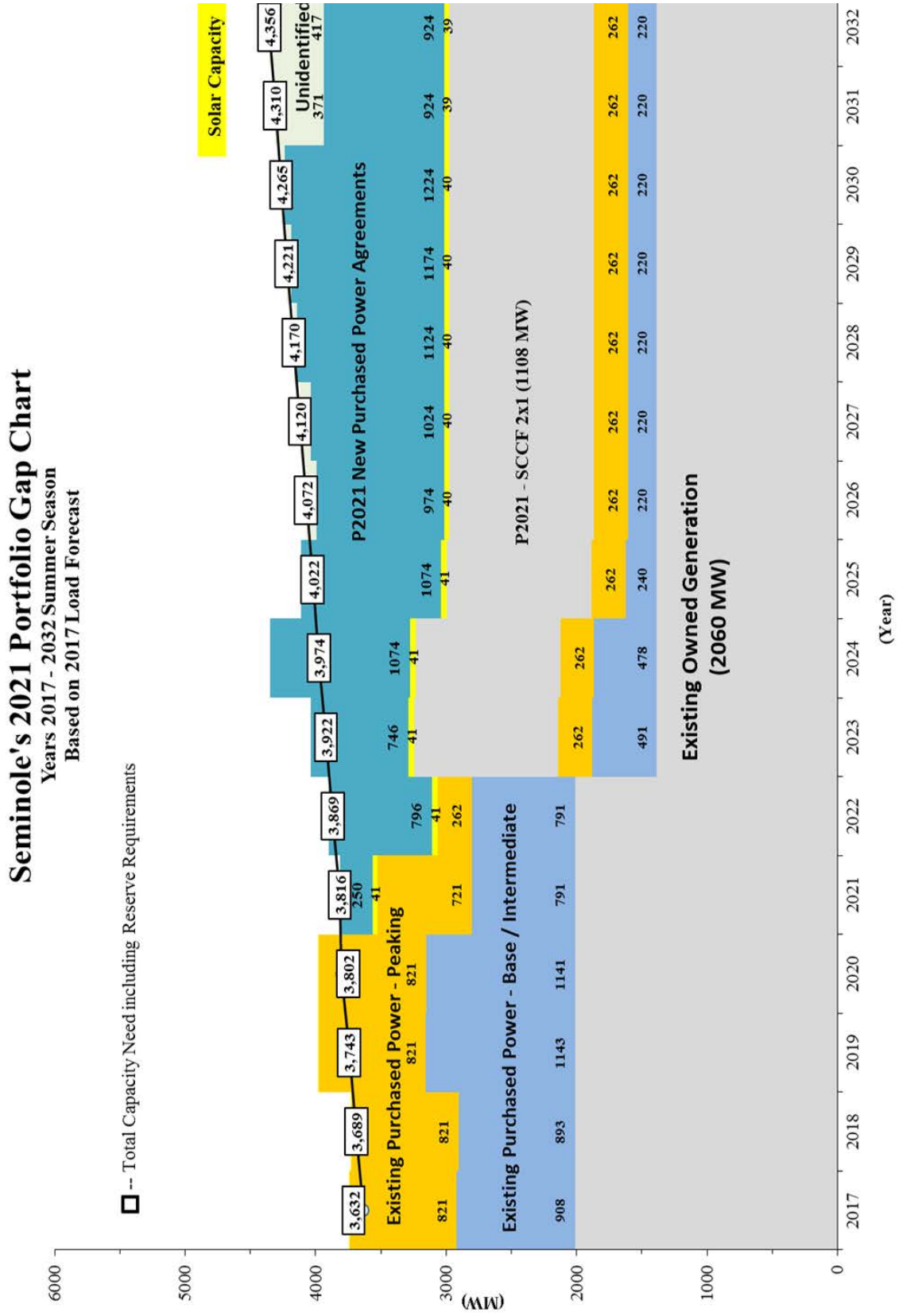


Figure 10 "Gap Chart" Showing Effect of Selected Portfolio (Summer)



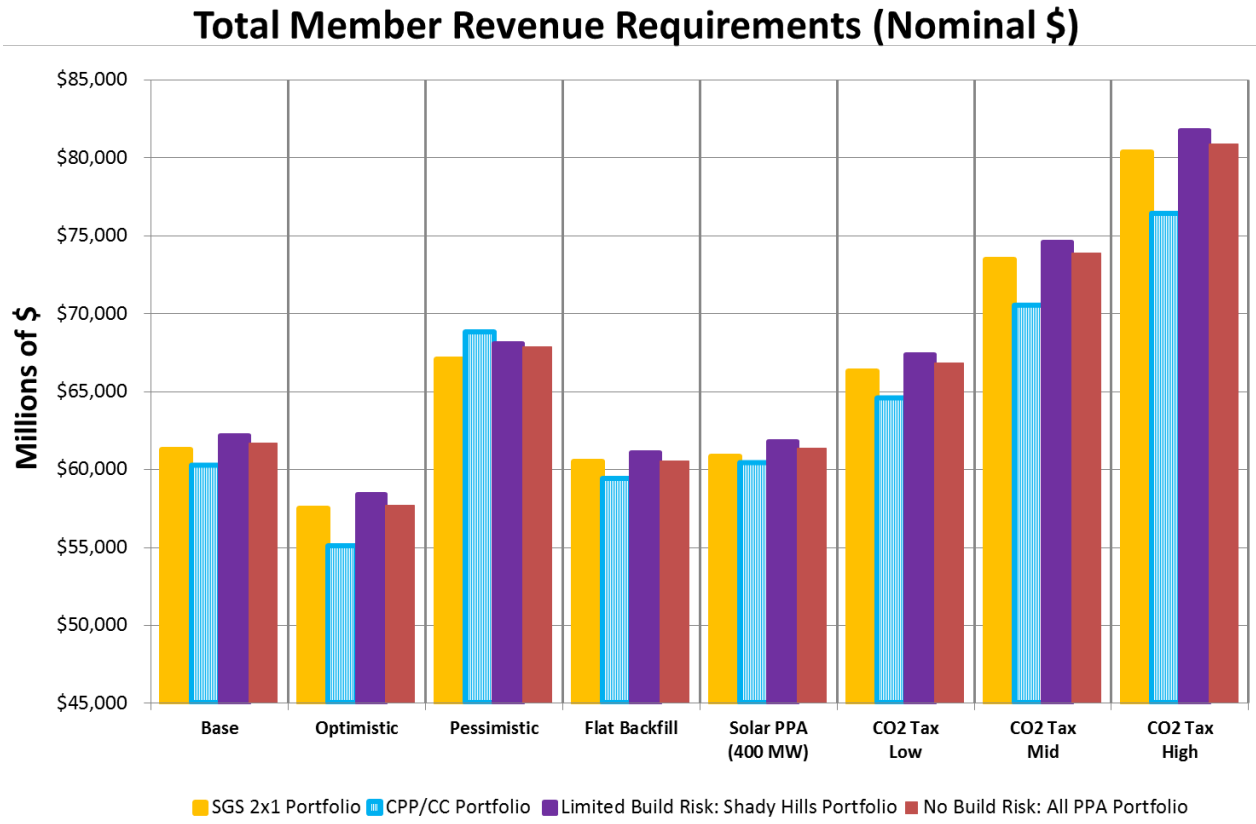
6.5 Sensitivity Analyses

Seminole also performed multiple sensitivity analyses to assess various uncertainties. The senstivity analyses include the following scenarios:

- **Optimistic (**High load growth with low gas prices)
- **Pessimistic** (Low load growth with high gas prices)
- **Flat Backfill** (No escalation of generic unit capacity costs)
- **Solar PPA 400 MW** (400 MW of additional solar PPA)
- **Various Carbon Tax** (based on Minnesota PSC Carbon tax assumptions)
    - Low – starting at $9.00/ton in 2019 and escalating
    - Mid – starting at $21.50/ton in 2019 and escalating
    - High – starting at $43.00/ton in 2019 and escalating

The results of these sensitivity analyses, which are summarized in Figure 11, support the conclusion that the CPP/CC Portfolio provides the most cost effective solution for Seminole's need.

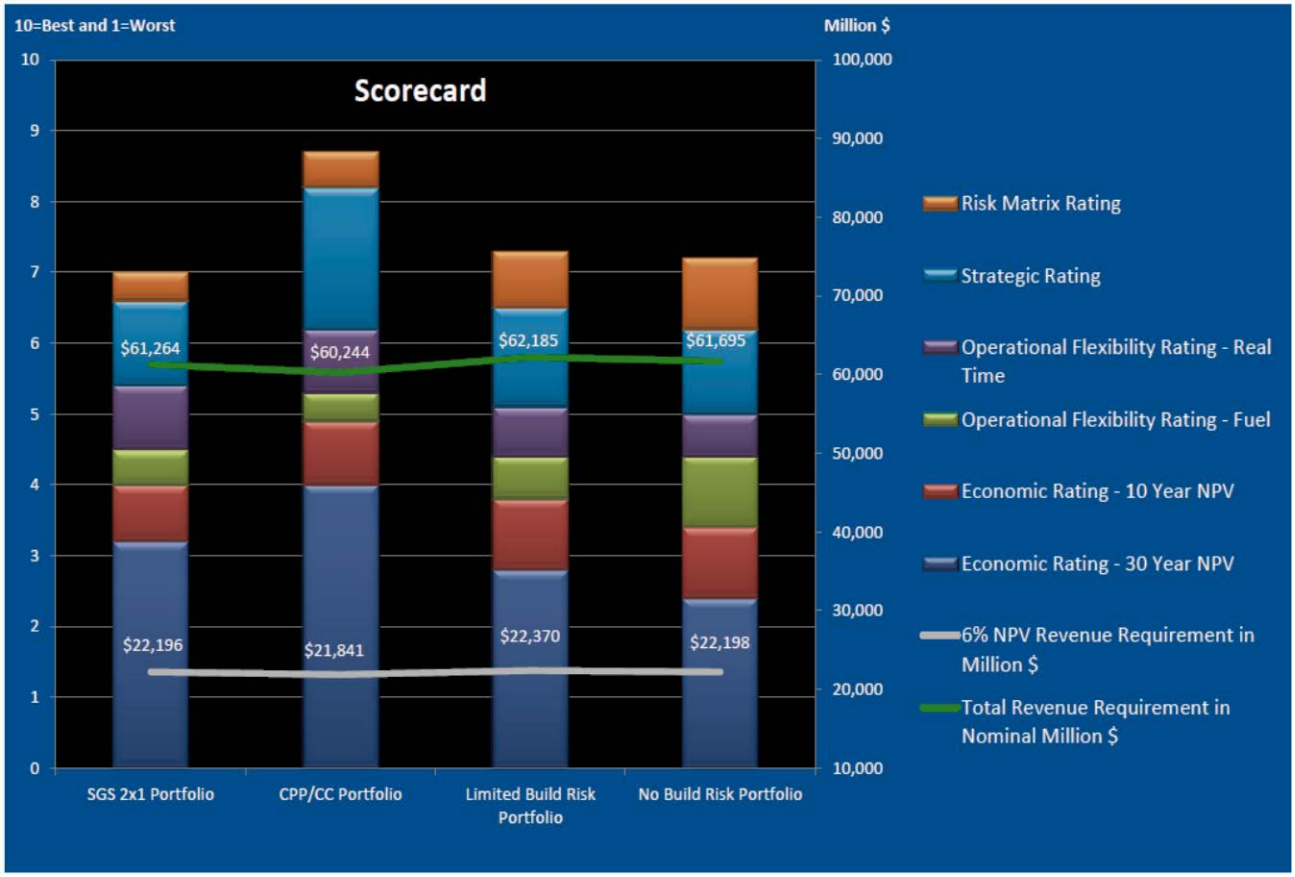
Figure 11 Results of Sensitivity Analyses



6.6 Consideration of Economic and Non-Economic Attributes

Once the production cost modeling was completed, Seminole's staff performed risk analysis for both individual alternatives and each of the remaining portfolios. Seminole produced scorecards for each portfolio which took into account a weighted risk rating, a strategic rating, operational flexibility ratings for fuel, real time operational flexibility, and an economic rating for a short-term (10 year) and long-term (30 year) net present value revenue requirement. These portfolio scorecard assessments are reflected in Figure 12.

Figure 12 Portfolio Scorecard Assessment



In addition to cost-effectiveness and risk impacts, Seminole considered the value of having optionality. One of the new PPAs included in the CPP/CC Portfolio provides Seminole with the advantage of optionality, giving Seminole the flexibility to modify its commitment up or down with relatively short notice. Given the vulnerability of load forecasts, the ability to modify resource commitments will give Seminole a hedge against economic acceleration/downturns or faster/slower load growth rates.

Seminole also considered the utilization of solar. However, Seminole is a winter-peaking utility that experiences its highest end-use demand on winter nights when solar energy is not a viable capacity source to offset peak demand. Nevertheless, in recognition of the energy value of solar, Seminole included 40 MW of new solar in the CPP/CC Portfolio.

Seminole also considered the potential impact of the resource plan on fuel diversity and supply reliability. The SCCF and SHCCF will be solely fueled by natural gas, but they will replace expiring purchased power resources that were also primarily natural gas-fired. Seminole's decision to maintain the operation of one SGS coal-fired generating unit will provide continued diversification in Seminole's fuel portfolio. Further, Seminole is implementing a natural gas transportation plan that includes contracts with four different counterparties for a variety of solutions to enhance the diversification and reliability of its delivered gas supply. For these reasons, the selected portfolio is not expected to significantly impact fuel diversity or supply reliability.

6.7 Selection of SCCF and SHCCF

Based on the analyses described above, Seminole determined that the most cost effective, risk-managed resource plan to meet its Members' future needs is a mix of resources consisting of existing generation resources, long-term PPAs, and the construction of two natural gas-fired combined cycle facilities. The first combined cycle unit would be a 573 MW (winter) one-on-one unit to be constructed, owned and operated by SHEC at the existing Shady Hills power plant site in Pasco County pursuant to a tolling agreement with Seminole. The second combined cycle plant would be a self-build 1,050 MW (nominal) two-on-one combined cycle plant adjacent to the existing SGS plant, along with the removal from service of one of the two existing 664 MW SGS coal units.

6.8 Updated Economic Assessment

Since the Board of Trustees' initial approval of the selected resource plan, Seminole conducted a present worth revenue requirements comparison for all four portfolios with the 2018 Budget assumptions approved in October 2017. While the total dollar values changed, the rankings between the portfolios did not. The CPP/CC Portfolio, which includes the SCCF and SHCCF along with the removal from service of one of the two existing 664 MW SGS coal units, remained the least cost portfolio. The

next portfolio in NPV revenue requirement terms was approximately $363 million more expensive over the study period. Figure 13 shows the differential between the portfolios.

Figure 13 Summary of Updated Economic Analysis

Portfolio Summaries Revised Economic Analysis Results (millions of $)				
	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	11,571
NPV @ 6.0%	8,641	8,568	8,549	8,432
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	56,465	58,312	58,289
NPV @ 6.0%	20,981	20,618	21,120	21,006

7.0 EVALUATION OF NON-GENERATING ALTERNATIVES

7.1 Current Conservation & Demand-Side Management Efforts

As a wholesale supplier of electric energy to its Member Cooperatives, Seminole is not directly responsible for DSM programs. However, Seminole's wholesale rate structure provides Members price signals that reflect Seminole's cost of supplying power in aggregate. Under this rate structure, Seminole's demand charge to each of its Members is applied to each Member's demand at the time of Seminole's peak. This encourages Members to concentrate their load management efforts on controlling Seminole's overall system peak rather than their separate peaks. In addition, Seminole's wholesale rate to its Members include time-of-use fuel charges to reflect the differences in fuel costs incurred by Seminole to serve its Members during the peak and off-peak periods. Each Member may use these price signals to evaluate the cost-effectiveness of DSM and conservation measures for its own circumstances. To ensure Members have the opportunity to achieve maximum load-management benefit, Seminole's system operators develop and implement a coordinated load management demand reduction strategy in real time to notify Members when Seminole's monthly billing peak is expected to occur.

Seminole also assists its Members in evaluating and implementing DSM measures. In 2008, Seminole and its Members jointly formed an Energy Efficiency Working Group to coordinate and further-promote energy conservation and efficiency initiatives. The function of this group is to promote conservation, efficiency and DSM programs through the sharing of information, member-consumer education, and joint assessment of energy efficiency technologies. In addition, Seminole has sponsored its own conservation/efficiency initiatives, which included giving light emitting diode light bulbs ("LEDs") to member-consumers during Member meetings and administering an LED bulk purchase program for Members. Seminole provides Members with materials that can be distributed to end-use member-consumers including educational brochures, manufactured housing weatherization brochures, videos on energy efficiency home

auditing, and a video on Cooperative Solar. Seminole also remains active in upgrading utility system efficiency at administration and generation facilities.

Because Seminole and its Members are not subject to the requirements of the Florida Energy Efficiency and Conservation Act ("FEECA"), they do not have Commission-approved DSM goals, programs or plans. However, Seminole's Members participate in a variety of utility system efficiency and DSM programs, including distribution system voltage reduction ("VR"), load management distributed generation and interruptible rate programs which help reduce Seminole's load during peak periods. Seminole's Members also offer a variety of programs and services to end-use member-consumers in order to promote energy conservation and cost savings. Member programs include:

- **Distribution System Voltage Reduction (VR):** Coordinated load management-demand reduction program where Member system operators lower voltage during critical peak billing periods, within allowable thresholds, on distribution feeders to reduce demand behind end-use meters during critical peak billing periods.
- **Commercial Coincident Peak Power (CPP) Rates:** Coordinated load management-demand reduction program where enrolled commercial and industrial member-consumers are signaled to shed load during critical peak billing periods.
- **Commercial Interruptible Rates:** Direct load control program where Seminole or the Member interrupts electrical service to enrolled commercial member-consumers during extreme peak demand, capacity shortage or emergency conditions.
- **Commercial Customer Load Generation:** Standby peak-shaving generators which Seminole and its Members may dispatch for purpose of load management and enhanced reliability. Members with standby generators under this program receive a billing credit.

- **Time-of-Use (TOU) Rates**: Residential, commercial, or industrial rates that encourage member-consumers to reduce power use during on-peak hours through price signals.
- **Residential Pre-Pay:** Residential member-consumers pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- **LED/CFL Efficient Bulb Giveaway:** This program provides participating end-use member-consumers with free energy-efficient 10 Watt (W) LED or 13W compact fluorescent light ("CFL") bulbs to replace their existing 60W incandescent bulbs.
- **LED Outdoor and Street Lighting:** Replacement of Member-owned outdoor and street lighting with lower wattage LEDs.
- **Residential Energy Smart Rebates:** A rebate is given to residential member-consumers to upgrade to more efficient equipment and/or improve the building envelope. Rebate opportunities include: air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation – batt or spray foam – and window film.
- **Energy Audits:** On-site energy audit program for residential, commercial and industrial member-consumers.

Table 18 shows the specific conservation and demand-side offerings of each of Seminole's Members.

Table 18 Conservation & Demand-Side Offerings of Seminole Members

	Distribution System Voltage Reduction	Commercial Coincident Peak Power Rates	Commercial Interruptible Rate	Commercial Customer Load Generation	TOU Rates	Residential Pre-Pay	Lighting Conservation	Energy Rebates	Energy Audits
Central Florida	X			X	X	X	X		X
Clay	X		X	X	X		X	X	X
Glades				X	X		X		X
Peace River	X			X	X		X		X
SECO Energy	X	X	X	X	X	X	X		X
Suwannee Valley	X		X	X	X	X	X		X
Talquin	X			X			X		X
Tri-County		X				X	X		X
Withlacoochee River	X			X		X	X		X

In 2016, Seminole engaged Advanced Energy and Tierra Resource Consultants (AE/Tierra), an energy and natural resource consulting firm, to help quantify the energy efficiency and DSM savings achieved by Seminole and its Members. As shown in Table 19, AE/Tierra estimated that Seminole and its Members are achieving approximately 12,353 MWh in annual savings and approximately 85 MW in peak savings.

Table 19 Annual Energy Savings

Program Type	Annual MWh Savings	Annual kW Savings
Residential Pre-Paid Energy Program	7,172	201
Bulb Giveaways (LED & CFL)	287	33
TOU/CPP Rates	170	18,258
Utility System Savings (inlcuding VR)	3,475	66,298
Energy Smart Rebates	946	236
LED Outdoor Lights/Street lighting	303	0
TOTAL	**12,353**	**85,026**

7.2 Potential for Conservation and DSM Savings to Mitigate Need

In order to help Seminole evaluate whether DSM measures may be reasonably available to mitigate the projected need, Seminole also engaged AE/Tierra to identify potential new programs and to evaluate their cost-effectiveness. None of the additional measures evaluated by AE/Tierra satsified the Rate Impact Measure ("RIM") test traditionally relied upon by the Commission in evaluating the cost-effectiveness of DSM measures. Nevertheless, Seminole is planning to implement one of the identified measures (Smart Thermostat) of particular interest to Members. Seminole also is committed to working with its Members to implement recommendations made by AE/Tierra to help improve program tracking and increase future savings by enhancing current efforts and adding new measures to existing programs when appropriate.

The DSM and conservation savings actually achieved by Seminole's Members are reflected in Seminole's load forecast, yet Seminole will still need 901 MW of additional capacity beginning in 2021. To put this in perspective, in Order No. PSC-14-0696-FOF-EU, the Commission established DSM goals for the utilites subject to FEECA. Based on those goals, the largest electric utility in the State of Florida, FPL, is expected to achieve Commission-Approved DSM Goals of approximately 526 MW in summer demand reduction and 324 MW in winter demand reduction, over the course of a ten-year period from 2015 through 2024. As an additional point of comparison, TECO, which is comparable in size to Seminole in terms of consumers and annual peak demand, is expected to achieve Commission-Approved DSM Goals of approximately 56 MW in summer demand reduction and 78 MW in winter demand reduction, over the course of the same ten-year period. Based on these Commission-approved DSM goals even large, vertically integrated utilities comparable to and larger than Seminole's size with centralized staff and resources to offer DSM programs directly to their customers cannot cost-effectively achieve 901 MW peak demand reductions through DSM and conservation programs over the course of the next four years.

Even if additional DSM savings were theoretically achievable, the selected CPP/CC Portfolio would still be Seminole's most cost-effective alternative based on the results of Seminole's "low load" senstivity analysis. The low load forecast sensitivity is intended to reflect reductions in loads due to a combination of potential factors as compared to the base case, including but not limited to changes in economic conditions, decreased customer counts, mild weather, increased utilization of customer-owned distributed generation resources, and increased energy efficiency. The low load forecast sensitivity may be considered as a proxy for Seminole's Members' member-consumers achieving increased levels of demand and energy reductions due to DSM or conservation as compared to the base case load forecast. Because the CPP/CC Portfolio is the most cost-effective alternative even considering the low load forecast, there is no reasonable basis to conclude that DSM or conservation measures are reasonably available to Seminole or its Members that would mitigate the need for SCCF and SHCCF.

8.0 ADVERSE CONSEQUENCES OF DENIAL

Non-approval would mean that Seminole's Members and the Members' retail member-consumers would be denied the most cost-effective, risk-managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021. While additional off-system purchases could perhaps be made to fulfill Member power requirements and maintain the target reserve margin, Seminole would not be able to remove a coal unit from service and the costs of the resulting resource plan would be substantially higher.

If the requested need determination for the SCCF were denied, Seminole would not be able to take an SGS coal unit out of service (664 MW) and the resulting resource plan would increase costs as compared to the resource plan that includes the SCCF. Seminole estimates that if only the SCCF were denied, the NPV revenue requirements impact would be approximately $502 million.

If the SHCCF was denied, then again Seminole could pursue one of two options. One option would be to leave the SGS coal unit in service which would cover our Members and their member-consumers' needs, but at a higher cost. The second option would be to go to the market to find replacement capacity, likely resulting in higher costs. Seminole estimates that if only the SHCCF were denied, the NPV revenue requirements impact would be approximately $363 million along with the continuation of service of the coal unit.

If both projects were to be denied, Seminole estimates that the NPV revenue requirements impact would be approximately $388 million, without consideration of transmission impacts which could be significant. Moreover, Seminole would need to continue operating both SGS coal units.

9.0 CONCLUSION

The analyses and other information described in this Need Study demonstrate that affirmative need determinations are warranted for the SCCF and SHCCF projects based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to the expiration of existing PPAs, Seminole will have a need for 901 MW of additional generating capacity by the end of 2021, and that need will grow to 1,265 MW by the end of 2022. The proposed SCCF and SHCCF are part of an integrated resource plan that will ensure that Seminole has an adequate supply of power to serve its Members' needs at a reasonable cost. The competitive RFP process, together with separate economic analyses and risk analyses presented in this Need Study demonstrate that the selected resource plan, including the two new combined cycle facilities, is the most cost-effective, risk-managed alternative to meet Seminole's power supply needs. Seminole and its Members already utilize reasonably available DSM programs and renewable resources and they are committed to implementing more. Even with potential demand and energy reductions that could be achieved from additional conservation and DSM initiatives, however, there is still a significant capacity need and the resource plan including the new SCCF and SHCCF is the least cost alternative to reliably meet that need.

APPENDIX A

Seminole Electric Cooperative

Ten Year Site Plan

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

April 1, 2016

Moniaishi Mtenga
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Mtenga:

In accordance with Section 186.801, Florida Statutes, Seminole Electric Cooperative, Inc. hereby submits our 2016 Ten Year Site Plan.

Please do not hesitate to call me if you have any questions or comments.

Sincerely,

Julia A Diazgranados

Julia A Diazgranados
Planning Manager
813-739-1538 (office)
jdiazgranados@seminole-electric.com

Enclosure

cc: M. Sherman
L. Johnson

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2016 - 2025
(Detail as of December 31, 2015)
April 1, 2016

Submitted To:
State of Florida
Public Service Commission

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Seminole Electric COOPERATIVE, INC.

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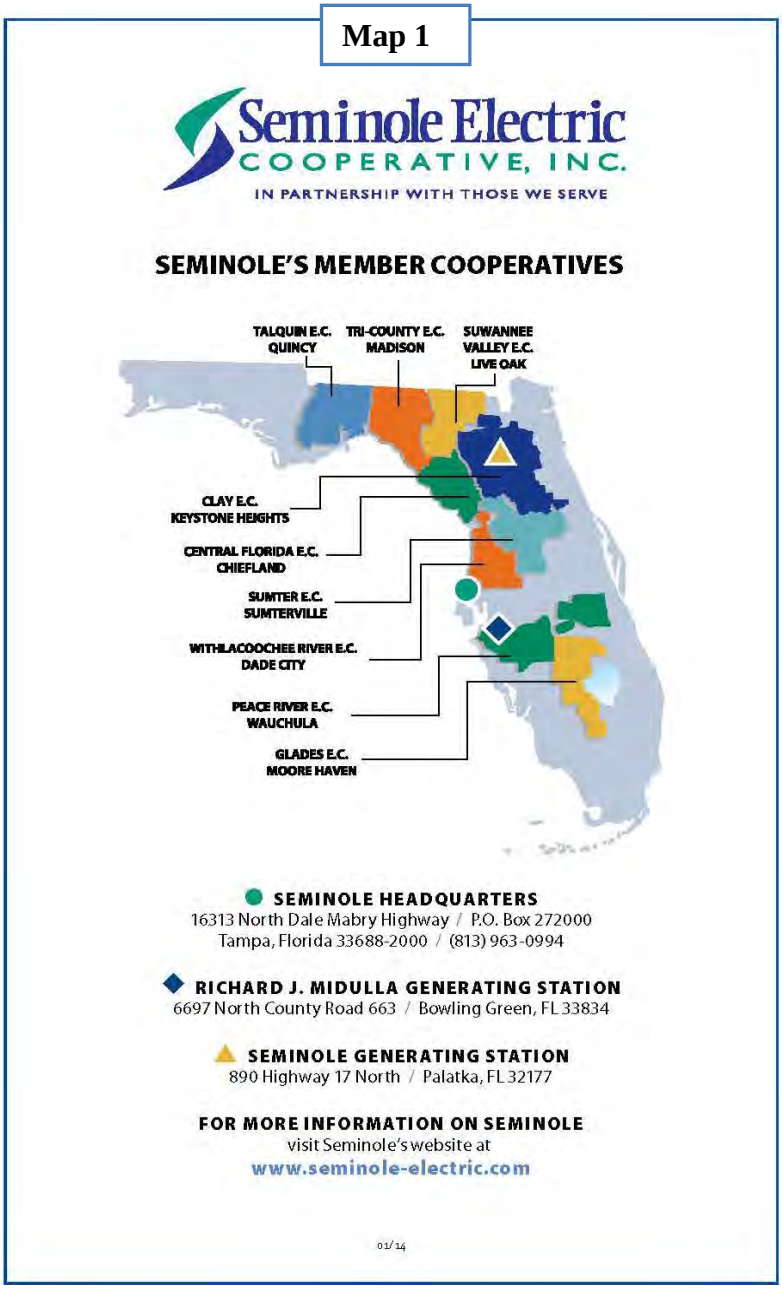
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1. DESCRIPTION OF EXISTING FACILITIES

1.1 Overview

Seminole Electric Cooperative, Inc. (Seminole) is a generation and transmission cooperative responsible for meeting the electric power and energy needs of its nine distribution cooperative members (Members). Member service areas are indicated on Map 1 below:

Map 1



Seminole provides full requirements service to all of its Members with the only exception relating to contracts between four Members with the Southeastern Power Administration (SEPA), which provides 26 MW or 1% of the total energy required by all Members. Seminole serves the aggregate loads of its Members with a combination of owned and purchased power resources. As of December 31, 2015, Seminole had total summer capacity resources of approximately 4,000 MW consisting of owned, installed net capacity of 2,012 MW and the remaining capacity in firm purchased power. Additional information on Seminole's existing resources can be found in Schedule 1 and Table 1.2 below.

1.2 Existing Facilities

1.2.1 Owned Generation

Seminole's existing generating facilities include:

1) Seminole Generating Station (SGS) Units 1 & 2 comprise a 1472 MW nameplate coal-fired plant located in Putnam County;
2) Midulla Generating Station (MGS) Units 1–3 comprise a 587 MW nameplate gas-fired combined cycle plant located in Hardee County; and,
3) MGS Units 4–8 comprise a 310 MW nameplate peaking plant.

Schedule 1
Existing Generating Facilities as of December 31, 2015

Plant	Unit No.	Location	Unit Type	Fuel		Fuel Transportation		Alt Fuel Days Use	Com In-Svc Date (Mo/Yr)	Expected Retirement (Mo/Yr)	Gen. Max Nameplate (MW)	Net Capability (MW)	
				Pri	Alt	Pri	Alt					Summer	Winter
SGS	1	Putnam County	ST	BIT	N/A	RR	N/A	N/A	02/84	Unk	736	626	664
SGS	2	Putnam County	ST	BIT	N/A	RR	N/A	N/A	12/84	Unk	736	634	665
MGS	1-3	Hardee County	CC	NG	DFO	PL	TK	Unk	01/02	Unk	587	482	539
MGS	4-8	Hardee County	CT	NG	DFO	PL	TK	Unk	12/06	Unk	310	270	310

Schedule Abbreviations:	General		
	Unit Type ST - Steam Turbine CC - Combined Cycle CT – Combustion Turbine PV – Photovoltaic	Fuel Type BIT - Bituminous Coal NG - Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy	Fuel Transportation PL – Pipeline RR – Railroad TK – Truck

Unk – Unknown
N/A – Not applicable

1.2.2 Transmission

Seminole serves its Members' load primarily in three transmission areas: Seminole Direct Serve (SDS) system, Duke Energy Florida (DEF) system, and Florida Power & Light (FPL) system. Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 141 circuit miles of 69 kV lines. Seminole's facilities are interconnected to the grid at twenty (20) 230 kV transmission interconnections with the utilities shown in Table 1.1.

Table 1.1

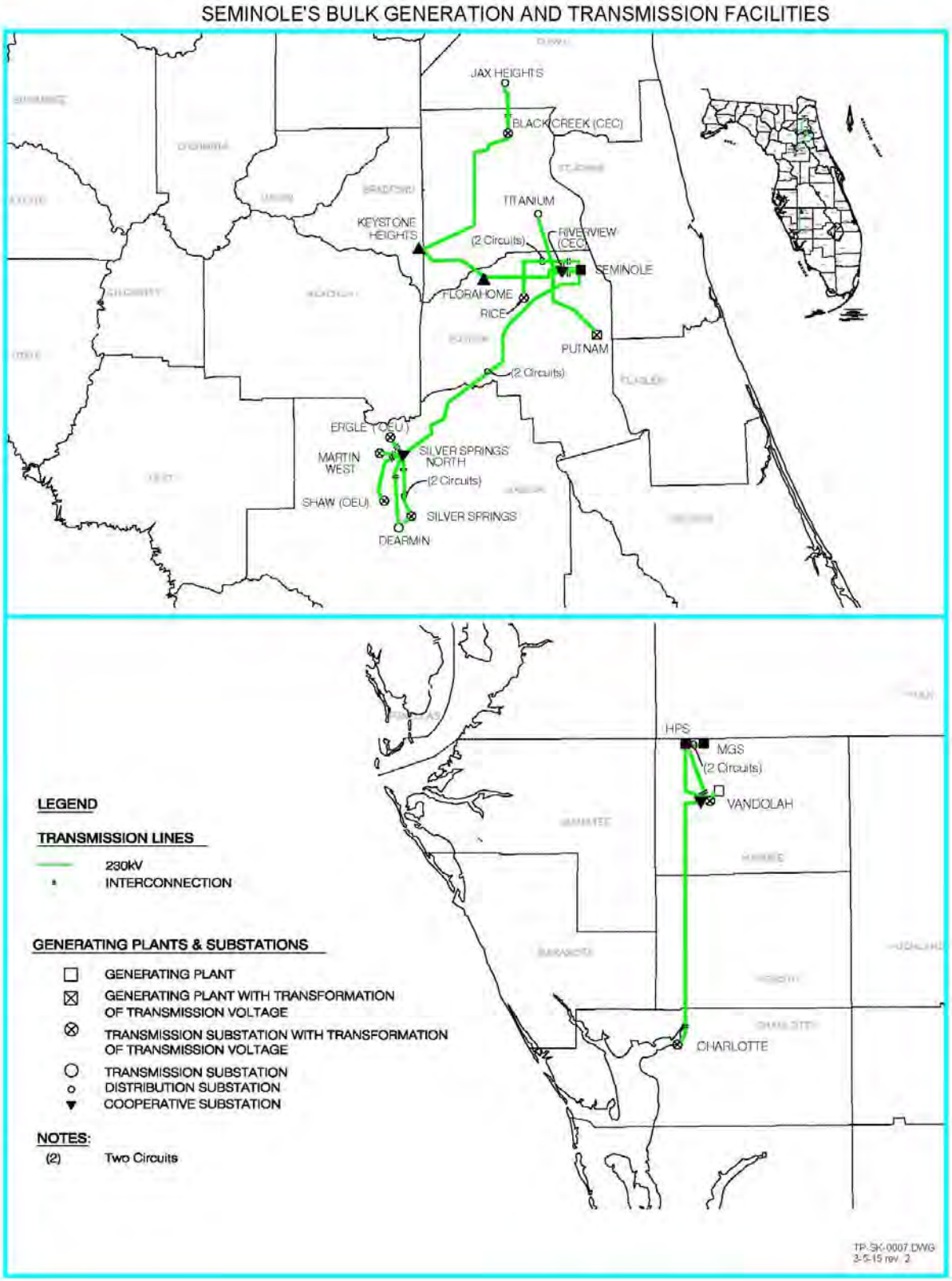
Transmission Grid Interconnections with Other Utilities

Utility	Voltage (kV)	Number of Interconnections
Florida Power & Light	230	6
Duke Energy Florida	230	7
JEA	230	1
City of Ocala	230	2
Tampa Electric Company	230	1
Hardee Power Partners	230	3

Note: This table describes physical facility interconnections, which do not necessarily constitute contractual interconnections for purposes of transmission service or interconnections between balancing areas.

Seminole contracts with other utilities for firm transmission service and interchange when required to serve loads. Map 2 below depicts Seminole's 230 kV transmission lines, including its interconnections with those entities identified in Table 1.1 above.

Map 2


SEMINOLE'S BULK GENERATION AND TRANSMISSION FACILITIES
JAX HEIGHTS
BLACK CREEK (CEC)
TITANIUM
KEYSTONE HEIGHTS
(2 Circuits)
RIVERVIEW (CEC)
SEMINOLE
FLORAHOME
RICE
PUTNAM
(2 Circuits)
ERGLE (OEU)
MARTIN WEST
SILVER SPRINGS NORTH
(2 Circuits)
SHAW (OEU)
SILVER SPRINGS
DEARMIN
HPS
MGS
(2 Circuits)
VANDOLAH
CHARLOTTE
LEGEND
TRANSMISSION LINES
230kV
INTERCONNECTION
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
DISTRIBUTION SUBSTATION
COOPERATIVE SUBSTATION
NOTES:
(2) Two Circuits
TP-SK-0007.DWG
3-5-15 rev. 2

1.3 Purchased Power Resources

Table 1.2 below sets forth Seminole's purchased power resources.

Table 1.2

2015				
SUPPLIER	**FUEL**	**MW (WINTER RATINGS)**	**IN SERVICE DATE**	**END DATE**
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	250	1/1/2014	5/31/2016
DEF	System	50	6/1/2016	12/31/2018
DEF	System	150	1/1/2014	5/31/2016
DEF	System	200-500	6/1/2016	12/31/2024
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026
Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.				

2. FORECAST OF ELECTRIC DEMAND AND ENERGY CONSUMPTION

2.1 Energy Consumption and Number of Customers

Residential consumer growth is projected to increase at an average annual rate of 1.6 percent from 2016 through 2025. Similarly, commercial consumer growth is projected to increase at an average annual rate of 1.4 percent during the same period. Residential energy sales are projected to grow at an average annual rate of 1.7 percent, and commercial energy sales are projected to grow at an average annual rate of 1.9 percent from 2016 through 2025.

Schedules 2.1, 2.2, and 2.3 below show the aggregate number of customers and energy consumption by customer classification of Seminole's nine Members, including other sales and purchases.

Schedule 2.1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Estimated Population Served by Members	Residential			
		Customers Per Household	GWh	Average Number of Customers	Average Consumption Per Customer (kWh)
2006	1,667,616	2.14	11,153	780,687	14,286
2007	1,716,841	2.14	11,444	803,957	14,235
2008	1,740,705	2.15	11,104	808,926	13,727
2009	1,748,408	2.15	11,293	811,767	13,912
2010	1,692,257	2.22	11,369	761,993	14,920
2011	1,716,516	2.24	10,412	765,279	13,605
2012	1,723,920	2.24	9,979	769,591	12,967
2013	1,749,359	2.25	10,018	777,493	12,885
2014	1,643,174	2.48	8,808	662,626	13,293
2015	1,666,850	2.48	9,068	673,215	13,470
2016	1,677,505	2.45	8,981	683,410	13,141
2017	1,697,061	2.44	9,177	695,982	13,185
2018	1,719,281	2.42	9,379	709,589	13,218
2019	1,746,279	2.42	9,555	722,026	13,234
2020	1,772,180	2.41	9,731	734,291	13,252
2021	1,795,824	2.41	9,892	745,826	13,263
2022	1,818,008	2.40	10,040	756,799	13,266
2023	1,839,569	2.40	10,183	767,621	13,266
2024	1,860,751	2.39	10,321	778,202	13,263
2025	1,881,770	2.39	10,452	788,493	13,256

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.
Estimated values for 2015.

Schedule 2.2

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Commercial[1]			Other Sales (GWh)[2]	Total Member Sales to Ultimate Consumers (GWh)[3]
	GWh	Average Number of Customers	Average Consumption Per Customer (kWh)		
2006	4,634	84,345	54,941	158	15,945
2007	4,839	88,306	54,798	165	16,448
2008	4,894	86,121	56,827	163	16,161
2009	4,776	84,318	56,643	167	16,236
2010	4,525	78,788	57,433	158	16,052
2011	4,366	78,828	55,386	160	14,938
2012	4,456	80,598	55,287	164	14,599
2013	4,482	82,302	54,458	166	14,666
2014	4,001	72,632	55,086	151	12,960
2015	4,155	73,290	56,689	151	13,374
2016	4,146	74,567	55,600	142	13,268
2017	4,262	75,722	56,282	140	13,579
2018	4,364	77,002	56,676	142	13,885
2019	4,478	78,212	57,249	143	14,176
2020	4,562	79,377	57,467	145	14,437
2021	4,640	80,508	57,636	146	14,679
2022	4,712	81,613	57,738	148	14,900
2023	4,781	82,694	57,816	149	15,114
2024	4,848	83,749	57,884	151	15,319
2025	4,912	84,790	57,928	152	15,516

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.
Estimated values for 2015

[1] Includes Industrial and Interruptible Customers.

[2] Includes Lighting Customers.

[3] Excludes Sales for Resale and includes SEPA.

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses, Less SEPA (GWh)*	Net Energy for Load (GWh)	Other Customers*	Total Number of Customers*
2006	0	1,288	17,233	5,101	870,133
2007	0	1,221	17,669	5,150	897,413
2008	0	1,171	17,332	5,075	900,122
2009	0	1,217	17,453	5,036	901,121
2010	0	1,294	17,346	4,956	845,737
2011	157	942	16,037	4,954	849,061
2012	134	1,036	15,769	4,818	855,007
2013	137	1,009	15,812	5,185	864,980
2014	170	724	13,854	5,308	740,566
2015	16	714	14,104	5,343	751,848
2016	5	651	13,925	5,332	763,309
2017	6	664	14,249	5,312	777,016
2018	6	675	14,566	5,335	791,927
2019	7	687	14,870	5,359	805,598
2020	9	687	15,133	5,392	819,060
2021	1	690	15,370	5,423	831,758
2022	0	702	15,602	5,455	843,868
2023	0	701	15,815	5,487	855,803
2024	0	707	16,026	5,517	867,467
2025	0	708	16,224	5,543	878,827

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative
* Estimated values for 2015.

2.2 Annual Peak Demand and Net Energy for Load

Schedules 3.1, 3.2, and 3.3 provide Seminole's summer peak demand, winter peak demand and net energy for load, respectively. Net firm peak demand reflects the energy reduction due to controllable interruptible load used in the historical years or made available for use in the forecasted years. Since population is the primary driver for Seminole's load growth, Seminole does not create high and low forecasts based upon alternative economic conditions.

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial[5]		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2006	3,813	3,813	0	0	51	130	N/A	N/A	N/A	3,632
2007	4,006	4,006	0	0	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	0	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	0	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	0	67	99	N/A	N/A	N/A	3,548
2011	3,829	3,829	0	0	79	97	N/A	N/A	N/A	3,653
2012	3,525	3,525	0	0	0	97	N/A	N/A	N/A	3,428
2013	3,665	3,665	0	0	0	99	N/A	N/A	N/A	3,566
2014	3,155	3,155	0	0	0	67	N/A	N/A	N/A	3,088
2015	3,092	3,092	0	0	0	71	N/A	N/A	N/A	3,021
2016	3,207	3,207	0	32	78	73	N/A	N/A	N/A	3,024
2017	3,275	3,275	0	41	78	74	N/A	N/A	N/A	3,082
2018	3,337	3,337	0	41	78	75	N/A	N/A	N/A	3,143
2019	3,396	3,396	0	41	78	76	N/A	N/A	N/A	3,201
2020	3,445	3,445	0	32	78	77	N/A	N/A	N/A	3,257
2021	3,480	3,480	0	32	78	78	N/A	N/A	N/A	3,291
2022	3,535	3,535	0	42	78	79	N/A	N/A	N/A	3,336
2023	3,576	3,576	0	41	78	80	N/A	N/A	N/A	3,377
2024	3,619	3,619	0	41	78	81	N/A	N/A	N/A	3,419
2025	3,657	3,657	0	41	78	82	N/A	N/A	N/A	3,457

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2005-06	4,349	4,349	0	0	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	0	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	0	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	0	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	0	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	0	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	0	66	134	N/A	N/A	N/A	3,918
2012-13	3,839	3,839	0	0	0	132	N/A	N/A	N/A	3,707
2013-14	3,333	3,333	0	0	0	93	N/A	N/A	N/A	3,240
2014-15	3,696	3,696	0	0	0	103	N/A	N/A	N/A	3,593
2015-16[5]	3,403	3,403	0	0	0	96	N/A	N/A	N/A	3,307
2016-17	3,696	3,696	0	36	78	101	N/A	N/A	N/A	3,481
2017-18	3,756	3,756	0	38	78	102	N/A	N/A	N/A	3,539
2018-19	3,815	3,815	0	38	78	103	N/A	N/A	N/A	3,596
2019-20	3,869	3,869	0	38	78	104	N/A	N/A	N/A	3,649
2020-21	3,919	3,919	0	38	78	106	N/A	N/A	N/A	3,698
2021-22	3,966	3,966	0	38	78	107	N/A	N/A	N/A	3,744
2022-23	4,010	4,010	0	38	78	108	N/A	N/A	N/A	3,787
2023-24	4,052	4,052	0	38	78	109	N/A	N/A	N/A	3,827
2024-25	4,091	4,091	0	38	78	110	N/A	N/A	N/A	3,866
2025-26	4,130	4,130	0	38	78	110	N/A	N/A	N/A	3,904

NOTE: Actual value for 2013-14 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)

Year	Total	Conservation		Retail	Total Sales Including Sales for Resale*	Utility Use & Losses, less SEPA*	Net Energy for Load	Load Factor %
		Residential	Commercial					
2006	17,233	N/A	N/A	0	15,945	1,288	17,233	48.9
2007	17,669	N/A	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	N/A	N/A	0	16,161	1,171	17,332	46.7
2009	17,453	N/A	N/A	0	16,236	1,217	17,453	42.1
2010	17,346	N/A	N/A	0	16,052	1,294	17,346	39.2
2011	16,037	N/A	N/A	0	15,095	942	16,037	46.7
2012	15,769	N/A	N/A	0	14,733	1,036	15,769	45.8
2013	15,812	N/A	N/A	0	14,803	1,009	15,812	45.7
2014	13,854	N/A	N/A	0	13,130	724	13,854	44.3
2015	14,104	N/A	N/A	0	13,390	714	14,104	48.7
2016	13,925	N/A	N/A	0	13,274	651	13,925	45.7
2017	14,249	N/A	N/A	0	13,585	664	14,249	46.0
2018	14,566	N/A	N/A	0	13,891	675	14,566	46.2
2019	14,870	N/A	N/A	0	14,183	687	14,870	46.5
2020	15,133	N/A	N/A	0	14,446	687	15,133	46.7
2021	15,370	N/A	N/A	0	14,680	690	15,370	46.9
2022	15,602	N/A	N/A	0	14,900	702	15,602	47.0
2023	15,815	N/A	N/A	0	15,114	701	15,815	47.2
2024	16,026	N/A	N/A	0	15,319	707	16,026	47.3
2025	16,224	N/A	N/A	0	15,516	708	16,224	47.4

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

* Estimated values for 2015

2.3 Monthly Peak Demand and Net Energy for Load

Schedule 4 shows peak demand and net energy for load by month for 2015 actuals and 2016 through 2017 forecasts.

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

Month	2015 Actual		2016 Forecast		2017 Forecast	
	Peak Demand (MW)[1]	NEL (GWh)	Peak Demand (MW)[2]	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	2,826	1,109	3,307	1,150	3,481	1,176
February	3,593	1,051	2,900	976	2,939	1,005
March	2,069	1,009	2,438	996	2,513	1,023
April	2,362	1,083	2,319	1,005	2,375	1,032
May	2,821	1,275	2,651	1,208	2,691	1,232
June	3,021	1,375	2,816	1,317	2,850	1,340
July	2,935	1,393	2,945	1,412	2,985	1,434
August	3,021	1,406	3,024	1,415	3,082	1,445
September	2,845	1,254	2,794	1,287	2,835	1,310
October	2,470	1,079	2,508	1,089	2,573	1,124
November	2,471	1,034	2,498	978	2,567	1,004
December	2,065	1,036	2,706	1,092	2,795	1,124
ANNUAL		**14,104**		**13,925**		**14,249**

[1] Peak Demand includes interruptible load; Excludes Distributed Generation, Load Management and SEPA allocations

[2] Peak Demand Excludes Interruptible Load, Distributed Generation, Load Management and SEPA allocations.

Note: Peak Demand for January 2016 is Actual.

2.4 Fuel Requirements

Seminole's coal, oil, and natural gas requirements for owned and future generating units are shown on Schedule 5 below.

Schedule 5
Fuel Requirements For Seminole Generating Resources

Fuel Requirements		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Nuclear		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-	-
Coal		1000 Tons	3,231	3,048	3,072	3,272	3,284	3,167	3,320	3,154	2,902	3,045	3,070	2,982
Residual	Total	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	Steam	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	CC	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
	CT	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	-
Distillate	Total	1000 BBL	20	33	35	37	37	36	38	36	33	38	38	49
	Steam	1000 BBL	19	32	35	37	37	36	38	36	33	35	35	34
	CC	1000 BBL	1	1	-	-	-	-	-	-	-	3	3	14
	CT	1000 BBL	-	-	-	-	-	-	-	-	-	-	-	1
Natural Gas	Total	1000 MCF	19,250	18,895	26,486	27,644	27,248	28,789	28,129	38,259	48,144	49,279	50,326	56,447
	Steam	1000 MCF	-	-	-	-	-	-	-	-	-	-	-	-
	CC	1000 MCF	18,346	17,529	25,567	26,844	26,263	28,189	27,628	37,913	47,815	47,736	48,275	51,098
	CT	1000 MCF	904	1,366	919	800	985	600	501	346	329	1,543	2,051	5,349

NOTE: Above fuel is for existing and future owned generating resources (excludes purchased power contracts).
Totals may not add due to rounding.

2.5 Energy Sources by Fuel Type

Seminole's total system energy sources in GWh and percent for each fuel type are shown on Schedules 6.1 and 6.2, respectively, on the following pages. Generation listed under renewable reflects the renewable units output but Seminole may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements. Seminole's additional requirements for capacity beyond 2021 are assumed to be from gas/oil resources. Due to concerns over proposed environmental regulations that would impact coal units negatively, future coal generation was not currently considered as a viable resource option.

Schedule 6.1
Energy Sources (GWh)

Energy Sources		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inter-Regional Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Coal		GWh	8,159	7,803	7,680	8,151	8,193	7,895	8,274	7,815	7,136	7,498	7,563	7,363
Residual	Total	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	Steam	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CC	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CT	GWh	-	-	-	-	-	-	-	-	-	-	-	-
Distillate	Total	GWh	35	36	37	39	43	42	37	38	29	35	35	50
	Steam	GWh	23	19	21	22	22	21	22	21	19	20	20	20
	CC	GWh	12	17	15	14	18	18	15	13	10	14	15	28
	CT	GWh	-	-	1	3	3	3	0	4	0	1	0	2
Natural Gas	Total	GWh	4,737	5,333	5,211	5,413	5,764	6,395	6,291	6,987	7,912	7,767	8,000	8,625
	Steam	GWh	-	-	-	-	-	-	-	-	-	-	-	-
	CC	GWh	4,570	5,052	5,093	5,294	5,579	6,256	6,200	6,901	7,875	7,603	7,787	8,086
	CT	GWh	167	281	118	119	185	139	91	86	37	164	213	539
NUG		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Renewables *		GWh	923	932	997	646	566	538	531	530	525	515	428	186
Other		GWh	-	-	-	-	-	-	-	-	-	-	-	-
Net Energy for Load		GWh	13,854	14,104	13,925	14,249	14,566	14,870	15,133	15,370	15,602	15,815	16,026	16,224

NOTE: Net interchange, unit power purchases and DEF and FPL system purchases are included under source fuel categories.
Totals may not add due to rounding.
* Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

Schedule 6.2
Energy Sources (Percent)

Energy Sources		Units	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inter-Regional Interchange		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Coal		%	58.89%	55.32%	55.15%	57.20%	56.25%	53.09%	54.67%	50.84%	45.74%	47.41%	47.19%	45.38%
Residual	Total	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Steam	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distillate	Total	%	0.25%	0.26%	0.27%	0.27%	0.30%	0.28%	0.24%	0.25%	0.19%	0.22%	0.22%	0.31%
	Steam	%	0.16%	0.14%	0.15%	0.15%	0.15%	0.14%	0.15%	0.14%	0.12%	0.13%	0.12%	0.12%
	CC	%	0.09%	0.12%	0.11%	0.10%	0.12%	0.12%	0.10%	0.08%	0.06%	0.09%	0.09%	0.17%
	CT	%	0.00%	0.00%	0.01%	0.02%	0.02%	0.02%	0.00%	0.03%	0.00%	0.01%	0.00%	0.01%
Natural Gas	Total	%	34.19%	37.81%	37.42%	37.99%	39.57%	43.01%	41.57%	45.46%	50.71%	49.11%	49.92%	53.16%
	Steam	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CC	%	32.99%	35.82%	36.57%	37.15%	38.30%	42.07%	40.97%	44.90%	50.47%	48.08%	48.59%	49.84%
	CT	%	1.20%	1.99%	0.85%	0.84%	1.27%	0.93%	0.60%	0.56%	0.24%	1.04%	1.33%	3.32%
NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Renewables		%	6.66%	6.61%	7.16%	4.53%	3.89%	3.62%	3.51%	3.45%	3.36%	3.26%	2.67%	1.15%
Other		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Net Energy for Load		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

NOTE: Net interchange, unit power purchases and DEF and FPL system purchases are included under source fuel categories.
Totals may not add due to rounding.
* Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements

3. FORECASTING METHODS AND PROCEDURES

3.1 Forecasting Methodology

Seminole adheres to generally accepted methodology and procedures currently employed in the electric utility industry to model number of consumers, energy and peak demand. Models are developed using regression and time series techniques and each Member Cooperative is modeled separately. Seminole produces monthly forecasts for each Member system and, when applicable, by multiple rate classifications. Seminole's system forecast is the aggregate of Member system forecasts.

3.1.1 Consumer Model

Numbers of consumers are modeled with regression and time-series techniques. Model input data sources include Member Rural Utilities Services Form-7 Financial and Statistical Reports (RUS Form-7), Moody's Economic Consumer and Credit Analytics (ECCA) and University of Florida's Bureau of Economic and Business Research (UF BEBR). Explanatory variables analyzed in these models include population, number of households, housing stock, gross county product and employment.

Consumers are modeled by Member total and by rate classification. Rate class forecasts are reconciled to match in aggregate the total consumer forecasts by each Member. Territorial agreements and information provided directly from Member representatives regarding anticipated changes in service territories are incorporated in forecast projections. The "other" consumer class represents a small portion of Member energy sales, including irrigation, street and highway lighting, public buildings and sales for resale.

3.1.2 Energy Model

Forecasts of Member energy purchases from Seminole are developed using regression

and time-series techniques. Model input data sources include Seminole's System Operations Power Billing System (PBS), RUS Form-7, Moody's ECCA, UF BEBR and AccuWeather. Explanatory variables analyzed in this model include heating and cooling degrees, population, number of households, housing stock and gross county product. The dependent variable, Member energy purchases from Seminole, is projected by aggregating hourly delivery point meter load to the monthly aggregate level.

Member rate class energy purchases from Seminole are projected by scaling RUS Form-7 energy sales to end-users by distribution loss factors. Rate class energy purchases forecasts are reconciled to match in aggregate the Member-total purchases forecasts. Historical reductions in energy consumption due to conservation and efficiency are reflected in historical sales and purchases data and are implied in forecasts.

3.1.3 Peak Demand Model

Maximum peak demand is modeled by month and by season for each Member system using regression and time-series techniques. Model input data sources include Seminole's PBS, Moody's ECCA, UF BEBR and AccuWeather. Explanatory variables analyzed in this model include heating and cooling degrees, minimum and maximum temperature, population, number of households, housing stock, gross county product and load factor.

Seasonal peak models are designed to predict winter and summer peaks based on a range of months when the highest peaks can be expected to occur in each season. Winter seasonal peak models regress the highest peak during November through March of each year against contemporaneous explanatory variables. Summer seasonal peak models regress the highest peak beginning as early as May and as late as September of each year against contemporaneous explanatory variables. Seasonal peak forecasts replace monthly model forecast results for the

month each seasonal peak is most likely to occur.

Seminole's maximum demand is the aggregate of the one-hour simultaneous demands of all Members that maximizes the peak of the system in a single month. Forecasts of Seminole maximum demand is derived by applying coincident factors to Member-maximum demand forecasts. Future peak demands coincident with Seminole may be equal to or less than Member non-coincident maximum peaks, if the Member peak is normally not coincident with Seminole.

Load factor forecasts are derived through regression analysis of monthly temperatures and daily temperatures leading up to the peak day. These models are also developed by month and by season.

3.1.4 Alternative-Scenario Models

In addition to the base forecasts, Seminole produces high and low forecasts based on population growth alternatives provided by UF BEBR. Seminole's system is primarily residential and population growth is the primary driver for load growth. Therefore, high and low population scenarios, rather than alternative economic growth scenarios, are developed for each Member system. Seminole also forecasts load conditions given mild and severe temperatures in a Member's geographical region. Last, we show a set of alternative projections associated with the statistical error of each model at the ninety-five percent prediction interval.

3.2 Load Forecast Data

The primary resources for load forecasting are weather data, economic data, Member retail data and delivery point meter data. Number of consumers and sales by consumer class are provided by Members through the Form-7 financial report. Hourly delivery point load data is provided monthly by Seminole's System Operations department. Independent source data for economic and demographic statistics are provided by government and credit rating agencies, as

well as local universities. A listing of load forecast data sources is provided below.

3.2.1 Materials Reviewed and/or Employed

Load Data by Delivery Point

- Seminole's System Operations' Power Billing System (PBS)

Retail Number of Consumers, Energy Sales by Rate Class:

- Rural Utilities Services Form-7 Financial and Statistical Reports (RUS Form-7)

Individual Large Consumer Loads Over 1000 kVA:

- Member provided

Demographic and Economic Indicators:

- Moody's Analytics Economic Consumer and Credit Analytics (ECCA)
- University of Florida Bureau of Economic and Business Research (UF BEBR)

Weather Data:

- AccuWeather

3.3 Significant Load Forecast Assumptions

3.3.1 Economic Assumptions

Seminole Members serve electricity to primarily rural areas within 42 counties in the north, central and south regions of Florida, which differ uniquely in geography, weather, and natural resources. These large, low-density land areas are largely undeveloped. Population growth in Seminole's territory is sensitive to national economic and demographic factors that influence population migration from other states and metropolitan areas within Florida.

This load forecast reflects expectations that the national economy, and Florida's economy in particular, will continue to recover from the Great Recession over the next several years. In

addition, Member territories will likely benefit from consumer growth due to "baby-boomer" retiree migration into Florida from other states. Improving economic conditions and expected net migration are leading indicators for overall load growth. Despite the potential growth opportunities however, electricity usage per residential consumer trends over the last decade for electric utilities in the state of Florida are on average flat to negative and Seminole projects this trend will generally continue into the future.

3.3.2 Weather Assumptions

Hourly temperature data for 25 weather stations in the proximity of Member service territories are provided by AccuWeather. Weather statistics for each Member's geographical area are derived from a set of weather stations that represent the optimal simple average combination of weather station temperature observations that best project Member aggregate load by date and time, using the lowest mean absolute percent error as an indicator of statistical efficiency.

Historical weather statistics input into forecast models include monthly average, minimum and maximum temperatures, as well as monthly heating and cooling degree days. Monthly heating degree days represent the sum of degrees each daily average temperatures falls below 61° Fahrenheit, which is an approximate temperature when consumers turn on heating devices. Alternatively, monthly cooling degree days represent the sum of degrees each daily average temperatures exceeds 72° Fahrenheit, which is an approximate temperature when consumers turn on A/C units.

Normal weather statistics are the thirty year median of historical observations by month. Seasonal weather statistics are the thirty year median of historical observations by month in which the highest peak demand occurred in a summer and winter season. Extreme weather used for alternative-scenario forecasts include the tenth and ninetieth percentile of historical

temperatures, representing mild and severe events, respectively.

4. FORECAST OF FACILITIES REQUIREMENTS

Seminole's forecasts of capacity and demand for the projected summer and winter peaks are in the following Schedules 7.1 and 7.2, respectively. The forecasts include the addition of approximately 1,700 MW of capacity by 2025. Such capacity is needed to replace expiring purchased power contracts and to serve increased Member load requirements while maintaining Seminole's reliability criteria.

Seminole's capacity expansion plan includes the need for four 224 MW class combustion turbine units and one 741 MW combined cycle plant, none of which are currently sited. The four combustion turbine units are scheduled to enter service in December 2021, December 2022, and two units in December 2024. In addition, by June 2021, Seminole also has a need for 741 MW of combined cycle capacity. A final decision as to whether Seminole will construct and own these additional facilities will be based upon future economic studies. The inclusion of these units in Seminole's capacity expansion plan does not represent at this time a commitment for construction by Seminole.

In March of 2015 Seminole issued a request for proposals for 2 MW of solar photovoltaic (PV) energy either through an Engineer, Procure, and Construct (EPC) contract or through a Purchase Power Agreement (PPA) to be in commercial operation on or before November 2, 2016. Seminole has incorporated a 2 MW solar photovoltaic facility into Seminole's ten year plan. On March 21 2016 Seminole finalized agreements for a 2.2 MW solar facility to be constructed at Seminole's MGS site in Hardee County.

Schedule 7.1
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak

Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)			Firm Capacity Export (MW)	QFs (MW)	Capacity Available (MW)		System Firm Summer Peak Demand (MW)		Reserve Margin Before Maintenance		Scheduled Maintenance (MW)	Reserve Margin After Maintenance	
		PR and FR	Other Purchases	Total			Total	Less PR and FR	Total	Obligation	MW	% of Pk		MW	% of Pk
2016	2,012	0	1,595	1,595	0	0	3,607	3,607	3,024	3,024	583	19%	0	583	19%
2017	2,012	0	1,650	1,650	0	0	3,662	3,662	3,082	3,082	580	19%	0	580	19%
2018	2,012	0	1,635	1,635	0	0	3,647	3,647	3,143	3,143	504	16%	0	504	16%
2019	2,012	0	1,885	1,885	0	0	3,897	3,897	3,201	3,201	696	22%	0	696	22%
2020	2,012	0	1,883	1,883	0	0	3,895	3,895	3,257	3,257	639	20%	0	639	20%
2021	2,661	0	1,135	1,135	0	0	3,796	3,796	3,291	3,291	505	15%	0	505	15%
2022	2,862	0	986	986	0	0	3,848	3,848	3,336	3,336	512	15%	0	512	15%
2023	3,063	0	833	833	0	0	3,896	3,896	3,377	3,377	519	15%	0	519	15%
2024	3,063	0	881	881	0	0	3,944	3,944	3,419	3,419	525	15%	0	525	15%
2025	3,465	0	522	522	0	0	3,987	3,987	3,457	3,457	530	15%	0	530	15%

NOTES: 1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.

2. Total Installed Capacity does not include SEPA or Solar.

3. Percent reserves are calculated at 15% of Seminole's obligation and include any surplus capacity.

Schedule 7.2
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak

Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)			Firm Capacity Export (MW)	QFs (MW)	Capacity Available (MW)		System Firm Winter Peak Demand (MW)		Reserve Margin Before Maintenance		Scheduled Maintenance (MW)	Reserve Margin After Maintenance	
		PR and FR	Other Purchases	Total			Total	Less PR and FR	Total	Obligation	MW	% of Pk		MW	% of Pk
2016/17	2,178	0	2,322	2,322	0	0	4,500	4,500	3,481	3,481	1,019	29%	0	1,019	29%
2017/18	2,178	0	2,322	2,322	0	0	4,500	4,500	3,539	3,539	960	27%	0	960	27%
2018/19	2,178	0	2,307	2,307	0	0	4,485	4,485	3,596	3,596	889	25%	0	889	25%
2019/20	2,178	0	2,557	2,557	0	0	4,735	4,735	3,649	3,649	1,086	30%	0	1,086	30%
2020/21	2,178	0	2,086	2,086	0	0	4,264	4,264	3,698	3,698	565	15%	0	565	15%
2021/22	3,143	0	1,174	1,174	0	0	4,317	4,317	3,744	3,744	573	15%	0	573	15%
2022/23	3,368	0	999	999	0	0	4,366	4,366	3,787	3,787	579	15%	0	579	15%
2023/24	3,368	0	1,046	1,046	0	0	4,413	4,413	3,827	3,827	586	15%	0	586	15%
2024/25	3,816	0	642	642	0	0	4,458	4,458	3,866	3,866	592	15%	0	592	15%
2025/26	3,816	0	685	685	0	0	4,501	4,501	3,904	3,904	597	15%	0	597	15%

NOTES: 1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.

2. Total Installed Capacity does not include SEPA or Solar.

3. Percent reserves are calculated at 15% of Seminole's obligation and include any surplus capacity.

4.1 Planned and Prospective Generating Facility Additions and Changes

Schedule 8 below shows Seminole's planned and prospective generating facility additions and changes.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No	Location	Unit Type	Fuel		Transportation		Const. Start Date	Comm. In-Service Date	Expected Retirement Date	Max Nameplate	Summer MW	Winter MW	Status
				Pri	Alt	Pri	Alt							
MGS Solar	1	Hardee County	PV	Sun		N/A		TBD	11/2016	Unk	2	2	2	P
Unnamed CC	1	TBA	CC	NG		PL		(1)	5/2021	Unk	741	649	741	P
Unnamed CT	1	TBA	CT	NG		PL		(1)	12/2021	Unk	224	201	224	P
Unnamed CT	2	TBA	CT	NG		PL		(1)	12/2022	Unk	224	201	224	P
Unnamed CT	3	TBA	CT	NG		PL		(1)	12/2024	Unk	224	201	224	P
Unnamed CT	4	TBA	CT	NG		PL		(1)	12/2024	Unk	224	201	224	P

NOTES:
(1) Future resource which may be existing or new as determined by future Request for Proposal results.
(2) Abbreviations – See Schedule 1
(3) MGS Solar is planned to be a leased facility

4.2 Proposed Generating Facilities

Schedule 9 below reports status and specifications of Seminole's proposed generating facilities.

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	MGS Solar Unit 1
2	Capacity a. Nameplate - AC (MW) b. Summer Firm - AC (MW): c. Winter Firm - AC (MW):	 2 0 0
3	Technology Type:	Photovoltaic
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 May 2016 November 2016
5	Fuel a. Primary fuel: b. Alternate fuel:	 Sun
6	Air Pollution Control Strategy	N/A
7	Cooling Method:	N/A
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 N/A N/A N/A 26.8% N/A
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 25 2,212 2,212 N/A N/A 0.02 N/A N/A N/A **NOTE:MGS Solar is planned to be a leased facility**

Schedule 9 **Status Report and Specifications of Proposed Generating Facilities**		
1	Plant Name & Unit Number	Unnamed Generating Station CC Unit 1
2	Capacity a. Summer (MW): b. Winter (MW):	 649 741
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 May 2018 May 2021
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	SCR
7	Cooling Method:	Wet Cooling Tower with Forced Air Draft Fans
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 4.50 2.50 93.00 50% 6684 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 30 808 742 66 Included in values above 12.72 1,728 0.08 N/A

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 1
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2019 December 2021
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.1 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2022) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 602 575 27 Included in values above 8.16 0.99* N/A *Variable O&M does not include start up charge of $7,301 per start

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 2
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2020 December 2022
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.11 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2023) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 613 588 25 Included in values above 8.40 1.01* N/A *Variable O&M does not include start up charge of $7,456 per start

Schedule 9 **Status Report and Specifications of Proposed Generating Facilities**		
1	Plant Name & Unit Number	Unnamed Generating Station CT Unit 3 & 4
2	Capacity a. Summer (MW): b. Winter (MW):	 201 224
3	Technology Type:	Combustion Turbine
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2022 December 2024
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	Dry Low NOx Burner
7	Cooling Method:	Air
8	Total Site Area:	TBD
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 1.4 3.5 95.11 5% 9915 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2024) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWH): K Factor:	 30 639 612 27 Included in values above 8.64 1.05* N/A *Variable O&M does not include start up charge of $7,765 per start

4.3 Proposed Transmission Lines

Schedule 10 below reports status and specifications of Seminole's proposed directly associated transmission lines corresponding with proposed generating facilities.

Schedule 10 **Status Report and Specifications of Proposed Associated Transmission Lines**		
1	Point of Origin and Termination:	Unknown
2	Number of Lines:	To be determined
3	Right-of-Way	To be determined
4	Line Length:	To be determined
5	Voltage:	To be determined
6	Anticipated Construction Timing:	To be determined
7	Anticipated Capital Investment:	To be determined
8	Substation:	To be determined
9	Participation with Other Utilities:	N/A

5. OTHER PLANNING ASSUMPTIONS AND INFORMATION

5.1 Transmission Reliability

In general, Seminole models its transmission planning criteria after the Florida Reliability Coordinating Council's ("FRCC") planning guidelines. The FRCC has modeled its planning guidelines consistent with the North American Electric Reliability Corporation's ("NERC") Reliability Standards. In addition, Seminole uses the following voltage and thermal criteria as guidelines for all stations:

1. No station voltages generally above 1.05 per unit or below 0.90 per unit under normal or contingency conditions.
2. Transmission facilities shall not exceed their applicable facility rating under normal or contingency conditions.

Since sites for future generation have not been selected, Seminole has not yet modeled any associated transmission or evaluated constraints and/or plans for alleviating such constraints.

5.2 Plan Economics

Power supply alternatives are compared against a base case scenario which is developed using the most recent load forecast, fuel forecast, operational cost assumptions, and financial assumptions. Various power supply options are evaluated to determine the overall effect on the present worth of revenue requirements (PWRR). All other things being equal, the option with the lowest long-term PWRR is normally selected. Sensitivity analyses are done to test how robust the selected generation option is when various parameters change from the base study assumptions (e.g., load forecast, fuel price, and capital costs of new generation).

5.3 Fuel Price Forecast

5.3.1 Coal

Spot and long-term market commodity prices for coal (at the mine) and transportation rates have shown increased volatility in recent years. This condition is expected to continue into the future, as environmental rules/standards, generating station retirements, coal supply/demand imbalances, coal transportation availability/pricing and world energy markets all combine to affect U.S. coal prices. The underlying value of coal at the mine will continue to be driven by changing domestic demand, reductions to the number of available coal suppliers, planned coal unit retirements, export opportunities for U.S. coal and federal/state mine safety rules/legislation affecting the direct mining costs. Additional coal delivered price increases and volatility will come from the cost of transportation equipment (railcars), handling service contracts and freight transportation impacts. Railroads are also affected by federal rules and legislative changes and fuel oil markets, which are impacting the volatility of the cost of rail service in the U.S. As long-term rail transportation contracts come up for renewals, the railroads have placed upward pressure on delivered coal costs to increase revenues to overcome operating cost increases and reduced demand. However, since 2012, lower natural gas prices have created an opportunity for electric utilities to swap natural gas for coal-fired generation and this price arbitrage may have reduced the railroads' near-term ability to apply upward pricing pressure during contract renewals. CSX Transportation, Inc. is Seminole's sole coal transport provider and the parties are operating under a confidential multi-year rail transportation contract. Seminole also has a confidential multi-year coal contract with Alliance Coal, LLC providing a majority of our coal requirements from the Illinois Basin. Both of these existing relationships reduce Seminole's coal price volatility risk for the near term.

5.3.2 Fuel Oil

The domestic price for fuel oils will continue to reflect the price volatility of the world energy market for crude oil and refined products. In late 2014 and through 2015, the price for fuel oil moved down significantly across the globe. Seminole is currently only purchasing ultra-low sulfur fuel oil for its generating stations.

5.3.3 Natural Gas

At year-end 2015, natural gas prices were near $2.30 per mmBtu and nominal Henry Hub prices are projected to increase slowly over the next ten years nearing $4.00 per mmBtu at the end of the ten-year study period.

5.3.4 Modeling of Fuel Sensitivity

Given the uncertainty of future fuel prices, the historical volatility of natural gas prices, and Seminole's reliance on gas as a significant component of its fuel portfolio, it is prudent to evaluate the impact of various gas prices on its alternative resources for meeting future needs. For this, Seminole incorporates both a high and low natural gas price forecast as a complement to its base case price forecast to support resource planning. Calculated with available market information (e.g. projected volatility of gas prices), Seminole’s high/low gas price curves form a statistical confidence interval around its base case price forecast. Seminole's base fuel price forecast for this Ten Year Site Plan does not take into account potential federal carbon emission initiatives, such as the proposed Clean Power Plan, that if approved, would impact the market prices for all fuels. If legislation that penalizes carbon emissions is enacted in future years, Seminole’s costs to use all fossil fuels will rise since all fossil fuels emit carbon dioxide when burned. Further, the price of natural gas and fuel oil relative to coal may rise because of the associated carbon emissions penalty imposed on coal, the competing fuel.

5.4 Coal/Gas Price Differential

The current natural gas and coal markets continue to reflect a significant narrowing, and even inversion during some years, of the price spread that existed between the two fuels over the prior ten years primarily due to soft gas prices. This spread is expected to remain compressed throughout the study period given the projected slow rise in gas prices.

5.5 Modeling of Generation Unit Performance

Existing units are modeled with forced outage rates and heat rates for the near term based on recent historical data. The long-term rates are based on a weighting of industry average data or manufacturers' design performance data.

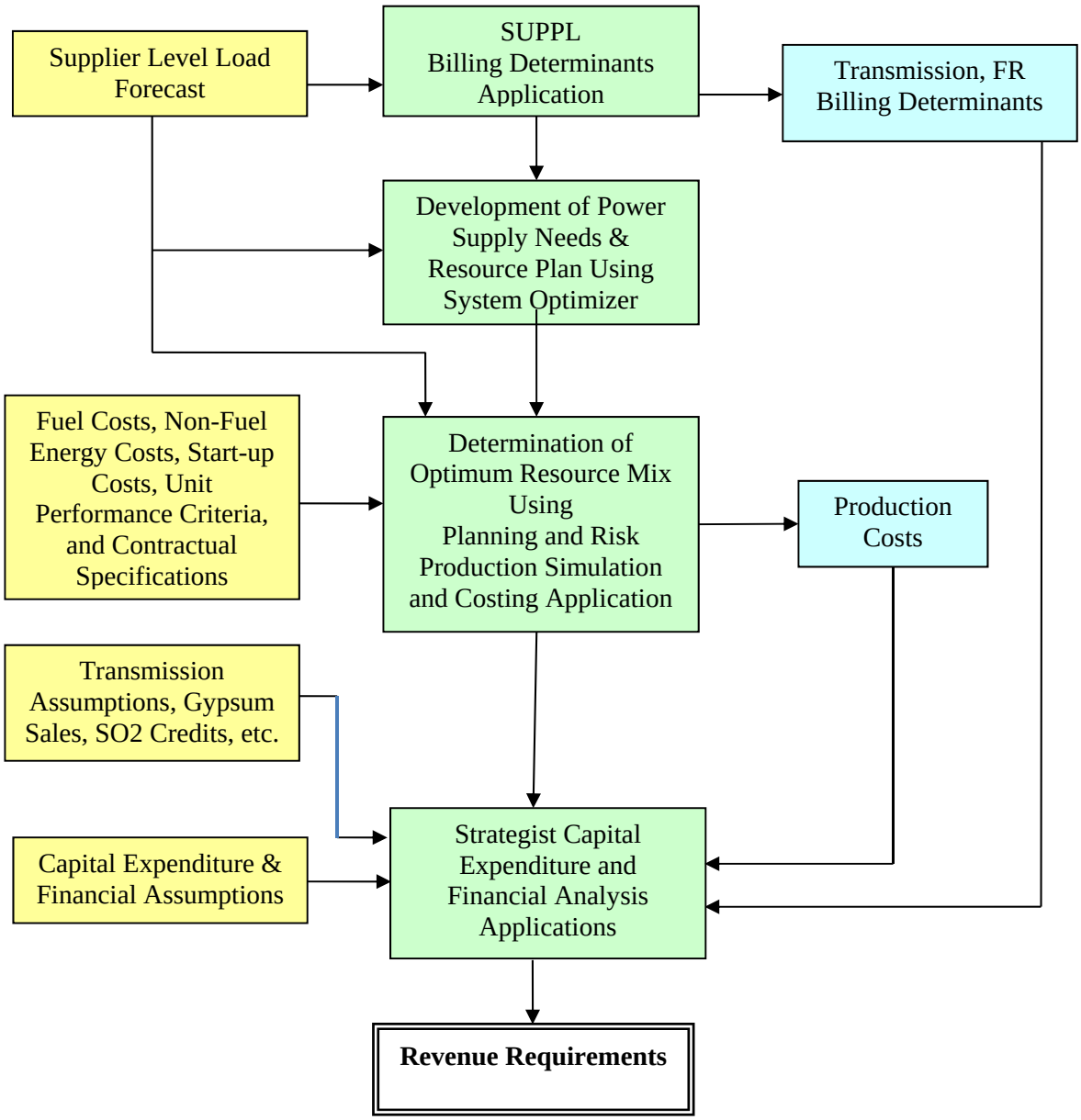
5.6 Financial Assumptions

Expansion plans are evaluated based on Seminole's forecast of market-based loan fund rates.

5.7 Resource Planning Process

Seminole's primary long-range planning goal is to develop the most cost-effective way to meet its Members' load requirements while maintaining high system reliability. Seminole's optimization process for resource selection is based primarily on total revenue requirements. As a not-for-profit cooperative, revenue requirements translate directly into rates to our Members. The plan with the lowest revenue requirements is generally selected, assuming that other factors such as reliability impact, initial rate impact, and strategic considerations are neutral. Seminole also recognizes that planning assumptions change over time, so planning decisions must be robust and are, therefore, tested over a variety of sensitivities. A flow chart of Seminole's planning process is shown below in Figure 5.1.

Figure 5.1
Resource Planning Process



5.8 Reliability Criteria

The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and its reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages; and to account for load forecast uncertainty. Seminole's primary reliability criteria is a minimum reserve margin of 15% during the peak season which ensures that Seminole has adequate generating capacity to provide reliable service to its Members and to limit Seminole's emergency purchases from interconnected, neighboring systems.

5.9 DSM Programs

Seminole promotes Member involvement in demand side management (DSM) through coincident peak billing and time-of-use energy rates as well as substation level conservation voltage reduction (CVR). The majority of Seminole's Members are active in managing their peak demand via one or more of these programs and several Members offer a time of use rate and a curtailable service rate to their commercial consumers for shifting energy usage from on-peak to off-peak periods.

Seminole's load management generation programs utilize standby generation on commercial consumer loads to lower demands at the time of the Seminole system peak demand. This program allows Seminole's Members to install distributed peaking generation resources on their system and/or to partner with their retail end-users to install "behind the meter" customer-based distributed generation (DG) to operate as dispatchable load management resources for Seminole's system, while providing load-center based generation to improve system reliability.

Seminole's load forecast accounts for reductions in peak demand resulting from DSM programs. Energy efficiency and energy conservation programs implemented by Seminole

Members have not been specifically quantified or estimated, but are both reflected in Seminole's load history and extrapolated into the future.

5.10 Strategic Concerns

In the rapidly changing utility industry, strategic and risk related issues are becoming increasingly important and will continue to play a companion role to economics in Seminole's power supply planning process. Seminole values resource diversity as a hedge against a variety of risks, as evidenced by our current generation portfolio. Long-term resources contribute stability while shorter term arrangements add flexibility. Seminole considers both system and unit-specific capacity when determining our reserve requirements. Resource location and transmission interconnection is also a consideration for Seminole in constructing its portfolio. Flexibility in fuel supply is another significant strategic concern. A portfolio that relies on a diverse number of fuel types is better protected against extreme price fluctuations, supply interruptions, and transportation constraints/instability. Seminole believes that the existing and future diversity in its power supply plan has significant strategic value, leaving Seminole in a good position to respond to both market and industry changes while remaining competitive.

The ongoing debate over the further need to regulate carbon emissions, mercury emissions and/or whether to establish renewable resource mandates has introduced new risks for electric utilities – among them is the risk of the most cost-effective fuels and associated technologies under current environmental regulations could change via new federal or state emissions rules. Using the best available information, Seminole is addressing these risks through its evaluation of a range of scenarios to assess what constitutes the best generation plan to ensure adequate and competitively priced electric service to its Members. Given the current regulatory environment, Seminole has assumed that all future large generation additions will be primarily

fueled with natural gas. Seminole is also reviewing the possibility of renewable generation additions, including solar.

5.11 Procurement of Supply-Side Resources

In making decisions on future procurement of power supply, Seminole compares self-build, acquisition and purchased power alternatives. Seminole solicits proposals from reliable counterparties. Seminole's evaluation of its options includes an assessment of economic life cycle cost, reliability, operational flexibility, strategic concerns and risk elements.

5.12 Transmission Construction and Upgrade Plans

Seminole is assessing future generation projects and needs for new, upgraded, or reconfigured transmission facilities over the ten-year planning horizon. At this time, Seminole has no specific transmission plans for future generating unit additions.

6. ENVIRONMENTAL AND LAND USE INFORMATION

6.1 Potential Sites

6.1.1 Gilchrist Site – Gilchrist County, Florida

Seminole owns land in Gilchrist County but has not made a final determination if or when the site will be used for any of Seminole's future resource requirements. The Gilchrist site is approximately five-hundred thirty (530) acres in size. The site is located in the central portion of Gilchrist County, approximately eight (8) miles north of the City of Trenton and may be suitable for installation of generation or transmission resources. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine communities. Few natural upland communities remain. Most of these large tracts have been

harvested, leaving xeric oak and pine remnants. A few wetland communities remain on the east side of the site with relatively minor disturbances due to adjacent silvicultural activities.

The initial site evaluation in 2007 included wetland occurrence information documented on National Wetland Inventory (NWI) map(s) from the U.S. Fish and Wildlife Service (USFWS), soils maps and information from the National Resource Conservation Service (NRCS), records of any listed plants or animals known from Gilchrist County that are available from online data and records maintained by the Florida Natural Areas Inventory (FNAI) and the Atlas of Florida Vascular Plants maintained by the University of South Florida Herbarium, lists of federally listed plants and animals maintained by USFWS, and records of eagle nest locations and wading bird rookeries that might occur within the site available on the Florida Fish and Wildlife Conservation Commission (FWC) website. At such time as Seminole has determined the Gilchrist site should be considered a preferred site for the construction of generation or transmission facilities, Seminole will update the site evaluation and will obtain approval of the site certification application.

6.1.2 Seminole Generating Station (SGS) - Putnam County, Florida

SGS is located in a rural unincorporated area of Putnam County approximately five (5) miles north of the City of Palatka. The site is one thousand nine-hundred seventy-eight (1,978) acres bordered by U.S. 17 on the west, and is primarily undeveloped land on the other sides. The site was certified in 1979 (PA78-10) for two 650 MW class coal-fired electric generating units, SGS Units 1 & 2.

The area around the SGS site includes mowed and maintained grass fields and upland pine flatwoods. Areas further away from the existing units include live oak hammocks, wetland conifer forest, wetland hardwood/conifer forest, and freshwater marsh. A small land parcel

located on the St. Johns River is the site for the water intake structure, wastewater discharge structure, and pumping station to supply the facility with cooling and service water.

The primary water uses for SGS Units 1 and 2 are for cooling water, wet flue gas desulfurization makeup, steam cycle makeup, and process service water. Cooling and service water is pumped from the St. Johns River and groundwater supplied from on-site wells is for steam cycle makeup and potable use. The site is not located in an area designated as a Priority Water Resource Caution Area by the St. Johns River Water Management District.

The local government future land use for the area where the existing units are located is designated as industrial use, and the site has not been listed as a natural resource of regional significance by the regional planning council.

Water conservation measures that are incorporated into the operation of SGS include the collection, treatment and recycling of plant process wastewater streams. This wastewater reuse minimizes groundwater and service water uses. A portion of recirculated condenser cooling water (cooling tower blowdown) is withdrawn from the closed cycle cooling tower and discharged to the St. Johns River. Site stormwater is reused to the maximum extent possible and any not reused is treated in wet detention ponds and released to onsite wetlands.

6.2 Preferred Sites

6.2.1 Midulla Generating Station (MGS) – Hardee County, Florida

MGS is located in Hardee and Polk Counties about nine (9) miles northwest of Wauchula. The site is bordered by County Road 663 on the east and by The Mosaic Company on the south, north and west. Payne Creek flows along the site's south and southwestern borders. The site was originally strip-mined for phosphate and was reclaimed as pine flatwoods, improved pasture, and a cooling reservoir with a marsh littoral zone. The proposed solar project

will be located on approximately 29-acres of land on the west side of the current plant entrance road and to the north of three onsite above ground storage tanks. A more detailed description of environmental, land use, as well as water use and supply, is available in the site certification application PA-89-25SA.

6.2.1.1 Land and Environmental Features

a. U.S. Geological Survey Map

   See Map 5

b. Proposed Facilities Layout

   The current proposed configuration of the single-axis tracking solar facility is attached. See Map 6

c. Map of Site and Adjacent Areas

   See Map 7

d. Existing Land Uses of Site and Adjacent Areas

   The existing land use for the majority of MGS is listed as utilities and zoned as industrial. There is a large reservoir and some wetlands located onsite as well. The solar PV area of the site will be located in an area that is currently active cattle pasture. The adjacent areas include reclaimed mine lands with both forested and non-forested uplands and wetlands interspersed, as well as industrial land use designations.

e. General Environmental Features On and In the Site Vicinity

   1. Natural Environment

      The majority of the site is currently made up of the MGS facilities, a 570-acre cooling reservoir, pastureland and some forested and non-forested

uplands and wetlands interspersed. The PV site is to be built completely on an area that is currently pastureland.

2. Listed Species

   A Florida Natural Areas Inventory (FNAI) database query was done for the site and indicated no documented occurrences of any state or federal listed species within 1-mile. Wildlife field surveys were performed on August 26 and 27, as well as December 8, 2015, and no listed species or signs of their presence were observed. Based on this information, no negative impacts to threatened or endangered species are anticipated as a result of the PV project.

3. Natural Resources of Regional Significance Status

   There are no natural resources of regional significance on or adjacent to the site.

4. Other Significant Features

   Seminole is not aware of any other significant site features.

f. Design Features and Mitigation Options

   The design includes construction of a single-axis tracking solar PV facility with approximately 2.2 MW of power generation.

g. Local Government Future Land Use Designations

   The Hardee County Future Land Use Map shows the entire site designated under the industrial category which should include solar PV.

h. Site Selection Criteria Process

   The Seminole Solar site at MGS has been selected as the location of the PV

facility based on various factors including system load, interconnection availability, and proximity to existing Seminole operations and maintenance personnel, as well as economics.

i. Water Resources

Minimal amounts of water, if any, would be required for cleaning the PV panels. The water would be provided by water trucks or obtained from existing onsite permitted water resources.

j. Geological Features of Site and Adjacent Areas

The soil types found on and adjacent to the site include Smyrna fine sand, Myakka fine sand, Basinger fine sand, Floridana muck fine sand (depressional), Ona fine sand, and Bradenton-Felda-Chobee Association (frequently flooded). The soils are disturbed in most areas since the site is on reclaimed mine lands.

k. Projected Water Quantities for Various Uses

The PV site requires minimal water, if any, for the cleaning of the panels in the absence of sufficient rainfall.

l. Water Supply Sources by Type

A water supply source is not required for this site. Any needed water may be brought to the site by water truck or obtained from existing onsite permitted water resources.

m. Water conservation Strategies Under Consideration

The PV site does not require a permanent water source. Water conservation strategies include minimizing water use by cleaning the panels with water only in the absence of sufficient rainfall and leaving the vegetation in and around the site

as is with no required watering.

n. Water Discharges and Pollution Control

Although no discharges of water are planned at the PV site, the facility will implement Best Management Practices (BMP) to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal and Pollution Control

No traditional fuel sources are required and no waste products will be generated at the site.

p. Air Emissions and Control Systems

Solar PV does not generate air emissions.

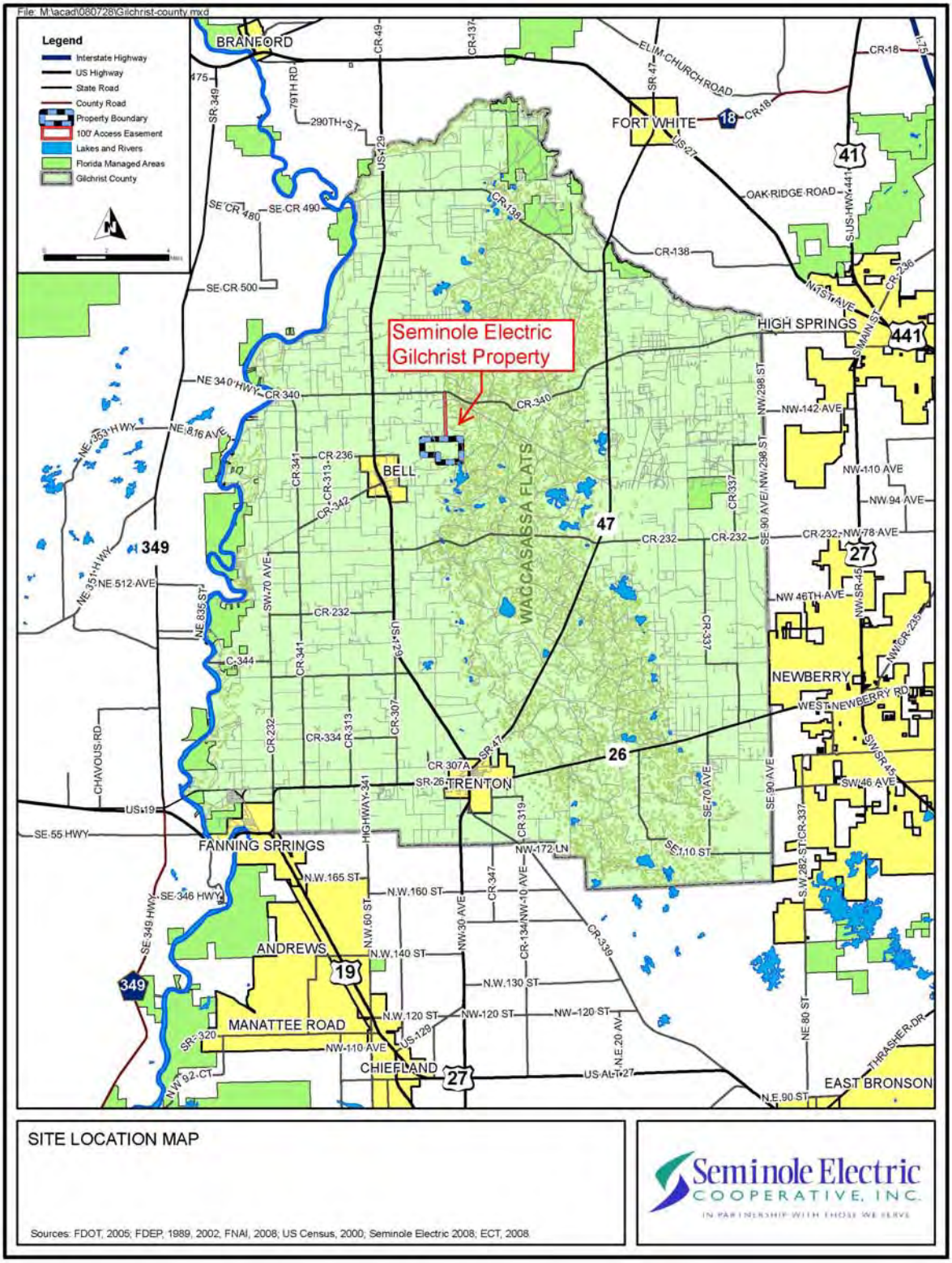
q. Noise Emissions and Control Systems

Solar PV does not generate noise.

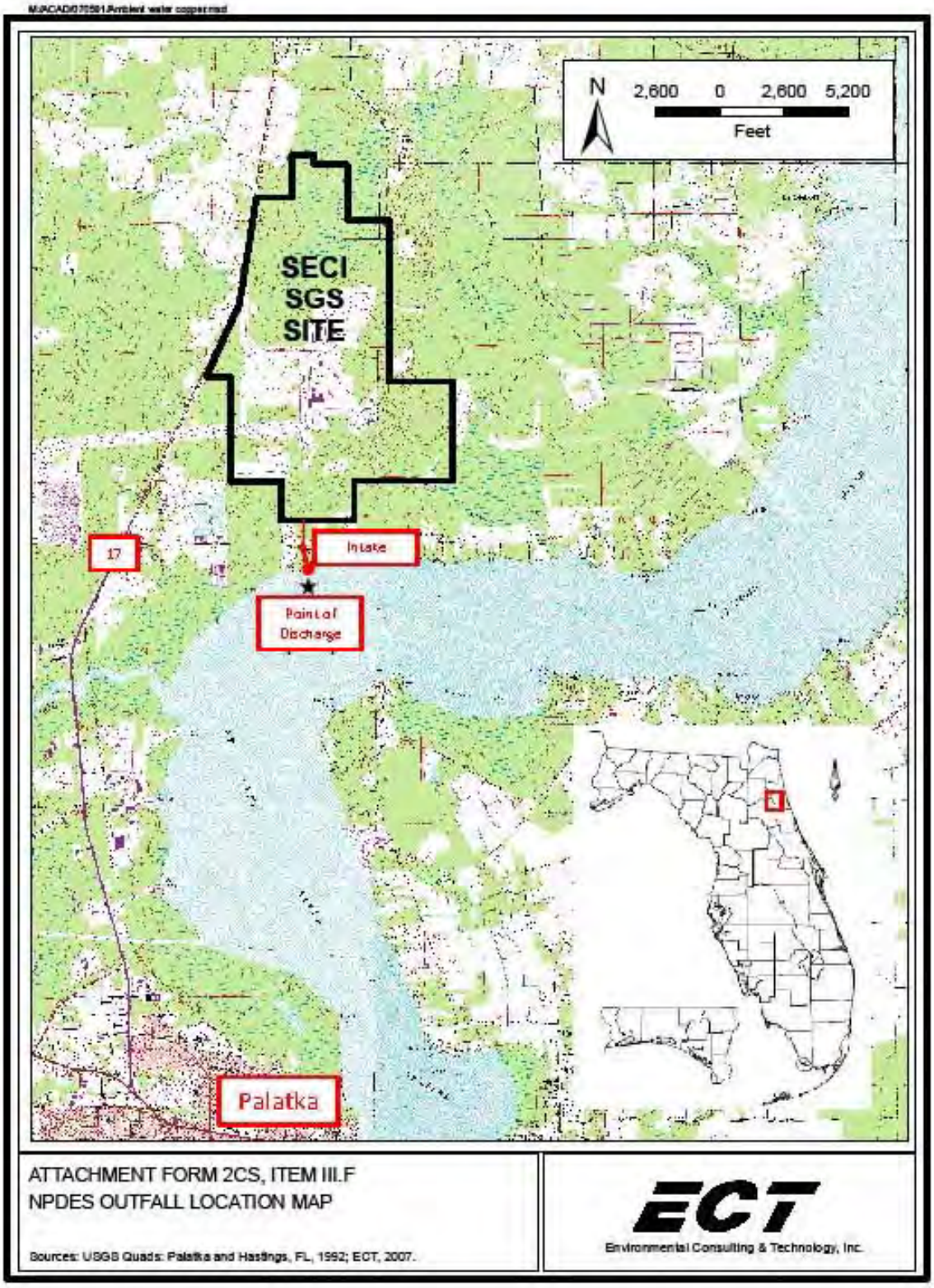
r. Status of Applications

Applications will be made to the Florida Department of Environmental Protection (FDEP) to amend the current Conditions of Certification for MGS. Hardee County will be contacted for local development approval.

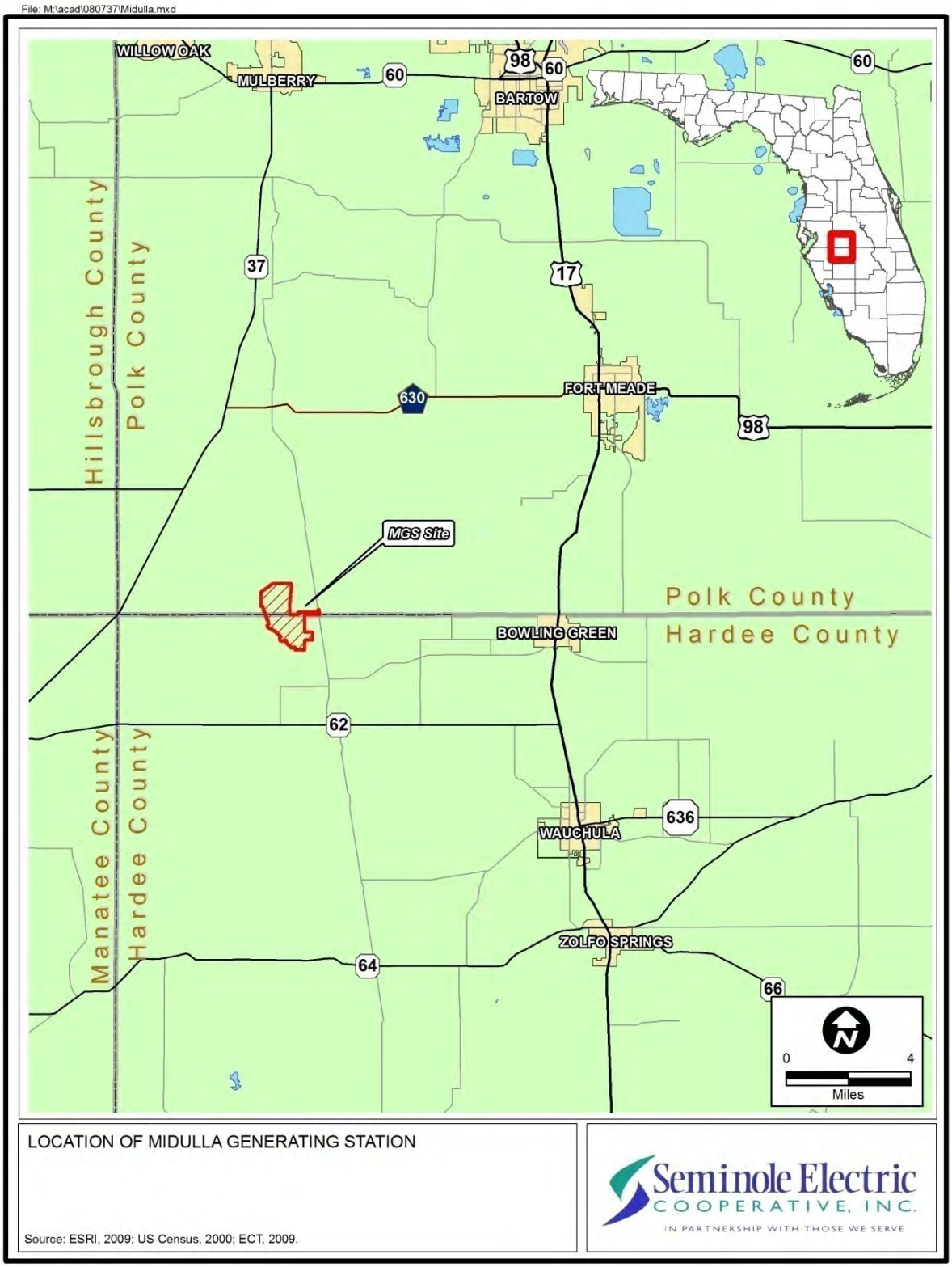
Map 3


File: M:\acad\080728\Gilchrist-county.mxd
Legend
Interstate Highway
US Highway
State Road
County Road
Property Boundary
100' Access Easement
Lakes and Rivers
Florida Managed Areas
Gilchrist County
Seminole Electric
Gilchrist Property
BRANFORD
FORT WHITE
HIGH SPRINGS
BELL
NEWBERRY
TRENTON
FANNING SPRINGS
ANDREWS
MANATTEE ROAD
CHIEFLAND
EAST BRONSON
WACCASASSA FLATS
SITE LOCATION MAP
Sources: FDOT, 2005; FDEP, 1989, 2002, FNAI, 2008; US Census, 2000; Seminole Electric 2008; ECT, 2008
Seminole Electric
COOPERATIVE, INC.

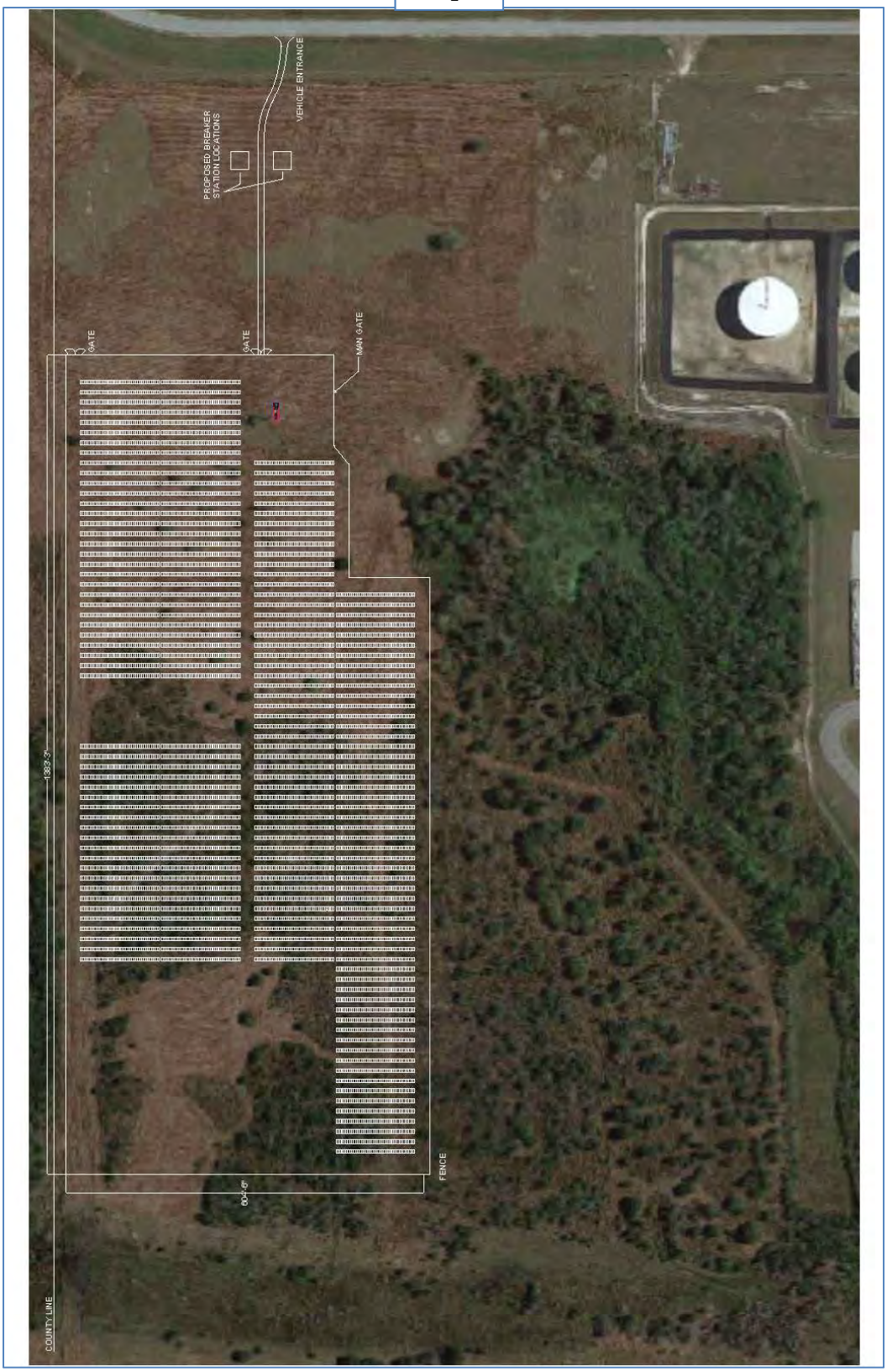
Map 4


N
2,600 0 2,600 5,200
Feet
SECI
SGS
SITE
17
Intake
Point of
Discharge
Palatka
ATTACHMENT FORM 2CS, ITEM III.F
NPDES OUTFALL LOCATION MAP
Sources: USGS Quads: Palatka and Hastings, FL, 1992; ECT, 2007.
ECT
Environmental Consulting & Technology, Inc.

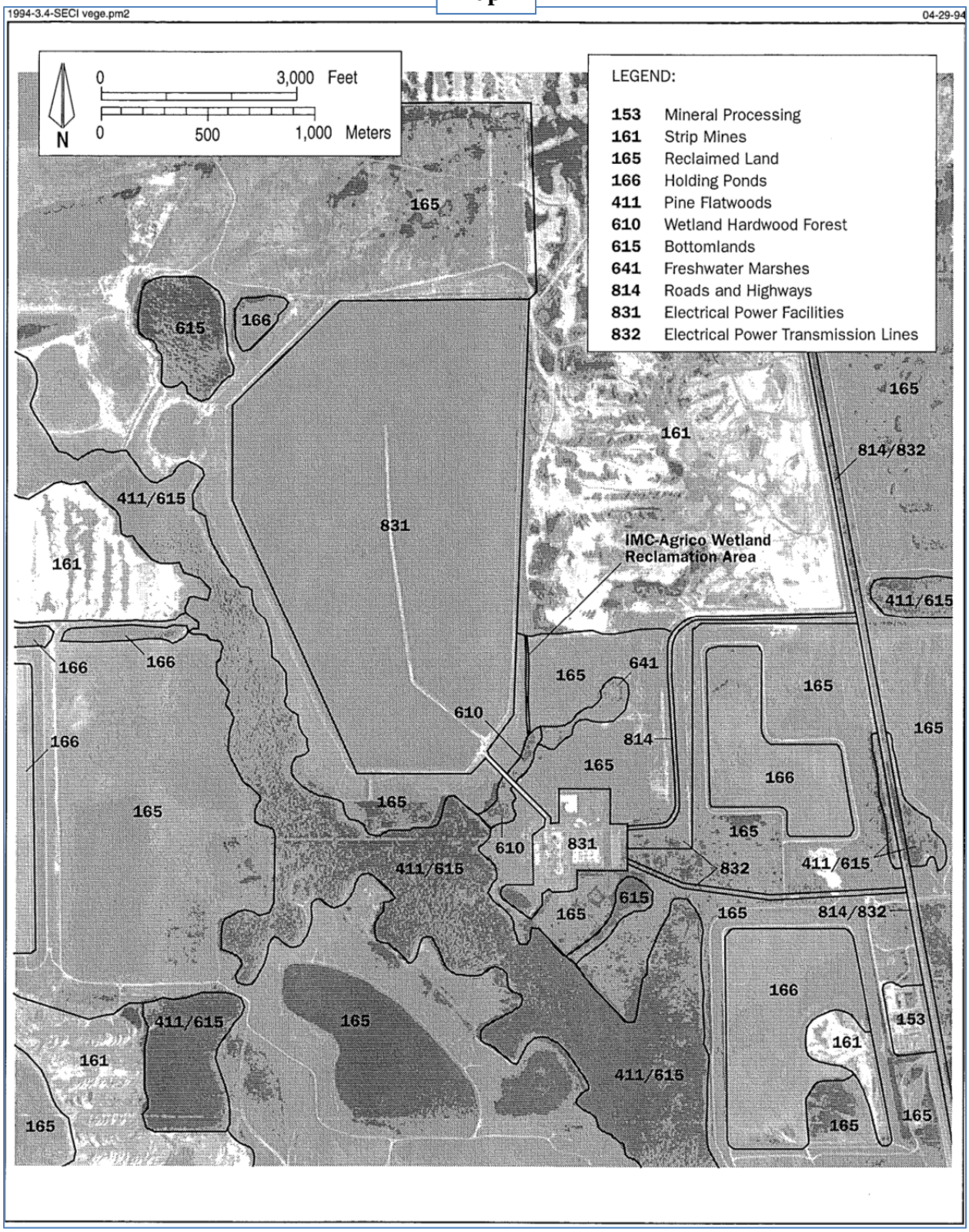
Map 5


File: M:\acad\080737\Midulla.mxd
WILLOW OAK
MULBERRY
BARTOW
FORT MEADE
BOWLING GREEN
WAUCHULA
ZOLFO SPRINGS
Hillsbrough County
Polk County
Manatee County
Hardee County
MGS Site
Polk County
Hardee County
60
98
37
17
630
62
636
64
66
0
4
Miles
LOCATION OF MIDULLA GENERATING STATION
Source: ESRI, 2009; US Census, 2000; ECT, 2009.
Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Map 6


PROPOSED BREAKER STATION LOCATIONS
VEHICLE ENTRANCE
GATE
GATE
MAIN GATE
1333'-3"
FENCE
COUNTY LINE

Map 7


1994-3.4-SECI vege.pm2
04-29-94
N
0 3,000 Feet
0 500 1,000 Meters
LEGEND:
153 Mineral Processing
161 Strip Mines
165 Reclaimed Land
166 Holding Ponds
411 Pine Flatwoods
610 Wetland Hardwood Forest
615 Bottomlands
641 Freshwater Marshes
814 Roads and Highways
831 Electrical Power Facilities
832 Electrical Power Transmission Lines
IMC-Agrico Wetland Reclamation Area

APPENDIX B

Seminole Electric Cooperative

Request for Proposal

& Addenda

Request for Proposals ("RFP")

Request for Firm Capacity
RFP No. FC 2021

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

March 1, 2016

Request for Proposals
RFP No. FC 2021

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1.0 Purpose
2.0 Description of Seminole Electric Cooperative, Inc.
3.0 RFP Provisions
4.0 Delivery to the Seminole System
5.0 Bidder Forms
6.0 Other Terms and Conditions
7.0 Reservation of Rights
8.0 Procedures for Application
9.0 Confidentiality
10.0 Bid Evaluation Process
11.0 Communication

Proposal Forms

All Bidders	Bidder Qualification Questionnaire
Schedule A	General Proposal Information
Schedule B	Firm Offer/Proposal Summary
Schedule C	Schedule for System Power Proposals
Schedule D	Schedules for New and Existing Unit Proposals

- Schedule D-1 Facility Information
- Schedule D-2 Pricing and Fuel Data
- Schedule D-3 Operating Performance Schedule
- Schedule D-4 Environmental and Regulatory Schedule
- Schedule D-5 Project Milestone Schedule
- Schedule D-6 Solar Energy Capacity Profile
- Schedule D-7 Air Emissions Schedule

Seminole Electric Cooperative, Inc.
RFP No. FC 2021

March 1, 2016
Request for Firm Capacity

1.0 Purpose

Seminole Electric Cooperative, Inc. ("Seminole") is seeking proposals from qualified and eligible bidders to provide up to 1,000 MW of firm capacity, beginning as early as June 1, 2021. Seminole has determined a need for capacity of 600 MW in June 2021, with total needs increasing to 1,000 MW in June 2022 and thereafter. Seminole encourages proposals of base, intermediate, and/or peaking capacity. Proposals providing demand side options will also be considered for evaluation. The evaluation among the proposals received will be seeking the least cost option, in consideration of all identified risks, when such resource(s) is operated as a part of Seminole's overall generation mix. Seminole is also evaluating self-build alternatives for the identified capacity needs.

2.0 Description of Seminole Electric Cooperative, Inc.

Seminole is an electric generation and transmission ("G&T") cooperative headquartered in Tampa Florida. Seminole provides wholesale electric service to nine (9) member electric distribution cooperatives ("Members"). The Members are located throughout peninsular Florida, serving loads located in 42 counties. More than 1,600,000 consumers rely on Seminole and its Members for electric service. Seminole has a current peak demand of approximately 3,500 MW, and continues to experience growth in its system.

Seminole supplies the Members' capacity and energy requirements from a mix of firm resources including both owned generation and purchased power agreements, supplemented by various interchange purchases. Seminole has an objective to continue to diversify its portfolio between resources it owns and purchased generation assets and is using this RFP to identify capacity and energy resources to help achieve this objective while meeting its future growth needs.

Seminole maintains "A" category investment grade credit ratings of A-/Stable with S&P and A3/Stable with Moody's. For additional information about Seminole, please see our website at **http://www.seminole-electric.com**.

3.0 RFP Provisions

3.1 This RFP is open to all parties, including, but not limited to: independent power producers, renewable energy providers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and electric utilities. Seminole will consider offers including purchased power proposals (system or tolling), generation proposals

that include Seminole taking an ownership/equity position in a portion of a facility, facility acquisitions, or proposals for firm energy.

3.2 Proposals received from specific units should be dispatchable and provide Seminole with scheduling flexibility (including real time control capability such as automatic generation control ("AGC")) and availability guarantees equivalent to the technical specifications of the units. Respondents should also indicate their ability to coordinate scheduled maintenance with Seminole.

3.3 Proposals sourced from a Seller's system of resources should be dispatchable and must offer intraday scheduling rights. Preference will be given to any proposals that can also provide contingency reserves, fast starts, and/or offer intra hour scheduling flexibility.

3.4 Seminole prefers the term of a proposal to be in the range of 2 years to 20 years, but may consider longer terms if proposed. Proposals longer than 30 years will not be considered.

3.5 Offers of capacity must be firm, from identifiable (either planned or existing) generating resources. Energy only products (such as Firm LD contracts) will be considered if adequate, reliable back-up capacity is specified and verifiable.

3.6 Proposals may be for less than the amount as shown in Section 1.0. However, proposals must be greater than a minimum of 25 MW.

3.7 Offers of capacity and energy may be from one or more resources. Such resources must be suitable to meet Seminole's firm load and/or reserve obligations Proposals based on system resources must provide Seminole with reliability equivalent to seller's firm native load customers.

3.8 Existing Seminole plant sites are not available for the addition of unit(s) to sell to Seminole.

3.9 Seminole also encourages the submission of proposals from renewable energy providers to meet its future power supply needs as defined in this RFP. Proposals from renewable resources do not have to be dispatchable, but must meet the 25 MW minimum stated in Section 3.6 above. Non-dispatchable renewable proposals of 75 MW or more will not be eligible to respond to this RFP and instead will need to pursue a standard offer agreement with Seminole, provided the facility has a Qualifying Facility certification under PURPA. Further details can be found on Seminole's website at **http://www.seminole-electric.com/index.php/S=0//site/qf**.

4.0 Delivery to the Seminole System

4.1 Seminole currently serves its load primarily through its own transmission system ("SSN") or through the transmission systems of Duke Energy Florida ("DEF") and Florida Power and Light Company ("FPL"). Wheeling and interconnection

arrangements and all costs to deliver the capacity and energy to the Seminole, DEF or FPL balancing authority areas are the responsibility of the bidder.

4.2 Proposed prices must include all integration and interconnection costs, and transmission network service upgrades to deliver the capacity and energy to one (or more) of the Seminole balancing authority areas.

4.3 All proposals must identify any wheeling and interconnection agreements with third parties that are required to deliver the capacity and energy to Seminole. Seminole requires that any transmission arrangements to deliver the offered capacity to the Seminole, DEF or FPL balancing authority areas to be firm. Seminole will accept and evaluate responses to the RFP in which arrangements of firm transmission for the delivery of energy to one of the Seminole balancing authority areas are in the process of being studied or finalized. In this case, the bidder should identify the underlying transmission service request, and provide Seminole with any existing studies and a summary of the study process and/or expected resolution.

4.4 For the benefit of the bidders in structuring their proposals, Seminole's forecasted peak loads in Winter 2022 in its three load serving balancing authority areas are as follows below. Bidders offering capacity amounts greater than the amounts listed in the SSN or FPL balancing authority areas will need to summarize their proposal to deliver the remainder of their offered capacity to one (or more) of the other balancing authority areas. Generally, Seminole does not want proposals for future generation resources to exceed the amount of its forecasted loads in any particular balancing authority area.

Balancing Authority Area	Winter Peak MW (2022)	Percentage (%) of Total Seminole Load
SSN	300	8
FPL	550	15
DEF	2,900	77
TOTAL	3,750	100

5.0 Bidder Forms

5.1 Bidders should complete and submit a Seminole Bidder Qualification Questionnaire ("BQQ") and Schedules A and B as part of each submittal. Schedules C through D will be completed by the bidders as required by the structure of their proposal. If

more than one submittal is made by a bidder, separate Schedules C through D must be prepared for each submittal.

5.2 All price quotes must be communicated on the attached Proposal Forms. Prices quoted shall always include all costs that Seminole would be expected to pay. Charges subject to change must be stated and estimates for the period provided along with their underlying assumptions.

6.0 Other Terms and Conditions

Each proposal must comply with all applicable federal and state laws. All permits, licenses, fees, emissions allowances, and environmental requirements are the responsibility of the bidder for the entire term of each proposal. If a resource detailed in a proposal is not yet in service, a detailed milestone schedule describing major project activities, including a permitting schedule, leading up to the commencement date for commercial service must also be provided. The minimum data required by Seminole to evaluate a bidder proposal is requested in Schedule D.

7.0 Reservation of Rights

Seminole expects to fulfill the capacity needs of this RFP through contracts resulting from this RFP, and/or from self-build options including joint ownership projects; however,

7.1 Seminole reserves the right to make resource commitments outside this RFP which result from (1) negotiated amendments to agreements with its current power suppliers, (2) negotiated arrangements with parties that Seminole is currently engaged in negotiations with for all or a portion of said capacity needs, or (3) negotiated arrangements for small power resources.

7.2 Seminole reserves the right, without qualification and at its sole discretion, to modify, supplement or withdraw this RFP and to reject any or all proposals or portions thereof or to waive irregularities or omissions. Those who submit proposals to Seminole do so without recourse against Seminole for either rejections by Seminole or failure to execute an agreement for any reason.

7.3 Seminole reserves the right to request further information, as necessary, to complete its evaluation of the proposals received.

7.4 No part of this RFP and no part of any subsequent communications with Seminole, its Members, trustees, employees, or officers shall be taken as providing legal, financial, or other advice, nor as establishing a commitment, promise or contractual obligation with a bidder.

7.5 Any negotiated contract shall be subject to the approval and award by the Seminole Board of Trustees.

8.0 Procedures for Application

8.1 A copy of this RFP, together with supporting forms, is on the Seminole website, "**www.seminole-electric.com**". The link to the RFP appears on the Seminole home page.

8.2 Bidders must submit their bid proposals via e-mail to the e-mail address below. Please note that an e-mail submission cannot exceed 20 MB in size. In addition, an **original bid proposal, signed by an authorized officer, plus two (2) copies must be mailed by either courier or U.S. Postal Service**. A separate point of contact for questions related to this RFP is defined in Section 11.4 below.

By Courier:
Seminole Electric Cooperative, Inc.
Attention: Mr. Timothy Nasello, Director of Supply Management
16313 North Dale Mabry Highway
Tampa, FL 33618

By U.S. Postal Service:
Seminole Electric Cooperative, Inc.
Attention: Mr. Timothy Nasello, Director of Supply Management
P.O. Box 272000
Tampa, FL 33688-2000

By E-Mail:
"**SeminolePowerRFP@seminole-electric.com**".

8.3 All proposals must arrive via e-mail by 5:00 PM Eastern Prevailing Time (EPT), **May 2, 2016**. Paper copies must arrive at Seminole's Tampa offices by 5:00 PM EPT on the next date (i.e., **May 3, 2016**). Seminole is not obliged to contact bidders concerning missing or incomplete forms. Only versions of the forms attached to this RFP may be used to submit proposals.

8.4 All bid packages should include any additional information required to support evaluation of the proposal, including a completed BQQ. Documents requested in support of the BQQ, including the applicant's most recent financial statements, must accompany the mailed versions of the proposals.

8.5 Seminole will not be assessing bidders a fee for any proposals submitted as a response to this RFP.

9.0 Confidentiality

9.1 Seminole recognizes that certain information contained in proposals submitted may be confidential and, as permitted by applicable law, will use reasonable efforts to maintain the information contained in the proposal as confidential. Seminole will not

treat submitted information as confidential if it already has the information, the information is clearly in the public domain or is readily available from public sources. However, Seminole reserves the right to submit the proposal to the Rural Utilities Service ("RUS") and to any other regulatory agency or judicial authority that may request it.

9.2 Seminole also reserves the right to disclose any or all of the information submitted in response to this request to any consultant(s) or attorney(s) retained by Seminole to assist with aspects of this process. Seminole will take reasonable steps to ensure that its consultant(s) or attorney(s) will also treat information received from bidders as confidential; however, Seminole will not be liable for any failure or for any damages of any consultant(s) or attorney(s) to do so. It is recommended that bidders clearly mark any response forms they desire to keep confidential as "Confidential".

10.0 Bid Evaluation Process

The procedures and criteria utilized to evaluate proposals will be as follows: first, to determine if the proposals are responsive to the RFP; second, to evaluate proposals from a technical, operational and commercial viewpoint, third, to evaluate proposals from an economic viewpoint, and fourth, if determined to be in the best interests of Seminole to develop a short-list for negotiations. Received proposals will be compared to Seminole's self-build alternatives as well as the other proposals. Seminole will use its planning and financial models to perform the analysis on the terms and conditions of each RFP proposal.

10.1 The economic evaluation of the RFP will use common economic assumptions for all proposals where appropriate.

10.2 Proposals may undergo a review from a technical and operational perspective on the following items:

- to ensure that the service offered is consistent with this RFP based upon the factors included herein, including, but not limited to:
  - a commercially viable term;
  - the reliability of the proposed power supply;
  - acceptable operational and scheduling characteristics;
  - acceptable fuel supply;
  - acceptable siting, construction and permitting plan (if applicable);
  - acceptable third party transmission arrangements (if applicable);
- to confirm that the capacity and energy will be delivered to the Seminole, DEF or FPL transmission systems, and can be delivered further to Seminole's member delivery points within the control areas of Seminole, DEF and/or the FPL; and if wheeling is required, that a firm transmission path will be available during the term;
- to evaluate the number and type of exceptions taken to the terms and

conditions of this RFP.

10.3 Proposals may then undergo a review from a commercial perspective, which will include but not be limited to the following, to ensure that the bidder has:

- adequate and pertinent experience, resources, and qualifications;
- the necessary financial assurance and operational viability to sustain an offer;
- made a commitment of guaranteed firm capacity to Seminole with adequate availability/non-performance guarantees and remedies;
- either itself, or through its guarantor, an investment grade credit rating, or is willing to post a letter of credit or other security acceptable to Seminole.

10.4 Seminole may conduct scenario and sensitivity analyses of proposals to evaluate risks and strategic value. The results of these analyses may be considered in Seminole's evaluation of proposals, including the selection of proposal(s) for the short list, if applicable.

11.0 Communication

11.1 Seminole expects to identify a short list by **August 19, 2016**. Contracts detailing the terms and conditions of completed agreement(s), if any, are expected to be executed by **January 31, 2017**.

11.2 This RFP is available on the Internet at **http://www.seminole-electric.com**, or by e-mail or U.S. mail. Please routinely check this web site for addendums and/or clarifications to this RFP.

11.3 Prospective bidders will be placed on Seminole's RFP e-mail distribution list for RFP updates. If your company intends to submit a proposal, please send your contact information (name, company name, title, phone and fax numbers, and e-mail address) to "**SeminolePowerRFP@seminole-electric.com**" no later than **March 15, 2016**.

11.4 If any prospective bidder has any questions or desires additional information related to this request for proposals, **such questions or information requests should be made in writing and directed via e-mail at "SeminolePowerRFP@seminole-electric.com"** to Mr. Jason Peters, Portfolio Director. Any RFP addendum(s), or question(s) of general interest and the respective answer will be posted on the above web site and directly e-mailed to parties that have provided their contact information to Seminole per Section 11.3 above.

Thank you for your interest in this RFP.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 1
ISSUED MARCH 18, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 1 in response to general questions and inquiries applicable to all potential bidders.

1. **RFP Proposal Forms.** Seminole has modified Schedule D-1, Facility Information. Modifications were made to the "Average Heat Rate Curves" portion of the form based on bidder questions. The changes made are as follows: 1) winter values were eliminated from Seminole's data request, 2) specific data for certain percentages of capacity states/unit output (100%, 80% 60% and minimum output were requested), and 3) comments were added to individual cells to facilitate bidder use of the form. The remaining forms were unchanged from those issued with the RFP on March 1, 2016.

2. **Seminole Self-Build Option.** Several bidders have requested general information on Seminole's self-build alternative. Seminole is evaluating a self-build combined cycle option. Generally, Seminole is reviewing both a 1x1 and a 2x1 combined cycle option. The power island equipment for the self-build project has not yet been selected, and multiple sites are being assessed. MW output will range from about 550 MW to 1150 MW, and any constructed generation will be expected to be fully commercial by June 2021.

3. **Proposals Beginning Before June 2021.** Several bidders have asked if their proposals can start before June 1, 2021. The reason Seminole chose June 1, 2021 as a start date is because that is the first period of significant capacity need in Seminole's portfolio. Any proposal with a start date prior to June 2021 will be considered compliant with the RFP and will be evaluated by Seminole staff. However, any proposals with an earlier than requested start date will be evaluated against Seminole's existing portfolio to ascertain any potential energy benefits, and capacity will have a minimal value, if any.

4. **Hourly Loads in the FPL Balancing Authority Area.** Several bidders have asked if they can obtain historical hourly loads for Seminole in the FPL BAA. Seminole has provided these historical loads (by individual delivery point) for years 2013-2015 as part of this RFP addendum so that it is available for all bidders.

5. **Variable Generation/Non-Dispatchable Generation.** Several bidders have asked if they can provide proposals of greater than 75 MW of non-dispatchable generation in response to the RFP. Seminole has reviewed the cap (less than 75 MW) in Section 3.9 of RFP FC 2021 and still prefers proposals of less than 75 MW. However, any proposal of 75 MW or greater will be considered compliant with the RFP and will be evaluated by Seminole staff.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 2
ISSUED APRIL 7, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 2 in response to general questions and inquiries applicable to all potential bidders. A number of bidders have asked for further detail regarding distribution, transmission facilities and wheeling.

1. **Seminole Network Resources – Transmission Level Interconnection.** If the proposed resource interconnects with 69kV (or higher) voltage on the transmission system in either of the Duke Energy Florida ("DEF") or Florida Power and Light ("FPL") balancing authority areas, Seminole will request to designate the resource a "designated network resource" for the respective balancing authority area. If a proposed resource is approved as a designated network resource, that resource will serve Seminole's native load in that balancing area and no incremental wheeling costs will be assessed. Similarly, if the project interconnects with the Seminole transmission system, there will be no incremental wheeling costs for the bidder or Seminole.

2. **Seminole Network Resources – Distribution Level Interconnection.** If the proposed resource interconnects at the distribution level on the FPL or DEF systems (below 69kV) there will be additional wheeling charges and losses for the bidder. The bidder is responsible for the distribution wheeling charges and the related energy losses. Under the RFP requirements, the bidder's delivery of energy must be made to Seminole at transmission level.

3. **Resources from SERC.** Seminole will accept proposals delivering to the FL-GA interface on firm transmission. Seminole will then request that the resource be a designated network resource on either the FPL or DEF transmission system and there will be no incremental wheeling costs.

Below is a list of Frequently Asked Questions regarding Transmission Arrangements for Proposals to RFP FC 2021:

Question: For this RFP, would projects that are in an interconnection queue have a preference over those not in the queue?

Answer: Yes. Proposals that are submitted without any work on interconnection/transmission wheeling may be considered non-compliant with the RFP requirements (see section 4.3).

Question: At the time of submission of the bid proposal, the supplier would not have any interconnection studies back from the transmission provider. Would this be an issue?

Answer: No. Per section 4.3 of the RFP, it is acceptable for interconnection or wheeling arrangements to be in study status. Generally, it would be unusual for a proposal to have secured all of the necessary transmission prior to submitting a bid, simply due to the amount of time it takes to finalize such arrangements.

Question: For this RFP, is there a preference to direct connect to the Seminole Electric transmission system or to interconnect into the FPL or DEF balancing areas?

Answer: In terms of our economic evaluation, projects interconnecting with a) Seminole's balancing area, b) Seminole's distribution members, c) DEF's balancing area (@ 69kV or above), or d) FPL's balancing area (@ 69kV or above) will all be treated equally.

Question: Is site control for the project required to participate in this RFP?

Answer: Yes. Please see sections 4.1 and 4.2 of RFP FC 2021.

Question: What is the definition of firm and non-firm used in this RFP?

Answer: Firm transmission will be requested by the bidder as 7-FN from the relevant transmission provider. Any transmission arrangements designated in classes NS-1 through NM-5 are considered to be non-firm.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 3
ISSUED APRIL 19, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 3 in response to general questions and inquiries applicable to all potential bidders. A number of bidders have asked for relief on the bid due date. In addition, Seminole has clarified its "Procedures for Application" in section 8.0. The clarifications to section 8.0 are largely in response to our finalization of an independent evaluation process for the RFP. Sedway Consulting, Inc. (with Alan Taylor as the principal contact) will be providing an independent evaluation of Seminole's RFP process and will need to be copied on all RFP FC 2021 proposals. Please see the revised section 8.0 below.

8.0 Procedures for Application

8.1 A copy of this RFP, together with supporting forms, is on the Seminole website, "**www.seminole-electric.com/index.php/S=0/site/suppliers**". The link to the RFP documents appears on the bottom half of the page.

8.2 Bidders must submit their bid proposals via e-mail to the e-mail addresses below. Please note that an e-mail submission cannot exceed 7 MB in size. ".ZIP" files are acceptable if larger documents need to be submitted. If a Bidder finds that its proposal materials may still exceed the 7 MB limit, the Bidder should split its submission materials into two or more emails. In addition to the e-mail submittal, **an original bid proposal, signed by an authorized officer, plus two (2) copies must be mailed by either courier or U.S. Postal Service**. A separate point of contact for questions related to this RFP is defined in Section 11.4 below.

By Courier:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

16313 North Dale Mabry Highway

Tampa, FL 33618

By U.S. Postal Service:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

P.O. Box 272000

Tampa, FL 33688-2000

By E-Mail:

SeminolePowerRFP@seminole-electric.com

With a carbon copy to:

Alan.Taylor@sedwayconsulting.com

8.3 All proposals must arrive via e-mail by 5:00 PM Eastern Prevailing Time (EPT), **May 9, 2016**. Paper copies must arrive at Seminole's Tampa offices by 5:00 PM EPT on the next date (i.e., **May 10, 2016**). Seminole is not obliged to contact bidders concerning missing or incomplete forms. Only versions of the forms attached to this RFP may be used to submit proposals.

8.4 All bid packages should include any additional information required to support evaluation of the proposal, including a completed BQQ. Documents requested in support of the BQQ, including the applicant's most recent financial statements, must accompany the mailed versions of the proposals.

8.5 Seminole will not be assessing bidders a fee for any proposals submitted as a response to this RFP.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 4 - OPERATING PERFORMANCE
ISSUED JULY 13, 2016

Seminole Electric Cooperative, Inc. issues this Addendum 4 to expand upon the information previously requested by Seminole in Schedule D-3 to RFP FC 2021. Please review the questions below and respond by COB Tuesday, July 19, 2016 to all questions applicable to your proposal. If a question is not applicable to your proposal, please add a response of "Not Applicable" in the answer section. Seminole's RFP Provisions 3.2 and 3.3 from RFP FC 2021 are also included below for your ease of reference.

> 3.2 Proposals received from specific units should be dispatchable and provide Seminole with scheduling flexibility (including real time control capability such as automatic generation control ("AGC")) and availability guarantees equivalent to the technical specifications of the units. Respondents should also indicate their ability to coordinate scheduled maintenance with Seminole.
>
> 3.3 Proposals sourced from a Seller's system of resources should be dispatchable and must offer intraday scheduling rights. Preference will be given to any proposals that can also provide contingency reserves, fast starts, and/or offer intra hour scheduling flexibility.

Seminole's additional questions regarding operational performance follow below:

1. Question: Please describe the desired next day scheduling requirements for your proposal. Your response should include information on the timing of scheduling notification, flexibility in regards to energy requested, delivery/nomination of fuel (if applicable), scheduling increments and requested method of communication.

   Answer:

2. Question: Please describe the desired intraday scheduling requirements for your proposal. Your response should include information on the timing of scheduling notification, flexibility in regards to energy requested, delivery/nomination of fuel (if applicable), scheduling increments and requested method of communication. Please distinctly note any desired differences between the next day and intraday processes. Are there any limits on the amount of schedule changes permitted in a single day?

   Answer:

3. Question: Regarding intraday scheduling rights, what is the minimum notice period (in minutes) that Seminole can provide for schedule adjustments? Please note that Seminole's preference would be to have the ability to call on energy from the resource within thirty (30) minutes at any point during a clock hour.

   Answer:

4. Question: Regarding intraday scheduling rights, would Seminole have any additional flexibility (beyond the intraday scheduling rights described in item 3 above) available in the event of an emergency situation (such as an unplanned transmission or generation outage) on its system? Seminole's preference for the availability of energy is notes in item 3 above.

   Answer:

5. Question: If your proposal is from a specific unit(s), would Seminole have available the full technical capability of the unit(s) for scheduling purposes? If not, what restrictions exist?

   Answer:

6. Question: If your proposal involves Seminole tolling the natural gas fuel for the requested energy, please note if Seminole will be the pipeline delivery point operator for the facility. Are the proposed units offered to Seminole on their own gas meter?

   Answer:

7. Question: If fuel supply for Seminole's energy requirements is included in your proposal, would Seminole have any optionality to bring its own fuel for its energy needs?

   Answer:

8. Question: Regarding the ramp in of energy schedules, please define a typical ramp in period for your proposal and any flexibility that may be available outside of ramping at the top and bottom of the hour. Seminole, as an FRCC entity, is accustomed to a 20-minute ramp schedule. Is dynamic scheduling available from your resource?

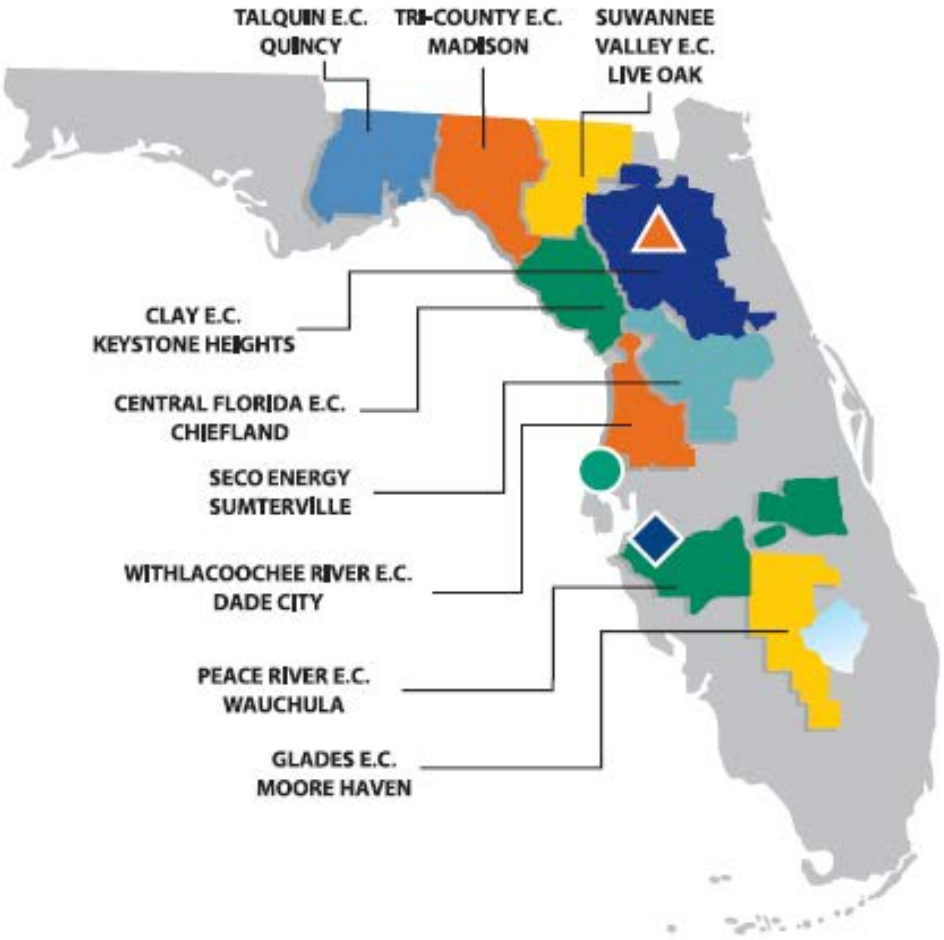
   Answer:

9. Question: Regarding availability, if your proposal is from a specific unit, please describe both the historical availability and capacity factor of the facility for each month during calendar years 2013-2015.

   Answer:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 30
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Michael P. Ward II MPW-3

SEMINOLE'S MEMBER COOPERATIVES



SEMINOLE HEADQUARTERS
16313 North Dale Mabry Highway / P.O. Box 272000
Tampa, Florida 33688-2000 / (813) 963-0994

RICHARD J. MIDULLA GENERATING STATION
6697 North County Road 663 / Bowling Green, FL 33834

SEMINOLE GENERATING STATION
890 Highway 17 North / Palatka, FL 32177

Seminole's Purchase Power Contracts
(as of December 31, 2016)

SUPPLIER	FUEL	MW (WINTER RATINGS)	IN SERVICE DATE	END DATE
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	50	6/1/2016	12/31/2018
DEF	System	200-500	6/1/2016	12/31/2024
DEF	System	50-600	1/1/2021	3/31/2027
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026

Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 31
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Michael P. Ward II MPW-4

Seminole's New Purchase Power Contracts

Supplier	Fuel	MW	In Service Date	End Date
Shady Hills Energy Center LLC	Gas	575*	12/1/2021	11/30/2051
Shady Hills Power Company LLC	Gas/Oil	364*	6/1/2024	5/31/2032
Oleander Power Project	Gas/OIl	546*	6/1/2021	12/31/2021
Southern Company Services	System	100-150*	6/1/2021	5/31/2026
DEF	System (IM)	50-400*	1/1/2021	12/31/2030
DEF	System (Peaking)	50-400*	1/1/2021	12/31/2035
Tillman Solar Center LLC	Solar/PV	40**	6/1/2021	5/31/2041

* Winter ratings
** Summer rating

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 32
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Michael P. Ward II MPW-5

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 33
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Ankur Mathur AM-1 SH

ANKUR MATHUR

901 Main Avenue, Norwalk, CT 06851 | 203-524-3486 | ankur.mathur1@ge.com

EXPERIENCE

GE Energy Financial Services, Inc., Norwalk, CT
Senior Vice President, Portfolio **2007 – Present**
Lead teams responsible for oversight of development, construction and operating stage equity investments; support M&A and development activities, including underwriting, for thermal and renewable energy projects. Key transactions include: Development of Towantic Energy Center, Colorado Highlands Wind Phase I and II, Linden Expansion, and Shady Hills Expansion; Development stage and equity investments in Russell City Energy Company (COD 2013); CPV Towantic (COD 2018); CPV Fairview (COD 2020); Colorado Highlands Wind (COD: 2012 for Phase I, 2013 for Phase II); development stage JVs, asset divestitures, tax equity financing.

Tyr Energy, Inc., Overland Park, KS
Senior Director **2003 – 2007**
Participated in business/corporate planning, capital raise and client marketing for this start-up asset management services and capital investment firm. Key transactions include: acquisition of Lincoln Generating Facility with ArcLight Capital Partners; acquisition of managing member interest in Green Country Energy from Cogentrix Energy; and acquisition of CalPeak Power from United Technologies with Starwood Energy Group. Evaluated several M&A targets with private equity partners and selected late-stage development opportunities.

Aquila, Inc., Kansas City, MO
Manager – Analysis; Manager - Business Development **2000 – 2002**
Implemented a regional capacity development program for the Southeast US markets; provided M&A due diligence and analytical support, including for Aquila's announced acquisition of Cogentrix Energy.

GPU International, Inc., Parsippany, NJ
Manager, Business Development **1998 – 2000**
Led project development activities including siting, interconnections, economic incentive packages and community relations, cost/schedule management, and power marketing. Secured funding from partner, including capital commitment for power block, based on advanced development status of CCGT project in Mississippi.

Gas Energy Inc., Brooklyn, NY
Manager of Engineering – Project Development **1995 – 1997**
Managed technical support functions for development stage power and cogeneration projects in the US, Central Europe, Middle East, and Mexico. Formulated repowering alternatives and scenarios for Long Island Lighting Company generating assets.

Burns and Roe Enterprises, Inc., Oradell, NJ

Mechanical Engineer **1989 – 1995**

Performed integrated resource planning analysis for utilities in Hong Kong and Former Soviet Republics; due diligence and analysis for domestic and international IPP projects as lender/owner engineer; power plant optimization studies; power and industrial plant system design/analysis.

EDUCATION

Master of Business Administration

Cornell University - S.C. Johnson Graduate School of Management, Ithaca, NY 2001

Master of Science - Mechanical Engineering

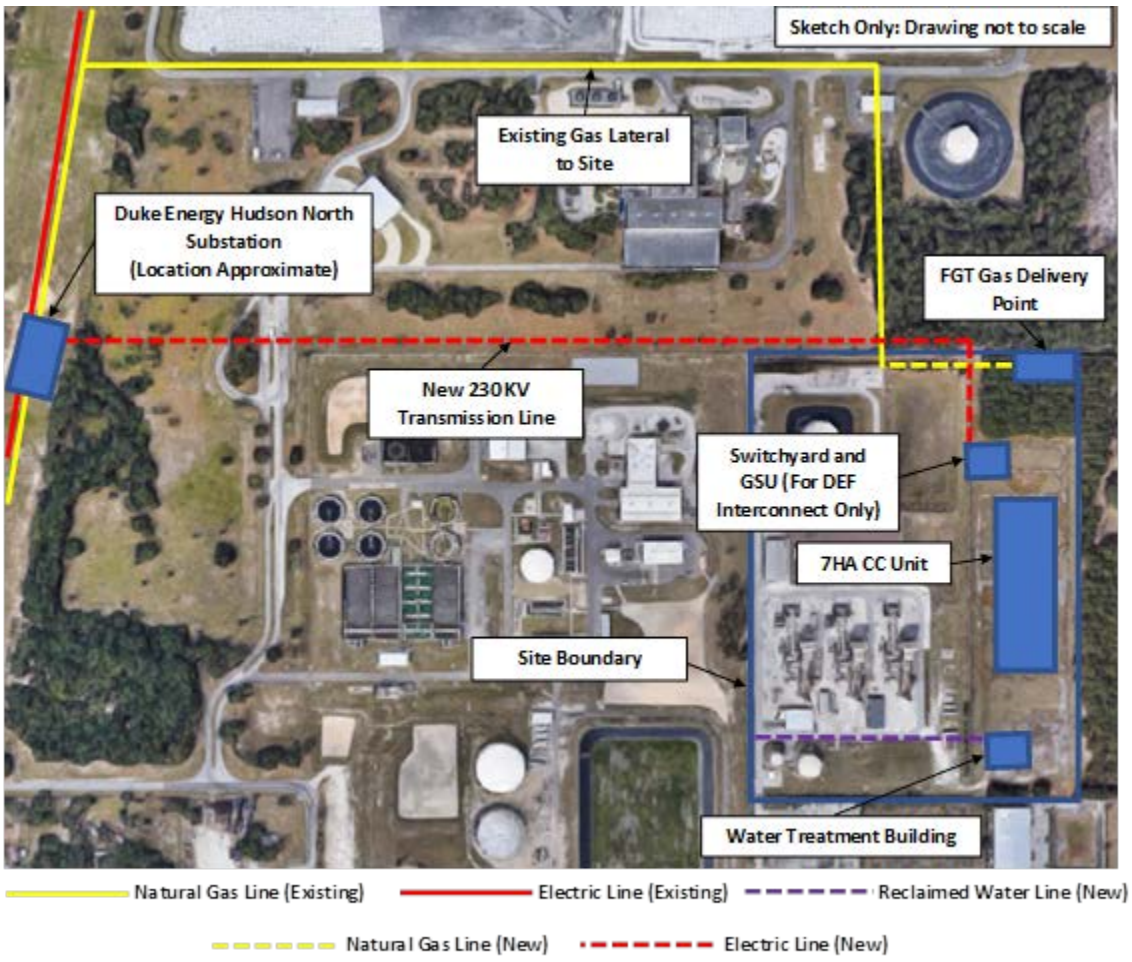
Columbia University - School of Engineering and Applied Science, New York, NY 1991

Bachelor of Science - Mechanical Engineering

Columbia University - School of Engineering and Applied Science, New York, NY 1989

Licensed Professional Engineer in the State of New York

Site Vicinity Map for the SHCCF



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 34
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Ankur Mathur AM-2 SH

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 35
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: David Wagner DW-1 SH

David Wagner

Experience

2010 – Current **Seminole Electric Cooperative, Inc.** Tampa, FL

Supervisor of Gas Supply; Manager of Gas Supply; Portfolio Director

- Revamped the natural gas procurement function at Seminole to make it an integral part of the organization's decision making processes leading to more reliable, lower cost fuel supply.
- Ensured competitive fuel costs through the implementation of modifications to Seminole's financial gas hedging program to create a more robust risk management tool.
- Lead a team of natural gas professionals to plan robust gas supply, transportation and storage strategies to meet Seminole's supply needs and support the execution of such activities.

2006 – 2010 **Florida Gas Utility** Gainesville, FL

Gas Buyer; Senior Trader

- Brought a trading/asset optimization mentality to the agency to lower gas supply costs and increase returns on gas pipeline assets.
- Led the operations team on the optimization of FGU's gas supply and transportation portfolio. Coordinated all daily and monthly activities including administrative and gas accounting functions.
- Obtained Board approval for and implemented a formal program for the optimization of a member's firm gas storage capacity.

2004 – 2006 **Florida Municipal Power Agency** Orlando, FL

Energy Risk Analyst

- Provided analysis to support the effective utilization of FMPA's generation resources and purchased power agreements.
- Administered the agency's fuel hedging program and developed the methodology used to forecast FMPA's total gas exposure to improve the effectiveness of the hedging program..
- Identified less arbitrage opportunities for FMPA's dual-fuel generation units designed to capture value, improve system reliability and reduce risk.

2002 – 2003 **Westar Energy, Inc.** Topeka, KS

Energy Market Analyst

- Performed analysis for the energy trading floor to identify emerging opportunities that maximized the value realized from the company's assets and returns from the trading book.
- Developed a natural gas storage model for projecting weekly withdrawals, built historical databases of physical power and gas prices for spread and volatility analysis, and performed volatility and pricing analysis of exotic gas and power options.

Education

University of Florida

- Master of Agri-Business
- Bachelor of Science – Food and Resource Economics

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 36
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: David Wagner DW-2 SH

Fuel Price Forecast – Updated

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.32	$3.63	$2.90	$3.45	$14.64
2018	$3.20	$4.28	$3.06	$3.52	$16.55
2019	$2.94	$4.11	$2.39	$3.13	$17.59
2020	$2.92	$4.15	$2.11	$3.28	$18.08
2021	$2.94	$4.25	$2.06	$3.36	$18.43
2022	$3.03	$4.38	$2.04	$3.42	$18.69
2023	$3.09	$4.43	$2.10	$3.50	$19.02
2024	$3.16	$4.48	$2.15	$3.57	$19.34
2025	$3.24	$4.67	$2.23	$3.65	$19.81
2026	$3.33	$4.87	$2.25	$3.74	$20.17
2027	$3.42	$5.06	$2.28	$3.82	$20.38
2028	$3.51	$5.25	$2.31	$3.91	$20.39
2029	$3.60	$5.44	$2.34	$4.00	$20.65
2030	$3.71	$5.65	$2.38	$4.09	$21.08
2031	$3.86	$5.93	$2.43	$4.19	$21.40
2032	$3.94	$6.10	$2.52	$4.28	$21.87
2033	$3.96	$6.16	$2.55	$4.38	$21.82
2034	$4.02	$6.27	$2.55	$4.47	$22.14
2035	$4.16	$6.52	$2.58	$4.58	$22.31
2036	$4.23	$6.64	$2.66	$4.68	$22.85
2037	$4.30	$6.78	$2.69	$4.79	$22.93
2038	$4.37	$6.90	$2.73	$4.89	$23.05
2039	$4.48	$7.08	$2.77	$5.01	$23.40
2040	$4.55	$7.20	$2.83	$5.12	$23.59
2041	$4.66	$7.37	$2.88	$5.24	$23.65
2042	$4.84	$7.66	$2.94	$5.36	$23.69
2043	$5.06	$8.01	$3.06	$5.48	$23.76
2044	$5.22	$8.25	$3.20	$5.60	$23.86
2045	$5.40	$8.53	$3.30	$5.73	$23.97
2046	$5.58	$8.81	$3.42	$5.86	$24.15
2047	$5.78	$9.11	$3.54	$5.99	$24.45
2048	$6.04	$9.49	$3.67	$6.12	$24.49
2049	$6.22	$9.77	$3.84	$6.26	$24.69
2050	$6.45	$10.10	$3.97	$6.40	$24.96
2051	$6.68	$10.44	$4.12	$6.55	$25.52

Fuel Price Forecast

Year	Natural Gas Base Price Forecast ($/MMBtu)	Natural Gas High Price Forecast ($/MMBtu)	Natural Gas Low Price Forecast ($/MMBtu)	Coal Price Forecast ($/MMBtu)	#2 Oil Price Forecast ($/MMBtu)
2017	$3.52	$4.34	$2.87	$3.53	$14.64
2018	$3.20	$4.43	$2.32	$3.59	$16.55
2019	$3.04	$4.30	$2.15	$3.41	$17.59
2020	$3.04	$4.34	$2.13	$3.53	$18.08
2021	$3.04	$4.43	$2.09	$3.62	$18.43
2022	$3.06	$4.53	$2.06	$3.70	$18.69
2023	$3.14	$4.71	$2.10	$3.78	$19.02
2024	$3.27	$4.94	$2.17	$3.86	$19.34
2025	$3.42	$5.25	$2.23	$3.95	$19.81
2026	$3.56	$5.55	$2.28	$4.03	$20.17
2027	$3.71	$5.86	$2.35	$4.13	$20.38
2028	$3.86	$6.16	$2.41	$4.22	$20.39
2029	$4.01	$6.48	$2.48	$4.32	$20.65
2030	$4.13	$6.74	$2.54	$4.42	$21.08
2031	$4.31	$7.07	$2.62	$4.52	$21.40
2032	$4.40	$7.27	$2.66	$4.62	$21.87
2033	$4.42	$7.35	$2.66	$4.73	$21.82
2034	$4.48	$7.49	$2.68	$4.83	$22.14
2035	$4.64	$7.79	$2.77	$4.94	$22.31
2036	$4.71	$7.93	$2.80	$5.05	$22.85
2037	$4.80	$8.10	$2.84	$5.17	$22.93
2038	$4.87	$8.24	$2.88	$5.29	$23.05
2039	$4.99	$8.46	$2.95	$5.41	$23.40
2040	$5.08	$8.60	$3.00	$5.53	$23.59
2041	$5.20	$8.81	$3.07	$5.66	$23.65
2042	$5.37	$9.10	$3.17	$5.78	$23.69
2043	$5.62	$9.51	$3.31	$5.92	$23.76
2044	$5.79	$9.80	$3.42	$6.05	$23.86
2045	$5.99	$10.13	$3.54	$6.19	$23.97
2046	$6.19	$10.45	$3.67	$6.33	$24.15
2047	$6.42	$10.81	$3.81	$6.47	$24.45
2048	$6.70	$11.26	$3.98	$6.61	$24.49
2049	$6.91	$11.59	$4.12	$6.76	$24.69
2050	$7.16	$11.97	$4.28	$6.92	$24.96
2051	$7.42	$12.37	$4.44	$7.07	$25.52

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 37
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Roberto Demelo RD-1 SH

ROBERT DEMELO

8334 Lagerfeld Drive, Land O' Lakes, FL 34637
Mobile: (813) 601-5805
Email: rdemelo@seminole-electric.com

Education

Bachelor of Science, Electrical Engineering — December 2007
University of South Florida (USF), Tampa, Florida
Awarded First Place in USF Senior Design Project Presentation

Ken Chapman and Associates Leadership Development — December 2013

Professional Experience

Seminole Electric Cooperative, Inc. Tampa, Florida
Manager, Transmission Planning & System (Power Delivery & Technical Services) — June 2014 to Present

Key Responsibilities
- Lead and develop a team of System Protection, Transmission Planning and Transmission Compliance Engineers
- Seminole's primary representative at the FRCC (Florida Reliability Coordinating Council) Order 1000 Steering Task Force, and Solar Task Force, Stability Analysis Subcommittee, and Vice-Chair of the Planning Committee (PC)
- Long-term strategy as it relates to transmission and generation (existing and planned)
- Evaluate economic options to increase transmission flexibility and lower rates to reduce dependence on third party transmission providers
- Plan and execute multiple capital projects to enhance reliability, adequacy, and security of Seminole's transmission system
- Work closely with Federal Energy Regulatory Commission (FERC) counsel to comment and/or incorporate new or modified FERC rules to Seminole practices and procedures
- Oversee Subject Matter Expert (SME) compliance assessment, evidence, processes and procedures associated with North American Reliability Corporation (NERC) Operations and Planning (O&P) Reliability Standards
- Manage budget and evaluate options to reduce Operations and Maintenance (O&M) expense and increase capital project work
- Evaluate asset acquisitions with risk assessment tools within cross-functional teams

Seminole Electric Cooperative, Inc. Tampa, Florida
Lead Transmission Planning (Power Delivery & Technical Services) — September 2011 to June 2014

Key Responsibilities/Projects
- Provided technical expertise and guidance to team members within Transmission Planning and NERC Compliance
- Seminole's primary representative at the FRCC Transmission Technical Subcommittee (TTS) and Stability Analysis Subcommittee (SAS)
- Vice-Chair of the FRCC TTS and provided training sessions for planning engineers within the region
- Seminole's SME for Transmission Planning (TPL), Facilities (FAC), and Modeling (MOD) NERC Reliability Standards
- Performed transmission optimization studies for Seminole Member systems
- Led efforts in the analysis/justification for the removal of two existing Seminole special protection systems and received regional approval
- Confirmed the use/need of Seminole's existing power system stabilizer
- Assisted in the technical due diligence surrounding the acquisition of an existing switching station
- Took on full responsibility/led all transient/stability modeling and analysis

Seminole Electric Cooperative, Inc. Tampa, Florida
Engineer III - Transmission Planning (Power Delivery & Technical Services) — July 2010 to September 2011

Key Responsibilities/Projects
- Took on responsibility as Seminole's alternate SME for NERC TPL, FAC and MOD Reliability Standards
- Assisted in the development of Seminole's long-term future transmission and generation expansion plan
- Seminole's alternate representative at the FRCC TTS and SAS
- Worked with Seminole's Protection and Control Group to evaluate single points of failure using steady-state and stability analysis
- Assisted in the development of Seminole's annual Ten-Year Site Plan for submission to the Florida Public Service Commission
- Performed a complete review and developed an inventory of Seminole's generation dynamic modeling
- Analyzed Seminole and its Member's system for transient/stability response
- Worked alongside Seminole Marketing staff to implement long-term unit designations via FRCC Interchange Transactions Database

Seminole Electric Cooperative, Inc. Tampa, Florida
Engineer II - Transmission Planning (Power Delivery & Technical Services) — June 2009 to July 2010

Key Responsibilities/Projects
- Assumed a more active role at the FRCC TTS and assisted in drafting regional planning procedures
- Developed knowledge and experience surrounding short circuit and stability modeling and analysis
- Verified Seminole and Seminole Member transmission modeling data
- Worked with Seminole Member staff to develop ten-year load forecasts via Schedule A process
- Assisted Seminole Regulatory staff with various FERC related filing, e.g. Open Access Transmission Tariff, Direct Assignment of Radials, etc.
- Increased my knowledge of NERC and the TPL, FAC, and MOD Reliability Standards
- Worked with Seminole Member staff to ensure compliance with power factor/power quality requirements within provider contracts

Seminole Electric Cooperative, Inc. Tampa, Florida

Engineer I – Transmission Planning (Power Delivery & Technical Services) May 2007 to June 2009

Key Responsibilities/Projects
- Assisted senior team members with transmission planning analysis and modeling
- Developed my skills and abilities with transmission planning software tools
- Worked with the FRCC TTS on regional studies
- Coordinated Seminole Member delivery point projects (new substations, meter points, etc)
- Helped evaluate future generation expansion plans for new baseload and peaking generation
- Tracked transmission reliability for Seminole and its Members utilizing IEEE SAIDI, CAIDI, and SAIFI indices

Skills

Certified in Siemens PSSE® Power Flow and Steady State Analysis & Modeling
Certified in Siemens PSSE® Short Circuit Analysis & Modeling
Certified in Siemens PSSE® Dynamic Simulation & Modeling
Proficient in PowerGEM's TARA (Transmission Adequacy & Reliability Assessment) Software
System Protection & Control Schemes
Microsoft Office Suite

2016 IEEE Florida West Coast Section Young Engineer of the Year

Kyle D. Wood

Education

M.A. Economics, University of South Florida, Tampa, FL

B.A. International Business, University of South Florida, Tampa, FL

Professional Experience

Manager of Load Forecasting and Member Analytics, Seminole Electric Cooperative, Tampa FL, 2012-Present

Senior Economic Analyst, Deiter Consulting Group, Tampa, FL, 2008-2012

Intern to International Trade Director, Greater Tampa Chamber of Commerce, Tampa, FL, 2007

Academic Awards and Honors

Undergraduate Degree with Distinction

Executive Board Member, College of Business Student Leadership Council, University of South Florida

Director of Corporate Relations, International Business Board, University of South Florida

Study Abroad Student, Osnabrück University, Germany

Professional Association Membership

Utility Advisory Board, SAS

Energy Forecasting Group, Itron

Load Forecasting Working Group, FRCC

Electric Utility Forecasters Forum

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 38
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Kyle D. Wood KDW-1 SH

TOM HINES

TOM HINES
Program Design and Regulatory Specialist
Tierra Resource Consultants, LLC
4446 E Camelback Rd, Suite 112
Phoenix, AZ 85018
Office: 602-505-4826 | Mobile: 602-505-4826
Email: Tom.Hines@tierrarc.com
Web: www.TierraRC.com

PROFESSIONAL HISTORY

- Principal, Tierra Resource Consultants, LLC
- President, Hines Consulting
- Analyst/Project Manager, EcoGroup (Aclara)

EDUCATION

- MS, Environnent Planning, Arizona State University, 1993
- BS, Psychology, Rutgers University, 1990

PROFESSIONAL ASSOCIATIONS

- Board of Directors, Energy and Environmental Building Alliance

BIOGRAPHY

Tom Hines is a demand side management expert with over 25 years of experience in program design, regulatory strategy, implementation and evaluation. Tom specializes in fully integrated distributed energy resource planning - working with utilty system planners and stakeholders to design comprehensive portfolios that meet the evolving needs of both the customer and the grid.

From 1997 to present, Tom has worked with Arizona Public Service Company (APS) as the lead designer in developing and managing the company's award-winning portfolio of residential energy efficiency programs, including: new homes, existing homes HVAC, home performance, consumer products lighting, pools, multi-family, behavioral conservation, commercial/industrial and energy efficiency financing programs. Throughout this time, Tom has worked closely with industry stakeholders to drive market transformation, including; builders, contractors, realtors, lenders, raters and other trade allies.

Mr. Hines has extensive experience working directly with the Arizona Corporation Commission (ACC) providing direct testimony, developing filings and working directly with ACC staff during energy efficiency proceedings. Recent work includes acting as a strategic advisor on the design and development of APS' entire portfolio of DSM programs, while integrating the next generations of technologies, including connected devices and storage. In this role, Tom prepares information and analysis on DSM program trends, technologies, opportunities, and challenges for senior executives and the utility's board of directors. His unique experience in policy, evaluation, and implemenation allows him to develop successful paths to compliance that maximize cost-effectiveness, deliver targeted load shapes, and meet the needs of customers and stakeholders.

Since joining Tierra, Tom has expanded his efforts to serve a wide range of investor owned utilities and co-ops across the country. Tom's experience extends beyond electric utilities, providing design assistance for national energy efficiency efforts for both the U.S. EPA and China. He has consulted for state/local governments and private sector manufactures developing grid-interactive products.

Mr. Hines holds a masters degree in Environmental Planning from Arizona State University and is a board member of "EEBA" the Energy and Environmental Building Alliance, an organization devoted to advancing building science and energy efficient building practices.

PROFESSIONAL EXPERIENCE

Integrated Distributed Energy Resource Planning and Design

Mr. Hines is currently a leading proponent of Distributed Energy Resource program design to address load shape challenges from high solar DG adoption on the grid, often referred to as the "duck curve." In this role at APS, Tom is tasked with coordinating with a wide range of utility disciplines, including; resource planning, technology assessment, system operations planning,

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DESCRIPTION: Thomas Hines TH-1 SH

regulatory, smart grid, customer service, and rates to identify new and innovate approaches to distributed energy resource programs that support the continued growth of solar, while minimizing grid impacts. Mr. Hines has begun to expand this effort to other utilities, since 2016.

Energy Efficiency Portfolio Design for Commercial and Residential Programs

Mr. Hines oversees the annual energy efficiency portfolio design for Arizona Public Service. In this role, he has designed multiple award winning EE programs including new homes, home performance, HVAC, duct repair, quality install, pool pumps, and lighting. He works closely with program managers to review cost-effectiveness, calculated emission reductions, develop program budgets, design program modifications and manage annual compliance targets. Recently, Tom has completed similar tasks for multiple electric Co-ops.

Policy and Strategic Consulting Support

Mr. Hines has provided EE regulatory support and policy development, including: testimony at commission proceedings, meeting with commissioners and staff, developing filings and reports for APS. Tom was an integral player in the development of the Arizona EE Standards. He has extensive experience working with EE program cost effectiveness tests, stakeholder coordination, regulatory development, program implementation plans, EE savings forecasts, and integrating new technology options into existing compliance approaches. This expertise has extended to assisting in consulting with other utilities and the EPA ENERGY STAR program.

Distributed Storage Technology Evaluations and Pilot Design

Mr. Hines has assisted in multiple technology evaluations and pilot program designs for emerging battery, thermal storage, load management and demand response projects including APS' Solar Innovation Study, the APS Demand Response, Energy Storage and Load Management program, and Tucson Electric Power's Sustainable Communities Project. These efforts have included an evaluation of the technology, control systems, and build-out of the full program design.

Program Management and Implementation

Tom has directly managed a wide range of successful EE programs including residential lighting, HVAC, duct repair, pool pumps, and new homes. Tom has managed multi-million-dollar program budgets and consistently exceeded savings goals. As an industry leader in these roles, he has collaborated with or worked for over 30 electric, gas and water utilities nationwide sharing best practices and strategies for successful market transformation.

Distributed Energy Resource Education

In 2016, Mr. Hines was the project lead for the APS Qualified Solar Sales and Installations training, in which he authored innovative training on the integration of EE and DR devices into solar sales to help customers better manage both their energy and demand. Prior to this effort, Tom oversaw the development of training for local ENERGY STAR programs, low-income weatherization, high bill management, and other cross-cutting resource management activities.

Energy Efficiency Marketing and Communications.

Tom has designed and developed multiple award-winning EE advertising and marketing campaigns. Additionally, served as the primary EE spokesperson for APS for many years and has extensive media experience in all forms.

SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT SAVINGS REPORT

Program Year 2015

FLORIDA PUBLIC SERVICE COMMISSION
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Original Report issued October 7, 2016
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advanced energy

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Organizations

Advanced Energy
Tierra Resource Consultants

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EXECUTIVE SUMMARY

In Q1 2016, Seminole Electric Cooperative, Inc. (Seminole) engaged the Advanced Energy and Tierra Resource Consultants team to help prepare for a Needs Determination for new generation and to compile savings reports for EIA Form 861. The process required collecting and quantifying Seminole's and its Member Co-ops' 2015 energy efficiency (EE) and demand management programs and savings. The AE/Tierra team worked with Seminole and Member Co-ops to identify applicable EE efforts, collect program data, run engineering models to determine costs and savings, and analyze key findings. The results of this analysis show that, based on reported program participation and data in 2015, Seminole produced total estimated savings of 12,353 annual megawatt-hours (MWh), 34,479 lifetime MWh, and 85 peak demand megawatts (MW) (at generator including transmission and distribution losses). Reported savings were equal to about 0.09% of total Seminole member retail energy sales and 2.5% of the peak demand in 2015.

AE/Tierra found that Member Co-ops had significant programs in place to help their members save energy and manage energy costs. However, it was difficult to accurately quantify all savings due to a lack of consistent tracking and reporting of program activities and member participation. To optimize current EE programs, AE/Tierra has made recommendations to help Seminole and its Member Co-ops improve program tracking and increase future savings by enhancing current efforts and adding new measures to existing programs. These recommendations are described in this report.

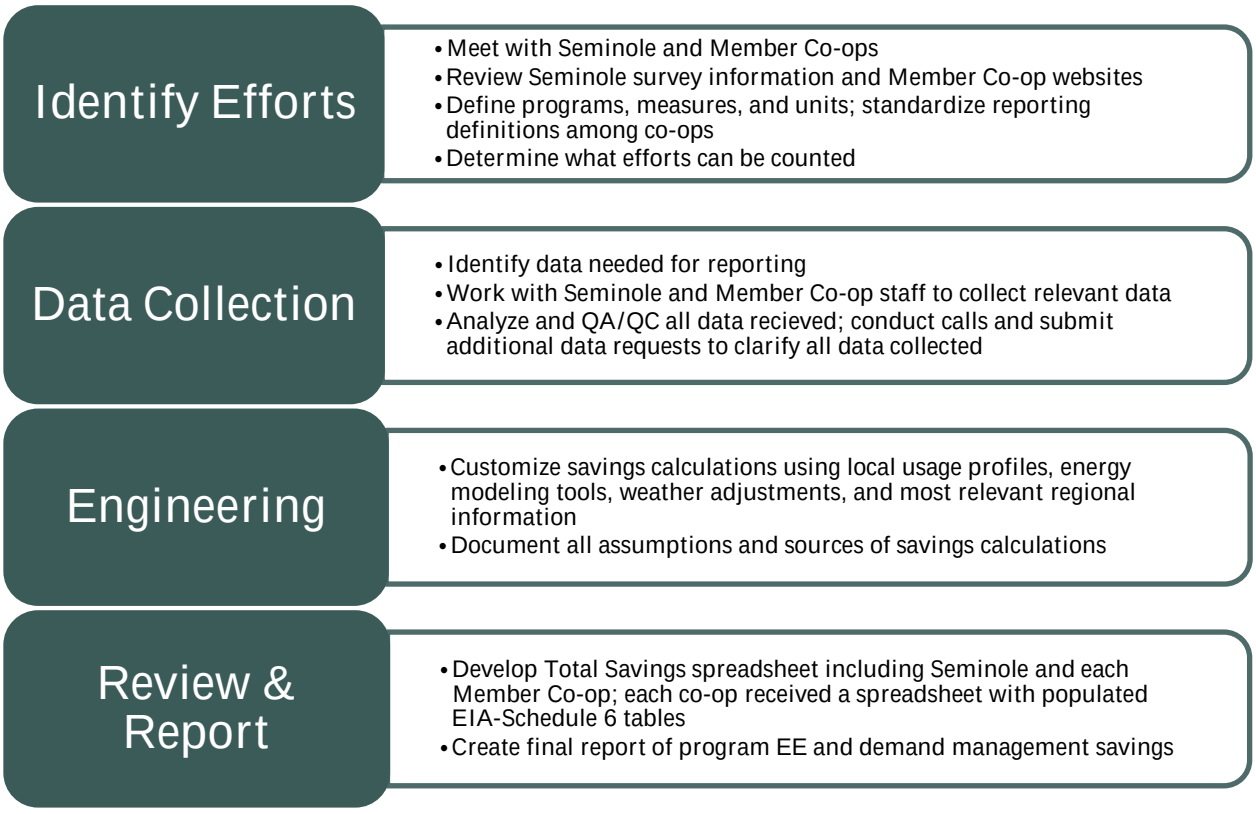
PROCESS FOR QUANTIFYING ENERGY EFFICIENCY RESULTS

To quantify Seminole and Member Co-ops' EE programs, AE/Tierra worked with Seminole and Member Co-ops through the following steps:

AE/Tierra researched all programs and EE measures currently offered by Seminole and Member Co-ops to collect cost and savings information. Seminole and Member Co-ops offer many programs and services to educate their members on ways to save energy, including web content, brochures, member outreach events, and on-site energy audits. Although it is expected that these efforts produce significant energy savings and market

transformation effects, it is difficult to accurately quantify and attribute these savings. Within the overall portfolio, the team identified a subset of EE measures and program activities where energy savings could be identified, quantified, and reported. The team also worked to standardize the program measures, units, and definitions across all Member Co-ops, ensuring consistent reporting. Per-unit energy savings estimates were developed using a variety of sources and custom energy-savings calculations, including regional technical reference manuals, national industry-recognized databases, custom energy modeling work using local weather and building characteristics, and engineering review of Seminole information submitted in response to data requests. Specific references are provided in the following section for each program type. Program participation, such as number of units or meters, and spending on incentives and labor were also collected and included in benefit/cost calculations for each measure. Finally, a tracking and reporting spreadsheet tool was developed for Seminole and each Member Co-op to document all data and summarize results.

EE Quantification Process:



PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

AE/Tierra identified a number of existing energy savings programs and initiatives offered by Seminole and/or Member Co-ops in 2015:

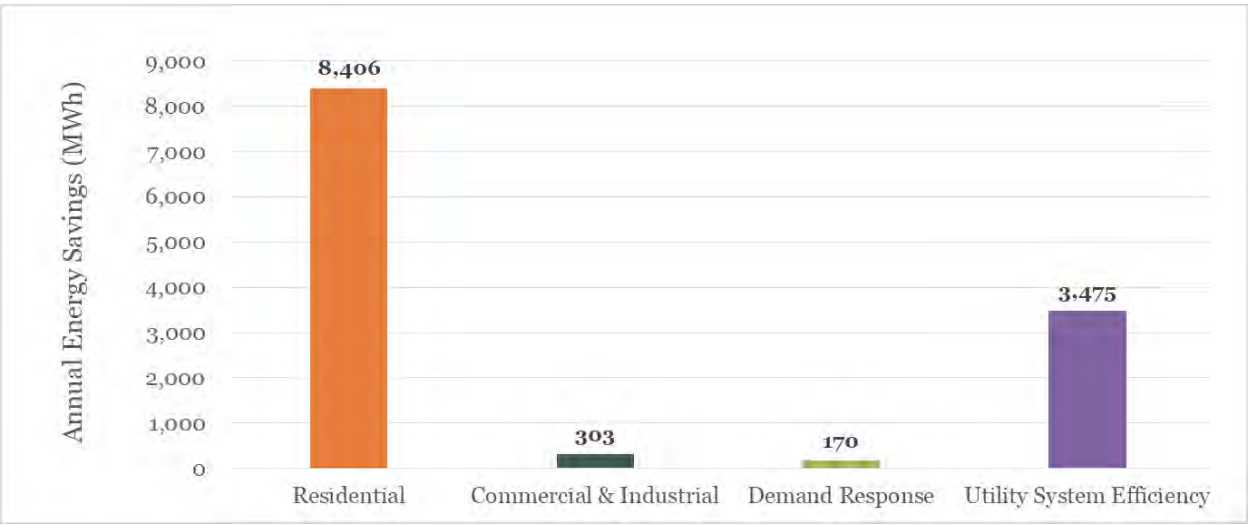
- Residential Pre-Pay Program: Residential members can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- LED/CFL Efficient Bulb Giveaway Lighting Programs: These Member Co-op programs provide participating members with free energy-efficient 10 Watt (W) LED or 13W CFL bulbs to replace their existing 60W incandescent bulbs.
- Energy Smart Rebate Programs: A rebate is given to residential members to upgrade to more efficient equipment and/or improve building envelope. Rebate measures include: air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation – batt or spray foam – and window film.
- LED Outdoor and Street Lighting: Replacement of utility-owned outdoor and street lighting with lower wattage LEDs. Each application was looked at separately: 100W high pressure sodium (HPS) to 40W, 48W, or 72W LED, 150W HPS to 70W LED, 250W HPS to 107W LED, 1000W metal halide (MH) to 283W or 316W LED
- Coincident Peak Power (CPP) Rates: Critical peak billing program where commercial members are signaled to initiate demand response to reduce short-term peak.
- Time-of-Use (TOU) Rates: Residential, commercial, or industrial rates that encourage members to use power during off-peak hours through less expensive prices. No demand or energy savings were claimed for these rates.
- Utility System EE Projects:
    - Lighting and HVAC upgrades at Seminole generation or administration facilities or Member Co-op facilities
    - Distribution System Voltage Reduction (VR): Reduction of voltage on certain distribution feeders during peak times

Sources of data for each program type are provided in the table below. Full references are provided in the last section of this report.

Program	Primary Data Sources
Residential Pre-Pay	Arizona Public Service, EPRI (2009), EPRI (2010), South Carolina Energy Office Budget and Control Board (2013)
LED/CFL Bulb Giveaways	Arkansas Public Service Commission (2015), Navigant Consulting (2012)
Energy Smart Rebates	Florida Department of Business and Professional Regulation (2014), National Renewable Energy Laboratory
LED Outdoor/Street Lights	Engineering Review of Utility Reported Data
TOU/CPP Rates	Utility reported
Utility System EE Projects	California Public Utilities Commission (2016), National Electric Manufacturers Association , Engineering Review

Total Annual Energy Savings by Program Type

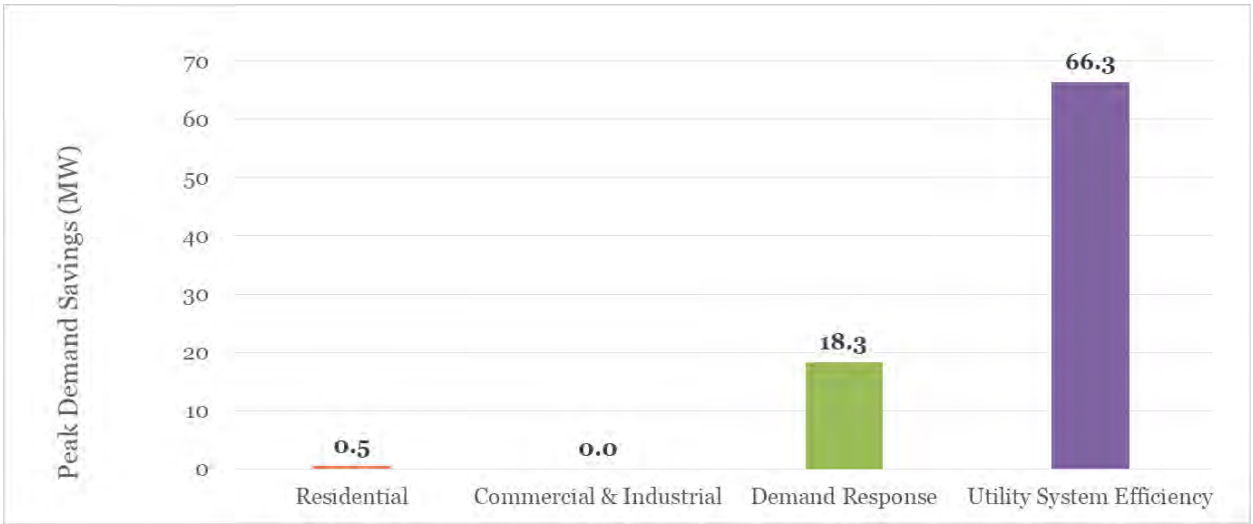
Total annual energy savings for Seminole in 2015 were 12,353 MWh and peak demand savings were 85 MW (at generator including transmission and distribution losses). Lifetime energy savings is 34,479 MWh. The chart below shows all Member Co-op program savings plus utility system savings projects. Residential programs accounted for 68.0% of savings, followed by utility system energy efficiency programs at 28.1%. The remaining 3.9% of savings came from commercial and industrial programs and demand response programs.



Sector	Annual MWh Savings	%
Residential	8,406	68.0%
Commercial & Industrial	303	2.5%
Demand Response	170	1.4%
Utility System Efficiency	3,475	28.1%
Total	**12,353**	**100%**

Total Annual Peak Demand Savings by Program Type

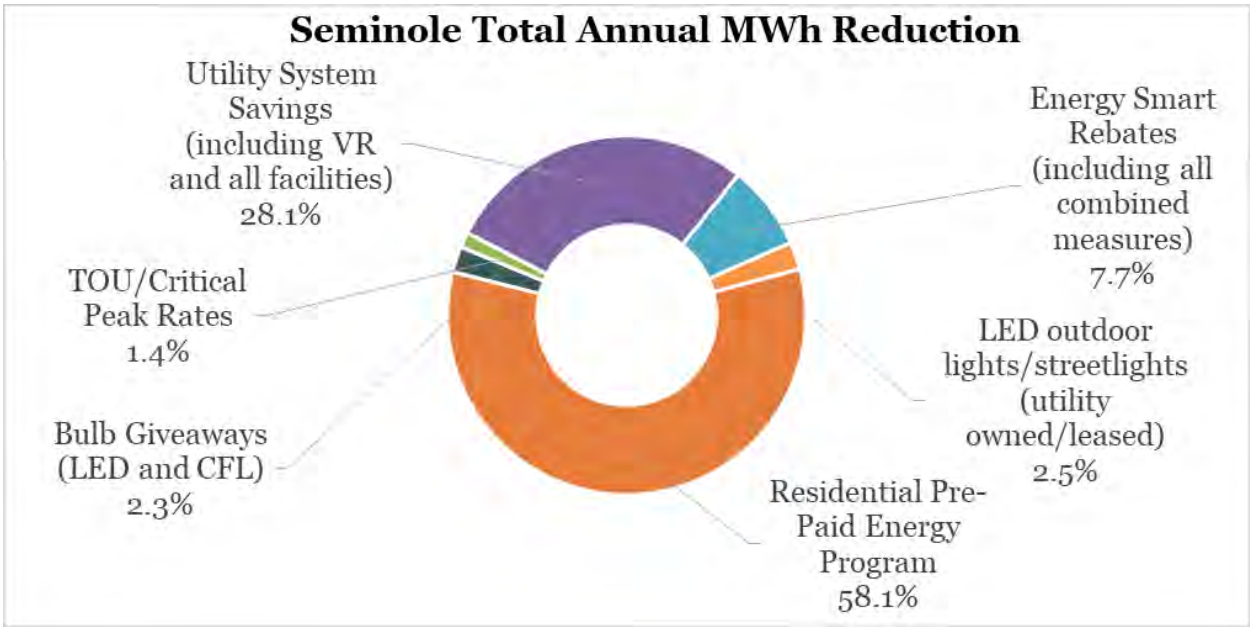
The majority of peak demand savings came from the utility system efficiency programs (78%) and demand response (21.5%). Residential Programs contributed less than 1% of annual demand savings.



Sector	Peak MW Savings	%
Residential	0.5	0.6%
Commercial & Industrial	0	0%
Demand Response	18.3	21.5%
Utility System Efficiency	66.3	78.0%
Total	**85.0**	**100%**

Percentage of Annual Savings by Program

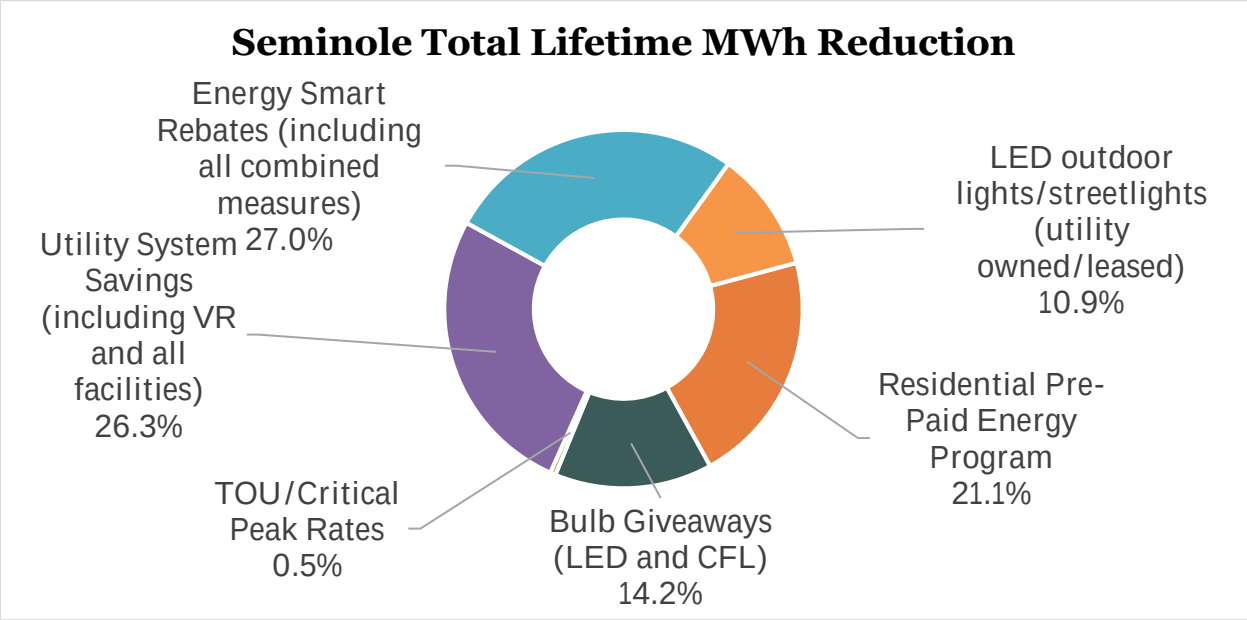
The majority of savings in 2015 came from three programs: pre-pay (58.1%), utility system savings projects (28.1%), and Energy Smart rebates (7.7%). The remaining 6% of savings came from bulb giveaways, TOU or CPP rates, and LED outdoor and street lights.



Program Type	Annual MWh Savings	%
Residential Pre-Paid Energy Program	7,172	58.1%
Bulb Giveaways (LED and CFL)	287	2.3%
TOU/CPP Rates	170	1.4%
Utility System Savings (including VR and all facilities)	3,475	28.1%
Energy Smart Rebates (including all combined measures)	946	7.7%
LED Outdoor Lights/Streetlights (utility owned/leased)	303	2.5%
Total	**12,353**	**100%**

Percentage of Lifetime Savings by Program

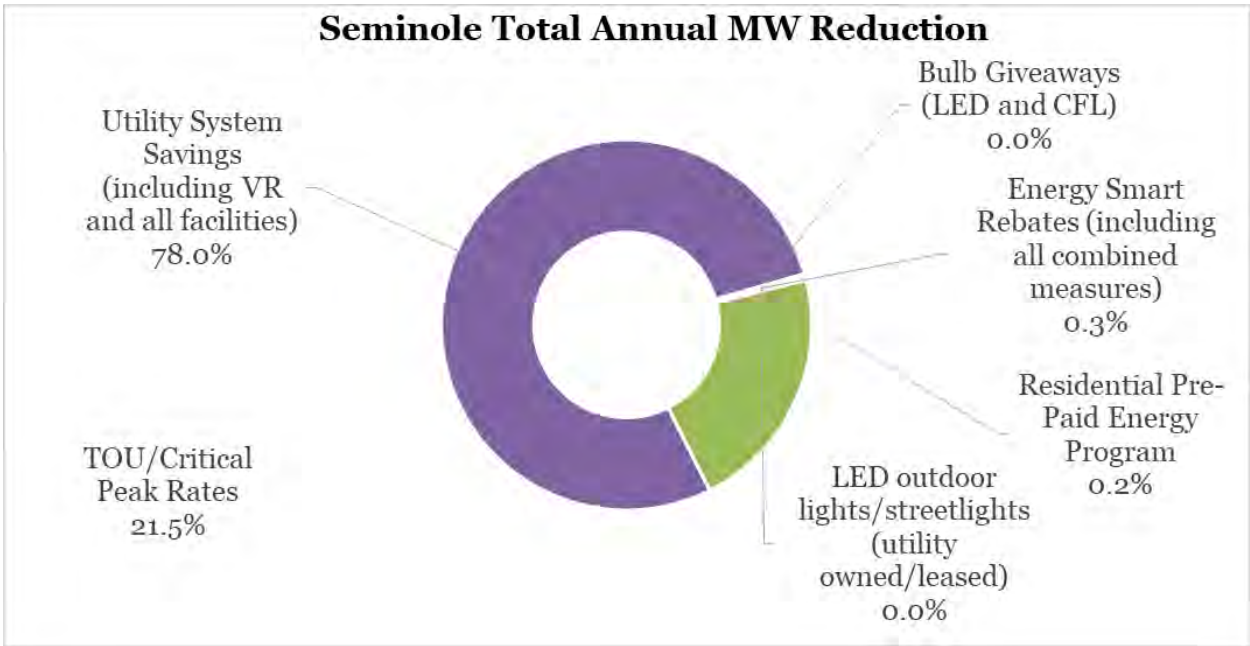
Lifetime savings refer to the cumulative EE savings over the expected lifetime of a measure. Energy Smart rebate measures consist of energy-efficient HVAC equipment and insulation that have much longer lives, so while they only contribute 8% of annual savings, they account for 27.0% of lifetime savings. In contrast, savings from the pre-pay program come from behavioral changes that participants make in response to receiving increased feedback on energy consumption and costs. These behavioral changes, while providing real energy savings, are generally considered to have a 1-year measure life and therefore this program goes from 58.1% of annual savings to only 21.1% of lifetime savings.



Program Type	Lifetime MWh Savings	%
Residential Pre-Paid Energy Program	7,290	21.1%
Bulb Giveaways (LED and CFL)	4,907	14.2%
TOU/CPP Rates	170	0.5%
Utility System Savings (including VR and all facilities)	9,068	26.3%
Energy Smart Rebates (including all combined measures)	9,296	27.0%
LED Outdoor Lights/Streetlights (utility owned/leased)	3,748	10.9%
Total	34,479	100%

Percentage of Annual Peak Demand Savings by Program

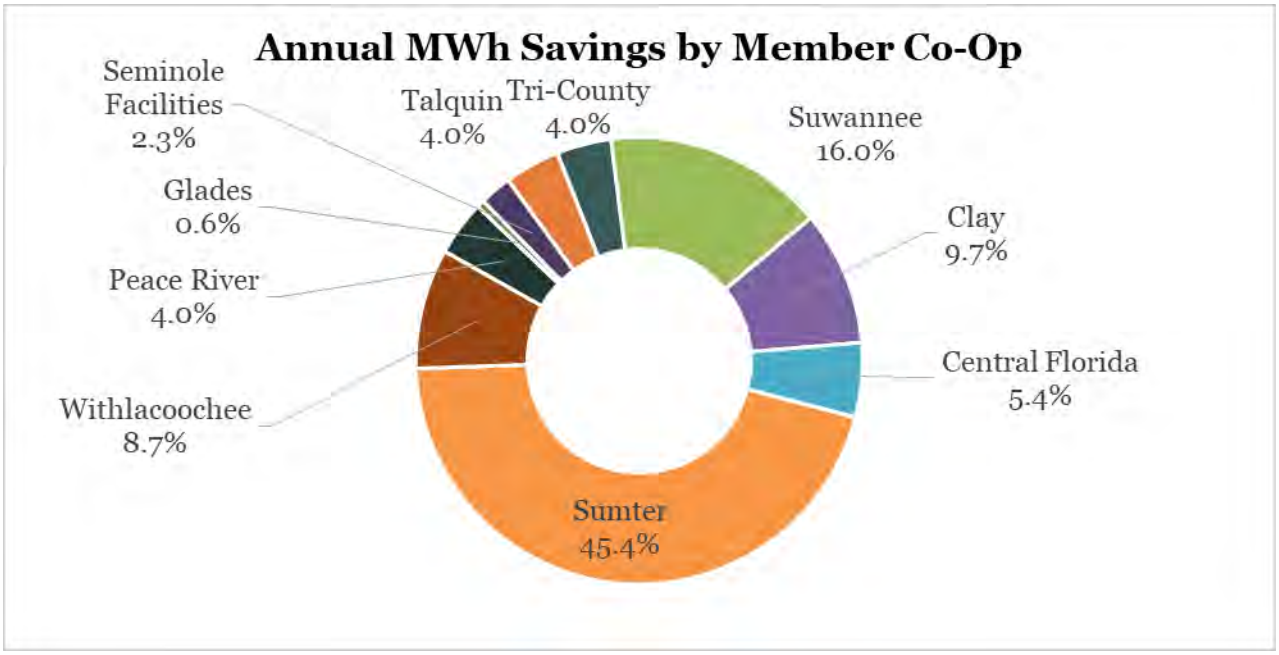
The majority of peak demand savings came from utility system savings projects (71.8%) and TOU/CPP rates (27.5%). Programs that are categorized as traditional customer EE programs contributed less than 1% of annual peak demand savings.



Program Type	Annual MW Savings	%
Residential Pre-Paid Energy Program	0.2	0.2%
Bulb Giveaways (LED and CFL)	0.03	0.0%
TOU/CPP Rates	18.3	21.5%
Utility System Savings (including VR and all facilities)	66.3	78.0%
Energy Smart Rebates (including all combined measures)	0.2	0.3%
LED Outdoor Lights/Streetlights (utility owned/leased)	0	0.0%
Total	85.0	100%

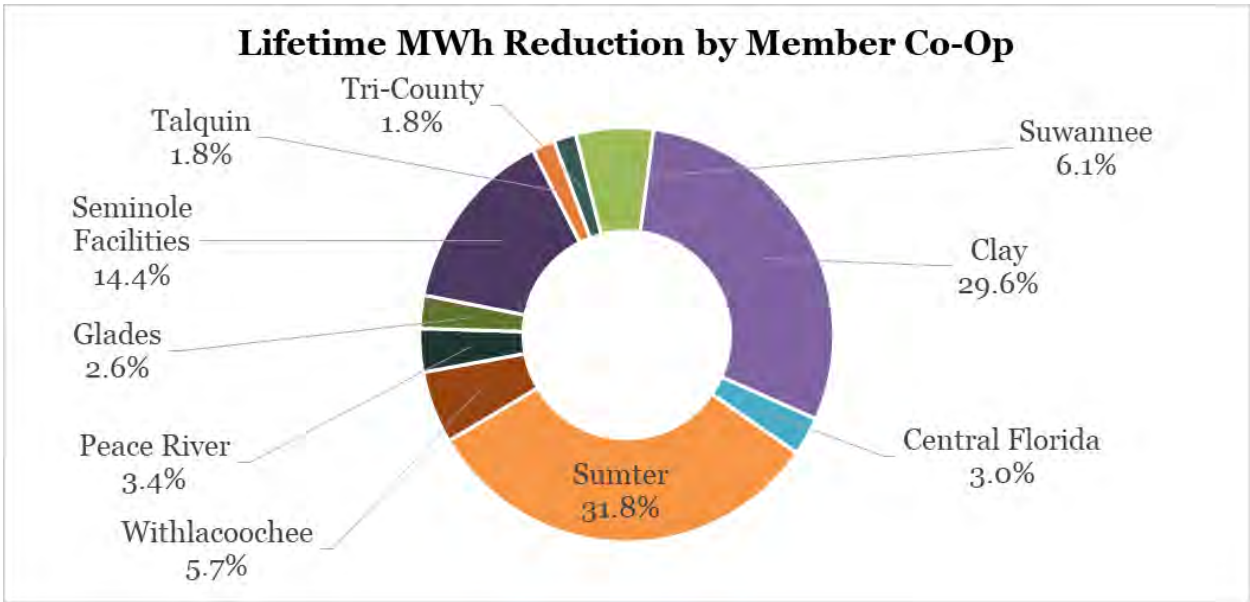
Percentage of Annual Savings by Member Co-op

When the overall savings were broken out by Member Co-op, almost half of the savings came from Sumter (45.4%), and 16.0% came from Suwannee. The remaining savings came from a combination of Clay (9.7%), Withlacoochee (8.7%), Talquin (4.0%), Central Florida (5.4%), Tri-County (4.0%), Peace River (4.0%), and Glades (0.6%).



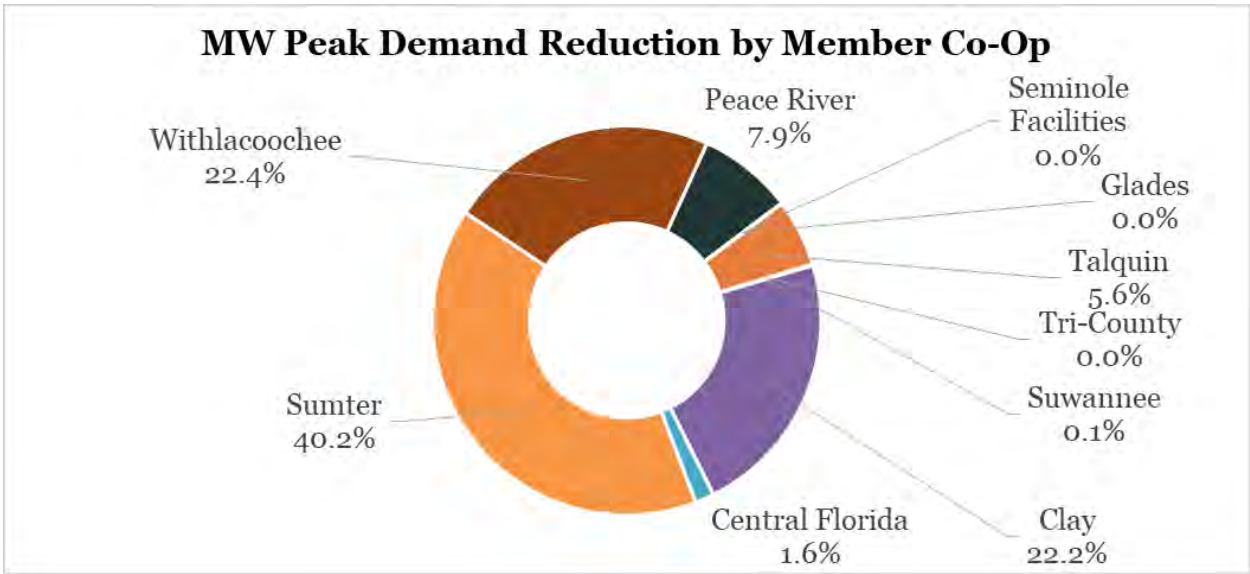
Percentage of Lifetime Savings by Member Co-op

Similar to Seminole's total lifetime savings results, the lifetime savings by Member Co-op differ significantly from annual savings due to the different types of EE programs and varying measure lives. Sumter's savings fell from 45.4% annual to 31.8% lifetime, while Clay's savings increased from 6.1% to 29.6%. Suwanee's savings fell from 16% to 6.1%. Co-ops implementing a pre-pay program will see lower lifetime savings results because of its 1-year measure life.



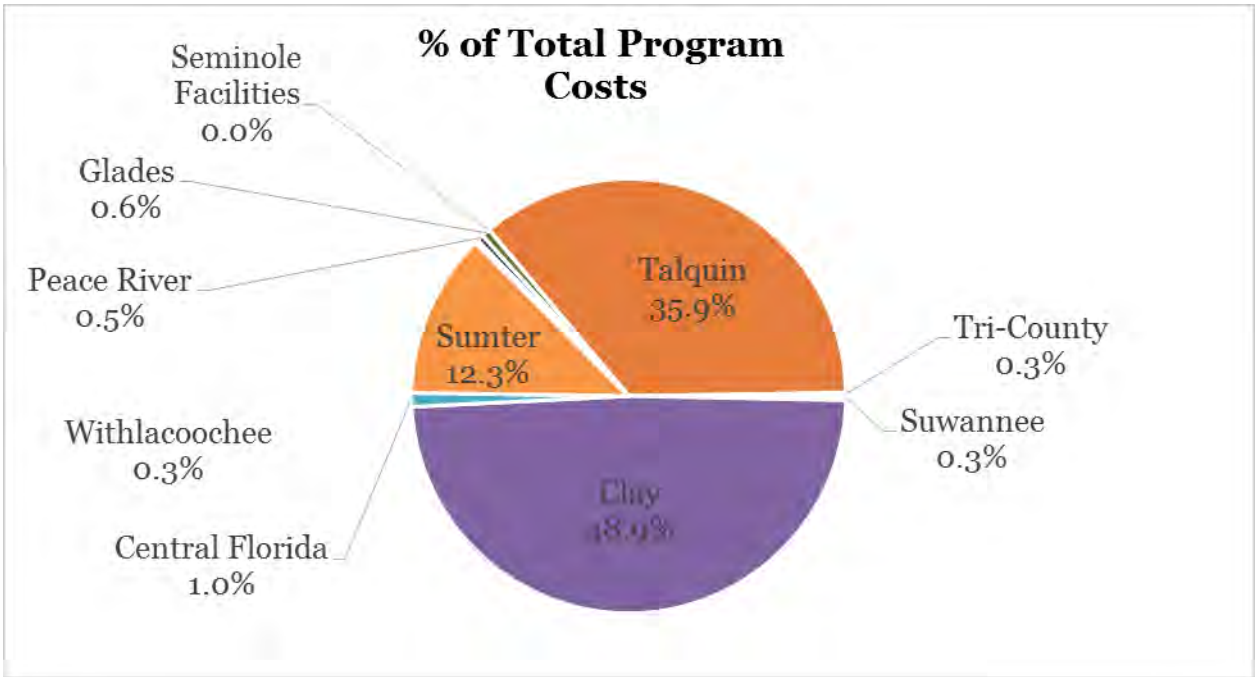
Percentage of Annual Peak Demand Savings by Member Co-op

The peak savings broken out by Member Co-op resulted in 40.2% of the savings coming from Sumter, 22.4% from Withlacoochee and 22.2% from Clay The remaining peak savings came primarily from Peace River (7.9%), Talquin (5.6%), and Central Florida (1.6%).



Percentage of Total Energy Efficiency Spending by Member Co-op

Energy efficiency spending does not necessarily correlate with savings. This outcome occurs partly because spending is not consistently tracked the same way across Member Co-ops, and partly because of differences in the energy efficiency programs and measures that each Member Co-op emphasizes. Clay spent 48.9% of Seminole's total, while Talquin spent 35.9%, and Sumter spent 12.3%. Together, these three Member Co-ops were responsible for 97.1% of all spending. Efforts to determine cost effectiveness were challenging due to incomplete and inconsistent tracking of program spending across Member Co-ops. Costs such as labor, program marketing, administration, training, and rebates/incentives must be separated and tracked consistently to accurately determine cost effectiveness.



Organization	Implementation Costs	Incentive Costs	Total Program Costs	% of Implementation Costs	% of Incentive Costs	% of Total Program Costs
Talquin	$ 251,160	$ 1,847	$ 253,007	53.13%	0.79%	35.88%
Tri-County	$ -	$ 1,847	$ 1,847	0.00%	0.79%	0.26%
Suwannee	$ 200	$ 1,847	$ 2,047	0.04%	0.79%	0.29%
Clay	$ 150,974	$ 193,808	$ 344,782	31.93%	83.39%	48.89%
Central Florida	$ 2,400	$ 4,817	$ 7,217	0.51%	2.07%	1.02%
Sumter	$ 65,187	$ 21,336	$ 86,523	13.79%	9.18%	12.27%
Withlacoochee	$ -	$ 1,847	$ 1,847	0.00%	0.79%	0.26%
Peace River	$ 166	$ 3,230	$ 3,395	0.04%	1.39%	0.48%
Glades	$ 2,677	$ 1,847	$ 4,524	0.57%	0.79%	0.64%
Seminole Facilities	$ -	$ -	$ -	0.00%	0.00%	0.00%
Seminole Total	**$ 472,764**	**$ 232,426**	**$ 705,189**	**100.00%**	**100.00%**	**100.00%**

Cost Effectiveness

To determine the cost effectiveness of EE programs, AE/Tierra looked at industry-accepted cost-effectiveness tests that are relevant to Florida, including

- Utility Cost Test (UCT) – Analyzes whether programs reduce utility revenue requirements and how energy efficiency compares to other resources
- Ratepayer Impact Measure (RIM) – Analyzes programs from the perspective of a non-participating member to determine if a program benefits all members or participants only

Each test shows a different perspective on the benefits versus costs of an EE program and is expressed as a benefit/cost (B/C) ratio.

To calculate cost effectiveness, the following information was collected from Seminole and Member Co-ops where available:

- Program Administrative Cost – The administrative costs associated with implementing energy efficiency and demand management programs by Seminole and Member Co-ops on a per-program basis
- Incentive Cost – The incentive costs paid by Seminole and its Member Co-ops to participants on a per-program basis
- Measure Incremental Cost ($/Unit) – The incremental cost of the measure (in excess of the standard costs for a non-energy-efficient device) used in cost-effectiveness calculations

- Billing Rate Escalation Rate – Co-op-specific expected escalation rate of retail rates - Default 0%
- Program Cost Escalation Rate – Co-op-specific expected escalation rate of program costs - Default 0%
- Avoided Costs Escalation Rate – Co-op-specific expected escalation rate of avoided costs - Default 0%
- IRP Discount Rate - The Weighted Average Cost of Capital (WACC) used in the integrated resource plan (IRP)
- Avoided Costs – The value of avoided costs of energy, capacity, and operations and maintenance (O&M)
- Retail Rates of Energy by Sector – The retail rates of energy by sector as used in cost-effectiveness testing to calculate the member cost savings per measure unit
- Transmission and Distribution Loss Factors – Includes total line losses from generation to member end-use meter

These data were combined with the energy savings and measure life to calculate UCT and RIM. The test results for all programs combined for Seminole were

- Utility Cost Test (utility's perspective) = 12.34 B/C ratio
- RIM Test (non-participant's perspective) = 1.12 B/C ratio

It is important to note that there are many limitations to these results due to the lack of available data. Specifically, AE/Tierra did not have a breakdown of accurate tracking of all program costs, including labor to deliver programs, an allocation of costs among programs, a separation of EE program- compared to non-program-related costs (e.g., pre-pay), and a distinction between incentive and non-incentive costs. Furthermore, for program benefits, Member Co-ops did not always accurately track the number of customers who participated in bulb giveaways and other programs. Therefore, it is expected that total program costs and program savings are higher than is reported.

KEY FINDINGS AND RECOMMENDATIONS

Through this research and analysis, AE/Tierra found that Seminole and its Member Co-ops currently offer a wide variety EE programs and demand management efforts to benefit their members. To maximize the benefits of these offerings, AE/Tierra has several recommendations:

Program Enhancement Recommendations

- Better program tracking
- Leverage what you are doing today
- Look at economies of scale
- Add targeted new programs and measures

1) Improve program tracking to ensure accurate accounting for all EE activities and expenses, which will allow for more comprehensive evaluation and verification of savings, costs, and benefits. This step includes aligning Member Co-ops around standardized program reporting and tracking and accounting procedures, including tracking program spending according to incentive and non-incentive costs.
2) Program administrative cost savings can be achieved through economies of scale, such as technology-enabled central services and partnering opportunities (within Seminole and/or with municipalities, water departments, and utilities). For example, simply partnering on bulk purchases of CFL and LED bulbs for giveaway programs among Member Co-ops can help save program costs. Aligning on centralized program tools, such as auditing software and tracking spreadsheets, is another opportunity to consider. By streamlining program delivery and driving down costs, Seminole can make these efforts even more cost effective and beneficial to members.
3) Increase the value of EE efforts by considering new measures that can be added to existing programs within the same delivery channels. This approach can leverage existing customer touch points to provide deeper energy savings per participant, which increases total program savings and cost effectiveness.
4) Investigate the costs and benefits of adding new cost-effective programs that meet the needs of the Member Co-ops and provide high value to their members. In this light, in the next phase of the project, the AE/Tierra team will be suggesting additional programs and measures for Seminole and its Member Co-ops to consider as smart additions to their current program portfolios.

A detailed list of key findings and recommendations by program type is shown in the table below.

Key Findings and Recommendations by Program Type

Program	Key Findings	Recommendations
Pre-Pay	• Large contributor to EE savings, producing 21% of total lifetime savings • Can provide utility operational savings (reduced collections and write offs) in addition to EE savings • Ideally, should be linked with enhanced program energy savings tips and information to bolster efficiency	• Explore opportunities to expand program participation • Expand energy savings tips and EE education for members to enhance EE benefits of the program • Improve tracking of EE costs to get a more accurate look at benefit/cost • Consider program evaluation and measurement and verification (EM&V) activities to better document savings for Seminole; this program is a large component of overall savings and relies on behavioral energy savings that can be difficult to document
Utility System Savings	• Represents 26% of total lifetime savings • Can be a very cost-effective savings opportunity that can reduce system losses and operating costs	• Look for opportunities to expand system savings • Institute better process for tracking utility system EE project data to better claim savings • Consider an in-depth opportunity assessment by feeder to determine savings potential. Voltage reduction savings can be a significant contributor to peak demand savings. They are also very specific to each feeder. For existing feeders with voltage reduction controls in place, consider conducting a metered measurement and evaluation study of voltage reduction savings to better document results.

Energy Smart HVAC	• Represent 27% of total lifetime savings • Savings from the HVAC rebates are reduced due to many cases of upsizing HVAC replacement equipment	• Consider updating the program design for Clay Energy Smart HVAC program to better capture savings (e.g., require sizing calculations or do not allow upsizing) • Offer HVAC quality installation training for local contractors to increase savings and impacts • Require proper sizing and quality installation • Consider multi-stage HVAC equipment and smart thermostats as emerging program opportunities
Energy Audits	• Most Member Co-ops have an on-site energy audit program for residential and/or commercial and industrial members • Bulb giveaways represent 14% of total lifetime savings	• Consider a standardized audit tool and/or set of audit data collected across all Member Co-ops • Leverage on-site audits to provide and track LED/CFL giveaways and claim additional EE savings • Combine efforts to make a bulk purchase at a lower cost per bulb

CONCLUSION

We thank Seminole and its Member Co-ops for their cooperation and assistance in preparing this report. The report contains the best available information from interviewing Seminole and Member Co-ops plus a variety of other sources: regional technical reference manuals, national industry-recognized databases, and custom energy modeling work using local weather and building characteristics. When necessary to make engineering judgements, the team chose conservative estimates. In the future, more consistent tracking and reporting of program activities and member participation could strengthen results and lead to greater savings.

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SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT PROGRAM ANALYSIS

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INTRODUCTION

Seminole Electric Cooperative Inc. (Seminole) is one of the largest generation and transmission cooperatives in the United States. Its mission is to provide reliable, competitively priced, wholesale electric power to its nine Member Cooperatives.

Recently, a pressing need for Seminole has been to secure additional resources to meet an upcoming shortfall in capacity in 2021 either through Power Purchase Agreements (PPAs) or by expanding generation. Seminole reached out to Advanced Energy (AE) and Tierra Resource Consultants LLC (Tierra) to help detail its energy efficiency (EE)/ demand-side management (DSM) portfolio to show the steps it has taken to reduce capacity and future generation needs. The AE/Tierra team assisted Seminole with determining and quantifying the EE/DSM efforts that it and its Member Cooperatives undertook in 2015 to reduce load. Together, they developed a short-term action plan for enhancing current and future EE/DSM efforts in as cost-effective a way as possible.

AE/Tierra found that Seminole and its Member Cooperatives have many programs in place to help their members save energy and manage energy costs. AE/Tierra also provided recommendations to help optimize the programs in the form of an Energy Efficiency and Demand Management Action Plan. This plan analyzes additional EE/DSM program concepts that Seminole and its Member could add to their portfolio in the future. However, none of the program concepts for the future pass the Rate Impact Measurement (RIM) test and may result in rate impacts to Member Cooperatives.

EXISTING PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

AE/Tierra found that Seminole and its Member Cooperatives offer many energy-saving programs, as well as services to educate their members about energy conservation. These services include web-based content, brochures, member outreach events, and on-site energy audits. Within Seminole's larger portfolio, AE/Tierra identified a subset of EE/DSM measures and programs where energy savings could be identified, quantified, and reported.

The existing EE/DSM programs and initiatives offered by Seminole and/or the Member Cooperatives include the following:

- Residential Pre-Pay Program: In this program, residential members can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness provided by this program produces behavioral changes that result in energy savings. Pre-Pay is limited to AMI customers only.
- LED/CFL Efficient Bulb Giveaway Lighting Programs: These Member Cooperative programs provide members with free energy-efficient 10 Watt (W) LED or 13W CFL bulbs to replace their existing 60W incandescent bulbs.
- Energy Smart Rebate Programs: These programs offer a rebate to residential members to upgrade to more efficient equipment and/or improve their building envelope. Rebate measures include air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation (batt or spray foam), and window film.
- LED Outdoor and Street Lighting: This initiative replaces utility-owned outdoor and street lighting with lower wattage LEDs. Each application was looked at separately: 100W high pressure sodium (HPS) to 40W, 48W, or 72W LED; 150W HPS to 70W LED; 250W HPS to 107W LED; and 1,000W metal halide (MH) to 283W or 316W LED.
- Coincident Peak Power (CPP) Rates: This billing program signals Members to signal commercial members to initiate demand response and reduce short-term peak. Members are offered an incentive of a Wholesale demand rate.
- Time-of-Use (TOU) Rates: These are residential, commercial, or industrial rates that encourage members to use power during off-peak hours through less expensive prices. No demand or energy savings were claimed for these rates.

- Utility System EE Projects
    - Example projects include lighting and HVAC upgrades at Seminole generation, administration facilities, or Member Cooperative facilities.
    - The Distribution System Voltage Reduction project reduces voltage on certain distribution feeders during peak times.

KEY FINDINGS AND RECOMMENDATIONS

Seminole and its Member Cooperatives currently offer a variety of EE/DSM programs and measures to benefit members. AE/Tierra Researched several other programs that ultimately did not meet the RIM test. However, there are some areas where Seminole could see marginal improvements on existing programs.

Program Enhancement Recommendations

- Improve program tracking
- Look at economies of scale
- Leverage what you are doing today
- Continue to evaluate new programs and measures

1) **Improve program tracking to ensure accurate accounting for all EE/DSM activities, savings impacts, and expenses.** The AE/Tierra team believes that Seminole is likely producing greater savings for members than is currently reported due to a lack of comprehensive program tracking. Improved tracking will allow for more comprehensive evaluation and verification of savings, costs, and benefits. This step includes aligning Member Cooperatives around standardized program reporting, tracking, and accounting procedures, including tracking program spending according to incentive and non-incentive costs.
2) **Program administrative cost savings can be achieved through economies of scale**, such as technology-enabled central services and partnering opportunities (within Seminole and/or with municipalities, water departments, and utilities). For example, partnering on bulk purchases of CFL and LED bulbs for giveaway programs can save program costs. Aligning on centralized program tools, including auditing software and tracking spreadsheets, is another opportunity to consider. By streamlining program delivery and driving down costs, Seminole can make these efforts even more cost effective and beneficial to members.
3) **Increase the value of EE/DSM efforts by considering new measures** that can be added to existing programs within the same delivery channels. This

approach can leverage existing member touch points to provide deeper energy savings per participant, which increases total program savings and cost effectiveness.

4) **Investigate the costs and benefits of adding new cost-effective programs** that meet the needs of Member Cooperatives and provide high value to their members. Below, the AE/Tierra team outlines five additional programs and measures for Seminole and its Member Cooperatives to consider.

Key Findings and Recommendations by Program Type

Program	Key Findings	Recommendations
Pre-Pay	• Produces 21% of total lifetime savings • Can provide utility operational savings (reduced collections and write-offs) in addition to EE savings • Ideally, should be linked with enhanced program energy savings tips and information to bolster efficiency • Available only to AMI customers	• Explore opportunities to expand participation • Target energy savings tips and education for members to enhance EE benefits • Improve tracking of EE costs to get a more accurate look at benefit/cost • Consider program evaluation, measurement, and verification (EM&V) activities to better document savings for Seminole; this program is a large component of overall savings and relies on behavioral energy savings that can be difficult to document
Utility System Savings	• Represents 25% of total lifetime savings • Can be a very cost-effective savings opportunity that can reduce system losses and operating costs	• Look for opportunities to expand system savings • Institute more thorough process for tracking utility system EE project data to better claim savings • Consider an in-depth opportunity assessment by feeder to determine savings potential. Voltage reduction savings can be a significant contributor to peak demand savings. They are also very specific to each feeder. For existing feeders with voltage reduction controls in place, consider conducting a metered measurement and evaluation study of voltage reduction savings to better document results. Also, consider working with a Conservation Voltage Reduction (CVR) vendor to assess potential feeders for a pilot

Program	Key Findings	Recommendations
Energy Smart HVAC	• Represents 27% of total lifetime savings • Savings from the HVAC rebates are reduced because of many cases of upsizing HVAC replacement equipment	• Consider updating the program design for Clay Energy Smart HVAC program to better capture savings (e.g., require sizing calculations or do not allow upsizing) • Offer HVAC quality installation training for local contractors to increase savings and impacts (see below) • Require proper sizing and quality installation • Consider multi-stage HVAC equipment and smart thermostats as emerging program opportunities (see below)
Energy Audits	• Bulb giveaways represent 14% of total lifetime savings • Most Member Cooperatives have an on-site energy audit program for residential, commercial, and industrial members	• Consider a standardized audit tool and/or set of audit data collected across all Member Cooperatives • Leverage on-site audits to provide and track LED/CFL giveaways and claim additional EE savings (see below) • Combine efforts to make a bulk purchase at a lower cost per bulb

NEW PROGRAM SUMMARIES

As noted above, in addition to offering recommendations for improving current EE/DSM offerings, AE/Tierra has proposed several new, program concepts for Seminole and its Member Cooperatives. The program concepts were selected based on AE/Tierra experience and feedback from Seminole on current activities in Member Cooperative territories. The focus of this report is on providing concepts that enhance existing programs or leverage current activities, improve the member experience, provide potential to shift peak demand, promote new technologies, and add value for members. At this time, none of the concepts for future programs meet the RIM test based on the information and assumptions used to analyze future program benefits and costs.

Seminole is not subject to the requirements and guidance of the Florida Energy Efficiency and Conservation Act (FEECA); however, it was interested in the cost effectiveness of potential EE/DSM programs. Specifically, Seminole requested information on the impact of implementing EE/DSM programs on rates for all member-consumers, as well as a comparison between the cost of EE/DSM programs and other resources, such as new generation. As such, the AE/Tierra team performed calculations

for two cost-effectiveness tests: the Ratepayer Impact Measure (RIM) test and the Utility Cost Test (UCT). (Note that the UCT is also called the Program Administrator Cost [PAC] test.) The team used the definitions of the tests provided in the California Standard Practice Manual. The RIM test was more strongly considered because of the desire for future program offerings to have a minimal impact on rates. It is noted that based on the information and assumptions used to analyze potential program opportunities, none of the future program offerings in this report pass the RIM test and may impact Member rates.

The RIM test analyzes programs from the perspective of a non-participating member to determine if a program benefits all members or participants only. The UCT analyzes whether programs reduce utility revenue requirements and how EE/DSM compares to other resources. The results for cost effectiveness are presented as a benefit to cost ratio. Higher values indicate that a program is more cost effective, and a value greater than one shows that the benefits outweigh the costs over the program life. Results for both tests are presented.

Performing cost-effectiveness tests requires estimating program participation, energy/demand savings, program implementation costs, incentive costs, and contributors to net-to-gross ratios, such as free-ridership. AE/Tierra considered numerous secondary sources for these inputs, including utility program filings in Florida, Arizona, Kentucky, and California, and made best estimates based on Seminole member demographics. We also consulted the Arkansas Technical Reference Manual (the closest regional manual) and used information from existing Seminole Member Cooperative programs. As part of this effort, AE/Tierra used the California Energy Data and Reporting System (CEDARS) database (https://cedars.sound-data.com/programs/list/) maintained by the California Public Utilities Commission (CPUC). This database was used because it contains a large amount of detailed program information.

Seminole also provided certain primary data based on the best available information at the time of analysis. This data included avoided energy, capacity, and transmission costs for the years 2017 to 2043, current average residential and commercial retail rates, and an escalation schedule for retail rates. For the avoided cost assumptions, we considered two scenarios. The first scenario (listed as (1) on all tables) included the total annual value of avoided capacity cost for a new generic unit coming online in May 2021. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest

contingency during four summer months only per year. The second scenario (listed as (2) on a tables) included the total value of avoided capacity cost based upon responses received in Seminole's March 1, 2016 Request for Firm Capacity for the period from June 2021 through December 2025. The total annual cost of a new generic unit coming online in year 2026 is reflected thereafter. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest contingency during four summer months only per year. Where the scenarios produced different values, we have noted them in the tables below with (1) and (2).

Below are five program concepts that we analyzed for the Seminole and Member Cooperative EE/DSM program portfolio, along with the results of cost-effectiveness calculations. Note that cost effectiveness calculations were based on the best information that could be collected on potential costs and benefits of each program concept within the project scope.

Commercial & Industrial Lighting Program

Currently, only a few programs, such as the coincident peak power rates, target commercial and industrial members.

Program Description

The Commercial & Industrial Lighting Program will incentivize non-residential members who have qualifying businesses for installing energy-efficient lighting equipment. Program delivery will involve rebates paid directly to participating contractors for replacement lamps and fixtures that meet or exceed program standards. Incentives may also be paid directly to members who self-install qualifying lighting equipment. Based on the assumptions applied here, the Commercial & Industrial Lighting Program is projected to result in average annual energy savings of 5,976 kWh per facility per year. This program recommendation received a 0.38 on the RIM test resulting in possible rate impacts for Member Cooperatives.

Target

Qualifying businesses must be current members of the cooperative and in good standing with regard to electricity payment.

Energy Efficiency Savings Measures

- LED direct replacement lamps for incandescent lamps
- LED replacement fixtures for T12 and T8 fluorescent fixtures
- LED replacement fixtures for indoor HID fixtures

- LED replacement fixtures for outdoor HID fixtures
- High performance T8 replacement lamps for standard T8 fluorescent lamps
- High performance T8 replacement kits for T12 fluorescent fixtures

Incentive Design

- Incentive basis
  - $0.08 per total annual kWh reduction
  - $150 per total peak kW reduction
- Specific incentive amounts will be developed based on the following:
  - Fixture wattage
  - Lamp wattage
  - Wattage reduction
  - Application

Implementation Plan

This program will be advertised through brochures and bill inserts to commercial and industrial members. Web-based tools will provide incentive applications and calculations. Training and certification will qualify electrical contractors and enroll them in the program, while in-house training will assist co-op energy auditors with facilitating the program.

Incentives in the form of rebates will be paid to members who have qualifying lighting technologies installed in their businesses by qualified installers. A percentage of installations will be inspected.

Marketing and Member Education

Outreach and education can help attract commercial and industrial members to the program. Seminole's larger distribution Member Cooperatives already provide energy audits to these members, and auditors can refer them to the lighting program to assist them with improving their lighting systems.

Brochures, web-based tools, and applications can be developed to assist with facilitating the program and educating members. Some tools will describe eligibility requirements, lighting product standards, and rebate amounts for qualifying lighting technologies. Others will provide information on accessing qualified lighting installers and how electrical contractors can become qualified installers.

Potential Results

Table 1 – Savings, Costs, and Cost-Effectiveness Summary Commercial & Industrial Lighting

Units & Savings		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
366	**2190**	**0.472**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$250,157	**$83,386**	**$333,543**
Cost Test Results		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**1.44 (1), 1.36 (2)**	
Ratepayer Impact Measure (RIM) Test	**0.38**	

Residential Audit Direct Install Kits

Numerous Seminole Member Cooperatives currently offer residential energy audit programs. These programs are traditionally expensive but are critical to address members' high-bill complaints. It is difficult to attribute savings to an audit alone, and adding direct install kits will allow for claiming savings with audits. In addition, it is recommended that Seminole consider using a standardized audit tool and/or set of audit data collected across all Member Cooperatives, as well as bulk purchasing for lower costs per bulb.

Program Description

This program will enhance existing residential energy audits by including free direct installation of light bulbs. Because auditors are already in the home during an audit, they can perform the installation without an additional trip. A maximum of 10 high use interior light bulbs will be changed from incandescent to LED. The program can also be run as a mail-out program; however, installation will be difficult to verify, and fewer savings will be realized. The LED direct install program is projected to result in average annual energy savings of 280 kWh per household (10 lamps) per year. This program received a 0.29 on the RIM test resulting in possible rate impacts for Member Cooperatives.

Target Audience

Members who receive a residential audit and have incandescent bulbs in high use areas.

Energy Efficiency Savings Measures

- 10 Energy Star LED light bulbs (downlights, standard bulbs, and/or mini bulbs)

Incentive Design

There is no monetary incentive paid to members; however, the LEDs will be free.

Implementation Plan

All members who receive an audit will receive direct install LEDs for high use areas. Auditors will use their discretion as to where and how many bulbs should be installed, up to a maximum of 10. These bulbs will be at no cost to the member and must be restricted to interior high use lights. This direct install of LEDs can be added to any visit by a cooperative staff member as long as the staff is trained on the correct documentation and safety. LED bulbs will be bulk purchased by Member Cooperatives to reduce costs.

Marketing and Member Education

There is no need to market the program because it is an addition to residential audits. Marketing the free direct install LEDs may increase the number of audits of homes interested only in this feature, which will reduce the cost effectiveness of the program as a whole because the audits may produce fewer savings.

Potential Results

For illustrative purposes, Table 2(a) presents the cost effectiveness of performing a residential audit with direct install kits, and Table 2(b) does the same for LED direct install alone, excluding residential audit costs. When the savings from light bulbs are added to an existing audit program, the program becomes slightly more cost effective but does not currently meet the RIM test.

Potential Results

Table 2(a) – Savings, Costs, and Cost-Effectiveness Summary LED Direct Install

Units & Savings		
Estimated Annual Projects (Homes)	**Annual MWhs Saved**	**Coincident MW Saved**
3,188	**891**	**0.09**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$206,104	**$68,095**	**$274,199**
Cost Test Results		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**0.99(1), 0.97(2)**	
Ratepayer Impact Measure (RIM) Test	**0.28(1), 0.29(2)**	

Table 2(b) – Savings, Costs, and Cost-Effectiveness Summary LED Direct Install Excluding Energy Audit Costs

Units & Savings		
Estimated Annual Projects (Homes)	**Annual MWhs Saved**	**Coincident MW Saved**
3,188	**891**	**0.09**
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$143,460	**$68,095**	**$211,555**
Cost Test Results		
Cost Test		**Estimated Result**
Utility Cost Test (UCT)		**1.29(1), 1.26(2)**
Ratepayer Impact Measure (RIM) Test		**0.30(1), 0.31 (2)**

Direct Load Control or Grid-Enabled Water Heater Program

Seminole expressed interest in water heater programs. The AE/Tierra team investigated programs for both direct load control water heaters and grid-enabled water heaters. The former may provide a good first step into water heater programs, while the latter are a new technology that is gaining traction. These programs could meet the overall goal of Seminole to reduce coincident peak. Many utilities have started running grid-enabled water heater programs, and some are still in pilot phases or have not completed a full EM&V cycle. For these reasons, the AE/Tierra team was unable to complete the calculation of cost-effectiveness tests for grid-enabled water heaters.

Program Description

This program will incentivize homeowners to replace existing water heaters with direct load control or grid-enabled water heaters. It will also allow Member Cooperatives to manage how homeowners' tank water heaters use energy. The goal of this program is to

develop protocols for different types and sizes of water heaters that can shift peak demand loads using their thermal storage potential without negatively impacting homeowners' access to hot water. This program could use either direct load control or grid-enabled water heaters but will not use both. Depending on current infrastructure and insight from Member Cooperatives, direct load control water heaters may be more reasonable; however, grid-enabled heaters can produce maximum peak shifting. Program delivery will include an equipment incentive to homeowners when replacing water heaters or during new construction, and an annual rebate for load shifting using grid-enabled or demand response control. The demand response control will have a limit to the number of events that can take place in a year. Based on the inherent demand-reducing nature of the Direct Load Control Water Heater Program, it is projected to result in no household energy savings. This program received a 0.67 under scenario (1) and 0.60 under scenario (2) on the RIM test and may result in rate impacts on Member Cooperatives.

Target Audience

Residential members who use electric tank water heaters. Grid-enabled water heaters require 80-gallon storage tanks, whereas direct load control water heaters require only 50-gallon tanks. We learned from the Residential Energy Consumption Survey (RECS) and Seminole that many houses have water heaters of less than 50 gallons, which could affect program design and participation. Both heat pump and standard resistant water heaters are eligible for participation.

Energy Efficiency Savings Measures (Either/Or)

- Grid-enabled water heaters allow the utility to design a load-shifting water heating profile that preemptively shifts water heater load to off-peak hours by preheating the water. These heaters also allow for rapid response to intermittent load and voltage issues, which requires at least an 80-gallon water heater because the thermal mass is needed to maintain the hot water. This will raise the amount of electricity homeowners use to heat their water but has the most potential to preemptively shift loads.
- Direct load control water heaters allow Member Cooperatives to temporarily turn off water heaters as demand response to high-peak events. This technology acts like a switch and does not use preheating. Direct load control can be applied to existing water heaters as long as the tank is at least 50 gallons. Homeowners' energy bills will not rise to heat their water, and the demand response events should be limited to 10 annually.

Incentive Design

The incentive for participating members will be a flat rate per year. To reduce administrative costs, incentives will be directly added to participants' bills. If a member opts out, the rebate amount will be prorated for the year. The incentive design can be adjusted to ensure installation and administration costs are appropriately covered.

Implementation Plan

Appropriate infrastructure will need to be in place for either grid-enabled or direct load control heaters. Radio frequency and Wi-Fi can be used for both programs, and the choice of communication will depend on existing infrastructure, cost, and capability with current cooperative systems.

Grid-Enabled Water Heaters: A predetermined plan for pre-charging water heaters during off-peak hours must be developed to ensure the maximum potential for load shifting while minimizing the impact on members. The pre-charging plan will be based on standard water draw patterns, thermal storage potential of the water heaters, and high-peak times for the cooperative.

Direct Load Control Water Heaters: A protocol for using switches on water heaters enrolled in the program for demand response events will be developed for different water heater sizes, which will determine the maximum amount of time during peak hours that a water heater can be switched off.

Qualified contractors will install equipment and water heaters. Once installation is complete, homeowners will receive an equipment rebate and later an annual rebate as long as they are still participating in the program. A website portal will be available for members to report hot water issues and will inform participants of the switching or grid-enabled protocols.

Marketing and Member Education

The program will need to be marketed by Member Cooperatives using stock materials created by Seminole. Potential resources include bill inserts, social media, website links, and the call/billing center. There will be two main goals of the marketing: 1) to educate homeowners about the available incentive for having the demand control device installed on their water heater or a grid-enabled water heater, and 2) to inform them that they will not see any change in hot water availability. This second goal will be the primary challenge for implementing the program.

Potential Results

Table 3 – Savings, Costs, and Cost-Effectiveness Summary Direct Load Control Water Heaters

Units & Savings		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
5,677	0	3.3
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$2,012,524	$393,108	$2,405,632
Cost Test Results		
Cost Test		**Estimated Result**
Utility Cost Test (UCT)		0.70(1), 0.63(2)
Ratepayer Impact Measure (RIM) Test		0.67(1), 0.60(2)

HVAC Quality Install Program

The HVAC Quality Install Program complements an existing HVAC rebate program from one of Seminole's Member Cooperatives. The current program has erosion of savings because of the installation of larger equipment. The Quality Install Program approach increases savings and impacts. Offering this program could lead to numerous benefits because HVAC systems dominate energy use in homes and have a relatively long useful life.

Program Description

This program will incentivize quality installations of replacement heating and cooling equipment in existing single-family homes, which will result in a better performing system. The Quality Install Program will follow the ACCA Quality Installation 5 Manual to ensure that the system is sized correctly, the total airflow of the system is set to the manufacturer's specifications, the duct system is well sealed, the refrigerant is correctly charged, and the total static is within the manufacturer's specifications. These five steps

are often overlooked during equipment change out, which results in underperforming equipment. Program delivery will include rebates to contractors that will reduce or cover the cost of the extra work associated with quality installations, a robust quality control/quality assurance protocol, and training to ensure contractors are capable of participating. A complementary program can be rolled out simultaneously that will retro-commission existing equipment to address duct tightness and refrigerant charge. The AE/Tierra team concentrated on a replacement program in this report but included cost-effectiveness calculations for a retro-commissioning program as well. The HVAC Quality Install and HVAC Quality Retrofit Programs are projected to result in average annual energy savings of 451 kWh and 305 kWh, respectively, per household per year. Neither program passed the RIM test and may result in rate impacts to Member Cooperatives.

Target Audience

Single-family homeowners in need of a replacement heating and cooling system and contractors who perform equipment change outs.

Energy Efficiency Savings Measures

- Correctly Sized System – A load calculation will be completed on the home, and a heating/cooling system will be selected to match the load calculation within 6,000 BTUs.
- Airflow Across Coil/Heat Exchanger – Airflow will be tested at coil, and speed will be adjusted until it falls within the manufacturer's specifications.
- Duct Sealing – Ducts will be tested and sealed to reduce leakage by 50 percent; ducts that have less than 10 percent leakage will not need to be sealed.
- Refrigerant Charge to Manufacturer's Specifications – Superheat or sub-cooling measurements will be taken to ensure refrigerant is charged to manufacturer's requirements. The charge will be adjusted as necessary.
- Correct Static – Total static will be measured and ductwork will be reworked as necessary to meet manufacturer's specifications.

Incentive Design

To reduce administrative costs, incentives will be paid directly to participating contractors, and the value will be passed on to members. As participating contractors complete the installations, they will submit applications for incentive payments until the program has reached its funding limit.

The incentive will be paid directly to the contractor to cover the additional cost to perform start-up tests and quality control measures required for the Quality Install

Program. To receive the incentive, contractors will have to undergo a qualification process that shows their ability to perform the appropriate tests and meet the requirements of the program. Contractors will complete the appropriate paperwork and submit per job for the incentive.

Implementation Plan

A network of local trade ally participating contractors will be developed to help implement and market the HVAC Quality Install Program to eligible members. Each participating contractor will be required to attend program training and meet minimum eligibility requirements. The training will not only teach contractors the requirements of the program but also educate them on how to market quality installation to potential members.

Contractor requirements will include filling out a start-up worksheet and providing photo verification of measurements that will be submitted with job forms for processing the incentive. In addition, skilled co-op staff or a third-party inspector will conduct random quality assurance inspections. If quality assurance staff discovers discrepancies in the HVAC system, the participating contractor will be put on probation and required to fix all discrepancies before new jobs are submitted. The program staff will develop plans and procedures for dealing with delinquent contractors.

Marketing and Member Education

The Quality Install Program will require a base of approved HVAC contractors capable of meeting program standards. HVAC contractors will need to be made aware of the value proposition of participating in the program, which will include the incentive amount, potential marketing from the cooperative, market differentiation, and value to members. These benefits will have to be equal to or greater than the extra cost associated with the additional paperwork and testing. Approved contractors will also sign an agreement that all eligible jobs will be enrolled in the program and not treated as an up sale to the member.

The program will need to be co-marketed by both the qualified contractors and the Member Cooperatives. The Member Cooperatives will create tools that market the program and contractors to members. The main purpose of the marketing will be to educate homeowners about the additional value they will receive by using a contractor that participates in the program. The contractors will market the program through incorporating Quality Install Program benefits into their sales materials.

Potential Results

Table 4(a) – Savings, Costs, and Cost-Effectiveness Summary HVAC Quality Install

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
550	248	0.076
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$110,000	$86,260	$196,260
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	0.38(1), 0.36(2)	
Ratepayer Impact Measure (RIM) Test	0.22(1), 0.21(2)	

Table 4(b) – Savings, Costs, and Cost-Effectiveness Summary HVAC Quality Retrofit

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,282	391	0.217
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$192,300	$69,167	$261,467
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	0.48(1), 0.43(2)	
Ratepayer Impact Measure (RIM) Test	0.26(1), 0.23(2)	

Smart Thermostat Program

Smart thermostats are ever-evolving technologies that bring the documented savings of an advanced programmable thermostat with adaptive recovery to the potential for demand response. These thermostats are often difficult to initially set up; however, they learn occupants' behaviors and self-program set-backs. In addition, smart thermostats are already heavily marketed and appeal to early adopters of new technology.

Program Description

This program will incentivize new and existing single-family homeowners to install smart thermostats on their heating and cooling systems. Smart thermostats are used to improve HVAC system efficiency by creating automated behavior-based set-points for heating and cooling systems, limiting the use of heat strips in heat pumps, and offering utility-enabled demand response. Some smart thermostats can also alert homeowners to underperforming systems and remind them of preventative maintenance. Program delivery will include incentives paid directly to homeowners, and installation can be performed by homeowners or HVAC contractors. The Smart Thermostat Program is projected to result in average annual energy savings of 366 kWh per household per year. For this analysis, the demand savings projected are consistent with a programmable thermostat program (0.14 kW). If utility-enabled demand response is included in the program design, demand savings will go up significantly and should increase the cost-effectiveness. This program received a 0.37 on the RIM test and may result in rate impacts to Member Cooperatives.

Target Audience

Single-family homeowners who have heat pumps and/or air conditioners with furnaces capable of functioning with a smart thermostat. Homeowners must have Wi-Fi available in their home to participate.

Energy Efficiency Savings Measures

- Smart thermostats learn occupants' behavioral patterns and schedule set-backs when the home is not occupied and/or occupants are asleep.
- Smart thermostats limit the use of heat strips on heat pumps when in heating mode.
- Smart thermostats can be used for demand response.

Incentive Design

Incentives will be paid directly to the member because installation may be done by the member or a contractor. A one-time equipment incentive will be paid to the member for

installing up to two smart thermostats in a single home. If demand response is activated, the member will receive a set incentive rate per year. There will be a limit to the number of demand events that can happen annually. The cost effectiveness results presented here are not based on the use of the demand response features. Utilizing demand response will significantly increase demand savings and program costs, and will require additional planning to maximize benefits.

Implementation Plan

It is recommended that a single type of smart thermostat be selected to reduce administrative costs and simplify implementation. The incentive will not be paid to the member until the thermostat has enrolled in the program over the manufacturer's platform and the serial number is submitted to the Member Cooperative. The member will opt in or out of the demand response part of the program. The Member Cooperative will work with the smart thermostat manufacturer to design how demand response will occur. Members who participate in demand response will receive a set number of credits.

Marketing and Member Education

The program will be marketed by Member Cooperatives through bill inserts, retail store displays, and social media. Member Cooperatives will partner with big-box stores to prominently display information about the program. Marketing material will educate members on the user features, energy savings, and demand response capabilities of smart thermostats.

Social media can be used to spread awareness and create energy savings competitions. Most smart thermostats calculate users' savings, which can be shared on social media, and Member Cooperatives could hold a gift card drawing for members who participate. Such an incentive may help create energy competition that could generate even more savings.

Potential Results

Table 5 – Savings, Costs, and Cost-Effectiveness Summary Smart Thermostat

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,517	**555**	**0.212**
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$75,850	**$158,250**	**$234,100**
COST TESTS		
Cost Test	**Estimated Result**	
Utility Cost Test (UCT)	**1.04 (1), 0.96(2)**	
Ratepayer Impact Measure (RIM) Test	**0.37(1), 0.36(2)**	

CONCLUSION

We thank Seminole and it's Member Cooperatives for their cooperation and assistance with preparing this report. The report summarizes information from AE/Tierra's work interviewing Seminole and Member Cooperatives about their current activities and member demographics. Seminole and its Member Cooperatives already have a number of effective energy-and demand-saving programs in place; and as programs become more cost effective, there could be opportunities for additional marginal savings.

Additional energy savings can be realized by implementing the new, program concepts outlined in this report: Commercial & Industrial Lighting, Residential Audit Direct Install Kits, Direct Load Control or Grid-Enabled Water Heaters, HVAC Quality Install, and Smart Thermostats. However, these programs do not meet the RIM test, and are not cost-effective.

To calculate the cost effectiveness of the new program ideas, we considered numerous secondary sources, such as utility program filings in Florida, Arizona, Kentucky, and California, and made best estimates based on Seminole member demographics. Each program concept was evaluated individually for cost effectiveness. As new programs move to implementation, it is beneficial to also evaluate cost effectiveness at the portfolio level including all programs offered.

No programs passed the RIM test due to the cost of lost revenues they produce. While additional DSM opportunities are available, they must be considered in the context of their impact on rates for non-participants.

JASON PETERS

Education:

Masters of Business Administration, University of South Florida 1998–2000
Bachelor of Arts, Criminology, University of South Florida 1992-1995

PROFESSIONAL EXPERIENCE

SEMINOLE ELECTRIC COOPERATIVE, INC. **2001-Present**

Various titles, currently a Portfolio Director

- Plan, develop and implement both short and long term power marketing and fuel strategies to optimize the resources of a nine member, 3500 MW rural G&T cooperative with a portfolio of fuel diverse generation assets (coal, and natural gas) and multiple purchased power agreements.
- Administrate all long term coal, rail transportation, railcar fleet and purchased power agreements in Seminole's resource portfolio, which includes duties such as contract interpretation, scheduling of resources, review of invoices, and resolution of disputes.
- Lead, train, develop and provide work direction to three employees.
- Established policies for and monitor compliance with both internal and external risk management controls.

FLORIDA POWER CORPORATION **1997 – 2001**

Power Trader

- Conducted buying and selling transactions of electric commodity in the near-term or spot market for a 9000 MW portfolio of nuclear, steam, coal, gas, and oil units in Florida and SERC regions.
- Utilized personal relationships, competitive nature, creativity and sales ability to assist real-time trading team in achieving over 200% of 2000 goal.
- Coordinated efforts with portfolio, generation, and long-term trading contacts to maximize profit potential of FPC's generation assets and assure system reliability.

Manager, Automated Payment Processes

- Designed and directed Automated Payment Systems for Florida Power's 32 county service territory, significantly improving customer perception of convenience and reliability of FPC customer service channels.
- Constructed and directly supervised a network of 53 Automated Agents to provide additional face-to-face venues for customer service.
- Recruited and contracted each Agent location, developing a system that accepted over 300,000 payments and collected $10 million in revenue yearly. Optimized placement of and increased Agent locations while reducing cost per payment by 23%.
- Implemented an automated multimedia kiosk for the acceptance of customer payments and service transactions. Led efforts involving external vendor and internal departments to custom build the kiosk and integrate to existing FPC software systems.

BARNETT BANK **1993 - 1997**

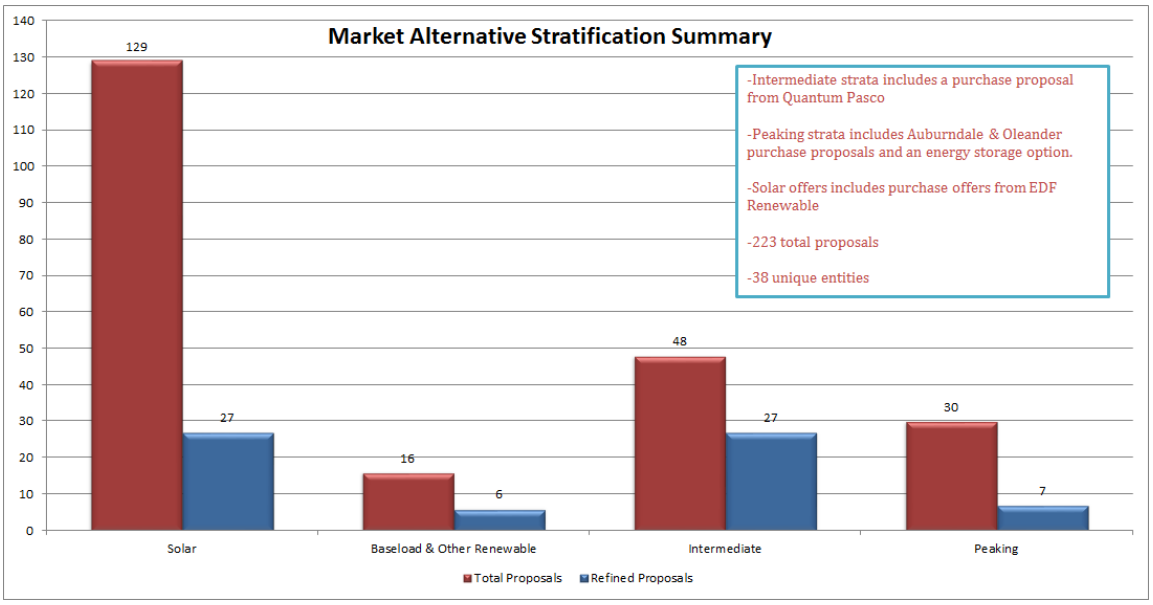
Business Banker

- Obtained new customer relationships and expanded existing customer relationships with Small Business customers (revenues of less than $5 million annually).

Sales and Service Coordinator

- Designed and implemented market plans for Barnett's Alternative Retail Delivery products to achieve affiliate level sales goals for each product line.
- Designed and conducted sales training for front-line sales personnel and designed sales incentive programs for a 35 branch network.
- Received 7 months centralized classroom and real time training focused on retails sales and management skills.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 42
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Jason Peters JP-1 SH



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DOCKET: 20170266-EC EXHIBIT: 43
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Jason Peters JP-2 SH

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 44
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-1

JULIA A. DIAZGRANADOS

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JDiazgranados@seminole-electric.com • Work 813-739-1538 • cell 813-789-8203

CAREER EXPERIENCE

SEMINOLE ELECTRIC COOPERATIVE INC.
16313 North Dale Mabry Highway, Tampa, Florida 33618

Director of Planning (2017-Present)
Leads budget and financial forecasting processes along with the planning and related analysis of Seminole's long range generating capacity needs including the evaluation of generation alternatives. Provides supervision and work direction to budget, financial forecast and generation planning personnel. Responsible for the application of production costing and corporate financial models in the performance of generation studies budgeting and financial forecasting. Enables integration of Seminole load forecasting into budget, financial and resource planning

Planning Manager (2013-2017)
Directs generation planning staff and cross-functional teams in order to develop studies used in establishing long-term rate projections; financial forecasts; and generation plans to meet future energy needs. Conducts risk assessment of power supply alternatives. Presents study results and recommendations to Executive Staff and Board of Directors. Seminole representative on the Florida Reliability Coordinating Council's Resource Subcommittee and the Generation & Transmission Resource Planning Association.

Generation Planning Supervisor (2010-2013)
Oversees the planning and related analysis of Seminole's long range generating capacity needs including the evaluation of generation alternatives. Provides supervision and work direction to generation planning personnel. Responsible for the application of production costing and corporate financial models in the performance of generation studies.

Lead Strategic Planning Analyst (2007-2009)
Coordinates and participates in the planning and related analysis of the long range generating capacity needs including evaluation of generation alternatives. Responsible for the application of production costing and system optimization models in the performance of generation planning studies.

Senior Strategic Planning Analyst (2005-2007)
Participates in the planning and related analysis of long range generation capacity needs including the evaluation of generation alternatives. Strategic plans included, but not limited to, the evaluation of proposed self-build generation units verses power purchase agreements, development of options for meeting renewable targets, and establishing financial strategies.

FUTURE SCOPE, INC.
400 WEST LAKE STREET, SUITE 306, ROSELLE, IL 60172

Principal – Utility Advisory (1999 – 2004)
Provided various utilities in the mid-west and east coast with situational assessments; resolution proposals; application design; project management including budgeting and resource requirements; implementation of systems; and development of user documentation. Created and conducted training courses of developed systems. Oversight of marketing campaigns; sales presentations; and implementation process of company's Capital Management and Cost of Service applications.

ALLEGHENY ENERGY SERVICE CORPORATION
800 CABIN HILL DRIVE, GREENSBURG, PA 15601

Financial Analyst 1996 -1999
Prepared assumptions and model runs to support operational decision-making, long-term forecasting, budgeting and strategic planning. Performed capital project evaluations/analysis on proposed investments to assist in the prioritizing/allocating of funds. Managed and coordinated the replacement of the Corporate Financial and Capital Management Systems with outside consultants.

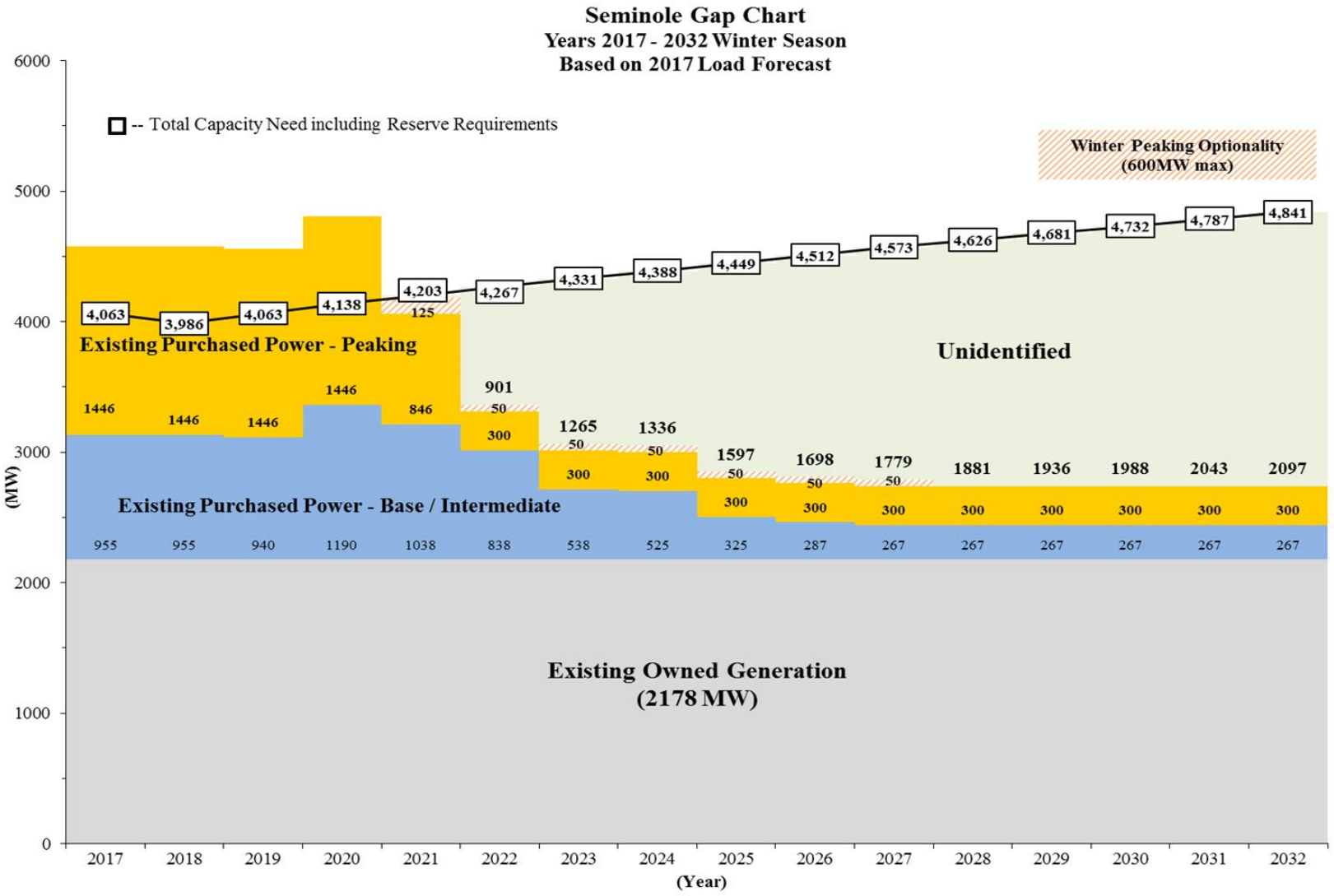
Financial Services Analyst 1991 -1996
Maintained and ran Corporate Financial Models. Responsible for the administrative duties of the Local Area Network (LAN) - setup servers, created backup/restore procedures, established user access rights, configured user workstations, and provided technical support for seven departments within Financial Service's area.

EDUCATION

Bachelors of Science Degree, Business Administration
Associate of Science Degree, Electronic Data Processing
FAIRMONT STATE UNIVERSITY
FAIRMONT, WV

- Awarded the Outstanding Electronic Data Processing Student Award

FLORIDA PUBLIC SERVICE COMMISSION
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PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-2



Docket No. 2017_____-EC
Seminole Need Gap Chart
Exhibit No. __ (JAD-2), Page 1 of 1

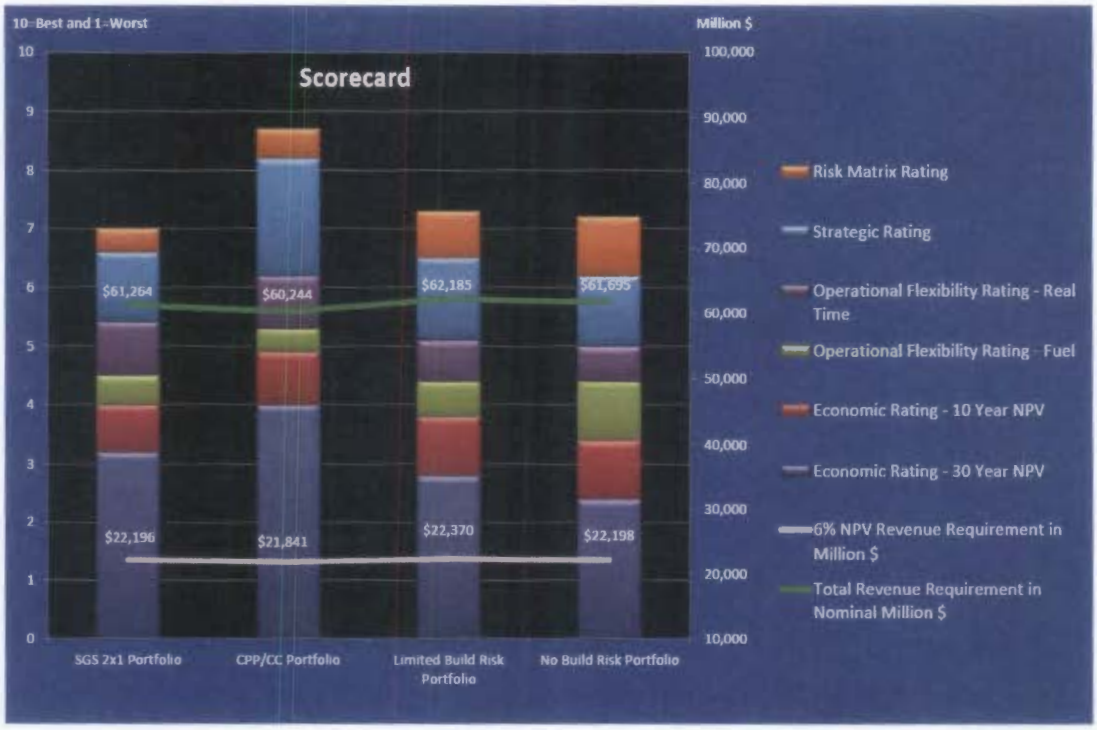
Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	12,381	12,266	12,196	12,096
NPV @ 6.0%	9,008	8,936	8,885	8,797
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	61,264	60,244	62,185	61,695
NPV @ 6.0%	22,196	21,841	22,370	22,198

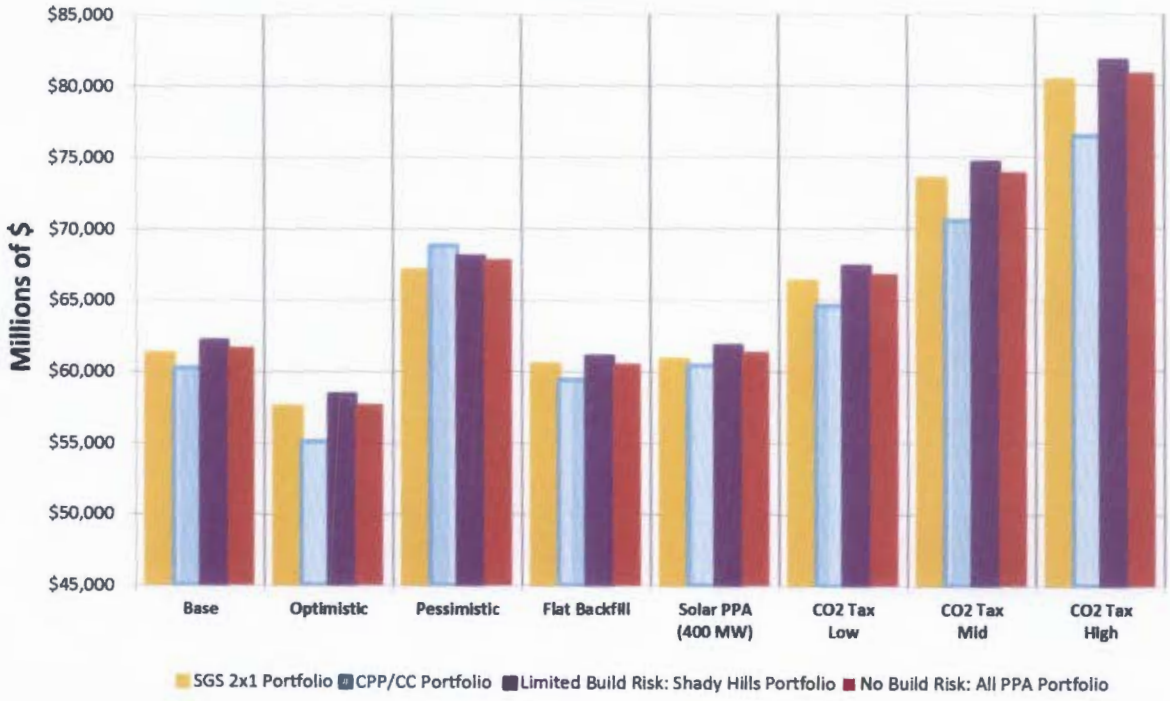
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 46
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-3

Portfolio Scorecard Assessment



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PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-4

Total Member Revenue Requirements (Nominal $)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 48
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados JAD-5

Portfolio Summaries
Revised Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	**11,666**
NPV @ 6.0%	8,641	8,568	8,549	**8,499**
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	**56,465**	58,312	58,616
NPV @ 6.0%	20,981	**20,618**	21,120	21,148

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 49
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Julia A. Diazgranados

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 50
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Alan S. Taylor AST-1Doc1

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, energy storage, energy efficiency projects, demand response, and off-system power purchases; analyzed thousands of such 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

2015- **Minnesota Solicitation for New Resources**
2017 Client: Minnesota Power Company

Provided independent evaluation services in five solicitations for new resources: up to 400 MW of gas-fired generation and up to 300 MW each of wind, solar, demand response, and customer cogeneration resources. Mr. Taylor reviewed the request for proposals (RFP), managed the Sedway Consulting team in performing a quantitative and qualitative evaluation of all proposals, monitored communications and negotiations with shortlisted bidders, and provided reports for filing with the Minnesota Public Utilities Commission regarding the results of the solicitations.

2014- **California Evaluation/Negotiation of Non-Conventional Resource Solicitation**
2017 Client: Southern California Edison

Provided independent evaluation services in several solicitations for new resources: two for up to 36 MW new energy storage resources, one for over 1,000 MW of near-term resource adequacy capacity, and one for a broad array of non-conventional resources to address over 100 MW of reliability needs in a local area. In that last project, solicited resource types included energy efficiency, demand response, in-front-of-meter and behind-the-meter energy storage, renewable resources, and hybrid transactions. For all four solicitations, Mr. Taylor managed the Sedway Consulting team in performing a parallel evaluation of offers and monitoring negotiations with shortlisted bidders.

2013- **Florida Solicitation for New Capacity**
2014 Client: Duke Energy Florida

Served as an independent evaluator in a solicitation for over 1,600 MW of new capacity in Florida. Resources had to be on-line by 2018. Proposals were compared to the utility's next planned generating unit – a natural-gas-fired combined-cycle generating 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.

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

Served as the independent evaluator 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 Wind 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 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

Served as the Independent Evaluator 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 the 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 Independent Evaluation 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 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.

2000-2001 **Solicitation for New Resources**
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.

REDACTED VERSION

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR SEMINOLE ELECTRIC'S POWER SUPPLY SOLICITATIONS FOR 2021 CAPACITY NEEDS

Submitted by:

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Sedway Consulting, Inc.
Boulder, Colorado

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 51
PARTY: SHADY HILLS ENERGY CENTER, LLC(Direct)
DESCRIPTION: Alan S. Taylor AST-1Doc 2

December 21, 2017

Introduction and Background

In early 2016, Seminole Electric Cooperative, Inc. (Seminole) launched three solicitations to seek resources or transactions that would help the cooperative meet its forecasted capacity needs in 2021 and beyond. Two of those solicitations were associated with Seminole's efforts to explore the development of a self-build resource at its Seminole Generating Station (SGS) site; they involved Requests for Proposals (RFP) for 1) power island equipment (PIE) and an associated long-term service agreement (LTSA), and 2) engineering, procurement and construction (EPC) services to install the selected power island equipment and construct the balance of the facility. The third solicitation was for market alternatives (i.e., new build facilities that would be owned and operated by others, sales of power from existing facilities, and system sales from a portfolio of resources). Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent monitoring and evaluation services over all of these RFPs and provide a parallel economic evaluation of responses that might address Seminole's capacity needs. The primary focus of this report is the market alternative RFP, with the results of the PIE/LTSA and EPC solicitations incorporated in the form of finalized self-build alternatives that competed with the market alternatives.

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 Seminole's market alternatives 2021 RFP and the Seminole finalized self-build options,
- Sedway Consulting's proprietary Response Surface Model (RSM) and Revenue Requirements Model (RRM) which were used to conduct the parallel economic evaluation,
- fundamental assumptions that were applied,
- additional economic factors that affected the final cost of each resource, and
- the development and comparison of complete portfolios of resources that would meet Seminole's capacity needs.

Receipt of Market Alternative Proposals

In Seminole's market alternatives RFP, bidders were instructed to email their submission to Seminole (and cc Sedway Consulting) by May 9, 2016. On or before that date, Sedway Consulting received 265 proposals from 40 power suppliers. For organizational and ease of comparison purposes, Seminole segregated the submitted proposals into four categories (with offer count totals next to each label):

- solar photovoltaic (PV) – 127 offers,
- baseload – 16 offers,
- intermediate – 75 offers, and
- peaking – 47 offers.

These offer totals represent the overall numbers of proposals received, prior to any disqualification decisions or qualitative review that ultimately reduced the number of proposals that moved through the evaluation process. Sedway Consulting and Seminole reviewed their respective proposal counts and confirmed that any differences are due to some disqualifications and minor interpretation issues.

One rationale for segregating solar PV proposals into a separate category was the fact that Seminole is a winter-peaking entity, with its peak loads occurring during hours that solar resources provide little or no generation. Therefore, while these resources may provide some energy and fuel-diversity benefits throughout the year, they could not appreciably meet the need that Seminole was hoping to address with its RFPs.

Virtually all of the proposals in the last three categories could be modeled and evaluated on a side-by-side basis in Sedway Consulting's Response Surface Model (RSM). Therefore, the differentiation of proposals into baseload, intermediate, and peaking was less important from Sedway Consulting's perspective than another critical factor in the evaluation process – namely, the regional location of resources or power supplies. Essentially, Seminole's Member loads are electrically connected or located in either Duke Energy Florida's (DEF) balancing authority area (BAA) or Florida Power & Light's (FPL) BAA, with a third BAA as Seminole's north system (SSN). That third area has relatively little load; the majority of Seminole's load is in DEF's BAA. It was important to procure resources or transactions that would support Seminole's Members' needs in those areas and minimize the costs and reliance of inter-regional transfers. With its market alternatives RFP, Seminole provided historical load information for both of these load areas to provide bidders with important locational information. The FPL BAA has a long-term projected peak load of approximately 600 MW and an average load of approximately 400 MW. It was recognized that procuring more than those quantities in the FPL BAA would result in additional transmission wheeling/transfer costs to bring the power into the DEF BAA to serve Seminole's predominant needs there. Similarly, it was recognized that resources outside of Florida (e.g., in the Southeast Electric Reliability Council, SERC) would incur transmission-related costs – and potential reliability concerns, if Seminole relied too heavily on such resources. Thus, this report depicts and segregates much of the offer statistics into five different categories: solar PV, DEF BAA, FPL BAA, SSN BAA (which can reasonably provide capacity to either the FPL or DEF BAAs), and SERC.

Table A-1 depicts the number of non-solar offers by resource type and locations.

Table A-2 provides a summary of the solar PV proposals that Sedway Consulting received from each bidder. As has been Sedway Consulting's reporting approach in all solicitations, the identities of bidders and projects who were not selected for final contracts has been redacted as confidential. Thus, the actual bidder and project names in Tables A-2 through A-6 for these non-selected bidders and projects are redacted and the tables include a "Code" column that provides a counterparty letter and project number reference that is used throughout the remainder of the report.

Table A-1
Offer Count and Location of Summary of Non-Solar PV Proposals

	DEF BAA	FPL BAA	SSN BAA	SERC/Other	Total
Baseload	3	4	0	9	16
Intermediate	39	2	18	16	75
Peaking	21	7	12	7	47
Total	63	13	30	32	138

Note: One of the baseload offers in the DEF BAA column was actually a combination of small existing resources in both the DEF and FPL BAAs.

The tables include the number of proposals provided by each bidder. In many instances, bidders provided multiple mutually-exclusive proposals for the same resource (e.g., with flat or escalating pricing, different delivery period durations). Thus, the total number of offers was considerably more than the total number of projects.

The final column in Table A-2 provides the levelized solar PV energy price (in $/MWh) as calculated by Sedway Consulting for each project's best offer. Obviously, for offers with a flat, non-escalating price, the levelized price is that proposed price; but for offers with escalating prices, the levelized price is that flat, non-escalating price that would result in the same net present value over the term of the proposed agreement as the escalating price – and provides for a comparable metric for ranking the offers. In cases where there were multiple, mutually-exclusive offers for a project, the value in the final column represents the lowest levelized price among those offers. The ranking of the bidders in the table is based on each bidder's best project levelized price.

Table A-3 provides the number of proposals from each bidder for baseload, intermediate, and peaking resources that would provide power deliveries in the DEF BAA. Some of the proposals were for resources that would be connected to Tampa Electric Company's (TECO) system, where power could be transferred (with a wheeling cost) into the DEF system. Tables A-4 through A-6 provide similar summaries for the proposals offered in the FPL BAA, SSN BAA, and SERC regions, respectively. The tables include a "Type" column that identifies the proposed technology (CC=combined cycle, CT=combustion turbine, System=system sale, MSW=municipal solid waste). Similar to Table A-2, the identities of bidders and projects that were not selected for final contracts are confidential and hence redacted. The rankings of the bidders in the tables are roughly based on the economics of their best proposal in the initial evaluation phase.

Disqualification Decisions

Of the bidders/ proposals listed in Table A-2, bidders SolarU-1 and SolarV-1 were disqualified for lack of specificity (e.g., failure to provide specific prices).

Table A-2
Summary of Solar PV Proposals

	Bidder	Project	Code	Nameplate Capacity (MW)	Number of Proposals	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	1	[redacted]
2	[redacted]	[redacted]	SolarB-1	75	6	[redacted]
3	[redacted]	[redacted]	SolarB-2	50	6	[redacted]
4	[redacted]	[redacted]	SolarB-3	50	6	[redacted]
5	[redacted]	[redacted]	SolarB-4	75	6	[redacted]
6	[redacted]	[redacted]	SolarC-1	375	3	[redacted]
7	[redacted]	[redacted]	SolarD-1	25	1	[redacted]
8	[redacted]	Tillman	SolarD-2	50	1	[redacted]
9	[redacted]	[redacted]	SolarD-3	50	1	[redacted]
10	[redacted]	[redacted]	SolarD-4	50	1	[redacted]
11	[redacted]	[redacted]	SolarD-5	75	1	[redacted]
12	[redacted]	[redacted]	SolarD-6	75	1	[redacted]
13	[redacted]	[redacted]	SolarE-1	75	2	[redacted]
14	[redacted]	[redacted]	SolarE-2	65	2	[redacted]
15	[redacted]	[redacted]	SolarF-1	75	2	[redacted]
16	[redacted]	[redacted]	SolarF-2	75	2	[redacted]
17	[redacted]	[redacted]	SolarF-3	53	2	[redacted]
18	[redacted]	[redacted]	SolarG-1	65	12	[redacted]
19	[redacted]	[redacted]	SolarH-1	75	12	[redacted]
20	[redacted]	[redacted]	SolarH-2	75	12	[redacted]
21	[redacted]	[redacted]	SolarI-1	75	12	[redacted]
22	[redacted]	[redacted]	SolarJ-1	465	2	[redacted]
23	[redacted]	[redacted]	SolarJ-2	75	2	[redacted]
24	[redacted]	[redacted]	SolarJ-3	125	2	[redacted]
25	[redacted]	[redacted]	SolarK-1	75	4	[redacted]
26	[redacted]	[redacted]	SolarL-1	50	1	[redacted]
27	[redacted]	[redacted]	SolarM-1	65	4	[redacted]
28	[redacted]	[redacted]	SolarN-1	125	6	[redacted]
29	[redacted]	[redacted]	SolarO-1	65	2	[redacted]
30	[redacted]	[redacted]	SolarP-1	225	4	[redacted]
31	[redacted]	[redacted]	SolarQ-1	50	1	[redacted]
32	[redacted]	[redacted]	SolarR-1	80	3	[redacted]
33	[redacted]	[redacted]	SolarS-1	75	1	[redacted]
34	[redacted]	[redacted]	SolarT-1	75	1	[redacted]
35	[redacted]	[redacted]	SolarU-1	75	1	[redacted]
36	[redacted]	[redacted]	SolarV-1	25	1	[redacted]

Table A-3
Summary of DEF BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-1	1,064	6
2			CC	A-2	863	6
3			CC	A-3	599	6
4			CT	A-4	482	12
5	GE Shady Hills	Project 2	CC	B-1	573	4
6		[redacted]	CC	B-2	463	4
7			CT	B-3	519	2
8	[redacted]	[redacted]	CT	C-1	117	1
9	[redacted]		CT	D-1	484	2
10		[redacted]	CC	D-2	538	2
11	DEF	Peaking	System	E-3	50-300	1
12		Intermediate	System	E-4	50-300	1
13	[redacted]	[redacted]	CC	F-1	121	5
14	[redacted]	[redacted]	CC	G-1	557	4
15	[redacted]		Biomass	H-1	70	2
16	[redacted]		ES	I-1	75-225	3
17	[redacted]		Biogas	J-1	34	1
18	[redacted]		CC	K-1	N/A	1

Of the bidders/proposals in Table A-3, ten offers from Bidder A (two each associated with Projects A-1, A-2, and A-3 and four associated with A-4) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP. Also, Bidder K-1 was disqualified for lack of specificity.

Table A-4
Summary of FPL BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CT	L-1	515	5
2			System	A-5	100-1000	2
3	[redacted]	[redacted]	System	A-6	100-1000	2
4		[redacted]	System	A-7	All	1
5	[redacted]		MSW	M-1	25	1
6	[redacted]		MSW	N-1	40	2

No proposals were disqualified from the set that is depicted in Table A-4.

Table A-5
Summary of SSN BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-8	1,058	6
2			CC	A-9	859	6
3			CC	A-10	641	6
4			CT	A-11	480	12

Of the bidders/proposals in Table A-5, ten offers from Bidder A (two each associated with Projects A-8, A-9, and A-10 and four associated with A-11) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP.

Table A-6
Summary of SERC Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	L-2	500	4
2			CC	L-3	350	4
3			CC	L-4	200	4
4			System	L-5	138	4
5			CC	O-1	225	2
6			CC	P-1	350	1
7			System	Q-1	50-440	3
8			CT	R-1	280	4
9			CC	R-2	533	1
10			Call Option	S-1	200	3
11			System	T-1	50	1
12			Wind	C-2	200	1

No proposals were disqualified from the set that is depicted in Table A-6.

Evaluation and Selection Process

As noted earlier, Seminole is winter peaking cooperative and solar PV projects are not in a position to address this need. At the times that the winter peak might occur, there is little or no sunshine. Thus, the evaluation process was bifurcated into a review of the solar PV proposals for potential selection for environmental and diversification benefits and a full analysis of the non-solar PV proposals that offered firm capacity that could meet Seminole's capacity needs.

Solar PV Proposal Analysis

In the case of the solar PV analysis, Seminole and Sedway reviewed the proposals (especially pricing and qualifications) and decided to shortlist five of the top six bidders (i.e., SolarA, SolarB, SolarC, SolarD [Coronal, the firm that was ultimately awarded a final contract], and SolarF). The SolarE and SolarF bidders were very close in pricing and thus on the cusp of either being included or excluded from the short list. Seminole opted to shortlist SolarF because of slightly better qualitative considerations. Seminole held meetings and calls with the shortlisted bidders in which Sedway Consulting participated. After learning more about the qualifications of these bidders and the status of their projects, Seminole asked all shortlisted bidders to review their proposed pricing and provide "best-and-final-offers" (BAFO) by September 9, 2016; also, Seminole let each bidder know which of each bidder's projects were of greatest interest to Seminole. These were the following: SolarA-1, SolarB-1, SolarB-2, SolarB-3, SolarC-1 (with guidance that Seminole was not interested in procuring more than 75 MW), SolarD-1, SolarD-2 (the Coronal Tillman project that was ultimately selected), SolarD-4, SolarF-1 and SolarF-2. In several cases, bidders provided multiple options for each project (e.g., different terms, fixed or escalating prices). Table A-7 shows the lowest levelized BAFO price for each project. Seminole reviewed the BAFOs and decided to select bidders SolarB and SolarD with whom to commence negotiations and perform further due diligence. Although bidder SolarA had the lowest pricing, the bidder did not yet have a site or any interconnection information. The two final shortlisted bidders were much further along with the development of their projects. Sedway Consulting concurred with the selection of the two bidders for negotiations.

Solar PV Proposal Final Selection

Negotiations and due diligence discussions continued into 2017 with both bidders. In late May 2017, given the passage of time and the recognition that solar PV panel prices had continued to decline, Seminole encouraged both bidders to sharpen their pencils and provide final lower pricing, if they so chose. Both did, with a range of sizes and terms. Bidder SolarD (Coronal) came in with the lowest prices, as depicted in Table A-8 as levelized prices for those bids that were in the same size range and term.

Table A-7
September 2016 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	20	[redacted]
2	[redacted]	[redacted]	SolarB-2	50	30	[redacted]
3		[redacted]	SolarB-1	75	30	[redacted]
4		[redacted]	SolarB-3	75	30	[redacted]
5	Coronal	[redacted]	SolarD-1	75	20	[redacted]
6		Tillman	SolarD-2	75	20	[redacted]
7		[redacted]	SolarD-4	75	20	[redacted]
8	[redacted]		SolarC-1	75	25	[redacted]
9	[redacted]	[redacted]	SolarF-1	75	28	[redacted]
10		[redacted]	SolarF-2	75	28	[redacted]

The Coronal Tillman project had the lowest price and was selected for final negotiations. On October 16, 2017, Seminole and Tillman Solar Center, LLC (a subsidiary of Coronal Energy) executed a 20-year PPA for solar PV generation from a new facility to be built in Alachua County, Florida with an expected commercial operation date of June 1, 2021.

Table A-8
June 2017 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	Coronal	Tillman	SolarD-2	40	20	[redacted]
2		[redacted]	SolarD-4	40	20	[redacted]
3	[redacted]	[redacted]	SolarB-2	50	20	[redacted]
4		[redacted]	SolarB-3	50	20	[redacted]
5		[redacted]	SolarB-1	50	20	[redacted]

Non-Solar PV Proposal Analysis

As noted earlier, solar PV capacity provides little or no contribution to meeting Seminole's winter peak. Thus, the cooperative's 2021 RFP was essentially soliciting proposals for other types of generation. The analysis of proposals for this other generation was the primary focus for Sedway Consulting's independent evaluation

efforts. In this report, all references to proposals and proposal evaluation tasks from this point forward are entirely associated with Sedway Consulting's and Seminole's non-solar PV proposal analyses.

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 Seminole's self-build options):

- 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 surplus/deficit capacity assumptions to adjust for the slightly different annual or seasonal sizes of competing portfolios, and
- the process of developing final cost estimates for competing portfolios.

RSM Evaluation Process

The economic information for all outside proposals and Seminole's self-build option(s) was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each resource on Seminole's system production costs. The RSM calculated each proposal's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each proposal, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period.

A proposal'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), and transmission revenue requirements. These annual total fixed costs were discounted to mid-2017 dollars.

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

PaR (R·V·N)

The RSM then estimated Seminole's system production costs for each month and each proposal by interpolating between production costs estimates that were extracted from a set of runs from ~~EPM~~ – Seminole'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 Seminole system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated Seminole's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 13,000 Btu/kWh. Thus, for each proposal, the RSM yielded estimates of the annual production cost savings that Seminole 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 proposal'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 (2051). 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 Seminole 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 use a blend of the cost and benefit streams associated with the three top-ranked individual proposals for long-term power supplies. By doing so, Sedway Consulting was using direct market information as guidance for what future capacity might cost. All capacity-related costs were escalated by a modest rate of 1.0%/year (which was assumed to be a reasonable assumption for the rate of inflation minus future potential for technology cost reductions). 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 these three top-ranked offers (which were fairly large in capacity). In other words, if a 200 MW proposal ended in 2031, the RSM assumed that a 200 MW CC facility replaced it in 2032; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW plant, but rather, they were a prorated portion of the construction costs of a larger facilities.

It is worth noting that this development of a smoothly escalating cost and benefit stream and the scaling process differed from the future generation expansion assumptions and methodologies employed by Seminole. In the end, however, the approaches probably did not significantly alter either evaluation team's results, as they accomplish the same general goal of continuing to meet Seminole's future capacity needs with generic replacement capacity. However, this is one of several reasons that Seminole's and Sedway Consulting's final portfolio cost differential are different. Sedway Consulting retains the right to evaluate utility solicitations with its own methodologies and believes that using two different approaches reinforces a solicitation's evaluation process when both approaches yield results that support the same conclusion(s).

As noted above, depending on the "in-service date" for the back-fill resource, the back-filler's capital costs were escalated from a 2021 base-year value by 1.0%/year. This escalation assumption represented Sedway Consulting's estimate of how construction costs were likely to increase for generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using Seminole's declining revenue requirements profile for the recovery of capacity costs of future generic resources, 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 1.0%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the component top-ranked project cost streams, which include the Seminole's 2x1H self-build resource and its traditional declining revenue requirements profile.

Over the full 30 years, the restructuring of the back-fill resource's capacity costs made no difference to the present value of the blended top-ranked proposals' cost streams. 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. In effect, it assumed that, following the expiration of an outside proposal's term, Seminole would procure replacement power supplies at a trended price based on the best market resources. In reality, if 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 Seminole's customers would likely pay.

Figure A-1



Proposal/Resource Cost Computation

Sedway Consulting used its own proprietary Revenue Requirements Model (RRM) to develop estimates of the annual revenue requirements for Seminole' self-build option(s) and cross-checked them with those provided by Seminole. Both sets of values compared quite closely, and Sedway Consulting relied on its RRM results for use in the RSM.

Most of the input assumptions for the proposals and other cost and operational parameters for Seminole's self-build option(s) 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:

- Firm gas transportation
- Third-party transmission costs
- Network upgrade-related transmission costs.

Firm gas transportation. Seminole'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 Seminole to estimate the expected annual firm gas transportation (i.e., pipeline reservation) charges for each project. Sedway Consulting reviewed Seminole's calculations, compared Seminole's values to some of its own calculations and ultimately adopted the same or close approximations to Seminole's values for each applicable proposal.

In addition to the annual firm gas pipeline reservation charges, bidders provided and/or Seminole 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.

Third-party transmission costs. As noted above, Seminole members have load in three balancing areas in Florida, and the cooperative sought to procure power supplies in locations that would minimize excessive transfers between those areas (or from out-of-state). That said, proposals that entailed such transfers were allowed; they simply needed to include the necessary third-party transmission wheeling costs associated with such transfers. In fact, 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 Seminole for such transfers or for wheeling across third-party transmission systems.

Network-update-related transmission costs. With the addition of new generation to a utility system (and sometimes even for redirected sales of power from existing resources), 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 for new resources that would be located in the relevant balancing area authorities, bidders were responsible for recognizing that their resource might trigger the need for network upgrades on the DEF or FPL transmission systems. It was each bidder's responsibility to initiate, when appropriate, an interconnection request to study what those costs would be. Seminole, in turn, calculated what the effect would be on the DEF and FPL transmission rate tariffs and the costs that its members would need to pay on any on-going basis for its portion of such network upgrades. Where appropriate, estimates of such network upgrade investments were sought from bidders and/or calculated by Seminole's transmission subject matter experts for specific proposals. Sedway Consulting reviewed and adopted these annual cost estimates. However, Sedway Consulting employed a different methodology than Seminole for attributing these network-upgrade-related costs to projects. Sedway Consulting calculated Seminole's portion of the levelized annual transmission revenue requirements[1] 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). Seminole 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;

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

each was based on slightly different but defensible end-effects assumptions. In any case, as noted earlier, Sedway Consulting was free to employ its own evaluation methodologies that may differ from Seminole's; and although that contributed to somewhat different final quantitative results, the fact that different approaches supported the same final conclusions reinforces provides greater assurance in the results of the solicitation.

Surplus/Deficit Capacity Benefit/Cost – 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 Seminole's detailed model. In its final analysis, Sedway Consulting accounted for the different capacity of each resource by developing portfolios of resources that relatively closely met Seminole's project seasonal (i.e., summer and winter) capacity needs in 2021-2025. In instances where there was a small surplus or deficit of capacity in a season, Sedway Consulting used short-term capacity valuation assumptions that Seminole provided at the start of the RFP project and periodically updated with the latest market information for small short-term capacity transactions. For long-term portfolio capacity differences (i.e., past 2025), Sedway Consulting used its filler resource assumptions to determine the benefits of surplus capacity or the costs of being slightly short.

The inclusion of these costs or benefits of marginal capacity in the RSM results placed those results on a more comparable footing with the Seminole detailed production costing and generation expansion results.

RSM Evaluation Results

The evaluation process for the non-solar PV resources went through a series of "shortlistings" over the course of the RFP process, with uncompetitive projects being set aside and released from further consideration at various stages. For the first cut, Sedway Consulting and Seminole identified proposals that had high risks and/or high prices that made them outliers and undesirable candidates for selection. The following Tables A-8 through A-11 depict the RSM levelized $/kW-month net cost results for the initial review of the qualified offers, segmented into the same delivery zones as was depicted in Tables A-3 through A-6. The proposal ranking in each table is based on the levelized net cost, from lowest to highest.

In Table A-8 (for the DEF BAA proposals), it was decided that the bottom five proposals (H-1, G-1, D-2, I-1, and J-1) had net costs that were too high to warrant continued evaluation. Also, as far as competing peaking CT resources, the least cost-effective CT proposal (D-1) was seen as unnecessary for continued evaluation, given that there were better CT/peaking proposals in the BAA to consider.

Table A-8
Initial RSM Results – DEF BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	C-1	117	[redacted]
2	[redacted]	CT	A-4	482	[redacted]
3	GE Shady Hills CT	CT	B-3	519	[redacted]
4	DEF Peaking	System	E-3	50-300	[redacted]
5	[redacted]	CT	D-1	484	[redacted]
6	DEF Intermediate	System	E-4	50-300	[redacted]
7	GE Shady Hills CC2	CC	B-1	573	[redacted]
8	[redacted]	CC	B-2	463	[redacted]
9	[redacted]	CC	A-1	1,064	[redacted]
10	[redacted]	CC	A-2	863	[redacted]
11	[redacted]	CC	A-3	599	[redacted]
12	[redacted]	CC	F-1	121	[redacted]
13	[redacted]	Biomass	H-1	70	[redacted]
14	[redacted]	CC	G-1	557	[redacted]
15	[redacted]	CC	D-2	538	[redacted]
16	[redacted]	ES	I-1	75-225	[redacted]
17	[redacted]	Biogas	J-1	34	[redacted]

Later in the evaluation process, discussions with the bidder behind the Proposals A-1, A-2, A-3, and A-4 – all of which were associated with the same site – yielded the conclusion that the development efforts were in a rather early stage. Given that this translated into greater risks and uncertainty, these offers were removed from the later stages of the evaluation.

Proposal C-1 was for the purchase of an existing CT facility, with the proposed transfer to occur well before Seminole's 2021 need. More importantly, the CT's generation technology was an old non-standard, one-of-a-kind technology in the southeast U.S. that Seminole concluded would be hard to maintain and find spare parts. Sedway Consulting participated in several discussions with Seminole about the possible options if the cooperative were to buy this facility. However, both concluded that the technology risks were too high and the proposal was set aside.

Lastly, the Proposal B-2 was at the same site and mutually exclusive with a higher-ranked more attractive GE Shady Hills CC2 project, so that proposal was set aside. The remaining proposals continued to be included in the portfolio evaluation process, including Proposal F-1, which was sold by [redacted] to [redacted] during Seminole RFP process and is labeled as such in later tables.

For the Table A-9 proposals associated with resources in the FPL BAA, the last one in the table (Proposal A-7) was set aside because selecting it would cause Seminole to lose it ability to tap any other future power supply opportunities in the FPL BAA (e.g., short-term economic purchases). The bidder had two other proposals (A-5 and A-6) that did not have this drawback and included valuable optionality in the amount of capacity that Seminole could procure. That optionality value is not reflected in the RSM net cost metrics but was captured later in the portfolio development process. Thus, Seminole and Sedway Consulting agreed that those proposals should continue to be evaluated. The small Proposals M-1 and N-1 had net costs that were too high to warrant continued inclusion in the evaluation process and were set aside.

Table A-9
Initial RSM Results – FPL BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	L-1	515	2.25
2	[redacted]	System	A-5	100-1000	3.76
3	[redacted]	MSW	M-1	25	4.38
4	[redacted]	System	A-6	100-1000	5.70
5	[redacted]	MSW	N-1	40	9.09
6	[redacted]	System	A-7	All	N/A

Table A-10 depicts the four SSN market alternative proposals as well as Seminole's two self-build options at the cooperative's SGS site in the SSN BAA – the 2x1H CC (SCF) and a smaller 1x1H CC. Seminole and Sedway Consulting had several calls/meetings with the bidder of the four market alternative proposals (which were all at the same proposed site) and concluded that gas supply constraints (and the associated costs of remedying those constraints) made the larger Proposals A-8 and A-9 too risky and expensive; thus, the self-build options and the smaller Proposals A-11 and A-10 continued to be evaluated.

Table A-10
Initial RSM Results – SSN BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	Seminole 2x1H (SCCF)	CC		1,122	[redacted]
2	[redacted]	CT	A-11	479	[redacted]
3	[redacted]	CC	A-8	1,058	[redacted]
4	Seminole Self-Build 1x1H	CC		595	[redacted]
5	[redacted]	CC	A-9	859	[redacted]
6	[redacted]	CC	A-10	641	[redacted]

Table A-11 depicts the proposals associated with resources in SERC. Because of transmission constraints and the potential for curtailments of power deliveries from SERC into peninsular Florida, Seminole recognized that it would be unwise to rely too heavily on resources in SERC to meet the cooperative's firm capacity needs. Thus, early in the evaluation process, it reviewed the supply portfolios of other peninsular Florida utilities to assess what percentage of their total capacity needs those utilities procured from SERC resources. Based on that review, Seminole concluded that it should set a maximum of 350 MW as the limit for SERC-based supplies.

Table A-11
Initial RSM Results – SERC Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CC	L-2	500	3.16
2	[redacted]	CC	L-3	350	3.16
3	[redacted]	CC	L-4	200	3.22
4	[redacted]	CC	O-1	225	3.48
5	[redacted]	CC	P-1	350	3.49
6	Southern Company	System	Q-1	50-440	3.55
7	[redacted]	Call Option	S-1	200	3.67
8	[redacted]	System	L-5	138	3.81
9	[redacted]	CT	R-1	280	3.98
10	[redacted]	System	T-1	50	7.22
11	[redacted]	CC	R-2	533	8.67
12	[redacted]	Wind	C-2	200	N/A

Given the 350 MW limit, two proposals were eliminated (L-2 and R-2) and one (Q-1), after discussions with Southern Company regarding its system sale proposal, was revised to have a maximum capacity of 350 MW.

One proposal (C-2) was for long-term energy deliveries from a wind facility in Kansas via point-to-point transmission service across a yet-to-be-developed transmission line to the Tennessee Valley Authority (TVA), then across the Southern Company system into Florida. The expected transmission costs resulted in a rather high $/MWh price for a non-firm, non-dispatchable product that would consume a majority of Seminole's 350 MW SERC limit. Thus, the proposal was set aside.

Low-ranked Proposals S-1, L-5, R-1, T-1, and R-2 were removed from further evaluation because of their poor quantitative metrics. The remaining proposals had net costs that were in a fairly tight range. Of the Projects L, O, and P, only Proposal O-1 was for deliveries from a full facility. The Proposals L-3, L-4, and P-1 were partial plant proposals and had the scheduling and settlement complications of dealing with other

offtakers. Proposals O-1 and Q-1 (the Southern Company system sale) were seen as the best SERC proposals. Ultimately, the optionality associated with the Southern Company transaction (which could be set as low as 50 MW in a delivery year) made it the best fitting SERC resource in the final portfolio.

Final Proposal and Portfolio Analysis

Table A-12 depicts the final set of all of the resources that were modeled for the final selection decision in mid-2017. These were the results that Sedway Consulting presented to Seminole's Board of Trustees on July 12, 2017. The ranking is based on each resource's levelized and normalized $/kW-month net cost.

There are several 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, on an individual basis, do not necessary meet the capacity need. Total portfolio considerations 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 Seminole to select any of the resources.

Third, as noted earlier, Sedway Consulting calibrated the RSM with proxy run information from Seminole's detailed production cost model prior to the receipt of proposals. Because Seminole was procuring resources to replace a rather significant percentage of its overall supply portfolio and because it received so many qualified proposals, the evaluation process took longer than expected. By the spring of 2017, Seminole had developed new load, fuel price, and other planning-related forecasts and incorporated this new information into its modeling systems. Sedway Consulting reviewed the new forecasts and believed them to be better than the previous 2016 forecasts. Thus, Seminole and Sedway Consulting coordinated on a new set of proxy runs to recalibrate Sedway Consulting's RSM for the 2017 forecasts. Given that this occurred well after Seminole had received and reviewed the proposals in its RFP process, Sedway Consulting reviewed the final rankings under both RSM vintages. Thus, in Table A-12, levelized net costs are shown for each final proposal under "Old" and "New" forecast assumptions, and the table is ranked on the "Old" metric. The rankings were essentially unchanged, with some minor flipping of some proposals in the ranking as indicated with italicized values in the "New" column.

It is important to note that both of the DEF System Sales and the Southern Company Services (SCS) System had significant optionality (with annual delivered capacities as low as 50 MW); this optionality is not reflected in the net cost statistics and rankings.

Table A-12
Ranking of Final Proposals

	Proposal/Resource	Code	Type	Status	Start Date	Capacity (MW)	Term (years)	Levelized Net Cost ($/kW-month)	
								Old	New
1	Self-Build 2x1		CC	New	12/1/2022	1,122	30	[redacted]	[redacted]
2	[redacted]	L-1	CT	Existing	6/1/2021	172-515	5		
3	Shady Hills	B-3	CT	Existing	6/1/2024	173-519	23*		
4	DEF Peaking	E-3	System	Existing	6/1/2021	50-300	9		
5	[redacted]	O-1	CC	Existing	6/1/2021	235	10		
6	SCS System	Q-1	System	Existing	6/1/2021	50-350	3		
7	[redacted]	A-5	System	Existing	6/1/2021	100-1000	10		
8	DEF Intermediate	E-4	System	Existing	6/1/2021	50-300	5		
9	Self-Build 1x1		CC	New	6/1/2021	595	30		
10	Shady Hills 1x1	B-1	CC	New	12/1/2021	573	30		
11	[redacted]	A-10	CC	New	5/1/2021	641	20		
12	[redacted]	A-6	System	Existing	6/1/2021	100-1000	10		
13	[redacted]	F-1	CC	Existing	6/1/2021	121	20		

* This was the contemplated term of the Shady Hills CT contract at the time of the July 12, 2017 Board of Trustees meeting; during the subsequent negotiation process, the term was reduced to 15 years.

Portfolio Analysis

Seminole and Sedway Consulting reviewed their respective evaluation results and developed portfolios of proposals that would meet the cooperative's capacity needs. As this process was underway in early 2017, two important considerations came to light. First, Seminole began to explore potential savings that might be achieved by removing one of its SGS coal units from service and replacing that capacity with cost-effective resources and transactions that were available from its 2021 RFP. In the spring of 2017, Seminole retained an engineering firm to develop detailed estimates of the costs of the service removal process and the difference in the costs of continuing to operate one instead of two of its coal units. Second, it was recognized that each portfolio had certain expected portfolio transmission impacts that needed to be taken into consideration.

With these issues in mind, three specific optimal portfolios (i.e., optimal within the context of their purpose and constraints) rose to the top in terms of economic and strategic value and were labeled the following:

1. Clean Power Plan (CPP)
2. SGS 2x1
3. Limited Build

Tables A-13 through A-15 provide the component resources and additional economic factors of the three portfolios. Sedway Consulting found that the CPP portfolio was the least-cost option, yielding estimated total portfolio net costs that were $282 million less than the next best portfolio (which was the SGS 2x1 portfolio).

The first portfolio is depicted in Table A-13 and reflects the least-cost portfolio that entailed removing an SGS coal unit from service, achieving the cost savings associated with that removal, and replacing the coal unit's capacity with the most cost-effective resources that were available from Seminole's 2021 RFP.

Table A-13
Portfolio Net Cost - CPP

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	GE Shady Hills CC2	B-1	573	12/1/2021	30	
3	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	
4	Southern Company	Q-1	350	6/1/2021	5	
5	DEF-intermediate	E-4	300	6/1/2021	9.5	
6	DEF-peaking	E-3	300	6/1/2021	9.5	
7	[redacted]	L-1	172	6/1/2021	5	
8	DEF-Winter Extension					
9	Surplus Capacity Impacts					
10	Remove SGS 1 from service					
11	Portfolio Transmission Impacts					
12	TOTAL					**130**

Table A-14 depicts the SGS 2x1 portfolio which was the least-cost portfolio that did not entail removing an SGS coal unit from service.

Table A-14
Portfolio Net Cost - SGS 2x1

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	Southern Company-5yr	Q-1	350	6/1/2021	5	
3	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	
4	DEF-peaking	E-3	300	6/1/2021	9.5	
5	[redacted]	L-1	172	6/1/2021	5	
6	DEF-Winter Extension					
7	Surplus Capacity Impacts					
8	Portfolio Transmission Impacts					
9	TOTAL					**412**

Table A-15 depicts the least-cost portfolio that does not entail Seminole's development of any new self-build resources (nor the removal from service of any coal unit). Only one new build resource would be constructed if Seminole pursued this Limited Build portfolio – Shady Hill's CC (SHCCF).

Table A-15
Portfolio Net Cost – Limited Build

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	GE Shady Hills CC2	B-1	573	12/1/2021	30	[redacted]
2	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	
3	Southern Company-5yr	Q-1	350	6/1/2021	5	
4	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	
5	DEF-peaking	E-3	300	6/1/2021	9.5	
6	[redacted]	L-1	172	6/1/2021	10	
7	DEF-Winter Extension					
8	Surplus Capacity Impacts					
9	Portfolio Transmission Impacts					
10	TOTAL					**621**

Thus, on a CPVRR basis, the CPP Portfolio that Seminole selected 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 it is likely that the RSM results did not fully capture the production cost benefits associated with replacing coal generation with gas-fired generation.

Conclusions

Sedway Consulting performed an independent evaluation of Seminole's self-build option(s) and the market alternatives that were submitted in response to Seminole's 2021 RFP and concluded that the CPP portfolio represented the lowest-cost portfolio for meeting Seminole's 2021 resource need. That portfolio was found to be $282 million less expensive on a CPVRR basis than the next cheapest portfolio of alternatives.

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- Support of merchant transmission developers in working through the market rule process between market operators to maximize value
- Advise organized market operators in the United States and Canada with respect to capacity and energy market design and well as integration of distributed energy resources
- Advise and provide due diligence and analysis for a gas midstream client to maximize their position through power purchases or self-generation for gas processing
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2015-2016 Contractor, YOH Inc. and working under the title of Senior Economic Policy Advisor, PJM Interconnection, L.L.C., Audubon, Pennsylvania

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- Provide analysis and advice with respect to the PJM market design and market performance including demand response mechanisms, intermittent and renewable resource integration, market power mitigation strategies, capacity markets, ancillary service markets, and the potential effects of environmental policies on the PJM markets.
- Co-authored papers related to effects of the proposed Waxman-Markey climate change bill in 2009, the implementation of the Mercury and Air Toxics Standards (MATS) and Cross State Air Pollution Rule in 2011, and the potential effects of the EPA-proposed Clean Power Plan in 2015.
- Led the Stakeholder Process to implement reserve shortage pricing in PJM in 2009-2010 and provided expert testimony associated with FERC filings in 2010.
- Co-authored paper to explain various market and policy concepts for PJM and its stakeholders including a paper explaining generator costs and compensation in 2010, a paper on possible routes to take on transmission cost allocation in 2010, and a whitepaper on capacity market issues in 2012.
- Advised PJM executives on market power mitigation issues related to the Three Pivotal Supplier test and cost-based offers used for market power mitigation in the PJM Energy Market in 2008-2009
- Advised PJM executives and Board of Managers on demand response compensation prior to the issuance of FERC Order 745.
- Supported and advised the Capacity Market Operations staff and PJM executives on all matters related to the Reliability Pricing Model (RPM) capacity market including implementation of the Minimum Offer Pricing Rule in its various iterations, determinations and/or reasonableness of Market Seller Offer Caps during disputes between Capacity Market Sellers and the Independent Market Monitor.

- Provided advice to Capacity Market Operations staff and PJM executives on the RPM Triennial Parameter Review Process in 2011 and in 2014 including supporting legal staff in making filings, providing expert testimony, and providing expert advice during the 2011 and 2012 hearing and settlement process at FERC.
- Supported and provided advice to Capacity Market Operations staff and PJM executives on Capacity Performance through stakeholder presentations, regulatory filings, and working jointly with the IMM in developing many of the ideas and concepts taken from ISO New England's Pay for Performance design for us in PJM.
- Supported the Federal State Government Policy outreach through by providing subject matter expertise during one-on-one meetings with regulatory staff and Commissioners related to any issues of mutual interest and import between PJM and state commission, state environmental regulators, FERC staff, and EPA staff as needed.
- Co-authored and co-led PJM's responses to the Independent Market Monitor's (IMM's) *State of the Market Reports* as well as remaining in communication with the IMM on various matters of concern and interest related to PJM market performance and design.
- Led technical and non-technical external outreach efforts to promote PJM markets or explain PJM positions on policy or market design issues of current interest to industry stakeholders including academic audiences, and invited presentations at industry sponsored events.
- Provided support in gas/electric coordination discussions within PJM and the between the power and gas industries, as well as operations support during critical operating periods in January 2014 through calls and inquiries to PJM generators and pulling environmental permits to better understand generator operating limitations on back-up fuel.
- Provided periodic reports on market performance and the state of PJM's markets to the PJM Board of Managers Competitive Markets Committee including the relationship between PJM's markets and major fuel market, environmental policy, and macroeconomic trends.
- Acted in the role of an internal consultant and advisor to all PJM departments and divisions, as needed, to address any questions or concerns surround market performance, market design, and general economic or environmental policy questions.
- Supported development and issuance of the PJM Renewable Integration Study by outside vendors.

2000–2008 Director of Energy Studies, Public Utility Research Center and Lecturer, Department of Economics, University of Florida, Gainesville, Florida

- Designed and delivered executive education and outreach programs in electric utility and regulatory policy and strategy for professionals in government, regulatory agencies, and industry primarily for developing countries.
- Responsible for electricity regulatory policy curriculum for the *PURC/World Bank International Training Program on Utility Regulation and Strategy* offered twice per year for 65 to 95 industry and regulatory professionals in each course.
- Acted as the electricity expert and liaison to the Florida electric utilities who were contributing members of PURC.
- Developed electricity related topics and obtained speakers for the PURC Annual Conferences held each February on matters related to environmental policy, wholesale market restructuring, so-called "hurricane hardening" of power systems after the 2004-2005 hurricane seasons, and other policy related matters of interest to the state of Florida.
- Served as the PURC liaison to the consultants retained by PURC to evaluate the hardening of electricity infrastructure in the wake of the 2004 and 2005 hurricane seasons.
- Served as an advisor and subject matter expert on wholesale restructuring and market issue to Florida Governor Jeb Bush's *Energy 2020 Study Commission* 2000-2001.
- Conducted original academic research related to electricity regulation and policy and published in peer reviewed academic and policy journals
- Developed customized regulatory training courses or sessions jointly prepared with other organizations for on-site delivery in Panama, Trinidad & Tobago, Brazil, Mexico, Peru, Bolivia, Argentina, Grenada, South Africa, Zambia, Namibia, and Cambodia

- Taught classes as needed in the Economics Department on environmental economics, regulatory economics, and a large lecture class of managerial economics

1999–2000 Economist, Office of Markets, Tariffs, and Rates, United States Federal Energy Regulatory Commission, Washington, DC

1998–1999 Economist, Office of Economic Policy, United States Federal Energy Regulatory Commission

- Provided analysis and research related to filings made by ISO/RTO markets as they commenced operations as centralized wholesale power markets.
- Led the economic analysis and evaluation of the NYISO wholesale power market in its initial filings of its market design and subsequent filings after operations commenced.
- Led economic analysis and evaluation of multiple filings by the California ISO related to requested market design changes filed after starting operations in 1998.
- Supported analysis and evaluation of other ISO/RTO markets as needed.
- Supported and provided analysis on merger applications as needed.
- Conducted original research while on the staff of the Chief Economic Advisor in the Office of Markets, Tariffs, and Rates related to unit commitment models used in day-ahead electricity markets and pricing in the presence of lumpy decisions and operational characteristics (technically known as non-convexities).

1992–1998 Instructor, Department of Economics, Augsburg College, Minneapolis, MN

- Taught small classes of introductory microeconomics, labor economics, money and banking, and environmental economics

1992–1998 Instructor, Department of Economics, University of Minnesota, Minneapolis, MN

- Taught large lecture classes of primarily introductory microeconomics to classes of up to 600 students 3 times per year, managing a staff of teaching assistants and graders and developing curriculum and exams.
- Taught smaller classes of introductory microeconomics as well as environmental economics

PUBLICATIONS AND BOOK CHAPTERS

Covino, Susan, Andrew Levitt, and Paul Sotkiewicz, "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution", in *Future of Utilities- Utilities of the Future: How Technological Innovations in Distributed Energy Resources Will Reshape the Electric Power Sector*, Fereidoon P. Sioshansi, editor, Chapter 22, pp.417-434, 2016.

M. Ahlstrom; E. Ela; J. Riesz; J. O'Sullivan; B. F. Hobbs; M. O'Malley; M. Milligan; P. Sotkiewicz; J. Caldwell, "The Evolution of the Market: Designing a Market for High Levels of Variable Generation", *IEEE Power and Energy Magazine*, Volume: 13, Issue: 6, 2015, Pages: 60 – 66.

Bresler, Stuart, Paul Centollela, Susan Covino, and Paul Sotkiewicz, "Smarter Demand Response in RTO Markets: The Evolution Towards Price Responsive Demand in PJM", in *Energy Efficiency: Towards the End of Demand Growth*, Fereidoon P. Sioshansi, editor, Chapter 16, pp.419-442, 2013.

Covino, Susan, Pete Langbein, and Paul Sotkiewicz, "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution", in *Smart Grid: Integrating Renewable, Distributed, and Efficient Energy*, Fereidoon P. Sioshansi, editor, Chapter 17, pp.421-452, 2012.

P. M. Sotkiewicz, "Value of Conventional Fossil Generation in PJM Considering Renewable Portfolio Standards: A Look into the Future", *Power and Energy Society General Meeting, 2012 IEEE*

R. F. Chu; P. F. McGlynn; P. M. Sotkiewicz, "Transmission Planning for Generation at Risk due to Environmental Regulations and Public Policy Initiatives" *Power and Energy Society General Meeting, 2012 IEEE*

P. M. Sotkiewicz; J. M. Vignolo, "The Value of Intermittent Wind DG under Nodal Prices and Amp-mile Tariffs", *Transmission and*

Distribution: Latin America Conference and Exposition (T&D-LA), 2012 Sixth IEEE/PES

Helman, Udi, Harry Singh, and Paul Sotkiewicz, "RTOs, Regional Electricity Markets, and Climate Policy", in *Generating Electricity in Carbon Constrained World,* Fereidoon P. Sioshansi, editor, Chapter 19, pp.527-564, 2010.

J. C. Smith; S. Beuning; H. Durrwachter; E. Ela; D. Hawkins; B. Kirby; W. Lasher; J. Lowell; K. Porter; K. Schuyler; P. Sotkiewicz, "The Wind at Our Backs", *IEEE Power and Energy Magazine*, Volume: 8, Issue: 5, 2010
Pages: 63 - 71

J. C. Smith; S. Beuning; H. Durrwachter; E. Ela; D. Hawkins; B. Kirby; W. Lasher; J. Lowell; K. Porter; K. Schuyler; P. Sotkiewicz, "Impact of Variable Renewable Energy on US Electricity Markets", *Power and Energy Society General Meeting, 2010 IEEE*

Holt, Lynne, Paul M. Sotkiewicz, and Sanford V. Berg. 2010. "Nuclear Power Expansion: Thinking About Uncertainty" *The Electricity Journal*, 235:26-33.

Holt, Lynne, Sotkiewicz, Paul, and Berg, Sanford, "(When) To Build or Not to Build? The Role of Uncertainty in Nuclear Power Expansion." *Texas Journal of Oil, Gas, and Energy Law*, Volume 3, Number 2, 2008, pp. 174-217.

Sotkiewicz, Paul M. and Vignolo, J. Mario, "Towards a Cost Causation Based Tariff for Distribution Networks with DG." *IEEE Transaction on Power Systems,* Vol. 22, No. 3, August 2007, pp. 1051-1060.

Sotkiewicz, Paul and Vignolo, Jesus Mario. "Distributed Generation." The Encyclopedia of Energy Engineering and Technology, Vol. 1, pp 296-302. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Sotkiewicz, Paul. "Emissions Trading." The Encyclopedia of Energy Engineering and Technology, Vol. 1, pp. 430-437. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Vignolo, Jesus Mario and Sotkiewicz, Paul M., "Towards Efficient Tariffs for Distribution Networks with Distributed Generation", *Cogeneration and On-site Power Production*, November-December 2006, pp. 67-75.

Jamison, Mark A. and Sotkiewicz, Paul M., "Defining the New Policy Conflicts," *Public Utilities Fortnightly*, July 2006, pp. 36-40, 50.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Nodal Pricing for Distribution Networks: Efficient Pricing for Efficiency Enhancing DG." *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 639-652.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Allocation of Fixed Costs in Distribution Networks with Distributed Generation," *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 1013-1014.

Sotkiewicz, Paul M., and Lynne Holt, "Public Utility Commission Regulation and Cost Effectiveness of Title IV: Lessons for CAIR." *Electricity Journal* 18(8): 68-80, October 2005.

O'Neill, Richard P., Sotkiewicz, Paul M., Hobbs, Benjamin F., Rothkopf, Michael H., and Stewart, William R. Jr., "Efficient Market Clearing Prices in Markets with Non-Convexities." *European Journal of Operational Research*, Volume 164, Issue 1, 1 July 2005, Pages 269-285.

Sotkiewicz, Paul M., "The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions" Ph.D. Dissertation, Department of Economics, University of Minnesota, January 2003.

O'Neill, Richard P., Helman, Udi, Sotkiewicz, Paul M., Rothkopf, Michael H., and Stewart, William R. Jr., "Regulatory Evolution, Market Design, and the Unit Commitment Problem" The Next Generation of Unit Commitment Models, B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors. 2001.

Sotkiewicz, Paul M. "Opening the Lines", Forum for Applied Research and Public Policy, Special Issue on the Role of Public Power in Utility Restructuring, Summer 2000, pp. 61-64.

SELECTED WORKING PAPERS AND UNPUBLISHED MANUSCRIPTS

Holt, Lynne, and Paul M. Sotkiewicz. "Understanding Fuel Diversity Trade-Offs and Risks: Making Decisions for the Future (pdf)" University of Florida, Department of Economics, PURC Working Paper, 2007.

O'Neill, Richard P., Sotkiewicz, Paul and Rothkopf, Michael. "Equilibrium Prices in Exchanges with Non-convex Bids." PURC Working Paper, January 2006, updated September 2007.

Sotkiewicz, Paul M. "Cross-Subsidies That Minimize Electricity Consumption Distortions" University of Florida, Department of Economics, PURC Working Paper, 2003.

CONSULTING AND ADVISING EXPERIENCE PRIOR TO JOINING PJM IN 2008

2007 Advisor to the Government of Vietnam regarding the design and experience of wholesale electricity markets as Government looked at the creation of US style ISOs to attract investment in generation assets for IPPs

2007 Independent Expert in the Matter of the Public Utilities Commission of Belize Initial Decision in the 2007 Annual Review Proceeding for Belize Electricity Limited

2006 Advisor to the Division of Air Resource Management, Florida Department of Environmental Protection (FDEP) Regarding Implementation the Clean Air Interstate Rule (CAIR)

HONORS AND AWARDS

2007 Fulbright Senior Specialist Grant in Economics with a specific request for expertise in electricity markets, electricity regulation, and distribution tariff design, Universidad de la República, Montevideo, Uruguay.

2007 Principal Investigator, PPIAF/World Bank Grant to conduct two on-site training courses on the regulation of the electric power sector and on independent power producers and power purchase agreements for the Electricity Authority of Cambodia. Grant award $59,900.

2006 "Efficient Market Clearing Prices in Markets with Non-Convexities" published in *European Journal of Operational Research* received New Jersey Policy Research Organization Bright Idea Research Award in Decision Sciences.

2003 Transportation and Public Utilities Group, Ph.D. Utilities Dissertation Award for "The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions"

1992-97 Distinguished Instructor, Department of Economics, University of Minnesota

1995-96
1994-95 Walter Heller Award for Outstanding Teaching of Economic Principles, Department of Economics,
1993-94 University of Minnesota
1992-93

1991-92 Distinguished Teaching Assistant, Department of Economics, University of Minnesota

1991 Phi Beta Kappa, University of Florida

Referee and Review Experience

Peer Reviewer for EPA Integrated Planning Model Base Case 5.13

IEEE Transactions on Power Systems

Ecological Economics

Environmental Science and Technology

Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure, prepared for The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II, September 28, 2006 Washington, DC

National Research Council of the National Academy of Sciences report entitled "Changes in New Source Review Programs for Stationary Sources of Air Pollutants", February 2006

California Energy Commission (CEC) Energy Innovations Small Grant (EISG) Program

Energy Journal

Journal of Environmental Economics and Management

IEEE PES Letters

IASTED International Journal of Power and Energy Systems

The Next Generation of Unit Commitment Models B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors

2001.

Professional Affiliations

American Economic Association
International Association for Energy Economics
Association of Environmental and Resource Economists
IEEE Power and Energy Society

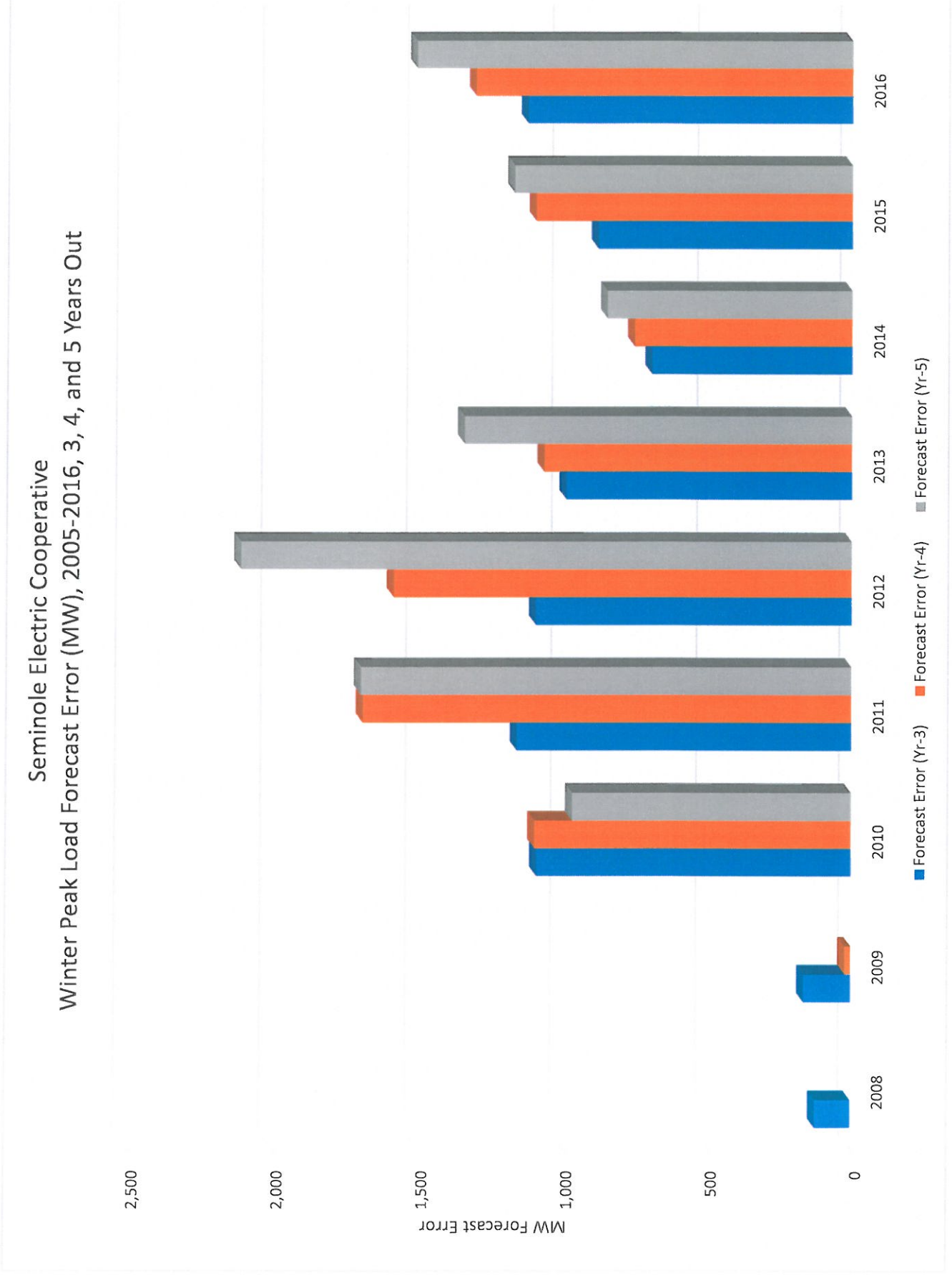
Seminole Electric Cooperative
Summary of Winter Peak Load Forecast Errors, 2005-2016
Megawatts & Percentages
(Forecast MW in Plan Year MINUS Actual MW in Given Year)

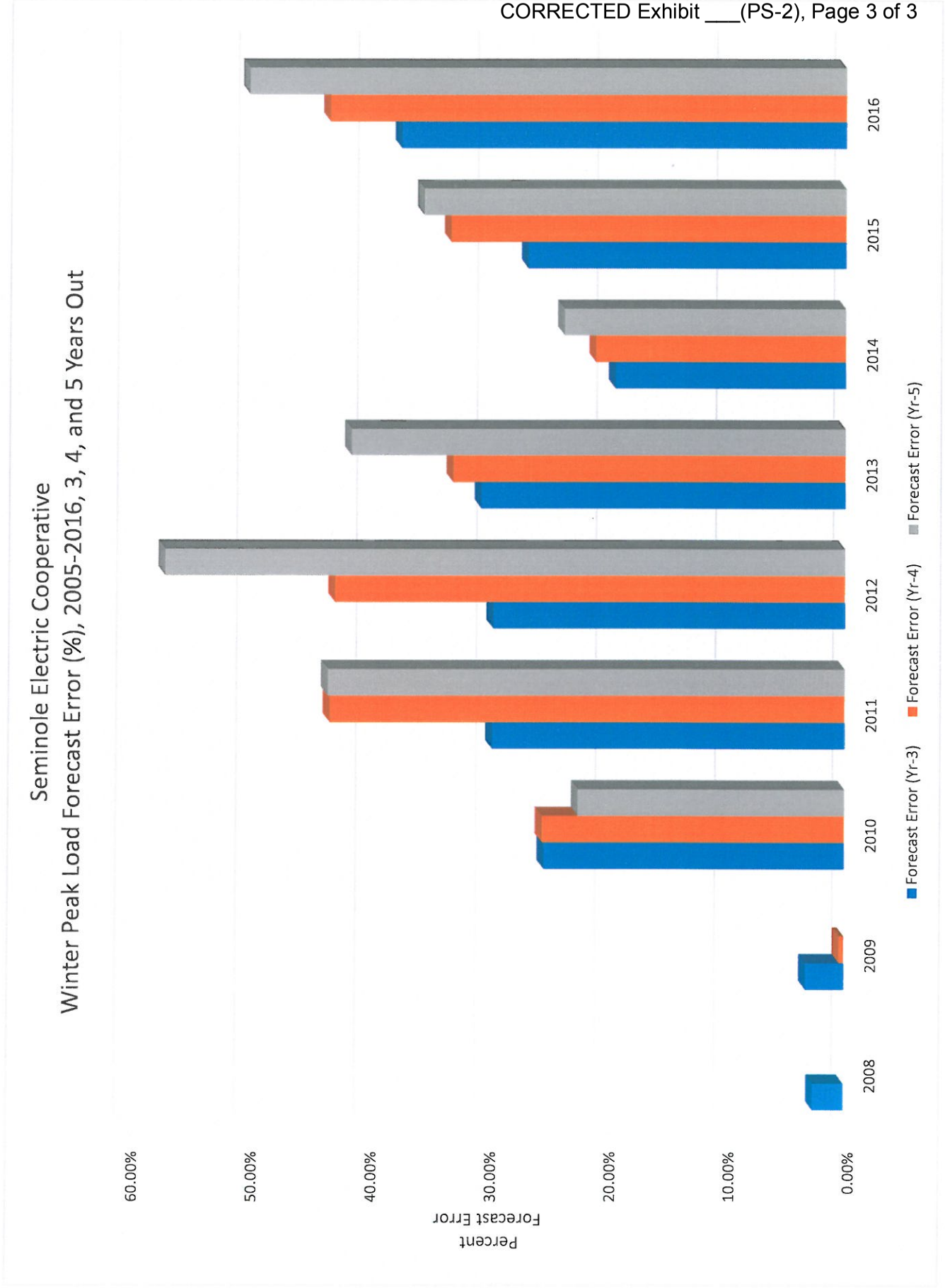
	Differences in MW			Percentage Differences		
	5 Years Out	4 Years Out	3 Years Out	5 Years Out	4 Years Out	3 Years Out
2005						
2006						
2007						
2008			125			2.64%
2009		21	166		0.42%	3.29%
2010	970	1,099	1,092	22.48%	25.47%	25.31%
2011	1,699	1,692	1,161	43.36%	43.19%	29.63%
2012	2,113	1,586	1,096	57.00%	42.78%	29.57%
2013	1,344	1,069	992	41.48%	32.99%	30.62%
2014	853	758	698	23.74%	21.10%	19.43%
2015	1,174	1,099	885	35.50%	33.23%	26.76%
2016	1,511	1,308	1,128	50.07%	43.34%	37.38%
Average	1,381	1,079	816	39.09%	30.31%	22.73%

NOTES: Positive values indicate forecast MW was greater than actual MW in the forecast year; negative values indicate forecast was less than actual in the forecast year.

SOURCES: Seminole Electric Cooperative Ten Year Site Plans, 2005 through 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 53
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)
DESCRIPTION: Paul M. Sotkiewicz, Ph.D. PS-2


Seminole Electric Cooperative
Winter Peak Load Forecast Error (MW), 2005-2016, 3, 4, and 5 Years Out
MW Forecast Error
2,500
2,000
1,500
1,000
500
0
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)


Seminole Electric Cooperative
Winter Peak Load Forecast Error (%), 2005-2016, 3, 4, and 5 Years Out
Percent
Forecast Error
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)

Seminole Electric Cooperative
Summary of Summer Peak Load Forecast Errors, 2005-2016
Megawatts & Percentages
(Forecast MW in Plan Year MINUS Actual MW in Given Year)

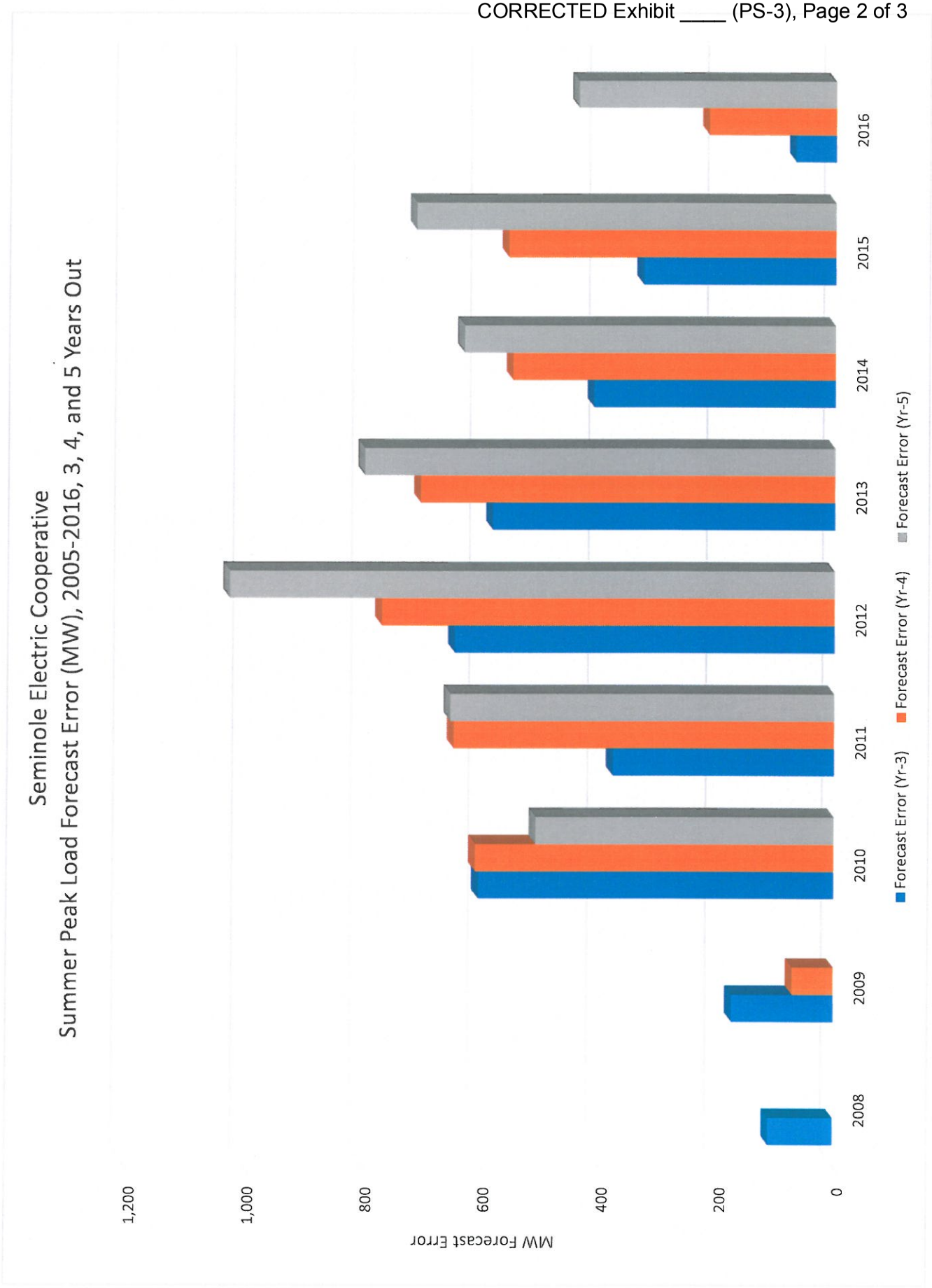
	Differences in MW			Percentage Differences		
	5 Years Out	4 Years Out	3 Years Out	5 Years Out	4 Years Out	3 Years Out
2005						
2006						
2007						
2008			112			3.09%
2009		71	176		1.86%	4.60%
2010	508	609	604	14.32%	17.16%	17.02%
2011	652	646	378	17.85%	17.68%	10.35%
2012	1,026	769	645	29.93%	22.43%	18.82%
2013	799	704	582	22.41%	19.74%	16.32%
2014	631	549	412	20.43%	17.78%	13.34%
2015	713	557	329	23.60%	18.44%	10.89%
2016	439	218	69	13.54%	6.72%	2.13%
Average	681	515	367	20.30%	15.23%	10.73%

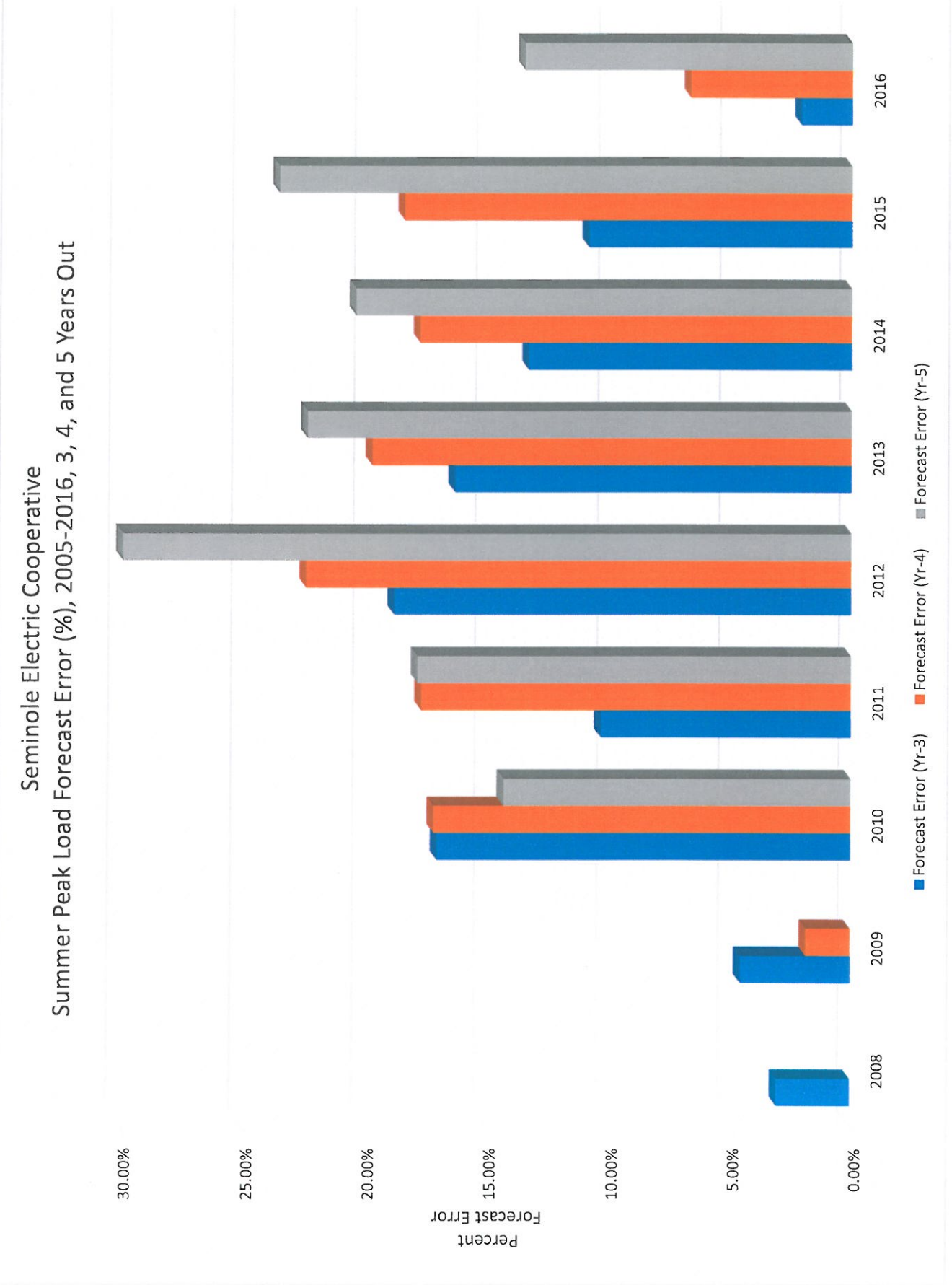
NOTES: Positive values indicate forecast MW was greater than actual MW in the forecast year; negative values indicate forecast was less than actual in the forecast year.

SOURCES: Seminole Electric Cooperative Ten Year Site Plans, 2005 through 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 54
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Docket No. 20170266-EC
Summary of Seminole's Summer Peak Forecast Errors, 2005-2016
CORRECTED Exhibit ____ (PS-3), Page 1 of 3


Seminole Electric Cooperative
Summer Peak Load Forecast Error (MW), 2005-2016, 3, 4, and 5 Years Out
MW Forecast Error
1,200
1,000
800
600
400
200
0
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)


Seminole Electric Cooperative
Summer Peak Load Forecast Error (%), 2005-2016, 3, 4, and 5 Years Out
Percent
Forecast Error
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)

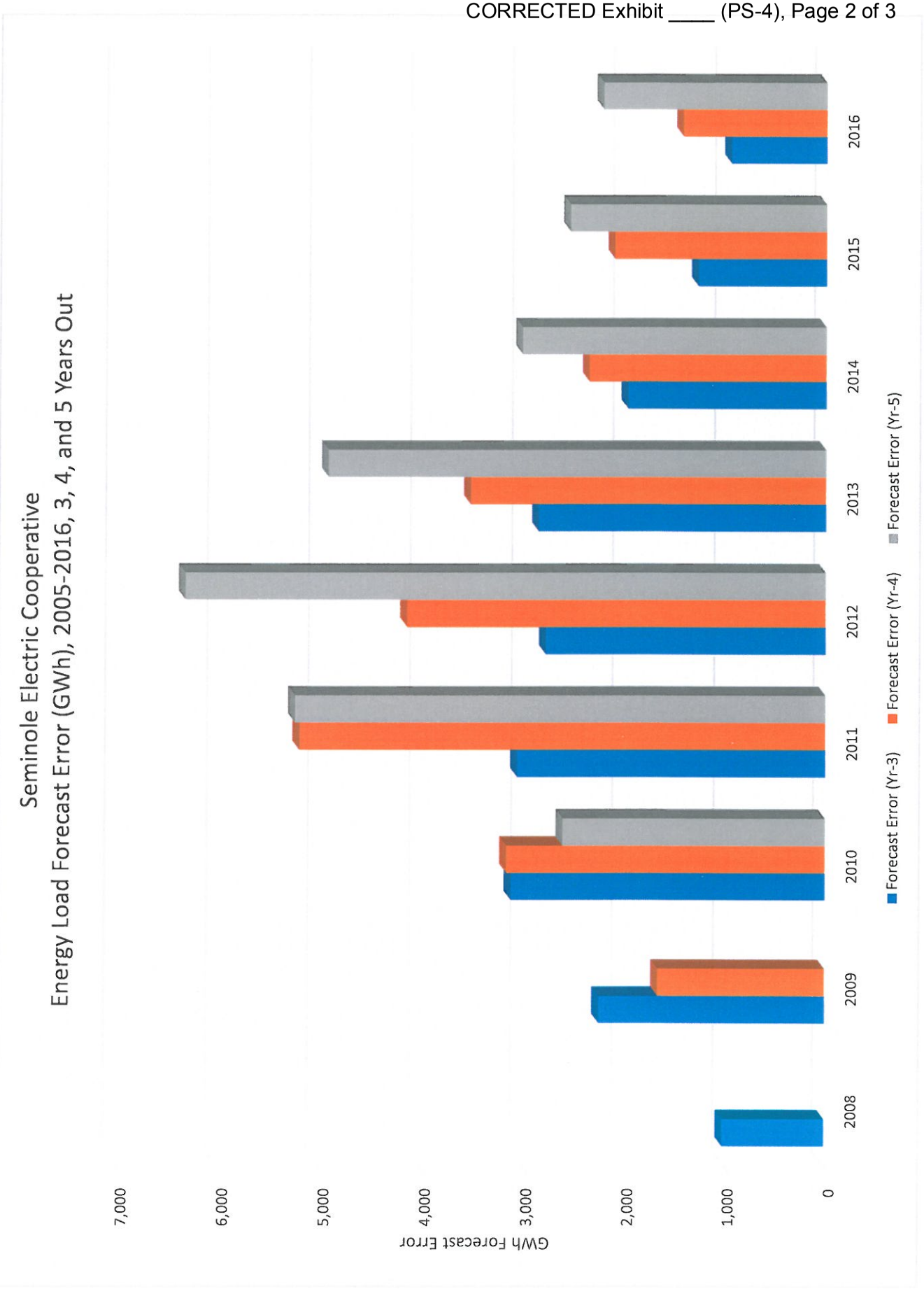
Seminole Electric Cooperative
Summary of Total Energy (GWh) Forecast Errors, 2005-2016
GWh & Percentages
(Forecast GWh in Plan Year MINUS Actual GWh in Given Year)

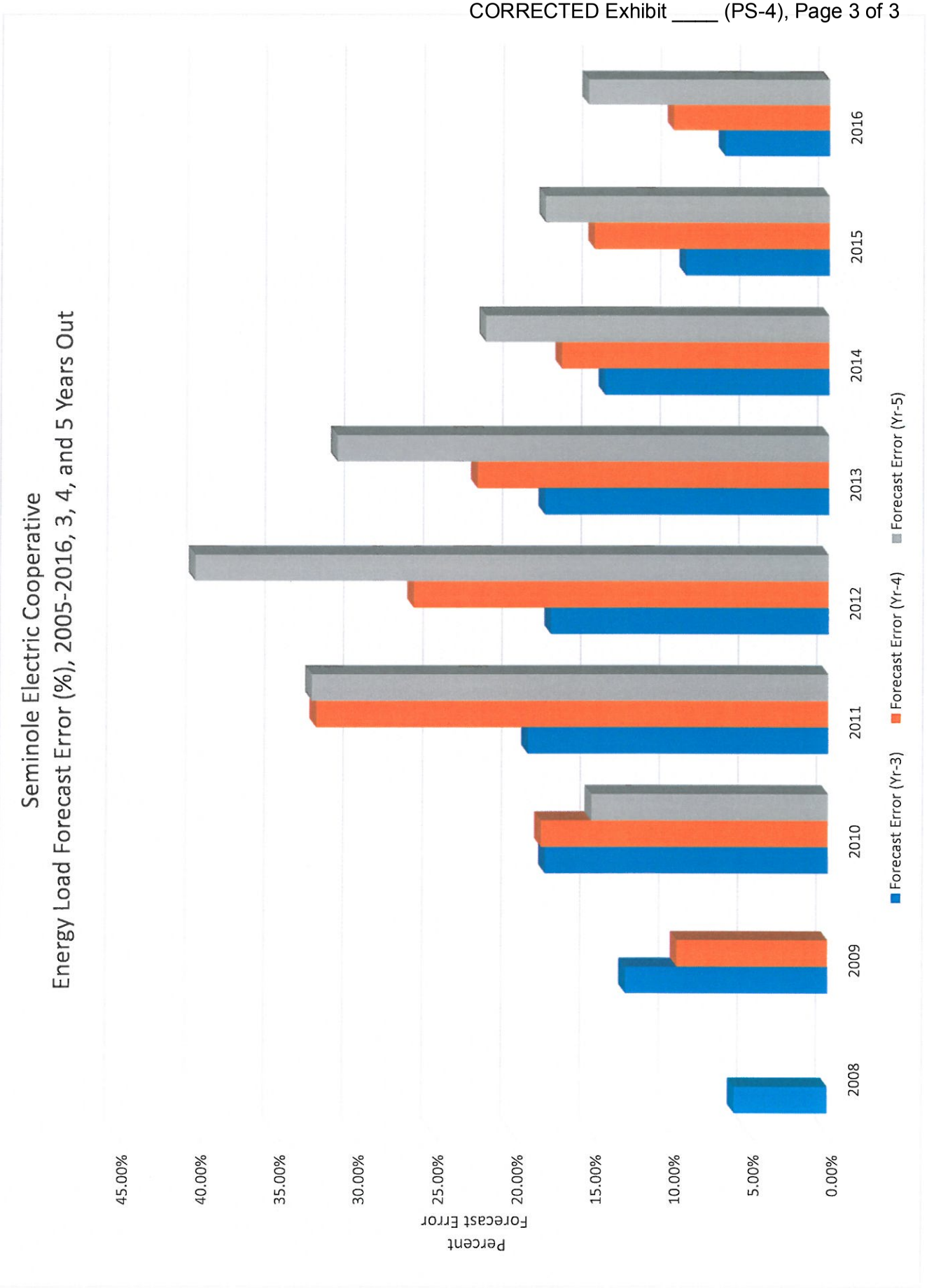
	Difference in GWh			Percentage Differences		
	5 Years Out	4 Years Out	3 Years Out	5 Years Out	4 Years Out	3 Years Out
2005						
2006						
2007						
2008			1,029			5.94%
2009		1,674	2,248		9.59%	12.88%
2010	2,614	3,168	3,123	15.07%	18.26%	18.00%
2011	5,254	5,208	3,065	32.76%	32.47%	19.11%
2012	6,338	4,150	2,787	40.19%	26.32%	17.67%
2013	4,932	3,528	2,859	31.19%	22.31%	18.08%
2014	3,024	2,358	1,974	21.83%	17.02%	14.25%
2015	2,552	2,108	1,286	18.09%	14.95%	9.12%
2016	2,222	1,435	963	15.35%	9.92%	6.65%
Average	3,848	2,954	2,148	24.93%	18.86%	13.52%

NOTES: Positive values indicate forecast GWh was greater than actual GWh in the forecast year; negative values indicate forecast was less than actual in the forecast year.

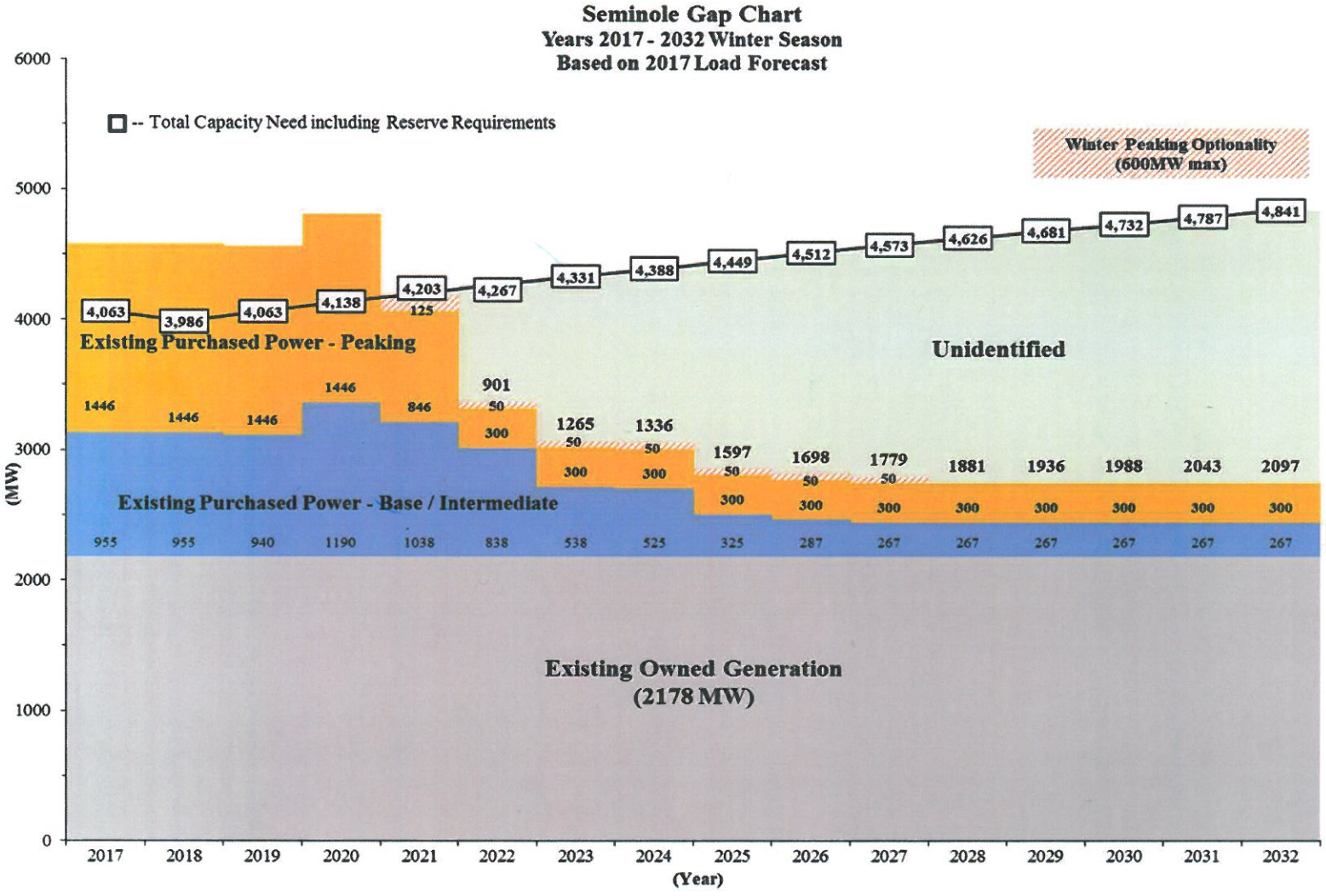
SOURCES: Seminole Electric Cooperative Ten Year Site Plans, 2005 through 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 55
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)


Seminole Electric Cooperative
Energy Load Forecast Error (GWh), 2005-2016, 3, 4, and 5 Years Out
GWh Forecast Error
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)


Seminole Electric Cooperative
Energy Load Forecast Error (%), 2005-2016, 3, 4, and 5 Years Out
Percent
Forecast Error
45.00%
40.00%
35.00%
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 56
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)



Docket No. 2017_____-EC
Seminole Need Gap Chart
Exhibit No. __ (JAD-2), Page 1 of 1

Docket No. 20170266-EC
Seminole Gap Chart (Seminole Exhibit JAD-2)
Exhibit _____ (PS-5), Page 1 of 1

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan
2005 - 2014
(Detail as of December 31,2004)
April 1,2005

Submitted To:
State of Florida
Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 57
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Schedule 2.3

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average Number)	Total Number of Customers
1995	0	1,052	10,624	3,366	601,618
7996	0	770	10,822	3,349	618,553
1997	0	828	10,997	3,514	637,121
1998	0	929	11,980	3,586	656,565
1999	0	939	12,167	3,593	669,695
2000	0	994	13,094	3,765	689,758
2001	0	864	13,294	3,901	710,920
2002	0	1,257	14,690	5,106	734,264
2003	0	1,337	15,485	5,240	761,644
2004	0	1,374	15,635	5,328	793,117
2005	0	1,339	16,179	5,377	797,799
2006	0	1,397	16,868	5,473	818,372
2007	0	1,457	17,572	5,570	838,940
2008	0	1,519	18,360	5,667	859,556
2009	0	1,587	19,127	5,765	881,536
2010	0	1,657	19,960	5,862	901,946
2011	0	1,730	20,547	5,958	922,065
2012	0	1,805	21,790	6,056	942,208
2013	0	1,882	22,647	6,152	962,362
2014	0	1,961	23,598	6,249	982,532

Schedule 3.1.1

History and Forecast of Summer Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment (1)	Conser-vation	Load Manage-ment	Conser-vation	
1995	2,329	2,329	0	NIA	112	N/A	N/A	N/A	2,217
1996	2,347	2,347	0	N/A	95	N/A	N/A	N/A	2,252
1997	2,443	2,443	0	N/A	123	N/A	N/A	N/A	2,320
1998	2,756	2,756	0	N/A	150	N/A	N/A	NIA	2,606
1999	2,729	2,719	0	N/A	92	N/A	NIA	N/A	2,627
2000	2,774	2,829	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,092	3,092	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,514	3,514	0	95	95	N/A	N/A	N/A	3,324
2006	3,650	3,650	0	95	95	N/A	N/A	N/A	3,460
2007	3,788	3,788	0	95	95	N/A	N/A	N/A	3,598
2008	3,932	3,932	0	95	95	NIA	N/A	N/A	3,742
2009	4,086	4,086	0	95	95	N/A	N/A	N/A	3,895
2010	4,246	4,246	0	95	95	N/A	N/A	N/A	4,056
2011	4,416	4,416	0	95	95	N/A	N/A	N/A	4,226
2012	4,584	4,584	0	95	95	N/A	N/A	NIA	4,394
2013	4,757	4,757	0	95	95	N/A	N/A	N/A	4,567
2014	4,938	4,938	0	95	95	N/A	N/A	N/A	4,748

NOTES: (1) Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available.

Schedule 3.2.1

History and Forecast of Winter Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment 1	Conser-vation	Load Manage-ment	Conser-vation	
1994-95	2,825	2,825	0	N/A	159	N/A	N/A	N/A	2,666
1995-96	2,896	2,896	0	N/A	**165**	N/A	N/A	N/A	2,731
1996-97	3,040	3,040	0	N/A	128	N/A	N/A	N/A	**2,912**
1997-98	2,529	2,529	0	N/A	115	N/A	N/A	N/A	2,414
1998-99	3,416	3,416	0	N/A	220	N/A	N/A	N/A	3,196
1999-00	3,148	3,148	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	NIA	3,626
2001-02	3,691	3,691	0	N/A	125	**N/A**	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3,698	3,698	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,115	4,115	0	60	85	N/A	N/A	NIA	3,970
2005-06	4,539	4,539	0	95	140	N/A	N/A	N/A	4,304
2006-07	4,718	4,718	0	95	140	N/A	N/A	NIA	4,483
2007-08	4,904	4,904	0	95	140	N/A	N/A	N/A	4,569
2008-09	5,098	5,098	0	95	140	N/A	N/A	N/A	4,863
2009-10	5,303	5,303	0	95	140	N/A	N/A	N/A	5,068
2010-11	5,520	5,520	0	95	140	N/A	N/A	N/A	5,285
2011-12	5,741	5,741	0	95	140	N/A	N/A	N/A	5,506
2012-13	5,963	5,963	0	95	140	N/A	N/A	N/A	5,728
2013-14	6,193	6,193	0	95	140	N/A	N/A	N/A	5,958
2014-15	6,431	6,431	0	95	140	N/A	N/A	N/A	6,196

NOTES: (Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh)
Base Case

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
1995	10,624	N/A	N/A	0	9,572	1,052	10,624	44.0
1996	10,822	N/A	N/A	0	10,052	770	10,822	39.1
1997	10,997	N/A	N/A	*0*	10,169	828	10,997	42.4
1998	11,980	N/A	N/A	0	11,051	929	11,980	49.8
1999	12,167	N/A	N/A	0	11,228	939	12,167	44.5
2000	13,094	N/A	N/A	0	12,100	994	13,094	46.6
2001	13,294	N/A	N/A	*0*	12,430	864	13,294	41.9
2002	14,690	N/A	N/A	0	13,433	1,257	14,690	46.6
2003	15,788	N/A	N/A	*0*	14,148	1,640	15,788	42.5
2004	15,413	N/A	N/A	0	14,261	1,830	16,413	50.6
2005	16,295	N/A	N/A	0	14,840	1,455	16,295	44.8
2006	16,868	N/A	N/A	*0*	15,471	1,397	16,868	44.8
2007	17,572	N/A	N/A	0	16,115	1,457	17,572	44.8
2008	18,360	N/A	N/A	0	16,841	1,519	18,360	44.9
2009	19,127	N/A	N/A	0	17,540	1,587	19,127	44.9
2010	19,960	N/A	N/A	0	18,303	1,657	19,960	45.0
2011	20,847	N/A	N/A	0	19,117	1,730	20,847	45.0
2012	21,790	N/A	N/A	0	19,985	1,805	21,790	45.2
2013	22,647	N/A	N/A	0	20,765	1,882	22,647	45.1
2014	23,598	N/A	N/A	0	21,637	1,961	23,598	45.2

ORIGINAL

Seminole Electric
COOPERATIVE, INC.

IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan
2006 - 2015
(Detail as of December 31, 2005)
April 1, 2006

Submitted To:
State of Florida
Public Service Commission

Seminole Electric
COOPERATIVE, INC.

DOCUMENT NUMBER-DATE
03146 APR-7 05
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Schedule 2.3

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average Number)	Total Number of Customers
1996	0	770	10,822	3,349	618,553
1997	0	828	10,997	3,514	637,121
1998	0	929	11,980	3,586	656,565
1999	0	939	12,167	3,593	669,695
2000	0	994	13,094	3,765	689,758
2001	0	864	13,294	3,901	710,920
2002	0	1,257	14,690	5,106	734,264
2003	0	1,640	15,778	5,240	761,639
2004	0	1,830	16,413	5,326	793,112
2005	0	1,760	17,177	5,473	827,651
2006	0	1,272	17,263	5,588	858,479
2007	0	1,436	18,134	5,714	886,957
2008	0	1,497	18,957	5,838	914,006
2009	0	1,561	19,701	5,963	940,980
2010	0	1,627	20,514	6,088	967,986
2011	0	1,689	21,291	6,207	991,904
2012	0	1,754	22,155	6,325	1,015,876
2013	0	1,821	22,933	6,442	1,039,763
2014	0	1,890	23,787	6,560	1,063,561
2015	0	1,959	24,646	6,680	1,087,362

Schedule 3.1.1

History and Forecast of Summer Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment (1)	Conser-vation	Load Manage-ment	Conser-vation	
1996	2,347	2,347	0	N/A	95	N/A	N/A	N/A	2,252
1997	2,443	2,443	0	N/A	123	N/A	N/A	N/A	2,320
1998	2,756	2,756	0	N/A	150	N/A	N/A	N/A	2,606
1999	2,719	2,719	0	N/A	92	N/A	N/A	N/A	2,627
2000	2,774	2,774	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,092	3,092	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,727	3, 727	0	62	101	N/A	N/A	N/A	3,564
2006	3,747	3,747	0	97	95	N/A	N/A	N/A	3,555
2007	3,887	3,887	0	97	95	N/A	N/A	N/A	3,655
2008	4,038	4,038	0	97	95	N/A	N/A	N/A	3,846
2009	4,192	4,192	0	97	95	N/A	N/A	N/A	4,000
2010	4,349	4,349	0	97	95	N/A	N/A	N/A	4,157
2011	4,497	4,497	0	97	95	N/A	N/A	N/A	4,305
2012	4,651	4,651	0	97	95	N/A	N/A	N/A	4,459
2013	4,809	4,809	0	97	95	N/A	N/A	N/A	4,617
2014	4,971	4,971	0	97	95	N/A	N/A	N/A	4,779
2015	5,133	5,133	0	97	95	N/A	N/A	N/A	4,941

NOTES: (1) Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available.

Schedule 3.2.1

History and Forecast of Winter Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment [1]	Conser-vation	Load Manage-ment	Conser-vation	
1995-96	2,896	2,896	0	N/A	165	N/A	N/A	N/A	2,731
1996-97	3,040	3,040	0	N/A	128	N/A	N/A	N/A	2,912
1997-98	2,529	2,529	0	N/A	115	N/A	N/A	N/A	2,414
1998-99	3,416	3,416	0	N/A	220	N/A	N/A	N/A	3,196
1999-00	3,148	3,148	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3,698	3,698	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4,390	4,390	0	59	99	N/A	N/A	N/A	4,232*
2006-07	4,840	4,840	0	97	140	N/A	N/A	N/A	4,603
2007-08	5,039	5,039	0	97	140	N/A	N/A	N/A	4,802
2008-09	5,241	5,241	0	97	140	N/A	N/A	N/A	5,004
2009-10	5,450	5,450	0	97	140	N/A	N/A	N/A	5,213
2010-11	5,651	5,651	0	97	140	N/A	N/A	N/A	5,414
2011-12	5,854	5,854	0	97	140	N/A	N/A	N/A	5,617
2012-13	6,065	6,065	0	97	140	N/A	N/A	N/A	5,828
2013-14	6,282	6,282	0	97	140	N/A	N/A	N/A	6,045
2014-15	6,500	6,500	0	97	140	N/A	N/A	N/A	6,263
2015-16	6,718	6,718	0	97	140	N/A	N/A	N/A	6,481

NOTES: (1) Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available. *2005-06 Peak demand is an estimate.

Schedule 3.3.1

History and Forecast of Annual Net Energy for Load (GWh)

Base Case

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
1996	10,822	N/A	N/A	0	10,052	770	10,822	45.1
1997	10,997	N/A	N/A	0	10,169	828	10,997	43.0
1998	11,980	N/A	N/A	0	11,051	929	11,980	56.5
1999	12,167	N/A	N/A	0	11,228	939	12,167	43.3
2000	13,094	N/A	N/A	0	12,100	994	13,094	46.5
2001	13,294	N/A	N/A	0	12,430	864	13,294	41.7
2002	14,690	N/A	N/A	0	13,433	1,257	14,690	46.9
2003	15,778	N/A	N/A	0	14,138	1,640	15,778	43.2
2004	16,413	N/A	N/A	0	14,583	1,830	16,413	52.9
2005	17,177	N/A	N/A	0	15,417	1,760	17,177	49.5
2006	17,384	N/A	N/A	0	15,991	1,272	17,263	46.4
2007	18,134	N/A	N/A	0	16,698	1,436	18,134	44.9
2008	18,957	N/A	N/A	0	17,460	1,497	18,957	44.9
2009	19,701	N/A	N/A	0	18,140	1,561	19,701	44.8
2010	20,514	N/A	N/A	0	18,887	1,627	20,514	44.8
2011	21,291	N/A	N/A	0	19,602	1,689	21,291	44.8
2012	22,155	N/A	N/A	0	20,401	1,754	22,155	44.9
2013	22,933	N/A	N/A	0	21,112	1,821	22,933	44.8
2014	23,787	N/A	N/A	0	21,897	1,890	23,787	44.8
2015	24,646	N/A	N/A	0	22,687	1,959	24,646	44.8

*2006 Estimated actual and forecast.

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan
2007 - 2016
(Detail as of December 31, 2006)
April 1, 2007

Submitted To:
State of Florida
Public Service Commission

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average Number)	Total Number of Customers
1997	0	828	10,997	3,514	637,121
1998	0	929	11,980	3,586	656,565
1999	0	939	12,167	3,593	669,695
2000	0	994	13,094	3,765	689,758
2001	0	864	13,294	3,901	710,920
2002	0	1,257	14,690	5,106	734,264
2003	0	1,640	15,778	5,240	761,639
2004	0	1,830	16,413	5,326	793,112
2005	0	1,345	16,766	5,473	827,651
2006	0	1,306	17,355	4,834	870,135
2007	0	1,397	18,095	5,714	886,957
2008	0	1,456	18,916	5,838	914,006
2009	0	1,518	19,658	5,963	940,980
2010	0	1,582	20,469	6,088	967,986
2011	0	1,643	21,245	6,207	991,904
2012	0	1,706	22,107	6,325	1,015,876
2013	0	1,771	22,883	6,442	1,039,763
2014	0	1,838	23,735	6,560	1,063,561
2015	0	1,905	24,592	6,680	1,087,362
2016	0	1,971	25,506	6,799	1,110,035

Schedule 3.1.1

History and Forecast of Summer Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment [1]	Conser-vation	Load Manage-ment	Conser-vation	
1997	2,443	2,443	0	N/A	123	N/A	N/A	N/A	2,320
1998	2,756	2,756	0	N/A	150	N/A	N/A	N/A	2,606
1999	2,719	2,719	0	N/A	92	N/A	N/A	N/A	2,627
2000	2,774	2,774	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,092	3,092	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,690	3, 690	0	73	78	N/A	N/A	N/A	3,539
2006	3,862	3,862	0	74	130	N/A	N/A	N/A	3,658
2007	3,883	3,883	0	97	95	N/A	N/A	N/A	3,691
2008	4,033	4,033	0	97	95	N/A	N/A	N/A	3,841
2009	4,187	4,187	0	97	95	N/A	N/A	N/A	3,995
2010	4,344	4,344	0	97	95	N/A	N/A	N/A	4,152
2011	4,491	4,491	0	97	95	N/A	N/A	N/A	4,299
2012	4,646	4,646	0	97	95	N/A	N/A	N/A	4,454
2013	4,804	4,804	0	97	95	N/A	N/A	N/A	4,612
2014	4,965	4,965	0	97	95	N/A	N/A	N/A	4,773
2015	5,127	5,127	0	97	95	N/A	N/A	N/A	4,935
2016	5,286	5,286	0	97	95	N/A	N/A	N/A	5,094

NOTES: (1) Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available.

Schedule 3.2.1

History and Forecast of Winter Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Manage-ment [1]	Conser-vation	Load Manage-ment	Conser-vation	
1996-97	3,040	3,040	0	N/A	128	N/A	N/A	N/A	2,912
1997-98	2,529	2,529	0	N/A	115	N/A	N/A	N/A	2,414
1998-99	3,416	3,416	0	N/A	220	N/A	N/A	N/A	3,196
1999-00	3,148	3,148	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3,698	3,698	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4457	4,457	0	63	143	N/A	N/A	N/A	4,251
2006-07	3,883	3,883	0	76	133	N/A	N/A	N/A	3,674
2007-08	5,033	5,033	0	97	140	N/A	N/A	N/A	4,796
2008-09	5,234	5,234	0	97	140	N/A	N/A	N/A	4,997
2009-10	5,443	5,443	0	97	140	N/A	N/A	N/A	5,206
2010-11	5,644	5,644	0	97	140	N/A	N/A	N/A	5,407
2011-12	5,847	5,847	0	97	140	N/A	N/A	N/A	5,610
2012-13	6,057	6,057	0	97	140	N/A	N/A	N/A	5,820
2013-14	6,274	6,274	0	97	140	N/A	N/A	N/A	6,037
2014-15	6,492	6,492	0	97	140	N/A	N/A	N/A	6,255
2015-16	6,710	6,710	0	97	140	N/A	N/A	N/A	6,473
2016-17	6,928	6,928	0	97	140	N/A	N/A	N/A	6,691

NOTES: (1) Historical load management data is actual amount exercised at the time of the seasonal peak demand. Forecast data is the maximum amount available.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh)
Base Case

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
1997	10,997	N/A	N/A	0	10,169	828	10,997	43.0
1998	11,980	N/A	N/A	0	11,051	929	11,980	56.5
1999	12,167	N/A	N/A	0	11,228	939	12,167	43.3
2000	13,094	N/A	N/A	0	12,100	994	13,094	46.5
2001	13,294	N/A	N/A	0	12,430	864	13,294	41.7
2002	14,690	N/A	N/A	0	13,433	1,257	14,690	46.9
2003	15,778	N/A	N/A	0	14,138	1,640	15,778	43.2
2004	16,413	N/A	N/A	0	14,583	1,830	16,413	52.9
2005	16,766	N/A	N/A	0	15,421	1,345	16,766	49.5
2006	17,355	N/A	N/A	0	16,049	1,306	17,355	46.4
2007	18,095	N/A	N/A	0	16,698	1,397	18,095	44.9
2008	18,916	N/A	N/A	0	17,460	1,456	18,916	44.9
2009	19,658	N/A	N/A	0	18,140	1,518	19,658	44.8
2010	20,469	N/A	N/A	0	18,887	1,582	20,469	44.8
2011	21,245	N/A	N/A	0	19,602	1,643	21,245	44.8
2012	22,107	N/A	N/A	0	20,401	1,706	22,107	44.9
2013	22,883	N/A	N/A	0	21,112	1,771	22,883	44.8
2014	23,735	N/A	N/A	0	21,897	1,838	23,735	44.8
2015	24,592	N/A	N/A	0	22,687	1,905	24,592	44.8
2016	25,506	N/A	N/A	0	23,534	1,971	25,506	44.8

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan
2008 - 2017
(Detail as of December 31, 2007)
April 1, 2008

DOCUMENT NUMBER-DATE
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TAMPA, FLORIDA
A GENERATION AND TRANSMISSION COOPERATIVE

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
1998	0	876	11,980	3,586	656,565
1999	0	939	12,167	3,593	669,695
2000	0	994	13,094	3,765	689,758
2001	0	864	13,294	3,901	710,920
2002	0	1,257	14,690	5,106	734,264
2003	0	1,640	15,778	5,240	761,639
2004	0	1,830	16,413	5,307	793,114
2005	0	1,345	16,766	5,544	827,710
2006	0	1,306	17,355	5,101	870,135
2007	0	1,130	17,670	5,054	897,385
2008	0	1,234	18,916	5,374	946,034
2009	0	1,234	18,812	5,245	931,161
2010	0	1,219	18,279	5,006	896,121
2011	0	1,265	19,102	5,135	928,379
2012	0	1,312	19,919	5,265	960,635
2013	0	1,359	20,744	5,392	992,892
2014	0	1,103	17,861	5,482	848,061
2015	0	1,147	18,563	5,597	873,197
2016	0	1,191	19,250	5,716	895,568
2017	0	1,234	19,947	5,836	917,943

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Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
1998	2,756	2,756	0	N/A	150	N/A	N/A	N/A	2,606
1999	2,719	2,719	0	N/A	92	N/A	N/A	N/A	2,627
2000	2,774	2,774	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,250	3,250	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,690	3, 690	0	73	78	N/A	N/A	N/A	3,539
2006	3,862	3,862	0	74	130	N/A	N/A	N/A	3,658
2007	*4,049*	*4,049*	0	107	103	N/A	N/A	N/A	*3,839*
2008	4,150	4,150	0	108	95	N/A	N/A	N/A	3,947
2009	4,123	4,123	0	108	95	N/A	N/A	N/A	3,920
2010	4,065	4,065	0	108	95	N/A	N/A	N/A	3,862
2011	4,234	4,234	0	108	95	N/A	N/A	N/A	4,031
2012	4,400	4,400	0	108	95	N/A	N/A	N/A	4,197
2013	4,568	4,568	0	108	95	N/A	N/A	N/A	4,365
2014	4,016	4,016	0	108	95	N/A	N/A	N/A	3,813
2015	4,160	4,160	0	108	95	N/A	N/A	N/A	3,957
2016	4,299	4,299	0	108	95	N/A	N/A	N/A	4,096
2017	4,439	4,439	0	108	95	N/A	N/A	N/A	4,236

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
1997-98	2,529	2,529	0	N/A	115	N/A	N/A	N/A	2,414
1998-99	3,416	3,416	0	N/A	220	N/A	N/A	N/A	3,196
1999-00	3,389	3,389	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3.672	3,672	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4,365	4,365	0	63	77	N/A	N/A	N/A	4,225
2006-07	4,240	4,240	0	105	109	N/A	N/A	N/A	4,026
2007-08	4,340	4,340	0	41	110	N/A	N/A	N/A	4,189
2008-09	4,966	4,966	0	108	140	N/A	N/A	N/A	4,718
2009-10	4,907	4,907	0	108	140	N/A	N/A	N/A	4,659
2010-11	5,115	5,115	0	108	140	N/A	N/A	N/A	4,867
2011-12	5,327	5,327	0	108	140	N/A	N/A	N/A	5,079
2012-13	5,541	5,541	0	108	140	N/A	N/A	N/A	5,293
2013-14	4,832	4,832	0	108	140	N/A	N/A	N/A	4,584
2014-15	5,012	5,012	0	108	140	N/A	N/A	N/A	4,764
2015-16	5,193	5,193	0	108	140	N/A	N/A	N/A	4,945
2016-17	5,372	5,372	0	108	140	N/A	N/A	N/A	5,124
2017-18	5,552	5,552	0	108	140	N/A	N/A	N/A	5,304

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available



Ten Year Site Plan

2009 - 2018
(Detail as of December 31, 2008)
April 1, 2009

Submitted To:
State of Florida
Public Service Commission

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
1999	0	939	12,167	3,593	669,695
2000	0	994	13,094	3,765	689,758
2001	0	864	13,294	3,901	710,920
2002	0	1,257	14,690	5,106	734,264
2003	0	1,640	15,778	5,240	761,639
2004	0	1,830	16,413	5,307	793,114
2005	0	1,345	16,766	5,544	827,710
2006	0	1,306	17,355	5,101	870,135
2007	0	1,221	17,670	5,089	897,384
2008	0	1,171	17,329	5,045	900,122
2009	0	1,277	18,077	5,296	913,721
2010	0	1,214	17,344	5,328	867,522
2011	0	1,258	17,982	5,444	893,638
2012	0	1,298	18,556	5,561	920,902
2013	0	1,352	19,340	5,676	950,662
2014	0	1,153	16,878	5,629	823,882
2015	0	1,189	17,405	5,739	849,296
2016	0	1,229	17,965	5,853	876,128
2017	0	1,267	18,527	5,967	902,803
2018	0	1,304	19,085	6,083	928,950

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
1999	2,719	2,719	0	N/A	92	N/A	N/A	N/A	2,627
2000	2,774	2,774	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,250	3,250	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,690	3, 690	0	73	78	N/A	N/A	N/A	3,539
2006	3,862	3,862	0	74	130	N/A	N/A	N/A	3,658
2007	4,021	4,021	0	77	105	N/A	N/A	N/A	3,839
2008	3,793	3,793	0	63	100	N/A	N/A	N/A	3,630
2009	4,131	4,131	0	102	97	N/A	N/A	N/A	3,932
2010	3,976	3,976	0	99	90	N/A	N/A	N/A	3,787
2011	4,135	4,135	0	99	90	N/A	N/A	N/A	3,946
2012	4,262	4,262	0	99	90	N/A	N/A	N/A	4,073
2013	4,459	4,459	0	99	90	N/A	N/A	N/A	4,270
2014	3,859	3,859	0	85	55	N/A	N/A	N/A	3,719
2015	3,975	3,975	0	85	55	N/A	N/A	N/A	3,835
2016	4,098	4,098	0	85	55	N/A	N/A	N/A	3,958
2017	4,221	4,221	0	85	55	N/A	N/A	N/A	4,081
	4,342	4,342	0	85	55	N/A	N/A	N/A	4,202

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
1998-99	3,416	3,416	0	N/A	220	N/A	N/A	N/A	3,196
1999-00	3,389	3,389	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3.672	3,672	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4,365	4,365	0	63	77	N/A	N/A	N/A	4,225
2006-07	4,240	4,240	0	105	109	N/A	N/A	N/A	4,026
2007-08	4,426	4,426	0	72	133	N/A	N/A	N/A	4,221
2008-09	4,993	4,993	0	78	150	N/A	N/A	N/A	4,765
2009-10	4,629	4,629	0	99	133	N/A	N/A	N/A	4,397
2010-11	4,739	4,739	0	99	133	N/A	N/A	N/A	4,507
2011-12	4,881	4,881	0	99	133	N/A	N/A	N/A	4,649
2012-13	5,035	5,035	0	99	133	N/A	N/A	N/A	4,803
2013-14	4,476	4,476	0	85	82	N/A	N/A	N/A	4,309
2014-15	4,613	4,613	0	85	82	N/A	N/A	N/A	4,446
2015-16	4,755	4,755	0	85	82	N/A	N/A	N/A	4,588
2016-17	4,902	4,902	0	85	82	N/A	N/A	N/A	4,735
2017-18	5,049	5,049	0	85	82	N/A	N/A	N/A	4,882
2018-19	5,195	5,195	0	85	82	N/A	N/A	N/A	5,028

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available

Seminole Electric COOPERATIVE, INC.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
1999	12,167	N/A	N/A	0	11,228	939	12,167	43.5
2000	13,094	N/A	N/A	0	12,100	994	13,094	46.6
2001	13,294	N/A	N/A	0	12,430	864	13,294	41.9
2002	14,690	N/A	N/A	0	13,433	1,257	14,690	47.0
2003	15,778	N/A	N/A	0	14,138	1,640	15,778	43.3
2004	16,413	N/A	N/A	0	14,583	1,830	16,413	53.1
2005	16,766	N/A	N/A	0	15,421	1,345	16,766	48.4
2006	17,355	N/A	N/A	0	16,049	1,306	17,355	46.9
2007	17,671	1	N/A	0	16,449	1,221	17,670	50.1
2008	17,330	1	N/A	0	16,158	1,171	17,329	46.9
2009	18,107	30	N/A	0	16,800	1,277	18,077	43.3
2010	17,395	51	N/A	0	16,130	1,214	17,344	45.0
2011	18,099	117	N/A	0	16,724	1,258	17,982	45.5
2012	18,767	211	N/A	0	17,258	1,298	18,556	45.6
2013	19,648	308	N/A	0	17,988	1,352	19,340	46.0
2014	17,288	410	N/A	0	15,725	1,153	16,878	44.7
2015	17,907	502	N/A	0	16,216	1,189	17,405	44.7
2016	18,507	542	N/A	0	16,736	1,229	17,965	44.7
2017	19,236	708	N/A	0	17,260	1,267	18,527	44.7
2018	19,907	822	N/A	0	17,781	1,304	19,085	44.6

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan
2010 - 2019
(Detail as of December 31, 2009)
April 1, 2010

Submitted To:
State of Florida
Public Service Commission

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Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
2000	0	1,070	13,094	3,764	689,765
2001	0	956	13,294	4,089	710,956
2002	0	1,357	14,690	5,123	735,240
2003	0	1,736	15,778	5,239	761,624
2004	0	1,880	16,413	5,307	793,050
2005	0	1,449	16,766	5,544	827,709
2006	0	1,410	17,355	5,101	870,146
2007	0	1,221	17,670	5,118	897,387
2008	0	1,171	17,331	5,042	900,062
2009	0	1,220	17,453	5,003	901,154
2010	0	1,191	16,837	5,103	857,208
2011	0	1,236	17,480	5,206	877,051
2012	0	1,279	18,100	5,311	899,900
2013	0	1,320	18,671	5,413	922,900
2014	0	1,122	16,212	5,353	800,884
2015	0	1,153	16,656	5,450	821,164
2016	0	1,189	17,172	5,557	844,874
2017	0	1,226	17,704	5,668	869,199
2018	0	1,264	18,245	5,778	893,692
2019	0	1,303	18,789	5,886	918,036

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2000	2,774	2,774	0	N/A	121	N/A	N/A	N/A	2,653
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,250	3,250	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,690	3, 690	0	73	78	N/A	N/A	N/A	3,539
2006	3,862	3,862	0	74	130	N/A	N/A	N/A	3,658
2007	4,021	4,021	0	77	105	N/A	N/A	N/A	3,839
2008	3,793	3,793	0	63	100	N/A	N/A	N/A	3,630
2009	4,001	4,001	0	82	101	N/A	N/A	N/A	3,818
2010	3,960	3,960	0	116	89	N/A	N/A	N/A	3,755
2011	4,088	4,088	0	116	89	N/A	N/A	N/A	3,883
2012	4,223	4,223	0	116	89	N/A	N/A	N/A	4,018
2013	4,353	4,353	0	116	89	N/A	N/A	N/A	4,148
2014	3,794	3,794	0	102	55	N/A	N/A	N/A	3,637
2015	3,891	3,891	0	102	55	N/A	N/A	N/A	3,734
2016	4,007	4,007	0	102	55	N/A	N/A	N/A	3,850
2017	4,125	4,125	0	102	55	N/A	N/A	N/A	3,968
2018	4,244	4,244	0	102	55	N/A	N/A	N/A	4,087
2019	4,363	4,363	0	102	55	N/A	N/A	N/A	4,206

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
1999-00	3,389	3,389	0	N/A	180	N/A	N/A	N/A	3,209
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3,672	3,672	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4,365	4,365	0	63	77	N/A	N/A	N/A	4,225
2006-07	4,240	4,240	0	105	109	N/A	N/A	N/A	4,026
2007-08	4,426	4,426	0	72	133	N/A	N/A	N/A	4,221
2008-09	4,957	4,957	0	69	150	N/A	N/A	N/A	4,738
2009-10	5,251	5,251	0	63	152	N/A	N/A	N/A	5,036
2010-11	4,708	4,708	0	116	133	N/A	N/A	N/A	4,459
2011-12	4,855	4,855	0	116	133	N/A	N/A	N/A	4,606
2012-13	5,005	5,005	0	116	133	N/A	N/A	N/A	4,756
2013-14	4,415	4,415	0	102	81	N/A	N/A	N/A	4,232
2014-15	4,534	4,534	0	102	81	N/A	N/A	N/A	4,351
2015-16	4,664	4,664	0	102	81	N/A	N/A	N/A	4,481
2016-17	4,803	4,803	0	102	81	N/A	N/A	N/A	4,620
2017-18	4,944	4,944	0	102	81	N/A	N/A	N/A	4,761
2018-19	5,088	5,088	0	102	81	N/A	N/A	N/A	4,905
2019-20	5,230	5,230	0	102	81	N/A	N/A	N/A	5,047

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
2000	13,094	N/A	N/A	0	12,100	994	13,094	46.6
2001	13,294	N/A	N/A	0	12,430	864	13,294	41.9
2002	14,690	N/A	N/A	0	13,433	1,257	14,690	47.0
2003	15,778	N/A	N/A	0	14,138	1,640	15,778	43.3
2004	16,413	N/A	N/A	0	14,583	1,830	16,413	53.1
2005	16,766	N/A	N/A	0	15,421	1,345	16,766	48.4
2006	17,355	N/A	N/A	0	16,049	1,306	17,355	46.9
2007	17,671	1	N/A	0	16,449	1,221	17,670	50.1
2008	17,332	1	N/A	0	16,160	1,171	17,331	41.6
2009	17,454	1	N/A	0	16,233	1,220	17,453	39.6
2010	16,881	44	N/A	0	15,646	1,191	16,837	44.4
2011	17,535	55	N/A	0	16,244	1,236	17,480	44.8
2012	18,215	115	N/A	0	16,821	1,279	18,100	44.9
2013	18,908	237	N/A	0	17,351	1,320	18,671	44.8
2014	16,526	314	N/A	0	15,090	1,122	16,212	43.7
2015	17,056	400	N/A	0	15,503	1,153	16,656	43.7
2016	17,655	483	N/A	0	15,983	1,189	17,172	43.7
2017	18,276	572	N/A	0	16,478	1,226	17,704	43.7
2018	18,913	668	N/A	0	16,981	1,264	18,245	43.7
2019	19,557	768	N/A	0	17,486	1,303	18,789	43.7

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2011 - 2020
(Detail as of December 31, 2010)
April 1, 2011

Submitted To:
State of Florida
Public Service Commission

Seminole Electric
COOPERATIVE, INC.

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Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
2001	0	956	13,294	4,089	710,956
2002	0	1,357	14,690	5,123	735,240
2003	0	1,736	15,778	5,239	761,624
2004	0	1,880	16,413	5,307	793,050
2005	0	1,449	16,766	5,544	827,709
2006	0	1,410	17,355	5,101	870,146
2007	0	1,221	17,670	5,118	897,387
2008	0	1,171	17,331	5,075	900,120
2009	0	1,217	17,453	5,002	901,121
2010	0	1,294	17,346	4,951	845,738
2011	316	1,183	17,261	5,062	869,703
2012	330	1,225	17,884	5,153	892,830
2013	330	1,267	18,490	5,244	915,869
2014	0	1,089	15,828	5,177	790,697
2015	0	1,115	16,212	5,262	807,979
2016	0	1,147	16,693	5,363	830,435
2017	0	1,181	17,178	5,464	852,915
2018	0	1,214	17,669	5,565	875,348
2019	0	1,249	18,180	5,667	897,730
2020	0	1,284	18,691	5,767	920,124

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2001	2,837	2,837	0	N/A	104	N/A	N/A	N/A	2,733
2002	3,140	3,140	0	66	99	N/A	N/A	N/A	2,975
2003	3,250	3,250	0	77	158	N/A	N/A	N/A	3,015
2004	3,359	3,359	0	58	74	N/A	N/A	N/A	3,227
2005	3,690	3, 690	0	73	78	N/A	N/A	N/A	3,539
2006	3,862	3,862	0	74	130	N/A	N/A	N/A	3,658
2007	4,021	4,021	0	77	105	N/A	N/A	N/A	3,839
2008	3,793	3,793	0	63	100	N/A	N/A	N/A	3,630
2009	4,015	4,015	0	90	101	N/A	N/A	N/A	3,824
2010	3,736	3,736	0	89	99	N/A	N/A	N/A	3,548
2011	3,990	3,990	0	123	90	N/A	N/A	N/A	3,777
2012	4,123	4,123	0	123	90	N/A	N/A	N/A	3,910
2013	4,242	4,242	0	123	90	N/A	N/A	N/A	4,029
2014	3,663	3,663	0	108	55	N/A	N/A	N/A	3,500
2015	3,741	3,741	0	108	55	N/A	N/A	N/A	3,578
2016	3,845	3,845	0	108	55	N/A	N/A	N/A	3,682
2017	3,946	3,946	0	108	55	N/A	N/A	N/A	3,783
2018	4,048	4,048	0	108	55	N/A	N/A	N/A	3,885
2019	4,154	4,154	0	108	55	N/A	N/A	N/A	3,991
2020	4,260	4,260	0	108	55	N/A	N/A	N/A	4,097

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2000-01	3,769	3,769	0	N/A	143	N/A	N/A	N/A	3,626
2001-02	3,691	3,691	0	N/A	125	N/A	N/A	N/A	3,566
2002-03	4,308	4,308	0	58	95	N/A	N/A	N/A	4,155
2003-04	3,672	3,672	0	56	85	N/A	N/A	N/A	3,531
2004-05	4,107	4,107	0	65	91	N/A	N/A	N/A	3,951
2005-06	4,365	4,365	0	63	77	N/A	N/A	N/A	4,225
2006-07	4,240	4,240	0	105	109	N/A	N/A	N/A	4,026
2007-08	4,426	4,426	0	72	133	N/A	N/A	N/A	4,221
2008-09	4,957	4,957	0	69	150	N/A	N/A	N/A	4,738
2009-10	5,268	5,268	0	69	152	N/A	N/A	N/A	5,047
2010-11	4,491	4,491	0	70	106	N/A	N/A	N/A	4,315
2011-12	4,845	4,845	0	123	133	N/A	N/A	N/A	4,589
2012-13	5,010	5,010	0	123	133	N/A	N/A	N/A	4,754
2013-14	4,381	4,381	0	109	81	N/A	N/A	N/A	4,191
2014-15	4,481	4,481	0	109	81	N/A	N/A	N/A	4,291
2015-16	4,596	4,596	0	109	81	N/A	N/A	N/A	4,406
2016-17	4,719	4,719	0	109	81	N/A	N/A	N/A	4,529
2017-18	4,843	4,843	0	109	81	N/A	N/A	N/A	4,653
2018-19	4,972	4,972	0	109	81	N/A	N/A	N/A	4,782
2019-20	5,103	5,103	0	109	81	N/A	N/A	N/A	4,913
2020-21	5,228	5,228	0	109	81	N/A	N/A	N/A	5,038

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
2001	13,294	N/A	N/A	0	12,338	956	13,294	42.6
2002	14,690	N/A	N/A	0	13,333	1,357	14,690	40.4
2003	15,778	N/A	N/A	0	14,042	1,736	15,778	51.0
2004	16,413	N/A	N/A	0	14,533	1,880	16,413	47.4
2005	16,766	N/A	N/A	0	15,317	1,449	16,766	45.3
2006	17,355	N/A	N/A	0	15,945	1,410	17,355	49.2
2007	17,671	1	N/A	0	16,449	1,221	17,670	47.8
2008	17,332	1	N/A	0	16,160	1,171	17,331	41.8
2009	17,454	1	N/A	0	16,236	1,217	17,453	39.5
2010	17,347	1	N/A	0	16,052	1,294	17,346	45.9
2011	17,285	24	N/A	0	15,762	1,183	17,261	44.3
2012	17,953	69	N/A	0	16,329	1,225	17,884	44.5
2013	18,610	120	N/A	0	16,893	1,267	18,490	44.4
2014	15,943	115	N/A	0	14,739	1,089	15,828	43.1
2015	16,374	162	N/A	0	15,097	1,115	16,212	43.1
2016	16,904	211	N/A	0	15,546	1,147	16,693	43.2
2017	17,440	262	N/A	0	15,997	1,181	17,178	43.3
2018	17,986	317	N/A	0	16,455	1,214	17,669	43.3
2019	18,526	346	N/A	0	16,931	1,249	18,180	43.4
2020	19,067	376	N/A	0	17,407	1,284	18,691	43.4

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2012 - 2021
(Detail as of December 31, 2011)
April 1, 2012

Submitted To:
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Schedule 2.3 History and Forecast of Energy Consumption and Number of Customers by Customer Class					
Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
2002	0	1,357	14,690	5,123	735,240
2003	0	1,736	15,778	5,239	761,624
2004	0	1,880	16,413	5,307	793,050
2005	0	1,449	16,766	5,544	827,709
2006	0	1,410	17,355	5,101	870,146
2007	0	1,221	17,670	5,118	897,387
2008	0	1,171	17,331	5,075	900,120
2009	0	1,217	17,453	5,002	901,121
2010	0	1,294	17,346	4,951	845,738
2011	157	905	16,037	4,954	849,059
2012	159	1,136	16,743	5,006	856,572
2013	162	1,195	17,403	5,106	873,864
2014	0	1,014	14,920	5,046	753,227
2015	0	1,046	15,390	5,130	769,633
2016	0	1,072	15,906	5,224	789,139
2017	0	1,116	16,415	5,318	808,327
2018	0	1,148	16,890	5,409	827,610
2019	0	1,183	17,403	5,501	846,938
2020	0	1,206	17,920	5,593	866,278
2021	0	1,255	18,460	5,682	884,874

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2002	3,111	3,111	0	37	99	N/A	N/A	N/A	2,975
2003	3,208	3,208	0	35	158	N/A	N/A	N/A	3,015
2004	3,336	3,336	0	35	74	N/A	N/A	N/A	3,227
2005	3,666	3,666	0	49	78	N/A	N/A	N/A	3,539
2006	3,839	3,839	0	51	130	N/A	N/A	N/A	3,658
2007	4,006	4,006	0	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	67	99	N/A	N/A	N/A	3,548
2011	3,820	3,820	0	70	97	N/A	N/A	N/A	3,653
2012	3,814	3,814	0	107	89	N/A	N/A	N/A	3,618
2013	3,936	3,936	0	107	89	N/A	N/A	N/A	3,740
2014	3,398	3,398	0	93	53	N/A	N/A	N/A	3,252
2015	3,496	3,496	0	93	53	N/A	N/A	N/A	3,350
2016	3,607	3,607	0	93	53	N/A	N/A	N/A	3,461
2017	3,712	3,712	0	93	53	N/A	N/A	N/A	3,566
2018	3,812	3,812	0	93	53	N/A	N/A	N/A	3,666
2019	3,922	3,922	0	93	53	N/A	N/A	N/A	3,776
2020	4,032	4,032	0	93	53	N/A	N/A	N/A	3,886
2021	4,142	4,142	0	93	53	N/A	N/A	N/A	3,996

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Distributed Generation	Residential		Commercial		Net Firm Demand
					Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2001-02	3,729	3,729	0	38	125	N/A	N/A	N/A	3,566
2002-03	4,288	4,288	0	38	95	N/A	N/A	N/A	4,155
2003-04	3,655	3,655	0	39	85	N/A	N/A	N/A	3,531
2004-05	4,082	4,082	0	40	91	N/A	N/A	N/A	3,951
2005-06	4,349	4,349	0	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	55	106	N/A	N/A	N/A	4,315
2011-12	4,095	4,095	0	60	133	N/A	N/A	N/A	3,902
2012-13	4,823	4,823	0	106	133	N/A	N/A	N/A	4,584
2013-14	4,172	4,172	0	106	133	N/A	N/A	N/A	3,933
2014-15	4,227	4,227	0	92	81	N/A	N/A	N/A	4,054
2015-16	4,365	4,365	0	92	81	N/A	N/A	N/A	4,192
2016-17	4,499	4,499	0	92	81	N/A	N/A	N/A	4,326
2017-18	4,628	4,628	0	92	81	N/A	N/A	N/A	4,455
2018-19	4,760	4,760	0	92	81	N/A	N/A	N/A	4,587
2019-20	4,899	4,899	0	92	81	N/A	N/A	N/A	4,726
2020-21	5,037	5,037	0	92	81	N/A	N/A	N/A	4,864
2021-22	5,179	5,179	0	92	81	N/A	N/A	N/A	5,006

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Forecast data is the maximum amount available and includes SEPA allocations.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
2002	14,690	N/A	N/A	0	13,333	1,357	14,690	40.4
2003	15,778	N/A	N/A	0	14,042	1,736	15,778	51.0
2004	16,413	N/A	N/A	0	14,533	1,880	16,413	47.4
2005	16,766	N/A	N/A	0	15,317	1,449	16,766	45.3
2006	17,355	N/A	N/A	0	15,945	1,410	17,355	49.2
2007	17,671	1	N/A	0	16,449	1,221	17,670	47.8
2008	17,332	1	N/A	0	16,160	1,171	17,331	41.8
2009	17,454	1	N/A	0	16,236	1,217	17,453	39.5
2010	17,347	1	N/A	0	16,052	1,294	17,346	45.9
2011	16,038	1	N/A	0	15,132	905	16,037	46.9
2012	16,804	61	N/A	0	15,607	1,136	16,743	43.7
2013	17,507	104	N/A	0	16,208	1,195	17,403	43.3
2014	15,014	94	N/A	0	13,906	1,014	14,920	43.3
2015	15,525	135	N/A	0	14,344	1,046	15,390	43.3
2016	16,084	178	N/A	0	14,834	1,072	15,906	43.3
2017	16,639	224	N/A	0	15,299	1,116	16,415	43.3
2018	17,161	271	N/A	0	15,742	1,148	16,890	43.3
2019	17,695	292	N/A	0	16,220	1,183	17,403	43.3
2020	18,234	314	N/A	0	16,714	1,206	17,920	43.3
2021	18,795	335	N/A	0	17,205	1,255	18,460	43.3

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

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Public Service Commission

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Schedule 2.3

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
2003	0	1,736	15,778	5,238	761,623
2004	0	1,880	16,413	5,307	793,051
2005	0	1,449	16,766	5,543	827,708
2006	0	1,410	17,355	5,100	870,133
2007	0	1,221	17,669	5,152	897,413
2008	0	1,171	17,331	5,077	900,122
2009	0	1,217	17,453	5,037	901,121
2010	0	1,294	17,346	4,957	845,737
2011	157	785	15,880	4,954	849,061
2012	134	1,084	15,769	5,078	855,295
2013	229	1,109	16,814	5,097	863,233
2014	98	937	14,620	5,022	742,461
2015	98	966	15,056	5,093	756,380
2016	0	997	15,434	5,178	772,645
2017	0	1,026	15,882	5,263	788,568
2018	0	1,053	16,299	5,347	804,417
2019	0	1,081	16,737	5,430	820,241
2020	0	1,110	17,177	5,514	836,110
2021	0	1,138	17,606	5,595	850,923
2022	0	1,166	18,045	5,674	865,738

Excludes Wholesale Interruptible Purchases

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Interruptible Load	Distributed Generation	Residential		Commercial		Net Firm Demand
						Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2003	3,208	3,208	0	N/A	35	158	N/A	N/A	N/A	3,015
2004	3,336	3,336	0	N/A	35	74	N/A	N/A	N/A	3,227
2005	3,666	3,666	0	N/A	49	78	N/A	N/A	N/A	3,539
2006	3,839	3,839	0	N/A	51	130	N/A	N/A	N/A	3,658
2007	4,006	4,006	0	N/A	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	N/A	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	N/A	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	N/A	67	99	N/A	N/A	N/A	3,548
2011	3,829	3,829	0	N/A	79	97	N/A	N/A	N/A	3,653
2012	3,557	3,557	0	N/A	16	97	N/A	N/A	N/A	3,444
2013	3,807	3,807	0	N/A	73	89	N/A	N/A	N/A	3,645
2014	3,342	3,342	0	22	73	53	N/A	N/A	N/A	3,194
2015	3,424	3,424	0	23	73	53	N/A	N/A	N/A	3,275
2016	3,470	3,470	0	32	73	53	N/A	N/A	N/A	3,312
2017	3,561	3,561	0	33	73	53	N/A	N/A	N/A	3,402
2018	3,647	3,647	0	34	73	53	N/A	N/A	N/A	3,487
2019	3,738	3,738	0	35	73	53	N/A	N/A	N/A	3,577
2020	3,827	3,827	0	35	73	53	N/A	N/A	N/A	3,666
2021	3,914	3,914	0	36	73	53	N/A	N/A	N/A	3,752
2022	4,003	4,003	0	36	73	53	N/A	N/A	N/A	3,841

Historical load management data is actual amount exercised at the time of the seasonal peak demand.

Forecast data is the maximum amount available and includes SEPA allocations.

Excludes Wholesale Interruptible Purchases

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Interruptible Load	Distributed Generation	Residential		Commercial		Net Firm Demand
						Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2002-03	4,288	4,288	0	N/A	38	95	N/A	N/A	N/A	4,155
2003-04	3,655	3,655	0	N/A	39	85	N/A	N/A	N/A	3,531
2004-05	4,082	4,082	0	N/A	40	91	N/A	N/A	N/A	3,951
2005-06	4,349	4,349	0	N/A	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	N/A	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	N/A	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	N/A	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	N/A	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	N/A	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	N/A	66	134	N/A	N/A	N/A	3,918
2012-13	3,611	3,611	0	N/A	11	115	N/A	N/A	N/A	3,485
2013-14	4,019	4,019	0	31	72	81	N/A	N/A	N/A	3,835
2014-15	4,134	4,134	0	32	72	81	N/A	N/A	N/A	3,949
2015-16	4,207	4,207	0	32	72	81	N/A	N/A	N/A	4,022
2016-17	4,332	4,332	0	33	72	81	N/A	N/A	N/A	4,146
2017-18	4,447	4,447	0	34	72	81	N/A	N/A	N/A	4,260
2018-19	4,565	4,565	0	35	72	81	N/A	N/A	N/A	4,377
2019-20	4,684	4,684	0	37	72	81	N/A	N/A	N/A	4,494
2020-21	4,799	4,799	0	38	72	81	N/A	N/A	N/A	4,608
2021-22	4,916	4,916	0	40	72	81	N/A	N/A	N/A	4,723
2022-23	5,034	5,034	0	40	72	81	N/A	N/A	N/A	4,841

Historical load management data is actual amount exercised at the time of the seasonal peak demand.

Forecast data is the maximum amount available and includes SEPA allocations.

Excludes Wholesale Interruptible Purchases

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales Including Winter Park	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
2003	15,778	N/A	N/A	0	14,042	1,736	15,778	43.3
2004	16,413	N/A	N/A	0	14,533	1,880	16,413	53.1
2005	16,766	N/A	N/A	0	15,317	1,449	16,766	48.4
2006	17,355	N/A	N/A	0	15,945	1,410	17,355	46.9
2007	17,670	1	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	1	N/A	0	16,160	1,171	17,331	46.7
2009	17,454	1	N/A	0	16,236	1,217	17,453	42.1
2010	17,347	1	N/A	0	16,052	1,294	17,346	39.2
2011	15,881	1	N/A	0	15,095	785	15,880	42.0
2012	15,770	1	N/A	0	14,685	1,084	15,769	45.8
2013	16,918	104	N/A	0	15,705	1,109	16,814	55.1
2014	14,714	94	N/A	0	13,683	937	14,620	43.5
2015	15,190	134	N/A	0	14,090	966	15,056	43.5
2016	15,611	177	N/A	0	14,437	997	15,434	43.7
2017	16,104	222	N/A	0	14,856	1,026	15,882	43.7
2018	16,568	269	N/A	0	15,246	1,053	16,299	43.7
2019	17,027	290	N/A	0	15,656	1,081	16,737	43.7
2020	17,488	311	N/A	0	16,067	1,110	17,177	43.5
2021	17,939	333	N/A	0	16,468	1,138	17,606	43.6
2022	18,400	355	N/A	0	16,879	1,166	18,045	43.6

Excludes Wholesale Interruptible Purchases



Ten Year Site Plan

2014 - 2023
(Detail as of December 31, 2013)
April 1, 2014

Submitted To:
State of Florida
Public Service Commission

Schedule 2.3

History and Forecast of Energy Consumption and

Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Avg. Number)	Total Number of Customers
2004	0	1,880	16,413	5,305	793,051
2005	0	1,449	16,766	5,544	827,708
2006	0	1,410	17,355	5,101	870,133
2007	0	1,221	17,669	5,150	897,413
2008	0	1,171	17,331	5,075	900,122
2009	0	1,217	17,453	5,036	901,121
2010	0	1,294	17,346	4,956	845,737
2011	157	785	15,880	4,954	849,061
2012	134	1,036	15,769	4,818	855,007
2013	137	1,044	15,812	5,191	864,996
2014	95	803	14,436	5,018	738,366
2015	0	833	14,794	5,087	751,847
2016	0	865	15,294	5,170	766,898
2017	0	896	15,739	5,253	782,664
2018	0	922	16,158	5,340	798,236
2019	0	951	16,592	5,424	813,663
2020	0	980	17,023	5,509	828,989
2021	0	1,006	17,432	5,589	842,981
2022	0	1,034	17,852	5,669	856,922
2023	0	1,062	18,284	5,747	870,822

Excludes Wholesale Interruptible Purchases.

History through 2013 includes LCEC.

Schedule 3.1.1
History and Forecast of Summer Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Interruptible Load	Distributed Generation	Residential		Commercial		Net Firm Demand
						Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2004	3,208	3,208	0	N/A	35	158	N/A	N/A	N/A	3,015
2005	3,336	3,336	0	N/A	35	74	N/A	N/A	N/A	3,227
2006	3,666	3,666	0	N/A	49	78	N/A	N/A	N/A	3,539
2007	3,839	3,839	0	N/A	51	130	N/A	N/A	N/A	3,658
2008	4,006	4,006	0	N/A	62	105	N/A	N/A	N/A	3,839
2009	3,778	3,778	0	N/A	48	100	N/A	N/A	N/A	3,630
2010	3,987	3,987	0	N/A	62	101	N/A	N/A	N/A	3,824
2011	3,714	3,714	0	N/A	67	99	N/A	N/A	N/A	3,548
2012	3,557	3,557	0	16	0	97	N/A	N/A	N/A	3,444
2013	3,692	3,692	0	25	0	101	N/A	N/A	N/A	3,566
2014	3,193	3,193	0	27	68	38	N/A	N/A	N/A	3,060
2015	3,235	3,235	0	28	68	38	N/A	N/A	N/A	3,101
2016	3,334	3,334	0	28	68	38	N/A	N/A	N/A	3,200
2017	3,425	3,425	0	28	68	38	N/A	N/A	N/A	3,291
2018	3,512	3,512	0	28	68	38	N/A	N/A	N/A	3,378
2019	3,600	3,600	0	29	68	38	N/A	N/A	N/A	3,465
2020	3,688	3,688	0	29	68	38	N/A	N/A	N/A	3,553
2021	3,769	3,769	0	29	68	38	N/A	N/A	N/A	3,634
2022	3,855	3,855	0	29	68	38	N/A	N/A	N/A	3,720
2023	3,941	3,941	0	29	68	38	N/A	N/A	N/A	3,806

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Distributed Generation reflects customer-owned self-service generation.
Excludes Wholesale Interruptible Purchases.
History through 2013 includes LCEC.

Schedule 3.2.1
History and Forecast of Winter Peak Demand (MW) - *Base Case*

Year	Total	Wholesale	Retail	Interruptible Load	Distributed Generation	Residential		Commercial		Net Firm Demand
						Load Mgmt.	Cons.	Load Mgmt.	Cons.	
2003-04	3,655	3,655	0	N/A	39	85	N/A	N/A	N/A	3,531
2004-05	4,082	4,082	0	N/A	40	91	N/A	N/A	N/A	3,951
2005-06	4,349	4,349	0	N/A	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	N/A	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	N/A	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	N/A	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	N/A	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	N/A	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	N/A	66	134	N/A	N/A	N/A	3,918
2012-13	3,860	3,860	0	21	0	132	N/A	N/A	N/A	3,707
2013-14*	3,368	3,368	0	22	0	124	N/A	N/A	N/A	3,222
2014-15	3,888	3,888	0	21	68	60	N/A	N/A	N/A	3,739
2015-16	4,015	4,015	0	21	68	60	N/A	N/A	N/A	3,866
2016-17	4,127	4,127	0	21	68	60	N/A	N/A	N/A	3,978
2017-18	4,240	4,240	0	21	68	60	N/A	N/A	N/A	4,091
2018-19	4,355	4,355	0	21	68	60	N/A	N/A	N/A	4,206
2019-20	4,471	4,471	0	21	68	60	N/A	N/A	N/A	4,322
2020-21	4,580	4,580	0	21	68	60	N/A	N/A	N/A	4,431
2021-22	4,689	4,689	0	21	68	60	N/A	N/A	N/A	4,540
2022-23	4,800	4,800	0	21	68	60	N/A	N/A	N/A	4,651
2023-24	4,915	4,915	0	21	68	60	N/A	N/A	N/A	4,766

* 2013-14 values represents actuals

Historical load management data is actual amount exercised at the time of the seasonal peak demand.
Distributed Generation reflects customer-owned self-service generation.
Excludes Wholesale Interruptible Purchases.
History through 2012-13 includes LCEC.

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load (GWh) - *Base Case*

Year	Total	Conservation		Retail	Total Sales Including Winter Park	Utility Use & Losses	Net Energy for Load	Load Factor %
		Residential	Commercial					
2004	16,413	N/A	N/A	0	14,533	1,880	16,413	52.9
2005	16,766	N/A	N/A	0	15,317	1,449	16,766	48.4
2006	17,355	N/A	N/A	0	15,945	1,410	17,355	46.9
2007	17,669	N/A	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	1	N/A	0	16,160	1,171	17,331	46.7
2009	17,454	1	N/A	0	16,236	1,217	17,453	42.1
2010	17,347	1	N/A	0	16,052	1,294	17,346	39.2
2011	15,881	1	N/A	0	15,095	785	15,880	42.0
2012	15,770	1	N/A	0	14,733	1,036	15,769	45.8
2013	15,813	1	N/A	0	14,768	1,044	15,812	48.7
2014	14,525	89	N/A	0	13,633	803	14,436	44.8
2015	14,922	128	N/A	0	13,961	833	14,794	45.2
2016	15,464	170	N/A	0	14,429	865	15,294	44.4
2017	15,952	213	N/A	0	14,843	896	15,739	45.2
2018	16,417	259	N/A	0	15,236	922	16,158	45.1
2019	16,871	279	N/A	0	15,641	951	16,592	45.0
2020	17,322	299	N/A	0	16,043	980	17,023	45.0
2021	17,750	318	N/A	0	16,426	1,006	17,432	44.9
2022	18,191	339	N/A	0	16,818	1,034	17,852	44.9
2023	18,644	360	N/A	0	17,222	1,062	18,284	44.9

Excludes Wholesale Interruptible Purchases.

History through 2013 includes LCEC.



Ten Year Site Plan

2015 - 2024
(Detail as of December 31, 2014)
April 1, 2015

Submitted To:
State of Florida
Public Service Commission

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

Year	Sales for Resale (GWh)	Utility Use, Losses, & SEPA (GWh)	Net Energy for Load (GWh)	Other Customers	Total Number of Customers
2005	0	1,448	16,766	5,544	827,708
2006	0	1,288	17,233	5,101	870,133
2007	0	1,221	17,669	5,150	897,413
2008	0	1,171	17,332	5,075	900,122
2009	0	1,217	17,453	5,036	901,121
2010	0	1,294	17,346	4,956	845,737
2011	157	942	16,037	4,954	849,061
2012	134	1,036	15,769	4,818	855,007
2013	137	1,009	15,812	5,185	864,980
2014	170	724	13,854	5,308	740,566
2015	0	772	13,768	5,180	750,347
2016	0	816	14,050	5,158	764,024
2017	0	790	14,268	5,189	777,783
2018	0	799	14,532	5,227	791,098
2019	0	808	14,774	5,289	805,148
2020	0	854	15,051	5,352	819,483
2021	0	824	15,237	5,406	832,906
2022	0	833	15,453	5,456	845,866
2023	0	839	15,661	5,508	858,468
2024	0	887	15,903	5,562	870,981

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2005	3,666	3,666	0	0	49	78	N/A	N/A	N/A	3,539
2006	3,813	3,813	0	0	51	130	N/A	N/A	N/A	3,632
2007	4,006	4,006	0	0	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	0	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	0	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	0	67	99	N/A	N/A	N/A	3,548
2011	3,829	3,829	0	0	79	97	N/A	N/A	N/A	3,653
2012	3,525	3,525	0	0	0	97	N/A	N/A	N/A	3,428
2013	3,665	3,665	0	0	0	99	N/A	N/A	N/A	3,566
2014	3,135	3,135	0	0	0	47	N/A	N/A	N/A	3,088
2015	3,038	3,038	0	28	63	38	N/A	N/A	N/A	2,909
2016	3,092	3,092	0	28	63	38	N/A	N/A	N/A	2,963
2017	3,151	3,151	0	28	63	38	N/A	N/A	N/A	3,022
2018	3,211	3,211	0	28	63	38	N/A	N/A	N/A	3,082
2019	3,264	3,264	0	28	63	38	N/A	N/A	N/A	3,135
2020	3,316	3,316	0	28	63	38	N/A	N/A	N/A	3,187
2021	3,364	3,364	0	28	63	38	N/A	N/A	N/A	3,235
2022	3,410	3,410	0	28	63	38	N/A	N/A	N/A	3,281
2023	3,454	3,454	0	28	63	38	N/A	N/A	N/A	3,325
2024	3,496	3,496	0	28	63	38	N/A	N/A	N/A	3,367

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2004-05	4,056	4,056	0	0	40	91	N/A	N/A	N/A	3,925
2005-06	4,349	4,349	0	0	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	0	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	0	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	0	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	0	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	0	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	0	66	134	N/A	N/A	N/A	3,918
2012-13	3,860	3,860	0	0	0	132	N/A	N/A	N/A	3,707
2013-14	3,290	3,290	0	0	0	50	N/A	N/A	N/A	3,240
2014-15[5]	3,628	3,628	0	0	0	56	N/A	N/A	N/A	3,572
2015-16	3,589	3,589	0	21	63	59	N/A	N/A	N/A	3,446
2016-17	3,659	3,659	0	21	63	59	N/A	N/A	N/A	3,516
2017-18	3,731	3,731	0	21	63	59	N/A	N/A	N/A	3,588
2018-19	3,794	3,794	0	21	63	59	N/A	N/A	N/A	3,651
2019-20	3,857	3,857	0	21	63	59	N/A	N/A	N/A	3,714
2020-21	3,917	3,917	0	21	63	59	N/A	N/A	N/A	3,774
2021-22	3,974	3,974	0	21	63	59	N/A	N/A	N/A	3,831
2022-23	4,030	4,030	0	21	63	59	N/A	N/A	N/A	3,887
2023-24	4,083	4,083	0	21	63	59	N/A	N/A	N/A	3,940
2024-25	4,135	4,135	0	21	63	59	N/A	N/A	N/A	3,992

NOTE: Actual value for 2013-14 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Estimated actuals

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)

Year	Total	Conservation		Retail	Total Sales Including Sales for Resale	Utility Use, Losses, & SEPA	Net Energy for Load	Load Factor %
		Residential	Commercial					
2005	16,766	N/A	N/A	0	15,317	1,449	16,766	45.3
2006	17,233	N/A	N/A	0	15,945	1,288	17,233	48.9
2007	17,669	N/A	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	N/A	N/A	0	16,161	1,171	17,332	46.7
2009	17,453	N/A	N/A	0	16,236	1,217	17,453	42.1
2010	17,346	N/A	N/A	0	16,052	1,294	17,346	39.2
2011	16,037	N/A	N/A	0	15,095	942	16,037	46.7
2012	15,769	N/A	N/A	0	14,733	1,036	15,769	45.8
2013	15,812	N/A	N/A	0	14,803	1,009	15,812	45.7
2014	13,854	N/A	N/A	0	13,130	724	13,854	44.3
2015	13,857	89	N/A	0	12,996	772	13,768	45.6
2016	14,177	127	N/A	0	13,233	817	14,050	45.6
2017	14,434	166	N/A	0	13,478	790	14,268	45.4
2018	14,739	207	N/A	0	13,733	799	14,532	45.4
2019	14,997	223	N/A	0	13,966	808	14,774	45.4
2020	15,291	240	N/A	0	14,197	854	15,051	45.5
2021	15,493	256	N/A	0	14,413	824	15,237	45.4
2022	15,726	273	N/A	0	14,620	833	15,453	45.4
2023	15,950	289	N/A	0	14,822	839	15,661	45.4
2024	16,208	305	N/A	0	15,016	887	15,903	45.5

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Ten Year Site Plan

2016 - 2025
(Detail as of December 31, 2015)
April 1, 2016

Submitted To:
State of Florida
Public Service Commission

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial[5]		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2006	3,813	3,813	0	0	51	130	N/A	N/A	N/A	3,632
2007	4,006	4,006	0	0	62	105	N/A	N/A	N/A	3,839
2008	3,778	3,778	0	0	48	100	N/A	N/A	N/A	3,630
2009	3,987	3,987	0	0	62	101	N/A	N/A	N/A	3,824
2010	3,714	3,714	0	0	67	99	N/A	N/A	N/A	3,548
2011	3,829	3,829	0	0	79	97	N/A	N/A	N/A	3,653
2012	3,525	3,525	0	0	0	97	N/A	N/A	N/A	3,428
2013	3,665	3,665	0	0	0	99	N/A	N/A	N/A	3,566
2014	3,155	3,155	0	0	0	67	N/A	N/A	N/A	3,088
2015	3,092	3,092	0	0	0	71	N/A	N/A	N/A	3,021
2016	3,207	3,207	0	32	78	73	N/A	N/A	N/A	3,024
2017	3,275	3,275	0	41	78	74	N/A	N/A	N/A	3,082
2018	3,337	3,337	0	41	78	75	N/A	N/A	N/A	3,143
2019	3,396	3,396	0	41	78	76	N/A	N/A	N/A	3,201
2020	3,445	3,445	0	32	78	77	N/A	N/A	N/A	3,257
2021	3,480	3,480	0	32	78	78	N/A	N/A	N/A	3,291
2022	3,535	3,535	0	42	78	79	N/A	N/A	N/A	3,336
2023	3,576	3,576	0	41	78	80	N/A	N/A	N/A	3,377
2024	3,619	3,619	0	41	78	81	N/A	N/A	N/A	3,419
2025	3,657	3,657	0	41	78	82	N/A	N/A	N/A	3,457

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)

Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential		Commercial		Net Firm Demand[4]
						Load Mgmt.[3]	Cons.	Load Mgmt.[3]	Cons.	
2005-06	4,349	4,349	0	0	47	77	N/A	N/A	N/A	4,225
2006-07	4,178	4,178	0	0	43	109	N/A	N/A	N/A	4,026
2007-08	4,410	4,410	0	0	56	133	N/A	N/A	N/A	4,221
2008-09	4,946	4,946	0	0	58	150	N/A	N/A	N/A	4,738
2009-10	5,263	5,263	0	0	64	152	N/A	N/A	N/A	5,047
2010-11	4,476	4,476	0	0	55	106	N/A	N/A	N/A	4,315
2011-12	4,118	4,118	0	0	66	134	N/A	N/A	N/A	3,918
2012-13	3,839	3,839	0	0	0	132	N/A	N/A	N/A	3,707
2013-14	3,333	3,333	0	0	0	93	N/A	N/A	N/A	3,240
2014-15	3,696	3,696	0	0	0	103	N/A	N/A	N/A	3,593
2015-16[5]	3,403	3,403	0	0	0	96	N/A	N/A	N/A	3,307
2016-17	3,696	3,696	0	36	78	101	N/A	N/A	N/A	3,481
2017-18	3,756	3,756	0	38	78	102	N/A	N/A	N/A	3,539
2018-19	3,815	3,815	0	38	78	103	N/A	N/A	N/A	3,596
2019-20	3,869	3,869	0	38	78	104	N/A	N/A	N/A	3,649
2020-21	3,919	3,919	0	38	78	106	N/A	N/A	N/A	3,698
2021-22	3,966	3,966	0	38	78	107	N/A	N/A	N/A	3,744
2022-23	4,010	4,010	0	38	78	108	N/A	N/A	N/A	3,787
2023-24	4,052	4,052	0	38	78	109	N/A	N/A	N/A	3,827
2024-25	4,091	4,091	0	38	78	110	N/A	N/A	N/A	3,866
2025-26	4,130	4,130	0	38	78	110	N/A	N/A	N/A	3,904

NOTE: Actual value for 2013-14 and prior includes Lee County Electric Cooperative.

[1] Excludes Wholesale Interruptible Purchases

[2] Distributed Generation reflects customer-owned self-service generation.

[3] Historical load management data is actual amount exercised at the time of the seasonal peak demand.

[4] Excludes SEPA allocations.

[5] Reduced demands associated with Member Cooperative coincident demand billing are not reflected, although reductions are reflected in "Total" & "Net Firm Demand"

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)

Year	Total	Conservation		Retail	Total Sales Including Sales for Resale*	Utility Use & Losses, less SEPA*	Net Energy for Load	Load Factor %
		Residential	Commercial					
2006	17,233	N/A	N/A	0	15,945	1,288	17,233	48.9
2007	17,669	N/A	N/A	0	16,448	1,221	17,669	50.1
2008	17,332	N/A	N/A	0	16,161	1,171	17,332	46.7
2009	17,453	N/A	N/A	0	16,236	1,217	17,453	42.1
2010	17,346	N/A	N/A	0	16,052	1,294	17,346	39.2
2011	16,037	N/A	N/A	0	15,095	942	16,037	46.7
2012	15,769	N/A	N/A	0	14,733	1,036	15,769	45.8
2013	15,812	N/A	N/A	0	14,803	1,009	15,812	45.7
2014	13,854	N/A	N/A	0	13,130	724	13,854	44.3
2015	14,104	N/A	N/A	0	13,390	714	14,104	48.7
2016	13,925	N/A	N/A	0	13,274	651	13,925	45.7
2017	14,249	N/A	N/A	0	13,585	664	14,249	46.0
2018	14,566	N/A	N/A	0	13,891	675	14,566	46.2
2019	14,870	N/A	N/A	0	14,183	687	14,870	46.5
2020	15,133	N/A	N/A	0	14,446	687	15,133	46.7
2021	15,370	N/A	N/A	0	14,680	690	15,370	46.9
2022	15,602	N/A	N/A	0	14,900	702	15,602	47.0
2023	15,815	N/A	N/A	0	15,114	701	15,815	47.2
2024	16,026	N/A	N/A	0	15,319	707	16,026	47.3
2025	16,224	N/A	N/A	0	15,516	708	16,224	47.4

NOTE: Actual value for 2013 and prior includes Lee County Electric Cooperative.

* Estimated values for 2015

Seminole Electric COOPERATIVE, INC.

Ten Year Site Plan

2017 – 2026
(Detail as of December 31, 2016)
April 1, 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 58
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Submitted To:
State of Florida
Public Service Commission

Schedule 1
Existing Generating Facilities as of December 31, 2016

Plant	Unit No.	Location	Unit Type	Fuel		Fuel Transportation		Alt Fuel Days Use	Com In-Svc Date (Mo/Yr)	Expected Retirement (Mo/Yr)	Gen. Max Nameplate (MW)	Net Capability (MW)	
				Pri	Alt	Pri	Alt					Summer	Winter
SGS	1	Putnam County	ST	BIT	N/A	RR	N/A	N/A	02/84	Unk	736	626	664
SGS	2	Putnam County	ST	BIT	N/A	RR	N/A	N/A	12/84	Unk	736	634	665
MGS	1-3	Hardee County	CC	NG	DFO	PL	TK	Unk	01/02	Unk	587	482	539
MGS	4-8	Hardee County	CT	NG	DFO	PL	TK	Unk	12/06	Unk	310	270	310

Schedule Abbreviations:			
	General	Unk – Unknown N/A – Not applicable	
	Unit Type	Fuel Type	Fuel Transportation
	ST – Steam Turbine CC – Combined Cycle CT – Combustion Turbine PV – Photovoltaic	BIT – Bituminous Coal NG – Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy	PL – Pipeline RR – Railroad TK – Truck

1.2.2 Transmission

Seminole serves its Members' load primarily in three transmission areas: Seminole Direct Serve (SDS) system, Duke Energy Florida (DEF) system, and Florida Power & Light (FPL) system. Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 127 circuit miles of 69 kV lines. Seminole's facilities are interconnected to the grid at nineteen (19) 230 kV transmission interconnections with the entities shown in Table 1.1.

1.3 Purchased Power Resources

Table 1.2 below sets forth Seminole's purchased power resources.

Table 1.2

2016				
SUPPLIER	**FUEL**	**MW (WINTER RATINGS)**	**IN SERVICE DATE**	**END DATE**
Hardee Power Partners	Gas/Oil	445	1/1/2013	12/31/2032
Oleander Power Project	Gas/Oil	546	1/1/2010	5/31/2021
FPL	System	200	6/1/2014	5/31/2021
DEF	System	<1	6/1/1987	-
DEF	System	600	1/1/2014	12/31/2020
DEF	System	150	1/1/2014	12/31/2020
DEF	System	50	6/1/2016	12/31/2018
DEF	System	200-500	6/1/2016	12/31/2024
DEF	System	50-600	1/1/2021	3/31/2027
Lee County Florida	Waste Landfill	55	1/1/2009	12/31/2016
Telogia Power	Biomass	13	7/1/2009	11/30/2023
Seminole Energy, LLC	Landfill Gas	6.2	10/1/2007	3/31/2018
Brevard Energy, LLC	Landfill Gas	9	4/1/2008	3/31/2018
Timberline Energy, LLC	Landfill Gas	1.6	2/1/2008	3/31/2020
Hillsborough County	Waste Landfill	38	3/1/2010	2/28/2025
City of Tampa	Waste Landfill	20	8/1/2011	7/31/2026

Note: Seminole Electric Cooperative may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

Portfolio Summaries
Revised Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	11,859	11,754	11,735	**11,666**
NPV @ 6.0%	8,641	8,568	8,549	**8,499**
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	57,539	**56,465**	58,312	58,616
NPV @ 6.0%	20,981	**20,618**	21,120	21,148

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 59
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)
DESCRIPTION: Paul M. Sotkiewicz, Ph.D. PS-8

Ten Year Power Plant Site Plan 2017 – 2026



FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 60
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lauderdale Modernization (Dania Beach Clean Energy Center)

(2) **Capacity**
a. Summer 1,163 MW
b. Winter 1,176 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2020
b. Commercial In-service date: June, 2022

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low Nox Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection

(7) **Cooling Method:** Once through cooling water

(8) **Total Site Area:** Existing Site 392 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%
Forced Outage Factor (FOF):	1.0%
Equivalent Availability Factor (EAF):	95.5%
Resulting Capacity Factor (%):	90.0% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	6,119 Btu/kWh on Gas
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	7,592 Btu/kWh on Gas

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40 years
Total Installed Cost (2022 $/kW):	764
Direct Construction Cost (2022 $/kW):	675
AFUDC Amount (2022 $/kW):	89
Escalation ($/kW):	Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr):	19.73
Variable O&M (2022 $/MWH):	0.23
K Factor:	1.55

* $/kW values are based on Summer capacity.
** Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC.

Seminole Electric
COOPERATIVE, INC.

Ten Year Site Plan

2017 – 2026
(Detail as of December 31, 2016)
April 1, 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 61
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Submitted To:
State of Florida
Public Service Commission

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	SGS CC Unit 1
2	Capacity a. Summer (MW): b. Winter (MW):	 593 592
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 May 2018 May 2021
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	SCR
7	Cooling Method:	Wet Cooling Tower with Forced Air Draft Fans
8	Total Site Area:	SGS
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 4.50 2.50 93.00 50% 6550 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 30 942 884 57 Included in values above 8.28 - 0.08 N/A

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	Unnamed Generating Station CC Unit 2
2	Capacity a. Summer (MW): b. Winter (MW):	 593 592
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	 December 2019 December 2022
5	Fuel a. Primary fuel: b. Alternate fuel:	 Natural Gas
6	Air Pollution Control Strategy	SCR
7	Cooling Method:	Wet Cooling Tower with Forced Air Draft Fans
8	Total Site Area:	SGS
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	 4.50 2.50 93.00 50% 6550 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2021) Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/Run Hour): Variable O&M ($/MWH): K Factor:	 30 980 904 76 Included in values above 8.40 - 0.08 N/A

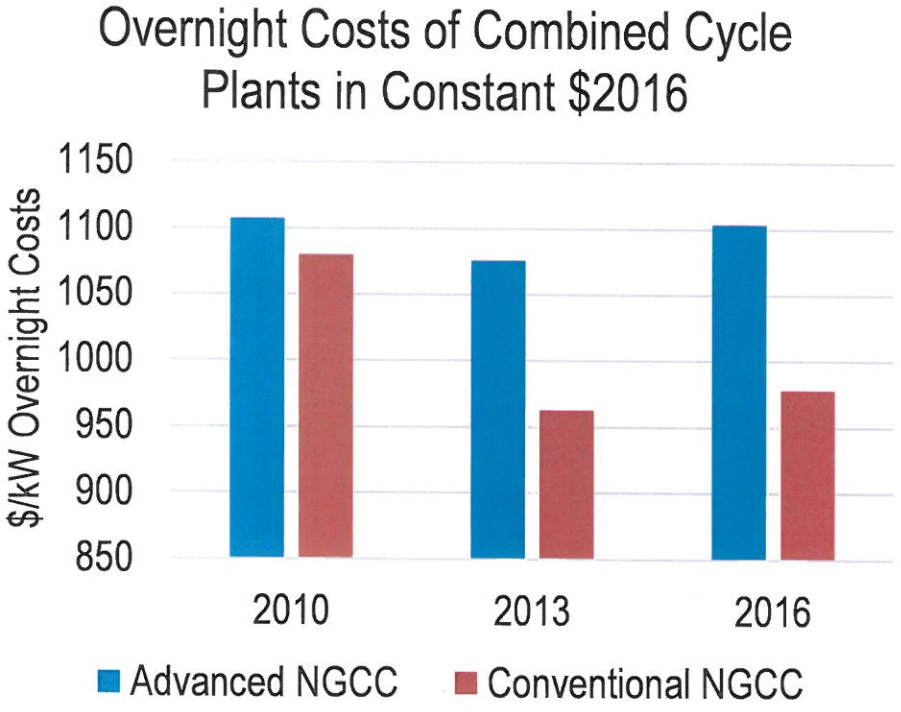
Does it Matter if the Clean Power Plan Goes Away?...Probably Not

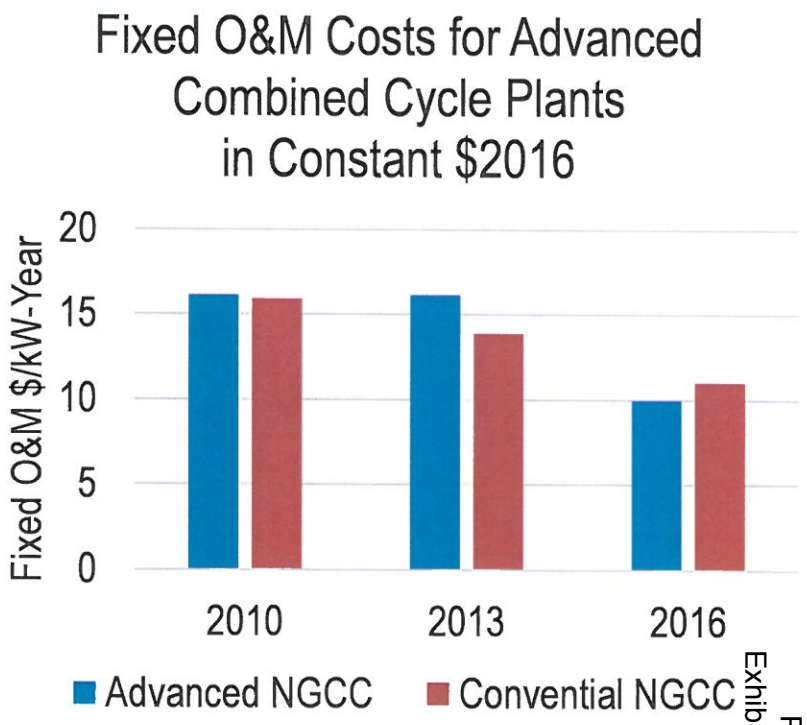
Harvard Electricity Policy Group
86th Plenary Session
March 31, 2017
Savannah, GA

Paul M. Sotkiewicz, Ph.D
President
E-Cubed Policy Associates, LLC
March 9, 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 62
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Docket No. 20170266-EC
Combined Cycle Costs for 2010-2016, U.S. Energy Information Administration, contained in presentation by Paul M. Sotkiewicz, Ph.D. to Harvard Electricity Policy Group, March 31, 2017
Exhibit _____ (PS-11), Page 1 of 3



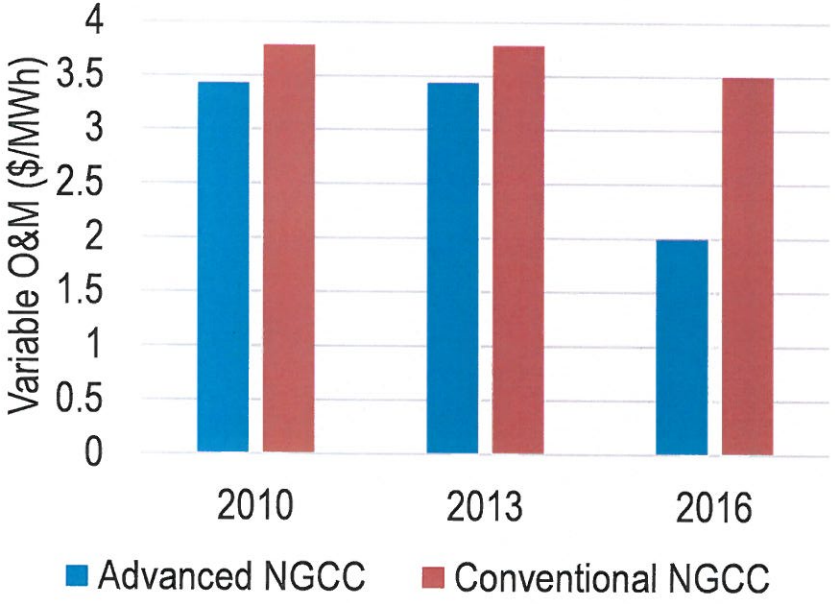


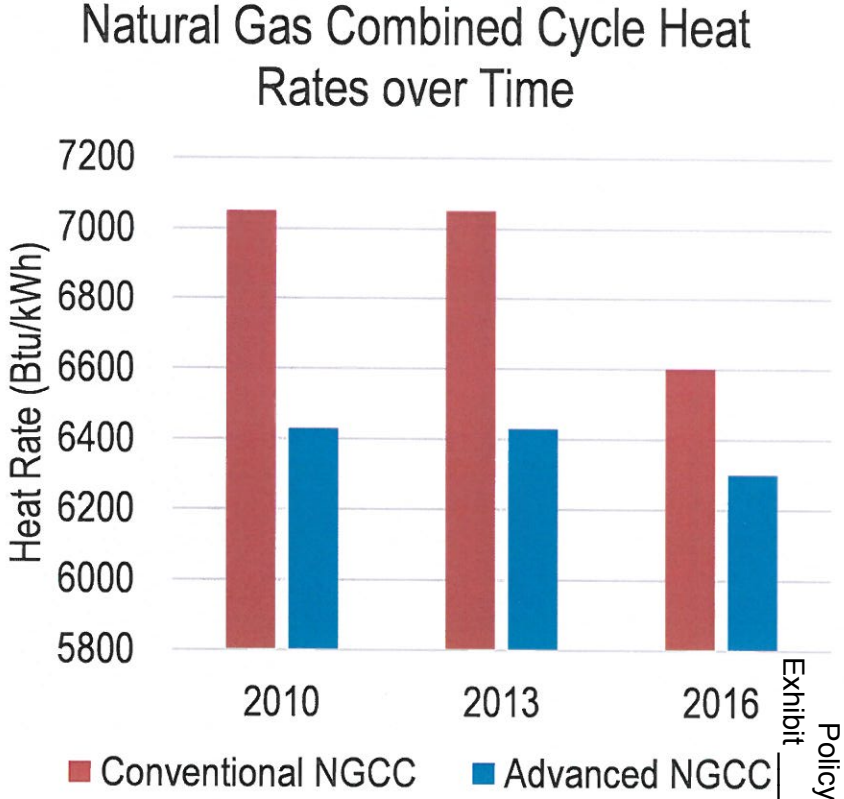
CPI inflation was 10% between 2010 and 2016…combined cycle costs are flat to declining

Source: United States Energy Information Administration, Capital Costs Reports 2010, 2013, 2016. CPI used to compare in constant dollars.

E-Cubed Policy Associates, LLC

Docket No. 20170266-EC
Combined Cycle Costs for 2010-2016, U.S. Energy Information Administration, contained in presentation by Paul M. Sotkiewicz, Ph.D. to Harvard Electricity Policy Group, March 31, 2017
Exhibit _____ (PS-11), Page 2 of 3





CPI inflation was 10% between 2010 and 2016…combined cycle costs are flat to declining

Source: United States Energy Information Administration, Capital Costs Reports 2010, 2013, 2016. CPI used to compare in constant dollars.

Docket No. 20170266-EC
Combined Cycle Costs for 2010-2016, U.S. Energy Information Administration, contained in presentation by Paul M. Sotkiewicz, Ph.D. to Harvard Electricity Policy Group, March 31, 2017
Exhibit ____ (PS-11), Page 3 of 3

FLORIDA POWER & LIGHT COMPANY

Eleventh Revised Sheet No. 10.311
Cancels Tenth Revised Sheet No. 10.311

APPENDIX II
TO RATE SCHEDULE QS-2
AVOIDED UNIT INFORMATION

The Company's Avoided Unit has been determined to be a 1,163 MW Combined Cycle Unit with an in-service date of June 1, 2022 and a heat rate of 6,120 Btu/kWh.

EXAMPLE STANDARD OFFER CONTRACT AVOIDED CAPACITY PAYMENTS
FOR A CONTRACT TERM OF TEN YEARS FROM THE IN-SERVICE DATE OF THE AVOIDED UNIT
($/KW/MONTH)

	Option A	Option B	Option C	Option D
Contract Year	Normal Capacity Payment	Early Capacity Payment	Levelized Capacity Payment	Early Levelized Capacity Payment
2018	$ -	$ 4.23	$ -	$ 4.75
2019	$ -	$ 4.31	$ -	$ 4.75
2020	$ -	$ 4.40	$ -	$ 4.75
2021	$ -	$ 4.49	$ -	$ 4.75
2022	$ 7.00	$ 4.58	$ 7.66	$ 4.75
2023	$ 7.15	$ 4.67	$ 7.66	$ 4.75
2024	$ 7.30	$ 4.76	$ 7.66	$ 4.75
2025	$ 7.45	$ 4.86	$ 7.66	$ 4.75
2026	$ 7.60	$ 4.96	$ 7.66	$ 4.75
2027	$ 7.76	$ 5.05	$ 7.66	$ 4.75
2028	$ 7.93	$ 5.16	$ 7.66	$ 4.75
2029	$ 8.09	$ 5.26	$ 7.66	$ 4.75
2030	$ 8.26	$ 5.36	$ 7.66	$ 4.75
2031	$ 8.43	$ 5.47	$ 7.66	$ 4.75
2032	$ 8.61	$ 5.58	$ 7.66	$ 4.75

ESTIMATED AS-AVAILABLE ENERGY COST

For informational purposes, the most recent estimated incremental avoided energy costs for the next ten years will be provided within thirty (30) days of written request.

ESTIMATED UNIT FUEL COSTS ($/MMBtu):
The most recent estimated unit fuel costs for the Company's avoided unit will be provided within thirty (30) days of written request.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 63
PARTY: QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY(Direct)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: July 13, 2017

FLORIDA POWER & LIGHT COMPANY

Fourth Revised Sheet No. 10.311.1
Cancels Third Sheet No. 10.311.1

FIXED VALUE OF DEFERRAL PAYMENTS - NORMAL CAPACITY OPTION PARAMETERS

Where, for a one year deferral:			Value
VAC_m	=	Company's value of avoided capacity and O&M, in dollars per kilowatt per month, during month m;	$7.00
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present valued to the middle of the first year;	1.5389
I_n	=	total direct and indirect cost, in mid-year dollars per kilowatt including AFUDC but excluding CWIP, of the Company's Avoided Unit with an in-service date of yearn;	$766.88
O_n	=	total fixed operation and maintenance expense, for the year n, in mid-year dollars per kilowatt per year, of the Company's Avoided Unit;	$14.62
i_p	=	annual escalation rate associated with the plant cost of the Company's Avoided Unit;	2.0%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Company's Avoided Unit;	2.50%
r	=	annual discount rate, defined as the Company's incremental after-tax cost of capital;	7.572%
L	=	expected life of the Company's Avoided Unit;	40
n	=	year for which the Company's Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the Standard Offer Contract.	2022

FIXED VALUE OF DEFERRAL PAYMENTS - EARLY CAPACITY OPTION PARAMETERS

A_m	=	monthly capacity payments to be made to the QS starting on the year the QS elects to start receiving early capacity payments, in dollars per kilowatt per month;	*
i_p	=	annual escalation rate associated with the plant cost of the Company's Avoided Unit;	2.0%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Company's Avoided Unit;	2.50%
n	=	year for which early capacity payments to a QS are to begin; (at the election of the QS early capacity payments may commence anytime after the actual in-service date of the QS facility and before the anticipated in-service date of the Company's avoided unit)	*
F	=	the cumulative present value of the avoided capital cost component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Company's Avoided Unit and continued for a period of 10 years;	$500.71
r	=	annual discount rate, defined as the Company's incremental after-tax cost of capital;	7.572%
t	=	the term, in years, of the Standard Offer Contract for the purchase of firm capacity commencing in the year the QS elects to start receiving early capacity payments prior to the in-service date of the Company's Avoided Unit;	*
G	=	the cumulative present value of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Company's Avoided Unit and continued for a period of 10 years.	$110.45

*From Appendix E

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: July 13, 2017



Load Forecasting Whitepaper

Forecasting Methodology and Model/Variable Selection Process

Studies from 2015-2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 64
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: Kyle D. Wood KDW-2

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Nomenclature of Terms

Abbreviation	Description
AEO	Annual Energy Outlook
BEA	U.S. Bureau of Economic Analysis
BEBR	University of Florida Bureau of Business and Economic Research
BLS	U.S. Bureau of Labor Statistics
BOC	U.S. Census Bureau
CDD	Cooling Degree Days
HDD	Heating Degree Days
EDR	Florida's Office of Economic and Demographic Research
EIA	U.S. Energy Information Administration
FORM-7	Member RUS Financial and Statistical Report
LFS	Load Forecast Study
MAPE	Mean Absolute Percentage Error
NEMS	National End-Use Modeling System
PBS	Power Billing System
RASS	Residential Appliance Saturation Survey
RUS	Rural Utilities Service
SAE	Statistically Adjusted End-use

Overview of Methodology: 2015 LFS – 2017 LFS

Seminole designs all models by Member and places emphasis on three models in particular:

1) Total Consumer Meters
2) Total Delivery Point Member Energy Purchases from Seminole
3) Total Delivery Point Member Non-Coincident Demand

In tandem with designing Member total level models for consumers and energy, Seminole designs models for each rate class—residential, commercial, and other. All rate class forecasts are reconciled bottom up to match total level forecasts.

Overview of Methodology: 2003 LFS – 2014 LFS

Prior to the 2015 LFS, the forecasting process was designed around four Member models:

1) Consumer Meters by Rate Class
2) Usage per Consumer by Rate Class Sales
3) Distribution Loss Factor
4) Delivery Point Load Factor

Member Energy Purchases from Seminole were a function of the first three models: consumers, usage per consumer and loss factor. Member non-coincident demands were a function of all four models: consumers, usage per consumer, loss factor and load factor.

Overview of Major Enhancements: 2015 LFS – 2017 LFS

Technology

In 2014, Seminole invested in state-of-the art statistical analysis software to move load forecasting data and models from “SAS® on the mainframe” to “SAS® on Windows PC.” The new technology enabled efficient data warehousing, coding, model design and analysis, and graphic visualization. Ultimately, this modern technology enabled Seminole to incorporate new data and engineer a robust forecasting process.

Weather Station Data

In 2014, Seminole more than tripled the number for weather stations it subscribes to from 8 previously, to 25, which cover a geographical area from the Everglades to southern Georgia. The types of weather variables collected from these stations increased substantially, as well. State-of-the-art weather station selection methodology was incorporated into the 2015 LFS to effectively choose which stations best represent weather in each Member territory.

The optimal set of weather stations by Member is derived by ranking the predictive power of each station's temperature readings to estimate electricity load and then re-estimating load based on combinatorial sets of stations ranked from lowest to highest MAPE. The set that achieves the lowest MAPE is chosen as the optimal combination. These analyses are conducted using regression models (PROC GLM in SAS®). The hourly weather profile of each Member is created by averaging the individual weather stations from a Member's optimal combination.

Economy Data

In the 2015 LFS, Seminole updated its approach to constructing economy variables for Member regression models. In previous forecasts, county-level data was weighted by the number of residential consumers in each Member service territory according to the most recent Member RASS. Member service areas are constantly changing; therefore modeling and forecasting load growth based on one set of weights provided limited flexibility. The updated approach does not weight, but aggregates in total the counties significant to Member service territories. The counties are deemed significant based on the following questions:

- What portion of a Member's consumers are from a given county?
- What portion of a given county's population is served by the Member?

The University of Florida Bureau of Business and Economic Research provides Seminole with annual updates to consumer by county distributions. Ultimately, this change in methodology resulted in minimal change to long-run forecasts.

In addition, Seminole no longer weights and combines economy projections from multiple sources and sparingly uses multiple third party sources for economy projections in a single regression model.

Load Data

A major focus area for improvement over previous LFS design was the use of monthly end-use sales data. Prior to the 2015 LFS, Seminole's methodology employed monthly-level, billing adjusted end-use meter data to forecast consumer meters and usage per meter by rate class. These forecasts were extrapolated along with loss factors and load factors to calculate Seminole's total energy and demand requirements at the delivery point, respectively. Since the 2015 LFS, hourly delivery point data has been used to model and forecasting total energy and demand requirements.

Energy Intensity Variables

Another focus area for improvement in the prior methodology was Seminole's use of appliance saturation data as a proxy for energy intensity trends in the usage per consumer model. Prior to 2015, Seminole treated the effects of energy efficient technologies in end-use

regression models with space heating and cooling system saturation variables. These variables were derived from Members' RASS and publicly available manufacturing data.

During the development of the 2016 LFS, Seminole joined Itron's Energy Forecasting Group to enhance its ability to control for trends in structural changes, end-use appliance saturation, and efficiency. Itron provides residential and commercial SAE spreadsheets and models that are updated with the EIA's most recent results from the NEMS presented in the AEO. Data included in these spreadsheets by Census region include:

- Updated equipment efficiency trends
- Updated equipment and appliance saturation trends
- Updated structural indices
- Updated annual heating, cooling, water heating and Non-HVAC indices
- Updated regional sales forecasts

End-use saturation, efficiency, structural changes (building shell efficiency improvements and square footage), are combined with base year appliance usage to develop historical and projected end-use intensity estimates. These intensity values are used in constructing heating, cooling, and "other" usage variables for energy and demand forecasting models.

Seminole incorporated the SAE approach into its own methodology by making several improvements. First, for spatial precision, Seminole replaced Census region historical data and incorporated Member area statistics for residential appliance saturation and commercial end-use intensity weighted by employment by industry. Second, Seminole scaled all usage-per-consumer appliance intensity estimates in Itron's calibration process to a total-usage-per appliance level. Third, Seminole adjusted Itron's "HeatUse" and "CoolUse" components (shown in the equation below as "ThermalUse"), removed degree day weights (representing the effect of lag months), household size, household income, and electricity prices. Instead, Seminole models these factors as individual independent variables in statistical models to evaluate their statistical significance, as opposed to relying on the elasticities provided by Itron. In addition, the reasonableness of the forecast for each of these factors is critically reviewed before inclusion into regression models. Last, Seminole weights rate class thermal and base intensity estimates by rate class sales to derive total level intensities. The derivation of heating and cooling index variables (thermal variables) and base index variables for the residential model are shown below.

Residential SAE Model

$$\boldsymbol{XThermal_{y,m}} = \boldsymbol{ThermalIndex_y} * \boldsymbol{ThermalUse_{y,m}}$$

$$\boldsymbol{ThermalIndex_y} = StructuralIndex_y * \sum_{EquipmentType,i}^{EquipmentType,j} \left[Consumption_{EIA09} * \frac{Consumption_{Utility09}}{Consumption_{EIA09}} * \left(\frac{Saturation_y / Efficiency_y}{Saturation_{09} / Efficiency_{09}} \right) \right]$$

$$\boldsymbol{ThermalUse_{y,m}}\ (\textbf{SEMINOLE APPROACH}) = \frac{DD_{y,m}}{DD_{09}}$$

$$\boldsymbol{ThermalUse_{y,m}}\ (\textbf{ITRON APPROACH}) = \frac{WgtDD_{y,m}}{WgtDD_{09}} * \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} * \left(\frac{Income_y}{Income_{09}}\right)^{0.20} * \left(\frac{ElecPrice_y}{ElecPrice_{09}}\right)^{-0.15}$$

$$\boldsymbol{XBase_{y,m}} = BaseIndex_{y,m}$$

$$\boldsymbol{BaseIndex_{y,m}} = \sum_{Type,i}^{Type,j} \left[Consumption_{EIA09} * \frac{Consumption_{Utility09}}{Consumption_{EIA09}} * \left(\frac{Saturation_y / Efficiency_y}{Saturation_{09} / Efficiency_{09}} \right) * MthlyMultiplier_{y,m} \right]$$

Behind the Meter Distributed Solar

In the 2017 LFS, Seminole developed incremental, additional behind-the-meter distributed solar generation forecasts for Members and their end-use consumers. Seminole incorporated this distributed solar generation forecast with the intent to reduce Seminole's expected energy and demand requirements in the future. A detailed description of the data and model is presented later in this document.

Model Data: 2017 LFS

The availability of relevant data drives model development and variable selection. During LFS development, Seminole's staff updates and objectively analyzes all available data known to influence both consumer growth and electricity consumption. The load forecasting database is comprised of data from Seminole, its Members, and third party sources. All data is subject to validation tests and graphical analysis. Data cleansing techniques are employed when necessary.

Load and Consumer Data

Seminole collects load data for forecasting from two primary sources (1) Seminole System Operation's PBS and (2) Member FORM-7. Members provide their own forecast data for a select number of large commercial Members on Seminole economic development rates or interruptible rates. Members also provide scheduled load and customer transfers due to territorial agreements.

PBS contains hourly-interval delivery point meter data, which is useful for energy purchases and peak demand analysis. FORM-7's are provided by each of our nine Members to report electricity billing sales, revenue, and customers by rate class. FORM-7 sales show load consumption net of distribution line losses and include billing cycle adjustments that may not coincide with calendar-month consumption shown in PBS data.

Member FORM-7 data provides information about the number of customers, revenues and sales by rate class whereas PBS data does not contain this information. Rate class data typically requires more data cleansing than other sources and class level forecasts reconcile up to total level projections. A list of FORM-7 rate classifications by billing groups is shown below.

Member RUS FORM-7 Member Rate Classifications
Residential
Non-Seasonal
Seasonal
Pre-paid
Yard Light
Commercial
50 kVA or Less
Over 50 kVA
69 kVA or Over
1000 kVA or Less
Over 1000 kVA
General Service Demand
General Service Time of Day
General Service Less Than 50 kVA
Large General Service Demand
Contracted Rate
Large Power
Other Commercial
Public Buildings and Authorities
Interruptible

Other
Irrigation
Street and Highway Lighting
Public Buildings and Authorities
Sales for Re-sale

Economic and Demographic Data

Historical economic data employed in the LFS are produced by the BOC, the BEA, and the BLS. Seminole collects these data primarily from Moody's Analytics DataBuffet system. Forecasts of variables used in Seminole's forecasts are provided by Moody's, BEBR, and EDR. Moody's projects a range of economic variables at the county-level and re-forecasts these variables monthly. BEBR provides annual updates to Florida county population projections in five-year increments. EDR decomposes BEBR forecasts into yearly and quarterly increments and provides these data to the Florida Legislature to support policy making and planning decisions.

County population projections from Moody's Analytics and BEBR/EDR have traditionally been the primary resource for trending growth in the Seminole territory. Recent productions of the LFS have reflected trends based on BEBR population projections to a greater degree than in the past. BEBR's population forecasts have remained consistent over recent years, where Moody's forecasts are more aggressive than in prior vintages. Load forecasting models generally include only one source for trend variables, since economic variables from multiple-sources may not follow a logical conditional distribution. Seminole forecasts may reflect the combination of models with different data sources.

Proxies to population such as number of households and housing stock sometimes exhibit a higher degree of statistical efficiency when modeling residential consumers. The majority of consumers in the residential classification are dwellings and approximately 90 percent of the Seminole system is residential. Gross county product and total employment are useful alternatives for commercial models, since these variables exhibit more volatility during business cycles.

Energy Intensity Data

Seminole utilizes appliance energy consumption and equipment stock projections based on the EIA's NEMS to derive energy intensity indices in load forecast models. The EIA produces updates to total consumption and equipment stock by appliance type and by residential and commercial rate class in the AEO. Seminole retained Itron to access a clean and organized version of EIA's AOE's database for the South Atlantic Census region. Additionally, the RASS, updated every 5 years since 1980, captures historic rates in electric equipment stock growth. Census regional estimates of commercial square footage by building type are replaced with county-specific square footage estimates as a function of employment by industry from the BLS. A list of residential appliances used to generate energy intensity variables for forecast models are listed below by usage type.

Energy Efficiency Variables Residential Electrical Appliances and Equipment
Heating Use
Electric Furnace and Space Heating
Heat Pump Space Heating
Sectional Heating
Furnace Fans
Cooling Use
Central Air Conditioning and Room Air Conditioning
Central Air Conditioning Heat Pump Cooling
Base Use
Electric Water Heating
Electric Cooking
Primary and Secondary Refrigeration and Freezer
Dishwasher
Electric Clothes Washer
Electric Dryer
Television
Lighting
Miscellaneous

Seminole's load forecasting models include energy-efficiency variables for "heat-use", "cool-use", and "base-use" derived from Itron's SAE methodology. Itron provides Seminole both residential and commercial appliance saturation and efficiency data along with methodology for projecting end-use electricity consumption. Seminole scales Itron's usage-per-consumer variables to fit total-use models and derives parameter estimates for people per household, household income, and price independently in load models rather than indexing them together. Indices developed using saturation, efficiency and utilization data were interacted with CDD, HDD, and monthly dummy variables for use in energy and demand models. For seasonal demand models, seasonal CDD, HDD, minimum and maximum temperature terms are utilized.

Weather Station Data

Temperature variables used in in load forecasting models include average monthly temperature and minimum and maximum temperatures by month. Other temperature-related variables utilized in load forecasting models include HDD and CDD. HDD represent the sum of degrees each day's average temperature falls below 61° Fahrenheit in a given month, which is the approximate temperature consumers turn on heating devices. Alternatively, CDD represent the sum of degrees that each day's average temperature exceeds 72° Fahrenheit in a given month, which is the approximate temperature consumers turn on A/C units.

Weather variables used to forecast base-case future are based on "normal" weather. Normal weather in these forecasting models represent the 30-year median of historical monthly observations and average for season observations. Extreme weather used for alternative-scenario forecasts reflect the 10^{th} and 90^{th} percentiles.

Solar Data

Behind-the-meter solar installation and capacity records are collected from Customer-Owned Renewable Generation forms submitted by our individual Member cooperatives to the Florida Public Services Commission. Seminole also utilizes the end-use solar capacity forecasts published by the EIA in the AEO. Solar insolation data, which assume optimal conditions, are downloaded from an online calculator service operated by researchers at Arizona State University's Solar Power Lab, after inputting the geo-coordinates of each of Seminole's Member territories. AccuWeather provides Seminole with hourly weather data for a multitude of variables including temperature, solar irradiance, and minutes of sunshine for 25 selected stations in Florida and Georgia. Hourly solar insolation and AC power output data for Talquin's 10 kW array were downloaded from their publicly viewable solar dashboard website for analysis purposes.

Load Forecasting Models: 2017 LFS

Seminole applies regression analysis to forecast number of consumers, energy, and demand. All models are developed at the Member-level, while and Seminole forecasts are the aggregate of Member-level forecasts. The different explanatory variables, combinations, transformations, and interactions capture the unique growth characteristics within the Members' service territories. The summation of county-level data in each Member's significant geographical area creates the explanatory variables unique to that Member's territory. Regression models include lagged variables to control for autocorrelation as indicator variables to limit the bias associated with outliers that have not been removed during data cleansing. Additionally, indicator variables control for seasonality and isolate independent variables to certain months or seasons. Model selection focuses on minimizing MAPE. General study of current Member conditions and growth rates also aids in fitting models. The LFS reflects relevant Member-provided details regarding changes to the services territory and expected developments.

Consumer Model

Consumer forecasts are derived using regression analysis. In these models, the number of consumers is used as the dependent variable, while and population, number of households, and/or housing stock are used as independent variables. Historical data used in these models are from FORM-7 reports and U.S. BOC estimates. The training period extends over 40 years. Moody's Analytics and BEBR provide the necessary data to project future number of consumers. Multiple models are fit to forecast per-Member total consumers and consumers by rate class. This hierarchical design allows for additional analysis of forecast

errors and top-down reconciliation that mitigates disturbance caused by “rate-class shifts” in FORM-7 data. For additional model validation and analysis purposes consumer and population data by city/unincorporated area are collected from BEBR.

Seminole develops all consumer models with population as the trend variable and relies on projections produced by BEBR. Then, other economy variables are explored to improve consumer growth models. Other economy variables include housing stock and occupied households which are provided by Moody’s Analytics. If these alternative variables provide significant explanatory power throughout the training period, Seminole determines whether the future growth projections appear reasonable. Consumer growth forecasts using these alternative variables may be blended with BEBR population based forecasts. Seminole may also use population projections from Moody’s in the models that include Moody’s forecasts of housing stock or occupied households. Seminole also employs BEBR’s low population forecast for Members expecting minimal gains in consumer growth.

The third component of Seminole’s consumer model development process is analyzing which lags to include. Seminole utilizes autoregressive and moving average orders 1 and 12 to account for the correlation in consumer growth given consumer growth in prior periods. Seminole also analyzes how it can improve model accuracy through including binaries for seasonality and apparent errors in the data not accounted for in initial data cleaning. Finally, Seminole tests forecast model accuracy through an ex-post error analysis on the prior 12 months. Seminole may re-examine model specification and make changes based on holdout results.

Energy Model Overview

Forecasts of Member energy purchases from Seminole are developed using regression models. Seminole’s hourly power billing system, Member RUS FORM-7 financial reports, BOC estimates and AccuWeather make up the models historical data with model training periods of 20 years. Explanatory variables analyzed in these models include monthly temperature statistics interacted with energy efficiency indices, price, and economic indicators such as population, number of households, housing stock, and gross county product.

Rate-class energy retail sales to end-users, which are naturally lower than Member energy purchases at the delivery point by a loss factor, are grossed up to the energy purchases level and forecasted along with total purchases. The sum of rate class forecasts are reconciled to match total energy projections and reduced by projected losses to arrive at rate-class sales forecasts. Future expectations of the losses are projected off the five-year historical time trend between the ratio of annual Member retail sales to end-use consumers and Member purchases from Seminole.

Energy Model Development and Variable Selection Process

Seminole designs the energy forecasting models to include the following primary components:

- Member forecasted consumer growth or BEBR population projections
- Heating degree day, cooling degree day and base usage interacted with end-use appliance intensity forecasts provided by Itron
- Seminole's wholesale price to its Members in real terms.
- Precipitation
- Monthly binaries
- Autoregressive terms and moving average terms

Energy models for several members do not include base usage and price if the statistical significance is low or the parameter estimate's sign is counterintuitive. Seminole also tests specifications with relative humidity and heating and cooling degree days without energy intensity interactions. If these variables provide significant explanatory power to the model, they may be included, as well. Secondly, Seminole examines other variables that explain energy growth, including economic variables:

- Housing Stock
- Employment
- The natural log of gross product
- Household income in real terms

If these economic variables are effective in explaining energy growth, it is determined whether the growth projections for these variables provided by Moody's Analytics are reasonable and whether it is beneficial to incorporate these variables given knowledge of the service territory. The forecasts of energy growth using these alternative variables may be combined with or included in projections derived from BEBR population based models.
The third component of the energy model development is analyzing which time series components to include. For Seminole's smallest Member, an unobserved component model is incorporated to account for white noise and random walk due to a high level of commercial and industrial activity in training data. Finally, forecast model accuracy is analyzed through ex-post error analysis of the prior 12 months and model specification may revised based on these results.

Demand Model Overview

Demand for capacity forecasts are predictions of the most likely one-hour maximum peak in electricity consumption in a given month based off most probable economic and weather conditions at that point in time. Demand models are developed at the Member level and are trained with 20 years of training data. The different demand models make prediction for monthly demand, and for the winter and summer peaks. Demand model inputs include

temperature statistics interacted with energy efficiency indices, economic trend variables, and load factor.

Peak models regress contemporaneous explanatory variables with the highest peak during December through March for Winter models and April through September for Summer models. Seasonal peak forecasts typically replace monthly-model results for the months seasonal peaks are most likely to occur.

Seminole's demand is the aggregate of the one-hour simultaneous demand of all Members that maximizes the peak of the system in a single month. The ratio between Member peak demand and Member demand coincident with the Seminole system as a whole derives the coincident factor. Member demands coincident with Seminole may be equal to or less than Member peak demand. Future expectations of Member coincident factors are extrapolated as the median of ten years of historical observations by month and by season.

Winter Demand Model Development and Variable Selection Process

Seminole develops the winter demand forecast model to include the following primary components:

- Member forecasted consumer growth or BEBR population projections
- Heating degree days and minimum temperature interacted with heating end-use equipment and appliance intensity forecasts provided by Itron
- Load Factor
- Seminole's Wholesale price to Members in real terms

Several Member models do not include price or minimum temperature variables if the statistical significance is low or if the parameter estimate's sign is counterintuitive. Seminole also attempts to use the base end-use intensity index to explain non-weather sensitive loads. However, the base-use parameter sometimes has low statistical significance in the winter demand model or a counterintuitive explanatory effect. In place of end-use base intensity, Seminole employs the natural logarithm or square root transformation on consumer-growth trend variables for nearly all Member models as a proxy for conservation growth. Seminole also examines other variables that explain demand growth, including:

- Average Relative Humidity
- Household income in real terms
- Maximum temperature interacted with end-use cooling equipment and appliance intensity forecasts provided by Itron

Finally, forecast model accuracy is analyzed through ex-post error analysis of the prior 12 months and model specification may revised based on these results.

Load Factor Model Development and Variable Selection Process

Load factor models are system-generated using SAS® Forecast Studio to produce the most efficient model using 20 years of observations and also for 12 and 48-month ex-post holdout periods. The final model based on results from this analysis. Trend variables are not employed in the load factor model or forecast. The variables used in the load factor model are shown below:

- Monthly maximum temperature
- Monthly minimum temperature
- Monthly average temperature
- Monthly mean humidity
- Monthly precipitation
- Temperature at time of Member peak
- Heating degree hours at the time of Member peak
- 3-hour moving average temperature leading up to Member peak
- 24-hour moving average heating degree hours leading up to Member peak
- 24-hour weighted moving average temperature leading up to Member peak
- 24-hour moving average temperature leading up to Member peak
- 48-hour moving average temperature leading up to Member peak
- 48-hour moving average cooling degree hours leading up to Member peak
- Number of days in the month
- Monthly binaries
- Monthly binaries interacted with weather statistics above

Alternative Models

Additional forecasts are prepared to manage the risks associated with inherent modeling error, changes in economic conditions, and weather uncertainty. Three sets of alternative projections provide upper and lower intervals around the baseline forecasts for consumers, energy, and demand. The first set of alternative projections are associated with the statistical error of each model at the 95 percent prediction interval. This interval shows the range into which approximately 95 percent of future projections will fall, if the distribution of forecast error is similar to the past distribution.

The second set of alternative scenarios are produced to show the projected outcome of severe and mild temperature events. These extreme weather cases cover the highest 90 percent and lowest 10 percent of historical temperature statistics in a Member's region. The last set of alternatives provide an upper and lower range into which future projections will fall, if the distribution of explanatory-variable forecast error is similar to the past distribution. BEBR provides a high and low interval around their "medium" population forecast. The BEBR high and low interval provides a rough approximation of error around explanatory variables employed in Seminole load forecasting models. Therefore, this alternative presents future outlooks of consumers, energy, and demand if the predictor variables deviate from their baseline trend.

Solar Model

Seminole developed projections of behind-the-meter solar output from future installations for each of its nine Members, and reduced energy and demand forecasts by these results. Outputs from existing behind-the-meter solar installations are reflected in actual energy and demand load history. Therefore the solar forecasts reflect only future increases in solar output. Existing generation is almost exclusively residential and forecasts are assumed to reflect residential-scale adoption. The forecast also includes an adjustment for a Member-owned 3.5 MW (AC) facility expected to come online during the summer of 2018.

The first component of the solar forecasts includes Member-level projections of total annual AC capacity growth. Linear and exponential models were trained with a five-year trend in capacity growth. These data are contained in net metering reports submitted by Members to the PSC and are publically available online. These capacity forecasts were presented individually to Members and reflect edits from feedback received during each consultation. Long-term growth in this analysis was extrapolated at a monthly level from national end-use solar projections published in the EIA's AEO.

Using historic weather data from the unique station-combination created for each member, normalized statistics for minutes-of-sunshine by hour were combined with optimal-condition solar insolation data to create hourly solar potential profiles for each Member territory. These profiles reflect not just the quality of sunlight typical for each territory throughout the year, but also the quantity of this sunlight typically available during each hour of a normal year.

The final component of the solar forecasting model combines the hourly solar-potential index curve with the projected monthly solar installations to create hourly solar generation forecasts. Results from this engineering approach were then calibrated using observed hourly radiance and solar generation data collected from sensors integrated into Talquin's 10 kW array. These data are publicly available on their solar dashboard website. Total energy projections are reduced by monthly aggregates of forecasted solar generation, and demand forecasts are reduced by solar output at the time of peak demand. For LFS winter/summer peak demand forecasts, unique solar potential index curves were derived for winter and summer, respectively. These unique curves incorporate ten years of actual winter-peak hour and summer-peak hour data to calculate the average number of minutes of sunshine, during each respective peak event.

LFS Vintage Factsheet

2013 LFS
Prepared by: Bill Lawton, Kyle Wood, Sarah Bridges and Gerardo Lopez
Primary Models: End-Use Consumers, End-Use Sales, Loss Factor, Load Factor
Primary Source for Load Data: Member Monthly End-Use Billing Report by Rate Class
Weather Stations: 8
Weather Normalization: 25 Years
Statistical Software: Mainframe SAS®
Forecast Origin: December 2012
Presented in TYSP: 2014

2014 LFS
Prepared by: Bill Lawton, Kyle Wood, Sarah Bridges and Gerardo Lopez
Primary Models: End-Use Consumers, End-Use Sales, Loss Factor, Load Factor
Primary Source for Load Data: Member Monthly End-Use Billing Report by Rate Class
Weather Stations: 8
Weather Normalization: 25 Years
Statistical Software: Mainframe SAS®
Forecast Origin: December 2013
Presented in TYSP: 2015

2015 LFS
Prepared by Kyle Wood and Gerardo Lopez
Primary Models: End-Use Consumers, Total Energy Purchases, Load Factor, Total Demand
Primary Source for Load Data: Seminole Hourly Delivery Point Meter
Weather Stations: 25
Weather Normalization: 30 Years
Statistical Software: SAS® on Windows PC (DI Studio, Enterprise Guide, Forecast Studio)
Forecast Origin: December 2014Major Enhancement: State-of-the-art Weather Station Selection Process
Forecast Origin: December 2014
Presented in TYSP: 2016

2016 LFS
Prepared by: Kyle Wood and Matthew Siler
Primary Models: End-Use Consumers, Total Energy Purchases, Load Factor, Total Demand
Primary Source for Load Data: Seminole Hourly Delivery Point Meter
Weather Stations: 25
Weather Normalization: 30 Years
Statistical Software: SAS® on Windows PC (DI Studio, Enterprise Guide, Forecast Studio)
Forecast Origin: February 2016
Major Enhancement: Residential and Commercial End-Use Intensity Variables
Forecast Origin: February 2016
Presented in TYSP: 2017

2017 LFS

Prepared by: Kyle Wood, Matthew Siler, Abby Mayer
Primary Models: End-Use Consumers, Total Energy Purchases, Load Factor, Total Demand
Primary Source for Load Data: Seminole Hourly Delivery Point Meter
Weather Stations: 25
Weather Normalization: 30 Years
Statistical Software: SAS® on Windows PC (DI Studio, Enterprise Guide, Forecast Studio)
Forecast Origin: February 2017
Major Enhancement: Behind the Meter Distributed Solar Forecast
Forecast Origin: February 2017
Presented in TYSP: 2018

Latest LFS Initiatives

Seminole upgraded the primary software platform to SAS® Windows version M.4 Maintenance Release 4 in June of 2017. The latest upgrade provides Seminole access to the state of the art applications, including SAS® Energy Forecasting and SAS® Visual Analytics. The Energy Forecasting application will provide Seminole additional capability to develop and implement probabilistic forecasting methodology. Seminole will also have enhanced capability to view data for analysis and reporting through SAS® Visual Analytics.

SEMINOLE ELECTRIC COPPERATIVE, INC
WINTER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			125	2008			2.64%
2009		21	166	2009		0.42%	3.29%
2010	970	1,099	1,092	2010	22.48%	25.47%	25.31%
2011	1,699	1,692	1,161	2011	43.36%	43.19%	29.63%
2012	2,113	1,586	1,096	2012	57.00%	42.78%	29.57%
2013	1,344	1,069	992	2013	41.48%	32.99%	30.62%
2014	853	758	698	2014	23.74%	21.10%	19.43%
2015	1,174	1,099	885	2015	35.50%	33.23%	26.76%
2016	1,511	1,308	1,128	2016	50.07%	43.34%	37.38%
AVERAGE	**1,381**	**1,079**	**816**	**AVERAGE**	**39.09%**	**30.31%**	**22.73%**

Season	Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005-06	2005										
2006-07	2006										
2007-08	2007										
2008-09	2008	4,738	4,863								
2009-10	2009	5,047	5,068	5,213							
2010-11	2010	4,315	5,285	5,414	5,407						
2011-12	2011	3,918		5,617	5,610	5,079					
2012-13	2012	3,707			5,820	5,293	4,803				
2013-14	2013	3,240				4,584	4,309	4,232			
2014-15	2014	3,593					4,446	4,351	4,291		
2015-16	2015	3,307						4,481	4,406	4,192	
2016-17	2016	3,018							4,529	4,326	4,146

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 65
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC. (Rebuttal)
DESCRIPTION: Kyle D. Wood KDW-3

Docket Nos. 20170266-EC and 20170267-EC
Comparison of Historical Error Rates based on Sotkiewicz Approach
Exhibit No. __ (KDW-3), Page 1 of 9

DUKE ENERGY FLORIDA
WINTER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			99	2008			0.99%
2009		(1,157)	(1,146)	2009		-9.91%	-9.82%
2010	1,454	1,440	1,397	2010	15.65%	15.50%	15.04%
2011	3,274	3,293	3,273	2011	42.51%	42.76%	42.50%
2012	4,387	4,357	3,835	2012	63.64%	63.21%	55.64%
2013	4,096	3,391	2,398	2013	56.72%	46.95%	33.20%
2014	2,528	1,385	1,508	2014	30.43%	16.67%	18.15%
2015	2,360	2,538	2,375	2015	31.95%	34.36%	32.16%
2016	NA	NA	NA	2016	NA	NA	NA
AVERAGE	**3,017**	**2,178**	**1,717**	**AVERAGE**	**40.15%**	**29.94%**	**23.48%**

Season	Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005-06	2005										
2006-07	2006										
2007-08	2007										
2008-09	2008	10,034	10,133								
2009-10	2009	11,670	10,513	10,524							
2010-11	2010	9,288	10,742	10,728	10,685						
2011-12	2011	7,701		10,975	10,994	10,974					
2012-13	2012	6,893			11,280	11,250	10,728				
2013-14	2013	7,222				11,318	10,613	9,620			
2014-15	2014	8,308					10,836	9,693	9,816		
2015-16	2015	7,386						9,746	9,924	9,761	
2016-17	2016	NA							9,889	9,682	9,910

TAMPA ELECTRIC COMPANY
WINTER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			565	2008			15.05%
2009		209	157	2009		4.91%	3.69%
2010	882	809	833	2010	23.61%	21.66%	22.30%
2011	1,412	1,433	1,343	2011	43.22%	43.86%	41.11%
2012	1,921	1,824	1,427	2012	65.83%	62.51%	48.90%
2013	1,797	1,360	916	2013	58.36%	44.17%	29.75%
2014	1,146	654	642	2014	33.81%	19.29%	18.94%
2015	925	916	784	2015	29.17%	28.89%	24.72%
2016	NA	NA	NA	2016	NA	NA	NA
AVERAGE	**1,347**	**1,029**	**833**	**AVERAGE**	**42.33%**	**32.18%**	**25.56%**

Season	Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005-06	2005										
2006-07	2006										
2007-08	2007										
2008-09	2008	3,754	4,319								
2009-10	2009	4,256	4,465	4,413							
2010-11	2010	3,735	4,617	4,544	4,568						
2011-12	2011	3,267		4,679	4,700	4,610					
2012-13	2012	2,918			4,839	4,742	4,345				
2013-14	2013	3,079				4,876	4,439	3,995			
2014-15	2014	3,390					4,536	4,044	4,032		
2015-16	2015	3,171						4,096	4,087	3,955	
2016-17	2016	NA							4,145	4,003	3,887

SEMINOLE ELECTRIC COPPERATIVE, INC
SUMMER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			112	2008			3.09%
2009		71	176	2009		1.86%	4.60%
2010	508	609	604	2010	14.32%	17.16%	17.02%
2011	652	646	378	2011	17.85%	17.68%	10.35%
2012	1,026	769	645	2012	29.93%	22.43%	18.82%
2013	799	704	582	2013	22.41%	19.74%	16.32%
2014	631	549	412	2014	20.43%	17.78%	13.34%
2015	713	557	329	2015	23.60%	18.44%	10.89%
2016	439	218	69	2016	13.54%	6.72%	2.13%
AVERAGE	**681**	**515**	**367**	**AVERAGE**	**20.30%**	**15.23%**	**10.73%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	3,630	3,742								
2009	3,824	3,895	4,000							
2010	3,548	4,056	4,157	4,152						
2011	3,653		4,305	4,299	4,031					
2012	3,428			4,454	4,197	4,073				
2013	3,566				4,365	4,270	4,148			
2014	3,088					3,719	3,637	3,500		
2015	3,021						3,734	3,578	3,350	
2016	3,243							3,682	3,461	3,312

DUKE ENERGY FLORIDA
SUMMER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			1	2008			0.01%
2009		(271)	(71)	2009		-2.82%	-0.74%
2010	790	1,002	872	2010	8.85%	11.22%	9.77%
2011	1,518	1,356	1,237	2011	17.58%	15.70%	14.32%
2012	1,836	1,858	1,548	2012	22.02%	22.29%	18.57%
2013	2,376	2,058	1,109	2013	29.64%	25.67%	13.83%
2014	1,540	464	360	2014	18.07%	5.44%	4.22%
2015	621	495	533	2015	7.37%	5.87%	6.32%
2016	(180)	(36)	427	2016	-2.00%	-0.40%	4.74%
AVERAGE	**1,214**	**866**	**668**	**AVERAGE**	**14.50%**	**10.37%**	**7.89%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	9,185	9,186								
2009	9,624	9,353	9,553							
2010	8,929	9,719	9,931	9,801						
2011	8,636		10,154	9,992	9,873					
2012	8,337			10,173	10,195	9,885				
2013	8,017				10,393	10,075	9,126			
2014	8,523					10,063	8,987	8,883		
2015	8,431						9,052	8,926	8,964	
2016	9,014							8,834	8,978	9,441

TAMPA ELECTRIC COMPANY
SUMMER NET FIRM DEMAND (MW)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			250	2008			6.72%
2009		308	292	2009		8.11%	7.69%
2010	534	504	525	2010	14.39%	13.58%	14.15%
2011	639	658	592	2011	17.27%	17.79%	16.00%
2012	857	788	556	2012	23.63%	21.73%	15.33%
2013	925	657	290	2013	25.59%	18.18%	8.02%
2014	605	199	107	2014	16.10%	5.30%	2.85%
2015	220	125	75	2015	5.81%	3.30%	1.98%
2016	52	(7)	(119)	2016	1.33%	-0.18%	-3.05%
AVERAGE	**547**	**404**	**285**	**AVERAGE**	**14.88%**	**10.98%**	**7.74%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	3,723	3,973								
2009	3,799	4,107	4,091							
2010	3,710	4,244	4,214	4,235						
2011	3,699		4,338	4,357	4,291					
2012	3,627			4,484	4,415	4,183				
2013	3,614				4,539	4,271	3,904			
2014	3,757					4,362	3,956	3,864		
2015	3,784						4,004	3,909	3,859	
2016	3,907							3,959	3,900	3,788

SEMINOLE ELECTRIC COPPERATIVE, INC
NET ENERGY FOR LOAD (GWh)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			1,028	2008			5.93%
2009		1,674	2,248	2009		9.59%	12.88%
2010	2,614	3,168	3,123	2010	15.07%	18.26%	18.00%
2011	5,254	5,208	3,065	2011	32.76%	32.47%	19.11%
2012	6,338	4,150	2,787	2012	40.19%	26.32%	17.67%
2013	4,932	3,528	2,859	2013	31.19%	22.31%	18.08%
2014	3,024	2,358	1,974	2014	21.83%	17.02%	14.25%
2015	2,552	2,108	1,286	2015	18.09%	14.95%	9.12%
2016	2,222	1,435	963	2016	15.35%	9.92%	6.65%
AVERAGE	**3,848**	**2,954**	**2,148**	**AVERAGE**	**24.93%**	**18.86%**	**13.52%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	17,332	18,360								
2009	17,453	19,127	19,701							
2010	17,346	19,960	20,514	20,469						
2011	16,037		21,291	21,245	19,102					
2012	15,769			22,107	19,919	18,556				
2013	15,812				20,744	19,340	18,671			
2014	13,854					16,878	16,212	15,828		
2015	14,104						16,656	16,212	15,390	
2016	14,471							16,693	15,906	15,434

DUKE ENERGY FLORIDA
NET ENERGY FOR LOAD (GWh)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			2,909	2008			6.10%
2009		7,524	6,024	2009		17.05%	13.65%
2010	7,381	5,846	6,356	2010	15.99%	12.66%	13.77%
2011	10,729	11,286	10,423	2011	25.25%	26.56%	24.53%
2012	13,803	13,481	11,271	2012	33.49%	32.71%	27.35%
2013	15,273	12,875	5,105	2013	37.46%	31.58%	12.52%
2014	11,784	5,483	5,392	2014	28.76%	13.38%	13.16%
2015	4,535	4,514	1,353	2015	10.73%	10.68%	3.20%
2016	3,322	742	567	2016	7.75%	1.73%	1.32%
AVERAGE	**9,547**	**7,719**	**5,489**	**AVERAGE**	**22.78%**	**18.29%**	**12.85%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	47,658	50,567								
2009	44,124	51,648	50,148							
2010	46,160	53,541	52,006	52,516						
2011	42,490		53,219	53,776	52,913					
2012	41,214			55,017	54,695	52,485				
2013	40,772				56,045	53,647	45,877			
2014	40,975					52,759	46,458	46,367		
2015	42,280						46,815	46,794	43,633	
2016	42,854							46,176	43,596	43,421

Docket Nos. 20170266-EC and 20170267-EC
Comparison of Historical Error Rates based on Sotkiewicz Approach
Exhibit No. __ (KDW-3), Page 8 of 9

TAMPA ELECTRIC COMPANY
NET ENERGY FOR LOAD (GWh)
Comparison of Historical Error Rates based on Sotkiewicz Approach

	Difference				% Difference		
Year	5 Years Out	4 Years Out	3 Years Out	Year	5 Years Out	4 Years Out	3 Years Out
2005				2005			
2006				2006			
2007				2007			
2008			1,750	2008			8.47%
2009		3,147	3,302	2009		15.78%	16.56%
2010	2,904	2,986	2,778	2010	14.05%	14.45%	13.44%
2011	4,744	4,437	4,014	2011	24.58%	22.99%	20.80%
2012	4,990	4,553	3,251	2012	25.83%	23.57%	16.83%
2013	5,228	3,792	2,107	2013	27.26%	19.77%	10.99%
2014	4,067	2,155	1,244	2014	21.06%	11.16%	6.44%
2015	1,624	661	253	2015	8.08%	3.29%	1.26%
2016	834	398	(382)	2016	4.13%	1.97%	-1.89%
AVERAGE	**3,484**	**2,766**	**2,035**	**AVERAGE**	**17.86%**	**14.12%**	**10.32%**

Year	Actual	TYSP2005	TYSP2006	TYSP2007	TYSP2008	TYSP2009	TYSP2010	TYSP2011	TYSP2012	TYSP2013
2005										
2006										
2007										
2008	20,650	22,400								
2009	19,943	23,090	23,245							
2010	20,667	23,571	23,653	23,445						
2011	19,298		24,042	23,735	23,312					
2012	19,320			24,310	23,873	22,571				
2013	19,177				24,405	22,969	21,284			
2014	19,315					23,382	21,470	20,559		
2015	20,105						21,729	20,766	20,358	
2016	20,173							21,007	20,571	19,791

Winter Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2015
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	(FORECAST - ACTUAL) 4 Years Out	(FORECAST - ACTUAL) 5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	(FORECAST - ACTUAL) / ACTUAL 4 Years Out	(FORECAST - ACTUAL) / ACTUAL 5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	79	457	348	1.87%	11.35%	8.24%
	2005 LFS	Dec.2004	2006 TYSP	581	266	-139	13.76%	5.61%	-2.75%
*	2005 LFS	Dec.2004	2007 TYSP	575	259	-146	13.62%	5.47%	-2.89%
	2007 LFS	Dec.2006	2008 TYSP	-388	552	1,161	-7.69%	12.79%	29.63%
	2008 LFS	Dec.2007	2009 TYSP	192	731	1,096	4.45%	18.66%	29.57%
	2009 LFS	Dec.2008	2010 TYSP	688	1,049	992	17.56%	28.30%	30.62%
	2010 LFS	Dec.2009	2011 TYSP	1,047	951	698	28.24%	29.35%	19.43%
	2011 LFS	Dec.2010	2012 TYSP	693	461	885	21.39%	12.83%	26.76%
	2012 LFS	Dec.2011	2013 TYSP	356	715	1,128	9.91%	21.62%	37.38%
	2013 LFS	Dec.2012	2014 TYSP	559	960	238	16.90%	31.81%	6.18%
	2014 LFS	Dec.2013	2015 TYSP	498	-265		16.50%	-6.88%	
	2015 LFS	Dec.2014	2016 TYSP	-314			-8.15%		
			AVERAGE	**381**	**558**	**626**	**10.70%**	**15.54%**	**18.22%**
			***AVERAGE (Excluding Duplicate)**	**363**	**588**	**712**	**10.43%**	**16.54%**	**20.56%**

bienually(RVN)

Note: Load Forecast Study Conducted ~~Bi-Annually~~ prior to 2008.
Source: Ten Year Site Plans 2005 through 2016.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 66
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: Kyle D. Wood KDW-4

Docket Nos. 20170266-EC and 20170267-EC
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Exhibit No. __ (KDW-4), Page 1 of 3

Summer Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	4 Years Out	5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	4 Years Out	5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	-172	-241	112	-4.74%	-6.28%	3.09%
	2005 LFS	Dec.2004	2006 TYSP	216	176	382	5.95%	4.60%	10.77%
*	2005 LFS	Dec.2004	2007 TYSP	211	171	377	5.81%	4.47%	10.63%
	2007 LFS	Dec.2006	2008 TYSP	314	378	769	8.85%	10.35%	22.43%
	2008 LFS	Dec.2007	2009 TYSP	293	645	704	8.02%	18.82%	19.74%
	2009 LFS	Dec.2008	2010 TYSP	590	582	549	17.21%	16.32%	17.78%
	2010 LFS	Dec.2009	2011 TYSP	463	412	557	12.98%	13.34%	18.44%
	2011 LFS	Dec.2010	2012 TYSP	164	329	218	5.31%	10.89%	6.72%
	2012 LFS	Dec.2011	2013 TYSP	254	69	288	8.41%	2.13%	9.25%
	2013 LFS	Dec.2012	2014 TYSP	-43	177		-1.33%	5.68%	
	2014 LFS	Dec.2013	2015 TYSP	-92			-2.95%		
			AVERAGE	**200**	**270**	**440**	**5.78%**	**8.03%**	**13.20%**
			***AVERAGE (Excluding Duplicate)**	**199**	**281**	**447**	**5.77%**	**8.43%**	**13.53%**

Note: Load Forecast Study Conducted ~~Bi-Annually~~ biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

Docket Nos. 20170266-EC and 20170267-EC
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Exhibit No. __ (KDW-4), Page 2 of 3

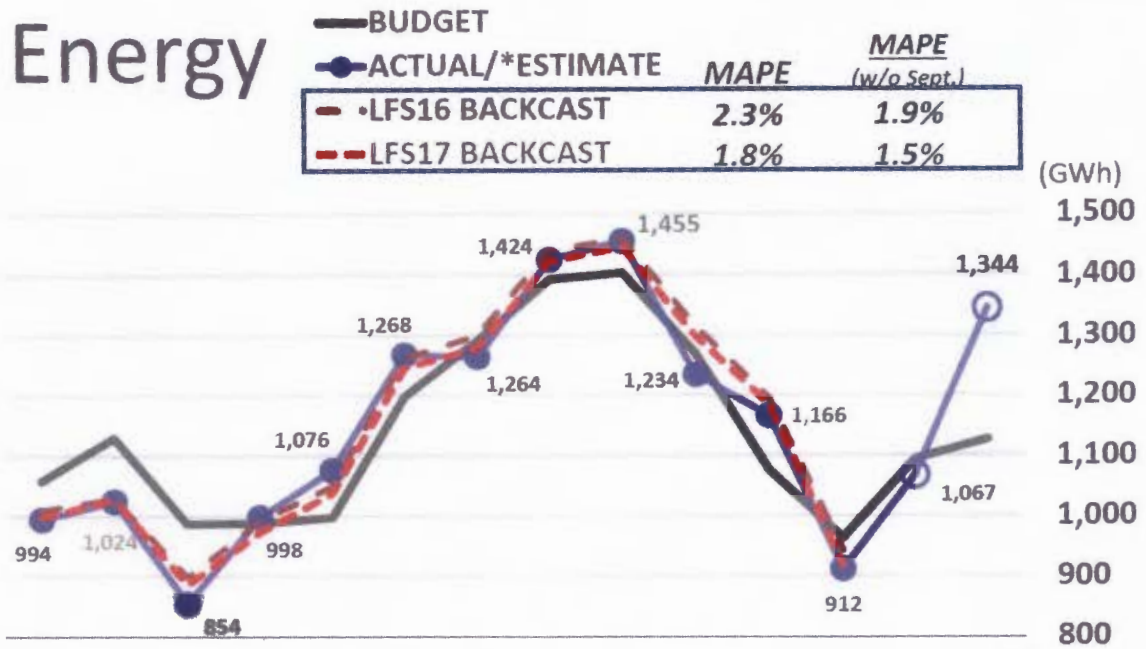
Net Energy for Load (GWh)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

			(FORECAST - ACTUAL)			(FORECAST - ACTUAL) / ACTUAL		
LFS	Forecast Origin	TYSP	*3 Years Out*	*4 Years Out*	*5 Years Out*	*3 Years Out*	*4 Years Out*	*5 Years Out*
2003 LFS	Dec.2002	2005 TYSP	-365	-97	1,028	-2.12%	-0.55%	5.93%
2005 LFS	Dec.2004	2006 TYSP	1,625	2,248	1,869	9.38%	12.88%	10.77%
* 2005 LFS	Dec.2004	2007 TYSP	1,584	2,205	1,824	9.14%	12.63%	10.52%
2007 LFS	Dec.2006	2008 TYSP	933	3,065	4,150	5.38%	19.11%	26.32%
2008 LFS	Dec.2007	2009 TYSP	1,945	2,787	3,528	12.13%	17.67%	22.31%
2009 LFS	Dec.2008	2010 TYSP	2,331	2,859	2,358	14.78%	18.08%	17.02%
2010 LFS	Dec.2009	2011 TYSP	2,678	1,974	2,108	16.94%	14.25%	14.95%
2011 LFS	Dec.2010	2012 TYSP	1,066	1,286	1,435	7.69%	9.12%	9.92%
2012 LFS	Dec.2011	2013 TYSP	952	963	1,557	6.75%	6.65%	10.87%
2013 LFS	Dec.2012	2014 TYSP	823	1,414		5.69%	9.87%	
2014 LFS	Dec.2013	2015 TYSP	-57			-0.40%		
		AVERAGE	**1,229**	**1,870**	**2,206**	**7.76%**	**11.97%**	**14.29%**
		AVERAGE *(Excluding Duplicate)	**1,193**	**1,833**	**2,254**	**7.62%**	**11.90%**	**14.76%**

Note: Load Forecast Study Conducted ~~Bi-Annually~~ biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

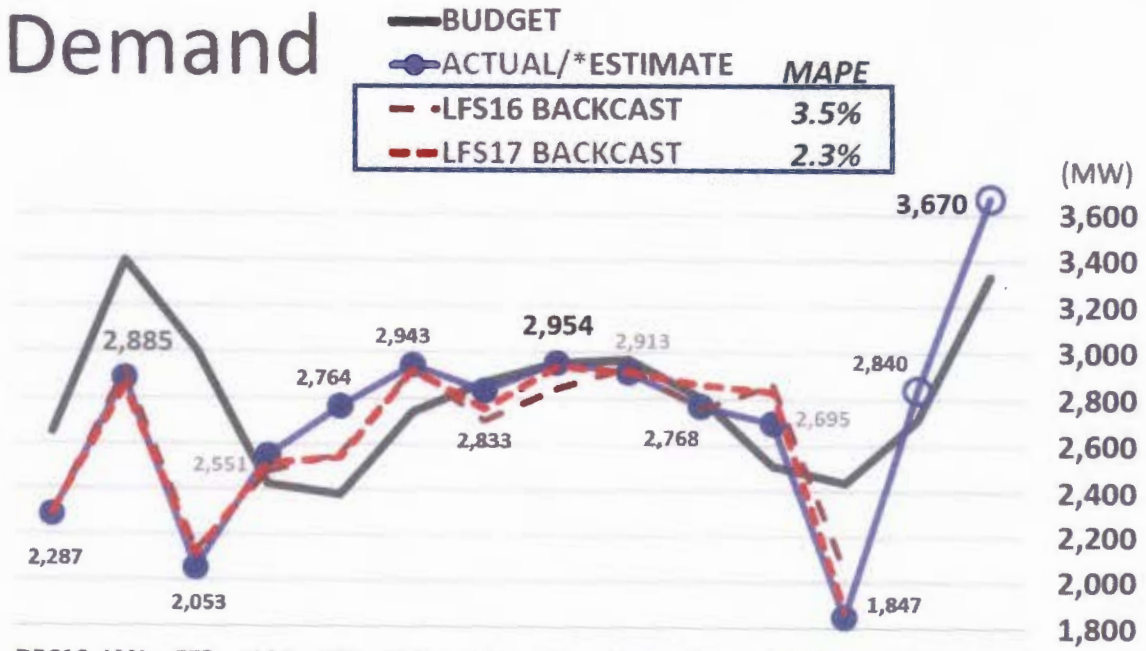
Docket Nos. 20170266-EC and 20170267-EC
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Exhibit No. ___ (KDW-4), Page 3 of 3

Energy



	DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*
LFS16 Backcast	-1.5%	-0.5%	-5.1%	0.6%	2.5%	0.4%	-2.9%	-1.0%	-0.3%	-6.6%	-2.5%	-3.4%	
LFS17 Backcast	-0.3%	-0.4%	-3.7%	2.5%	3.5%	1.7%	-1.2%	0.2%	0.7%	-5.2%	-1.6%	-0.6%	

Demand



	DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*
LFS16 Backcast	-0.1%	-1.2%	-3.7%	2.9%	7.5%	0.6%	4.5%	3.7%	-0.7%	0.5%	-6.1%	-10.9%	
LFS17 Backcast	-0.1%	1.3%	-2.8%	1.4%	8.1%	0.8%	2.8%	0.5%	0.0%	-3.4%	-5.0%	-1.5%	

2018 RUN

*December 2017 and January 201~~7~~ are Estimated-Actual

Note: **In Sample Fit** through February 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 67
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: Kyle D. Wood KDW-5

Tao Hong
Curriculum Vitae
February 2018

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URL:	www.drhongtao.com | www.honganalytics.com

Appointments

Current Appointments

2017-	Associate Professor (with tenure), Systems Engineering and Engineering Management Department, University of North Carolina at Charlotte, Charlotte, NC
2014-	Owner and Chief Data Scientist, Hong Analytics, Charlotte, NC

Previous Appointments

2013-2017	Assistant Professor and Graduate Program Director, Systems Engineering and Engineering Management Department, University of North Carolina at Charlotte, Charlotte, NC
2013-2013	Senior Industry Consultant, US Energy Business Unit, SAS Institute Inc., Cary, NC
2012-2013	Industry Consultant, US Utilities Business Unit, SAS Institute Inc., Cary, NC
2011-2012	Analytical Consultant, US Retail Professional Services, SAS Institute Inc., Cary, NC
2010-2011	Principal Engineer, Quanta Technology, Raleigh, NC
2009-2010	Senior Engineer, Quanta Technology, Raleigh, NC
2008-2009	Intern/Engineer, Quanta Technology, Raleigh, NC

Education

2010	Ph.D., Operations Research and Electrical Engineering, North Carolina State University
2008	M.S., Operations Research and Industrial Engineering, North Carolina State University
2008	M.S., Electrical Engineering, North Carolina State University
2005	B.Eng., Automation, Tsinghua University, Beijing, China

Awards and Honors

2017	Charlotte Business Journal Energy Education Leader of the Year
2016	IEEE Power & Energy Society Technical Committee Prize Paper Award
2015	IEEE Power & Energy Society Technical Committee Working Group Recognition Award
2015	Global Energy Forecasting Competition 2014 Institute Prize
2014	IEEE Power & Energy Society Technical Council Distinguished Service Award

Teaching

Courses at UNC Charlotte

1. SEGR4961/EMGT5961 Introduction to Energy Systems
2. SEGR4963/EMGT5963 Energy Systems Planning
3. SEGR4964/EMGT5964 Case Studies in the Energy Industry
4. EMGT6910 Technological Forecasting and Decision Making
5. EMGT6965 Energy Analytics
6. EMGT6980 Engineering Management Project

Courses at Hong Analytics

1. T101 Fundamentals of Utility Analytics: Techniques, Applications and Case Studies
2. T201 Introduction to Energy Forecasting
3. T302 Long Term Load Forecasting
4. T303 Power Distribution Outage Analytics
5. T401 Electric Load Forecasting II: Advanced Topics and Case Studies

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Publications

Scholarly Journal Papers

1. Yi Wang, Qixin Chen, Tao Hong, and Chongqing Kang, "Review of smart meter data analytics: applications, methodologies, and challenges," IEEE Transactions on Smart Grid, in press.
2. Jingrui Xie and Tao Hong, "Variable selection methods for probabilistic load forecasting: empirical evidence from seven states of the United States," IEEE Transactions on Smart Grid, in press, available online.
3. Jingrui Xie and Tao Hong, "Temperature scenario generation for probabilistic load forecasting," IEEE Transactions on Smart Grid, in press, available online.
4. Jingrui Xie and Tao Hong, "Load forecasting using 24 solar terms," Journal of Modern Power Systems and Clean Energy, in press, available online.
5. Jian Luo, Tao Hong and Meng Yue, "Real-time anomaly detection for very short-term load forecasting," Journal of Modern Power Systems and Clean Energy, in press, available online.
6. Jian Luo, Tao Hong and Shu-Cherng Fang, "Benchmarking robustness of load forecasting models under data integrity attacks," International Journal of Forecasting, vol.34, no.1. pp 89-104, January-March 2018
7. Qiaochu He and Tao Hong, "Integrated facility location and production scheduling in multi-generation energy systems," Operations Research Letters, vol.46, no.1, pp 153-157, January 2018.
8. Jingrui Xie, Ying Chen, Tao Hong and Thomas D. Laing, "Relative humidity for load forecasting models," IEEE Transactions on Smart Grid, vol.9, no.1, pp 191-198, January 2018.
9. Jingrui Xie and Tao Hong, "Wind speed for load forecasting models", Sustainability, vol 9, no 5, pp 795, May, 2017
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11. Bidong Liu, Jakub Nowotarski, Tao Hong and Rafal Weron, "Probabilistic load forecasting via quantile regression averaging on sister forecasts", IEEE Transactions on Smart Grid, vol.8, no.2, pp 730-737, March, 2017.
12. Jingrui Xie and Tao Hong, "GEFCom2014 probabilistic electric load forecasting: an integrated solution with forecast combination and residual simulation", International Journal of Forecasting, vol.32, no.3, pp 1012-1016, July-September, 2016.
13. Tao Hong and Shu Fan, "Probabilistic electric load forecasting: a tutorial review", International Journal of Forecasting, vol.32, no.3, pp 914-938, July-September, 2016.
14. Tao Hong, Pierre Pinson, Shu Fan, Hamidreza Zareipour, Alberto Troccoli and Rob J. Hyndman, "Probabilistic energy forecasting: Global Energy Forecasting Competition 2014 and beyond", International Journal of Forecasting, vol.32, no.3, pp 896-913, July-September, 2016.
15. Pu Wang, Bidong Liu and Tao Hong, "Electric load forecasting with recency effect: a big data approach", International Journal of Forecasting, vol.32, no.3, pp 585-597, July-September, 2016.
16. Jakub Nowotarski, Bidong Liu, Rafal Weron and Tao Hong, "Improving short term load forecast accuracy via combining sister forecasts", Energy, vol.98, pp 40-49, March 1, 2016.
17. Jingrui Xie, Tao Hong and Joshua Stroud, "Long term retail energy forecasting with consideration of residential customer attrition", IEEE Transactions on Smart Grid, vol.6, no.5, pp. 2245-2252, September, 2015.
18. Tao Hong, Pu Wang and Laura White, "Weather station selection for electric load forecasting", International Journal of Forecasting, vol.31, no.2, pp 286-295, April-June, 2015.
19. Tao Hong, Pierre Pinson and Shu Fan, "Global energy forecasting competition 2012", International Journal of Forecasting, vol.30, no.2, pp 357-363, April-June, 2014.
20. Tao Hong and Pu Wang, "Fuzzy interaction regression for short term load forecasting", Fuzzy Optimization and Decision Making, vol.13, no.1, pp. 91-103, March, 2014.
21. Tao Hong, Jason Wilson and Jingrui Xie, "Long term probabilistic load forecasting and normalization with hourly information", IEEE Transactions on Smart Grid, vol.5, no.1, pp.456-462, January, 2014.

Journal Editorials

1. Tao Hong, Chen Chen, Jianwei Huang, Ning Lu, Le Xie and Hamidreza Zareipour, "Guest Editorial: big data analytics for grid modernization", IEEE Transactions on Smart Grid, vol.7, no.5, pp 2395-2396, September, 2016.

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Trade Journal and Magazine Papers

1. Jonathan Black, Alex Hofmann, Tao Hong, Joseph Roberts, and Pu Wang, "Weather data for energy analytics: from modeling outages and reliability indices to simulating distributed photovoltaic fleets," accepted by Power and Energy Magazine.
2. Tao Hong, David Gao, Tom Laing, Dale Kruchten, and Jorge Calzada, "Producing energy data scientists," accepted by Power and Energy Magazine.
3. Tao Hong, "Big data analytics: making smart grid smarter" accepted by Power and Energy Magazine.
4. Jingrui Xie and Tao Hong, "Improving gas load forecasts with big data", Natural Gas & Electricity, vol.32, no.10, pp 25-30, May, 2016.
5. Tao Hong, "Crystal ball lessons in predictive analytics", EnergyBiz, pp. 35-37, Spring, 2015
6. Tao Hong, "Integrated energy forecasting: improving T&D planning and operations." Electricity Today, pp. 58-62, January/February, 2015
7. Tao Hong, "How to juggle the analytics of forecasting: 13 lucky tips", Intelligent Utility, pp. 11-13, July/August, 2014
8. Tao Hong, "Energy forecasting: past, present and future", Foresight: The International Journal of Applied Forecasting, issue 32, pp. 43-48, Winter 2014.
9. Tao Hong and Alyssa Farrell, "Utilities dust off the forecasting playbook: smart grid data brings challenges and opportunities", Analytics Magazine, pp.50-57, July/August, 2013

Thesis & Dissertation

1. Tao Hong, "Short Term Electric Load Forecasting". PhD dissertation, North Carolina State University, Sep 10th, 2010
2. Tao Hong, "Long-Term Spatial Load Forecasting Using Human Machine Co-construct Intelligence Framework". Master thesis, North Carolina State University, Oct 28th, 2008

White Papers

1. Tao Hong and Mohammad Shahidehpour, "Load forecasting case study", National Association of Regulatory Utility Commissioners, pp.1-171, 2015.
2. Sen-Hao Lai and Tao Hong, "When one size no longer fits all: electric load forecasting with a geographic hierarchy", SAS White Paper, pp.1-14, 2013

Conference Proceedings

1. Antonio Bracale, Guido Carpinelli, Pasquale De Falco and Tao Hong, "Short-term industrial load forecasting: a case study in an Italian factory," 2017 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Torino, Italy, September 26-29, 2017
2. Jingrui Xie and Tao Hong, "Comparing two model selection frameworks for probabilistic load forecasting", 2016 International Conference on Probabilistic Methods Applied to Power Systems, Beijing, China, October 16-20, 2016
3. Jingrui Xie; Tao Hong and Chongqing Kang "From high-resolution data to high-resolution probabilistic load forecasts", 2016 IEEE PES Transmission and Distribution Conference and Exposition, Dallas, TX, May 2-5, 2016
4. Jingrui Xie, Bidong Liu, Xiaoqian Lyu, Tao Hong, and David Basterfield, "Combining load forecasts from independent experts: experience at NPower forecasting challenge 2015", the 47th North American Power Symposium (NAPS2015), Charlotte, NC, October 4 - 6, 2015
5. Tao Hong, Tom Laing and Pu Wang, "Four best practices of load forecasting for electric cooperatives", 2014 IEEE Rural Electric Power Conference, Fort Worth, Texas, May 18 - 21, 2014
6. Tao Hong and Pu Wang, "On the impact of demand response: load shedding, energy conservation, and further implications to load forecasting", 2012 IEEE PES General Meeting, San Diego, CA, July 19-22, 2012
7. Tao Hong; Pu Wang, and H. Lee Willis, "A naive multiple linear regression benchmark for short term load forecasting," 2011 IEEE PES General Meeting, Detroit, MI, July 24-29, 2011

8. Tao Hong; Min Gui; Mesut E. Baran; H. Lee Willis , "Modeling and forecasting hourly electric load by multiple linear regression with interactions," Power and Energy Society General Meeting, 2010 IEEE , vol., no., pp.1-8, July 25-29, 2010
9. Tao Hong; Pu Wang; Anil Pahwa; Min Gui; Simon M. Hsiang, "Cost of temperature history data uncertainties in short term electric load forecasting," Probabilistic Methods Applied to Power Systems (PMAPS), 2010 IEEE 11th International Conference on , vol., no., pp.212-217, June 14-17, 2010
10. Tao Hong; James J Burke, "Calculating line losses in smart grid: A new rule of thumb," 2010 IEEE PES Transmission and Distribution Conference and Exposition, April 19-22, 2010
11. Tao Hong; Hsiang, S.M.; Le Xu; , "Human-machine co-construct intelligence on horizon year load in long term spatial load forecasting," IEEE Power & Energy Society General Meeting, July 26-30, 2009
12. Tao Hong and Mo-Yuen Chow, "Resource allocation for a life science automation line: a Petri nets approach". Proceedings of CASE07, the 3rd Annual IEEE Conference on Automation Science and Engineering, pp 255-260, Scottsdale, AZ, USA, September 22-25, 2007
13. Tao Hong, Mo-Yuen Chow, Perry Haaland, Dylan Wilson and Robert Walker "Scheduling a life science high-throughput platform under starvation constraints using timed transition Petri nets and heuristic search". Proceedings of ISIE07, 2007 IEEE International Symposium on Industrial Electronics, Vigo, Spain, June 4-7, 2007
14. Tao Hong and Mo-Yuen Chow, "Timed Petri nets modelling of high-throughput screening process for fault study", Proceedings of IECON06, The 32nd Annual Conference of the IEEE Industrial Electronics Society, pp 4425-4430, Paris, France, November 7-10, 2006
15. Yunfei Wang, Geng Yang and Tao Hong, "Analysis and implementation of AC motor braking method without energy returning or braking unit", The 8th International Conference on Electrical Machines and Systems (ICEMS 2005), Volume II, pp 1447-1451, Nanjing, China, September 27-29, 2005.

Talks

Keynotes

1. "Sharing in Power & Energy Grids," 2017 Workshop on Network Economy and Big Data, Beijing, China, December 17, 2017.
2. "Probabilistic Load Forecasting: Past, Present and Future", The 2nd International Conference on Forecasting Economic and Financial Systems, Beijing, China, October 30 - November 1, 2015
3. "Big Data Analytics for Grid Modernization", 2014 Electric System Brazilian Symposium (SBSE2014), Paraná, Brazil, April 22-25, 2014

Tutorials

1. "Energy Forecasting in the Smart Grid Era", Tutorial at 2016 IEEE PES General Meeting, Boston, MA, July 17-21, 2016 (with Hamidreza Zareipour and Pierre Pinson)
2. "Energy Forecasting in the Smart Grid Era", Tutorial at 2015 IEEE PES General Meeting, Denver, CO, July 26-30, 2015 (with Shu Fan and Hamidreza Zareipour)
3. "Energy Forecasting in the Smart Grid Era", Tutorial at 2014 IEEE PES General Meeting, National Harbor, MD, July 27-31, 2014 (with Hamidreza Zareipour)
4. "100 Years of Load Forecasting: Classics, Challenges, and Best Practices with Smart Grid Information", 2014 Electric System Brazilian Symposium (SBSE2014), Paraná, Brazil, April 22-25, 2014
5. "Energy Forecasting in the Smart Grid Era", Tutorial at 2013 IEEE PES General Meeting, Vancouver, BC, Canada, July 21-25, 2013 (with Shu Fan, Hamidreza Zareipour and Pierre Pinson)
6. "100 Years of Load Forecasting: Classics, Challenges, and Best Practices with Smart Grid Information", Pre-conference Workshop at Western Load Research Association Conference, Long Beach, CA, Oct 9, 2012

Conference Presentations

1. "Lessons Learned from the Open Data Track of Global Energy Forecasting Competition 2017", 2017 IEEE PES General Meeting, Chicago, IL, July 16 - 20, 2017
2. "Research Trends in Load Forecasting and Their Implications to Energy Trading", 2017 IEEE PES General Meeting, Chicago, IL, July 16 - 20, 2017

3. "Forecasting Load of New England Using 24 Solar Terms of China", 2017 International Symposium on Energy Analytics, Cairns, Australia, June 22 - 23, 2017
4. "Load Forecasting with Big Models: the Surprising Accuracy Improvement from Big Computers", 2016 AEIC Load Research Conference and WLRA Fall Conference, Chicago, IL, September 18 - 21, 2016
5. "Energy Forecasting: Past, Present and Future", Southwest Forecasting & Customer Analytics Forum, Tucson, AZ, September 15 - 16, 2016
6. "What's New in Load Forecasting since 2010?", 2016 IEEE PES General Meeting, Boston, MA, July 17 - 21, 2016
7. "What's New in Load Forecasting since 2010?", 36th International Symposium on Forecasting, Santander, Spain, June 19 - 22, 2016
8. "Lessons Learned from Organizing Energy Forecasting Competitions", ARPA-E GRID DATA Kick-off Meeting, Denver, CO, March 30 - 31, 2016
9. "Analytics, Smart Grid and Big Data: Are They Like Teenage Sex?", 2015 CAPER Summer Research Planning Workshop, Boone, NC, August 27 - 28, 2015
10. "Weather Station Selection for Load Forecasting", 2015 AEIC Load Research Conference and WLRA Fall Conference, Chicago, IL, August 23 - 26, 2015
11. "GEFCom2014 Institute Prize - University of North Carolina at Charlotte", 2015 IEEE PES General Meeting, Denver, Colorado, July 26-30, 2015
12. "How does Relative Humidity Affect Electricity Demand?", 3rd International Conference on Energy & Meteorology, Boulder, Colorado, June 22 - 26, 2015
13. "Electricity Demand Interval Forecasting With Quantile Regression Averaging", 35th International Symposium on Forecasting, Riverside, California, June 21 - 24, 2015
14. "The Myths Of Residual Simulation For Probabilistic Load Forecasting", 35th International Symposium on Forecasting, Riverside, California, June 21 - 24, 2015
15. "Combining Sister Load Forecasts", 35th International Symposium on Forecasting, Riverside, California, June 21 - 24, 2015
16. "Load Forecasting with Energy Efficiency: Challenges and Fundamentals", 2015 OPSI Spring Meeting, Phoenixville, PA, April 13, 2015
17. "A Crowdsourcing Approach to Energy Forecasting", 2014 Great Lakes Symposium on Smart Grid and the New Energy Economy, Chicago, IL, September 22-25, 2014
18. "The Art and Science of Reconciliation in Long Term Load Forecasting", 2014 AEIC Load Research Conference and WLRA Fall Conference, Chicago, IL, September 21-24, 2014
19. "Combining Load Forecasts from Multiple Vendors", 2014 IEEE PES General Meeting, National Harbor, MD, July 27-31, 2014
20. "Energy Forecasting Competition: Past, Present and Future", 34th International Symposium on Forecasting, Rotterdam, The Netherlands, June 29 - July 2, 2014
21. "Understanding Electricity Consumer Behavior through Smart Meter Data", NSF Workshop on Understanding Human Behaviors for Sustainable Building Ecosystems, Charlotte, NC, May 27, 2014
22. "Four Best Practices of Load Forecasting for Electric Coorperatives", 2014 IEEE Rural Electric Power Conference, Fort Worth, TX, May 18 - 21, 2014
23. "Integrating Energy Forecasts into Utility Planning and Operations: Perspectives from Market Participants", 2014 IEEE PES T&D Conference & Exposition, Chicago, IL, April 14-17, 2014
24. "Forecasting in the Smart Grid Era", Utility Analytics Summit, Raleigh-Durham, NC, April 9-11, 2014
25. "Modernization of Electric Load Forecasting", Eastern Interconnection States' Planning Council Meeting: Approaches to Load Forecasting, Naples, FL, March 13-14, 2014
26. "Driving the Value of Smart Grid Data through Predictive Analytics", The 5th Innovative Smart Grid Technologies Conference, Washington DC, February 19-22, 2014
27. "Load Forecasting in the Smart Grid Era", 2013 Technology Conference, Myrtle Beach, SC, August 7-9, 2013 (with Jason Wilson, download presentation slides)
28. "Opportunities and Challenges of Energy Forecasting in the Smart Grid Era", 2013 IEEE PES General Meeting, Vancouver, BC, Canada, July 21-25, 2013
29. "Global Energy Forecasting Competition: An Introduction", 2013 IEEE PES General Meeting, Vancouver, BC, Canada, July 21-25, 2013
30. "Three Myths about Weather Normalization", AEIC Load Research Conference, Alexandria, VA, July 7-10, 2013

31. "Modernization of Long Term Load Forecasting: An Integrated Approach Taking Advantage of Hourly Load and Weather Information", Electric Utility Forecasters Forum, Orlando, FL, November 8, 2012
32. "When Predictive Analytics Meets Smart Grid: Electric Load Forecasting with Geographic Hierarchy", 2012 SAS Analytics Conference, Las Vegas, NV, October 8-9, 2012 (with Sen-hao Lai)
33. "Modernization of Long Term Load Forecasting: An Integrated Approach Taking Advantage of Hourly Load and Weather Information", AEIC Load Research Conference, July 9, Alexandria, VA, 2012
34. "Electric Load Forecasting with Holiday Effect", AEIC 2012 Load Research Workshop, Orlando, FL, March 18, 2012
35. "On the Holiday Effect of Electricity Demand", 2011 SAS Analytics Conference, October 24-25, Orlando, FL, 2011
36. "Rethinking Short Term Electric Load Forecasting: Experience at US Utilities," 2011 INFORMS Conference on Business Analytics and Operations Research, Chicago, IL, April 10-12, 2011
37. "Behavior Mining of Electric Load Consumption: A Regression Approach", SAS' 12th Annual Data Mining Conference, M2009, Las Vegas, NV, October 26-27, 2009
38. "Electric Load Forecasting: Two Perspectives", INFORMS Annual Meeting, San Diego, CA, October 11-14, 2009

Services

Editorial Services

2017-	Associate Editor, Journal of Modern Power and Clean Energy
2016-	Editor, Book Series on Energy Analytics, CRC Press
2016-	Associate Editor, International Journal of Forecasting
2016-	Editorial Board Member, Power & Energy Magazine
2015-	Associate Editor, International Journal of Energy Technology and Policy
2013-	Editor, IEEE Transactions on Smart Grid
2014-2016	Guest Editor-in-Chief, Special Section on Big Data Analytics for Grid Modernizations, IEEE Transactions on Smart Grid
2014-2016	Guest Editor, Special Section on Probabilistic Energy Forecasting, International Journal of Forecasting
2012-2014	Guest Editor, Special Section on Energy Forecasting, International Journal of Forecasting
2012-2014	Guest Editor-in-Chief, Special Section on Analytics for Energy Forecasting with Applications to Smart Grid, IEEE Transactions on Smart Grid

Professional Organization Services

2011-	Chair, IEEE Working Group on Energy Forecasting
2012-	General Chair, Global Energy Forecasting Competition
2011-2016	Member, IEEE Power Systems Planning and Implementation Committee

Conference Chair

2017	International Symposium on Energy Analytics (ISEA2017)

Session Chair

2017	"Accommodating Intermittent Renewable Energy by Multiple Energy Systems Integration: Forecasting, Operations and Planning", PESGM2017
2017	"Featured Session - Renewable Energy Forecasting: Nonlinearity, Dimensionality and Sharing Aspects", ISF2017
2016	"Load Forecasting: Research Progress and Challenges", ISF2016
2016	"Energy Forecasting 3". ISF2016
2015	"Global Energy Forecasting Competition 2014: An Overview", PESGM 2015
2015	"Global Energy Forecasting Competition 2014: Finalist Presentations", PESGM 2015
2015	"Frontiers in Electricity Demand Forecasting I: The State of The Practice", ISF 2015
2015	"Frontiers in Electricity Demand Forecasting II: Probabilistic Electric Load Forecasting", ISF 2015
2014	"Load Forecasting: the State of the Practice", PESGM 2014
2014	"Electricity Demand II", ISF 2014

2014	"Integrating Energy Forecasts into Utility Planning and Operations: Perspectives from Market Operators", T&D 2014
2014	"Integrating Energy Forecasts into Utility Planning and Operations: Perspectives from Market Participants", T&D 2014
2013	"Energy Forecasting: the State of the Art", PESGM 2013
2013	"Global Energy Forecasting Competition Final Presentations", PESGM 2013
2012	"Demand Response: Analytics, Practice, and Challenges in Smart Grid Environment", PESGM 2012
2012	"Load Forecasting Methodologies and Applications in Operations and Planning", PESGM 2012
2011	"Practical Aspects of Electric Load Forecasting", PESGM 2011
2009	"Forecasting", INFORMS 2009

Technical Program Committee Member

2013-	International Conference Energy & Meteorology 2015, 2017 & 2018
2010-	IEEE Power & Energy Society General Meeting
2010-	IEEE T&D Conference and Expositions
2015	2nd International Conference on Forecasting Economic and Financial Systems (FEFS2015)
2015	Modern Electric Power Systems conference 2015 (MEPS'15)
2014	33rd IEEE. International Performance Computing and Communications Conference (IPCCC2014)
2014	IEEE International Conference on Internet of Things (iThings2014)
2014	IEEE Innovative Smart Grid Technologies Conference 2014 (ISGT2014)

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"Long Term Probabiliste Load Forecasting and Nornalization With Hourly Information"
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Long Term Probabilistic Load Forecasting and Normalization With Hourly Information

Tao Hong, Jason Wilson, *Member, IEEE*, and Jingrui Xie, *Associate Member, IEEE*

***Abstract*—The classical approach to long term load forecasting is often limited to the use of load and weather information occurring with monthly or annual frequency. This low resolution, infrequent data can sometimes lead to inaccurate forecasts. Load forecasters often have a hard time explaining the errors based on the limited information available through the low resolution data. The increasing usage of smart grid and advanced metering infrastructure (AMI) technologies provides the utility load forecasters with high resolution, layered information to improve the load forecasting process. In this paper, we propose a modern approach that takes advantage of hourly information to create more accurate and defensible forecasts. The proposed approach has been deployed across many U.S. utilities, including a recent implementation at North Carolina Electric Membership Corporation (NCEMC), which is used as the case study in this paper. Three key elements of long term load forecasting are being modernized: predictive modeling, scenario analysis, and weather normalization. We first show the superior accuracy of the predictive models attained from hourly data, over the classical methods of forecasting using monthly or annual peak data. We then develop probabilistic forecasts through cross scenario analysis. Finally, we illustrate the concept of load normalization and normalize the load using the proposed hourly models.**

***Index Terms*—Load forecasting, load normalization, multiple linear regression models, weather normalization.**

I. Nomenclature

GSP:	Gross state product.
CDD:	Cooling degree days.
HDD:	Heating degree days.
Trend:	A linear trend variable.
$T_{\max}$:	Monthly peak temperature.
T_t:	Current hour temperature.
T_{t-k}:	Temperature of the previous kth hour.
T_a:	Average temperature of the past 24 hours.
Month:	Class variable, 12 months of the year.
Weekday:	Class variable, 7 days of a week.
Hour:	Class variable, 24 hours of a day.
Day:	Class variable, code for days of a year.

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Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

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II. Introduction

LONG TERM LOAD forecasting (LTLF) provides peak demand and energy forecasts for one or more years, and can be expanded out to a horizon of a few decades. Utilities typically produce long term forecasts ranging from 20 to 50 years into the future. Such forecasts are often being used for planning by multiple departments in a utility, such as system planning, finance, demand side management, and power supply, etc. North Carolina Electric Membership Corporation (NCEMC), is one of the largest electric generation cooperatives in the U.S., and is comprised of a family of corporations formed to support 26 of North Carolina's electric distribution cooperatives. These cooperatives provide energy and related services to more than 950 000 households and businesses in 93 of North Carolina's 100 counties. At NCEMC, long term load forecasts serve as the important inputs to the power supply group to support decisions on electricity purchase contracts. Because NCEMC owns generation units, it is required to file Integrated Resource Planning (IRP) documents with the North Carolina Public Utilities Commission, thus expanding the scrutiny from the member cooperatives and NCEMC board, to the state regulatory commission.

In the regulatory environment, utility forecasters have to defend the long term forecasts internally to the utility's management and externally to the regulatory commission. Although forecasting by nature is a stochastic problem, most utilities today are still developing and using point forecasts instead of probabilistic forecasts. Due to the poor predictability of the climate, which is a main driver of electricity demand, it is unrealistic and unfair to judge a long term forecaster by comparing a few years of point forecasts with the corresponding actual values. Instead, there are two important questions that should be asked and answered properly when defending the long term forecasts: 1) *is the current scenario covered by the forecasts?* 2) *how accurate is the forecast given the current scenario?*

Most utilities today follow the LTLF practices similar to the ones established a few decades ago, when there was not high resolution data available. Since the type of low resolution data used in the traditional approach provides a limited number of observations for predictive modeling, the forecasters may not be able to use enough explanatory variables to capture all the salient features of electric load. When given the actual values of the weather and economy variables to re-forecast the loads under the current scenario, the model may still produce some significant errors, which can be hard to explain by the forecasters.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 69
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: Tao Hong, Ph.D TAO-2

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There are a few ways to create weather scenarios for LTLF and weather normalization. A lot of utilities are using the average temperature profile (in hourly or daily interval for a year) from the previous few decades as the normal weather to derive the normal load, which is not a defensible approach: 1) an average temperature profile understates the peaks, so it can not accurately represent the normal weather; 2) a normal weather profile may not lead to a normal load profile due to the nonlinear relationship between the load and weather [1]. Another popular approach is to use normal or typical weather profiles created by third parties, such as National Oceanic and Atmospheric Administration (NOAA) and the U.S. Department of Energy (DOE). An advantage of this third-party profile approach is its simplicity. However, these weather profiles are not created specifically for utilities to calculate normalized load. Therefore, it is questionable that their best use is for normalizing the load profile in the utility industry. A more rigorous approach is based on Monte Carlo simulation, which is often adopted by the risk management teams in the utility industry. The quantitative risk analysts first analyze the distribution of temperatures on each hour of the year. They then create thousands of temperature profiles for scenario analysis. This simulation approach requires a lot of computational resources. The results, including thousands of load profiles, are sometimes too voluminous and become difficult to understand and be used by the system operators in practice.

Most literature in the load forecasting field has been devoted to short term load forecasting, of which the forecasting horizon is two weeks or less [1]–[7]. Not many papers have been devoted to LTLF, of which few papers present practical approaches verified through field implementations at utilities. An implementation of spatial load forecasting work at Madison Gas and Electric Company has been presented in [8]–[10]. A peak load forecasting methodology implemented at Australian Energy Market Operator (AEMO) has been reported in [11]. In this paper, we propose a probabilistic forecasting approach with hourly data, which is the continuation of Hong's load forecasting methodology presented in [1]. We dissect LTLF to three elements: predictive modeling, scenario analysis, and weather normalization. We then modernize each step with multiple linear regression (MLR) models and hourly data. The proposed approach has been deployed to many large and medium size utilities including NCEMC. The data required in the NCEMC case study includes hourly system load data at corporate level, which is available through NCEMC's Energy Management System, hourly weather data purchased from WeatherBank and annual economy data purchased from Moody's. Execution of the proposed approach on NCEMC data in automated mode can be finished within a day on a commodity server with an 8-core CPU and 32G RAM. This is well-acceptable for a once-per-year long term load forecasting task. In comparison with Fan's approach, which originated from a field implementation at an ISO, the approach proposed in this paper is more applicable to utilities operating within a regulatory environment, due to its relative simplicity and strong defensibility. The scope of this paper does not include forecasting under renewable penetration and demand response activities.

TABLE I
MAIN AND CROSS EFFECTS OF THE STARTING MODELS

Model	Main Effects	Cross Effects
C1	*GSP*, *CDD*, *HDD*, *Month*	N/A
C2	*GSP*, $T_{\max}$, $T_{\max}^2$, $T_{\max}^3$, *Month*	N/A
B	*Trend*, T_t, T_t^2, T_t^3, *Month*, *Weekday*, *Hour*	T_t **Month*, T_t^2 **Month*, T_t^3 **Month*, T_t **Hour*, T_t^2 **Hour*, T_t^3 **Hour*, *Weekday*Hour*
S_{2010}	*Trend*, T_t, T_t^2, T_t^3, T_{t-1}, T_{t-1}^2, T_{t-1}^3, T_{t-2}, T_{t-2}^2, T_{t-2}^3, T_{t-3}, T_{t-3}^2, T_{t-3}^3, T_a, T_a^2, T_a^3, *Month*, *Day*, *Hour*	T_t **Month*, T_t^2 **Month*, T_t^3 **Month*, T_t **Hour*, T_t^2 **Hour*, T_t^3 **Hour*, T_{t-1} **Month*, T_{t-1}^2 **Month*, T_{t-1}^3 **Month*, T_{t-1} **Hour*, T_{t-1}^2 **Hour*, T_{t-1}^3 **Hour*, T_{t-2} **Month*, T_{t-2}^2 **Month*, T_{t-2}^3 **Month*, T_{t-2} **Hour*, T_{t-2}^2 **Hour*, T_{t-2}^3 **Hour*, T_{t-3} **Month*, T_{t-3}^2 **Month*, T_{t-3}^3 **Month*, T_{t-3} **Hour*, T_{t-3}^2 **Hour*, T_{t-3}^3 **Hour*, T_a **Month*, T_a^2 **Month*, T_a^3 **Month*, T_a **Hour*, T_a^2 **Hour*, T_a^3 **Hour*, *Day*Hour*,

The rest of the paper is organized as follows: Section III reviews the fundamentals, including the models we start with; Section IV discusses the model selection approach and determines the length of historical data used in long term forecasting; Section V presents the long term probabilistic forecasts with cross weather and economy scenarios; Section VI introduces the methodology for load normalization; the paper is concluded in Section VI with discussions of potential future work.

III. FUNDAMENTALS

A. Multiple Linear Regression

Multiple linear regression analysis has been widely used in the forecasting fields, including load forecasting. Detailed coverage on the theory of regression analysis and linear models is provided in [13]. Implementation of MLR in SAS is presented in [14]. A comprehensive guideline about how to apply MLR models to short term load forecasting is discussed in [1].

In this case study, we start with several MLR models: a classical model for monthly energy forecasting denoted as $C1$, a classical model for monthly peak forecasting denoted as $C2$, Tao's vanilla benchmark denoted as B, and a group of customized short term load forecasting models denoted as S. The models in S are derived using Hong's methodology documented in [1], where by default, 3 years of data are used for parameter estimation and the year after is used for variable selection. When using year 2010 for variable selection, we denote the resulting variable combination as S_{2010}. All of these starting models have the dependent variable *Load* and an intercept term. The main effects and cross effects are described in Table I, where each class variables consists of several 0–1 indicator variables. S_{2010} is used as an example of S models.

TABLE II
MODIFICATIONS TO THE DAYS OF A YEAR FOR MODEL S_{2010}

Days of a Year (Original)	Day Code (Modified)
Wednesday (regular)	Tuesday
Day Before New Year's Day	Saturday
New Year's Day	Friday → Saturday; else → Sunday
Memorial Day	Saturday
Day After Memorial Day	Monday
Day Before Independence Day	Friday
Independence Day	Friday → Saturday; else → Sunday
Day Before Labor Day	Saturday
Labor Day	Saturday
Day After Labor Day	Thursday
Day Before Thanksgiving Day	Monday
Thanksgiving Day	Saturday
Day After Thanksgiving Day	Saturday
Day Before Christmas Day	Saturday
Christmas Day	Friday → Saturday; else → Sunday
Day After Christmas Day	Saturday

The *Day* variable is derived from the *Weekday* variable using rules described in Table II. We first group Tuesday and Wednesday together labeled as Tuesday. We then model some holidays and the surrounding days using weekdays and weekends [1]. For example, take New Year's Day: it is a fixed-date holiday. When it falls on a Friday, we modify the value of the *Day* variable to Saturday. Otherwise, we model it as a Sunday. We also model the day before New Year's Day as a Saturday.

B. Error Statistics

Despite of many criticisms, mean absolute percentage error (MAPE) is still a widely used error statistic in business forecasting. MAPE (%) can be calculated as follows:

$$MAPE = \frac{100}{N}\sum_{i=1}^{N}|(A_i - P_i)/A_i|, \quad (1)$$

where N is the number of observations, A_i represents the actual load, and P_i represents the predicted load.

Since the results of our case study are monthly energy forecasts and monthly peak forecasts, we also use the MAPE of monthly energy and MAPE of monthly peak to evaluate the forecasting accuracy. To calculate MAPE of monthly energy (or peak) based on hourly load forecasts, we have to first extract the actual and predicted monthly energy (or peak), and then apply (1) to the resulting series.

To properly answer the second question posted in Section II, the forecasts have to be evaluated based on ex post forecasting accuracy. Take one year ahead forecasting for example as covered in Section V. Assuming we are forecasting the monthly peaks of 2011, if we use the information available through the end of 2010 to forecast 2011, the resulting forecast is ex ante forecast, or "before the event" forecast. If we use the information available through the end of 2011 other than the loads of 2011 to forecast the loads of 2011, the resulting forecast is ex post forecast, or "after the event" forecast. At the beginning of 2012, instead of focusing on ex ante forecast of 2011, we should emphasize the ex post forecasting accuracy of 2011, which tells how the model behaves given the actual temperatures of 2011.

IV. PREDICTIVE MODELING

In this section, we first augment the S models to LTLF models, denoted as L, using the available data on and prior to 2006. We then determine the appropriate length of history for one year ahead load forecasting. At the end, we compare the ex post forecasting accuracy of the $C1, C2, B, S$, and L models on a rolling basis using 2007 through 2010 [15].

A. Model Selection

The general health of the economy is what ultimately drives long term electricity consumption. We would like to extend the model group S for long term forecasting by adding a macroeconomic indicator, *GSP*. The same annual value of GSP is assigned to each hour of a year. We use *GSP* in this paper mainly due to two reasons: 1) the territory of NCEMC covers most of North Carolina, which makes *GSP* a good driver of the NCEMC's long term load; 2) *GSP* is easy to access and understand. If the utility's territory covers one or a few counties or cities, *GDP* (gross domestic product) by county or *GMP* (gross metropolitan product) can be used as the macroeconomic indicator. In practice, depending upon the drivers of the load, we can also use several other indicators and their combinations, such as housing stock, employment rate, number of jobs, etc. For the utilities, especially retail electricity providers, who provide services in deregulated environment, the total loads are highly impacted by customer churn. In those situations, we can use customer count as the macroeconomic indicator.

The augmentation to a long term forecasting model can be achieved in three ways:

1) Replace *Trend* by *GSP*. There is an inherent assumption in this approach: the loads sensitive to weather and calendar stay in the same profile over time, while there is part of a base load that growing linearly in proportion to the economic growth. If the forecasting horizon is within a few years, this approach can be a good approximation in practice. As the horizon becomes longer, there can be significantly more customers moving into the territory. Consequently, the weather and calendar sensitive loads should grow as well.
2) Divide *Load* by *GSP*. The inherent assumption for this approach is that the load is growing at exactly the same rate as the economic growth. In other words, there is no base load that stays constant while the economy is growing. Take a residential community as a counterexample. Before everyone moves in, the feeders, transformers, and street lights are already placed in the community, which lead to a small base load, including no-load loss of transformers, street lighting load, etc. As people are moving in during the next a few years, the total load of this system is growing. However, the small base load stays almost the same since day one. Several ways to extend this approach are to take the natural log or square root of the load or macroeconomic indicator, or both in some combination before performing the division, which allows load to grow faster or slower than the economy.
3) Replace *trend* by *GSP* and then add interactions between *GSP* and the existing main and cross effects. This approach

TABLE III
COMPARISON AMONG THREE WAYS TO ADD GSP ON MAPE OF HOURLY LOAD

Extension	2002	2003	2004	2005	2006	Average
1	4.3	4.2	4.9	6.3	3.7	**4.7**
2	3.6	3.6	3.7	7.5	8.3	5.3
3	4.2	4.7	4.9	6.8	4.3	5.0

TABLE IV
COMPARISON AMONG DIFFERENT LENGTH OF HISTORICAL DATA

Length (yr)	2002	2003	2004	2005	2006	Average
1	4.9	5.5	4.6	4.1	4.7	4.8
2	3.6	4.2	4.8	5.1	3.5	**4.2**
3	4.3	4.2	4.9	6.3	3.7	4.7
4	4.2	4.8	4.9	7.4	4.6	5.2

TABLE V
COMPARISON AMONG MODELS $C1, C2, B, S$ AND L

MAPE	Model	2007	2008	2009	2010	Average
Annual Energy	*C1*	2.5	0.9	1.0	0.8	1.3
	L	0.2	0.1	0.1	0.1	0.1
Annual Peak	*C2*	1.1	7.5	13.8	8.6	7.8
	L	0.2	2.8	2.4	7.3	3.2
Monthly Energy	*C1*	3.4	2.0	2.7	3.4	2.9
	L	1.5	1.3	1.2	2.1	1.5
Monthly Peak	*C2*	3.8	4.2	9.3	6.9	6.1
	L	2.1	3.7	3.0	4.3	3.3
Hourly Load	*B*	4.8	5.1	5.0	4.9	5.0
	S	3.5	3.9	4.0	3.6	3.8
	L	3.5	3.3	3.4	3.7	3.5

assumes end-users' behavior changes as the economic environment changes. Since a significant amount of variables are being added through the additional interaction effects, the resulting model may be over-parameterized. Depending upon the forecasting horizon and the electricity usage pattern, this approach may not provide forecast results that are as accurate as the first two options.

Table III compares the MAPE of hourly loads of the three approaches discussed above for one year ahead forecasting. The MAPE values are generated on rolling basis with a history window fixed at 3 years. Take the 3.7% under 2004 for example. We used the second approach ("divide *Load* by *GSP*") mentioned above to augment the model S_{2004} to get the model for long term forecasting, denoted as L_{2004}. The parameters are then estimated using the load, temperature, and economy data from 2001 to 2003. Based on five years of validation results, we conclude that the "replace *Trend* by *GSP*" approach on average offers the lowest MAPE (4.7%) in this case study.

B. Length of Training Data

The length of historical data for parameter estimation is another factor that impacts forecasting accuracy. Table IV lists the MAPE values generated on rolling basis with different length of history window. For example: observe 2005, with a MAPE of 7.4% in the last row. We use 4 years of history from 2001 to 2004 to estimate the parameters of the model L_{2005} (S_{2005} augmented by replacing *Trend* by *GSP*). Based on five years of validation results, we conclude that in this case study, using 2 years of historical data offers the lowest average MAPE (4.2%) for forecasting one year ahead. While this rolling simulation approach can be used for determining multiple years ahead forecasting, we may not reach the same conclusion that 2 years of historical data is optimal for 5 years ahead forecasting.

C. Comparison

We would like to compare the ex post forecasting accuracy of models $C1, C2, B, S$, and L. Some of these models ($C1, C2$, and B) already have a pre-designated variable combination, while some (S and L) require model identification. Some ($C1$ and $C2$) are based on monthly data, while some (B, S, and L) are based on hourly interval data. Due to the above characteristics, we have to apply different treatments to the models to calculate the MAPE values of ex post forecasts:

1) Classical models $C1$ and $C2$: the variables are specified in Table I, while the parameters are estimated using the eight years of historical data prior to the year to be forecasted.
2) Tao's vanilla model B : the variables are specified in Table I, while the parameters are estimated using the three years of historical data prior to the year to be forecasted.
3) Customized short term forecasting model group S: to perform ex post forecasting for the loads of year y, we cannot use the loads of year y for model building, including the tasks of parameter estimation and variable selection. To avoid using the loads of year y, we first identify the model S_{y-1}, which is selected using the year $y-1$ as the validation data and the three years $y-4$ to $y-2$ as the training data. Parameter estimation of S_{y-1} is based on the 3 years prior to year y, namely from year $y-3$ to $y-1$.
4) Customized long term forecasting model group L: similar to the analogy above, we cannot use the loads of year y to build the model when ex post forecasting the same year. Therefore, we first identify model L_{y-1}, and then estimate the parameters based on two years of historical data, $y-1$ and $y-2$.

In Table V, we list the MAPE (and absolute percentage error for annual interval summary) values of annual energy, annual peak, monthly energy, monthly peak, and hourly load from the five model groups. Table V first shows that the LTLF models (L) derived based on the proposed approach have much lower MAPE values than the classical models $C1$ and $C2$ on one year ahead ex post forecasting. On monthly energy and peak forecasting, the proposed approach reduces the MAPE by over 45%. Table V also shows that the performance of L improves on both model B and model group S.

Figs. 1 and 2 show the line plots of monthly energy and monthly peak profiles from 2007 to 2010, which confirms that the proposed approach leads to more accurate forecasts than does the counterpart.

The classical approach based on monthly data leads to significantly higher error than the proposed approach. This is because the monthly data (peak temperature, HDD, and CDD) cannot tell: 1) which hour of the day and which day of the week the high/low temperatures fall into; 2) the variation of the temperatures throughout a day; 3) the temperature profiles for modeling recency effect [1]. In addition, the HDD and CDD require the forecasters to specify the threshold or comfortable zone, which may not be very defensible.

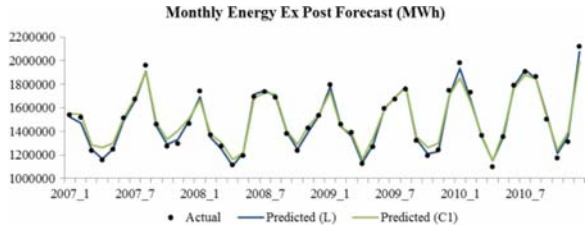


Fig. 1. Comparison on ex post forecasts of monthly energy (2007–2009).

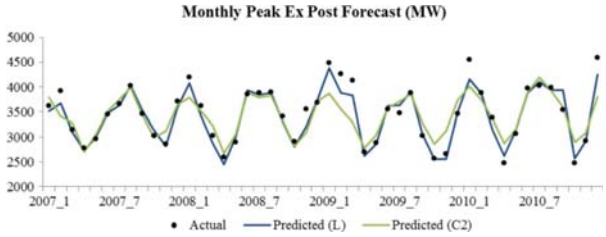


Fig. 2. Comparison on ex post forecasts of monthly peak (2007–2009).

V. Scenario Analysis

Forecasting is, by nature, a stochastic problem. Due to the uncertainty in climate and economic forecasts, long term load forecasters are encouraged to provide multiple forecasts based on different scenarios. This section discusses how to create weather and economic scenarios. Since 2011 is a year that many U.S. utilities had trouble forecasting, we use 2011 as an example to illustrate the proposed methodology.

A. Weather and Economic Scenarios

The pros and cons of several existing means to create weather scenarios have been discussed in Section II. In this paper, we use actual temperature profiles from the history to create weather scenarios. There are three components that should be clearly specified in the one year ahead load forecasting process for a given year y; or multiple years ahead load forecasting process for a given horizon starting from year y:

1) How to model the system, such as combination of weather and calendar variables, incorporation of macroeconomic indicator(s), and length of load, weather, and economy history for parameter estimation. Since the load of year y should be excluded from model building, we can use model L_{y-1}, which is identified using the most recent years of information.
2) How many years of temperature history to use. Different organizations may adopt different practices when selecting the length of temperature history, which ranges from 20 years to 50 years. NOAA, for instance, uses 30 years of history to create and update the typical meteorological year (TMY). In this paper, we also use 30 years of temperature history, from $y-30$ to $y-1$, to create 30 weather scenarios for year y. If the year y is a leap year, i.e., 2008, and the year of weather scenario is based on a non-leap year, i.e., 1991, we fill in 02/29/2008 with 02/28/1991's temperatures. If the year y is a non-leap year, i.e., 2011, and the year of weather scenario is based on a leap year, i.e., 2000, we can remove the temperatures of 02/29/2000. Based on each weather scenario, we can generate an hourly load profile for the year y using the model L_{y-1}.
3) How to extract normalized peak and energy. From each hourly load profile, we first derive monthly peak (or energy) profiles. We then find the median of the monthly peaks (or energy) for each month. The results are the normalized monthly peak (or energy) forecast. Many organizations also require the forecasts at the 10th and 90th percentiles to support the decision making processes.

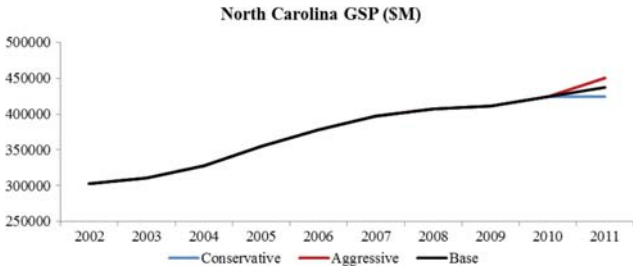


Fig. 3. History (2002–2010) and forecast (2011, 3 scenarios) of *GSP*.

Most utilities purchase economic forecasts from third parties for LTLF. The economic forecasts usually come with multiple scenarios. In this paper, we use three macroeconomic scenarios: base, aggressive, and conservative scenarios for the year of 2011 as shown in Fig. 3. For each macroeconomic scenario, we can have the same 30 weather scenarios as mentioned above. In total, we can create 90 cross scenarios.

B. Probabilistic Forecasts

Figs. 4 and 5 show one year ahead forecasting of 2011's monthly peak and energy respectively. There are 30 dashed lines representing the forecasts obtained using the 30 weather scenarios combined with the base economic scenario. In addition, we plot the 5 scenarios extracted from the 90 cross scenarios, including 10th (gray) 50th (black) and 90th (green) percentiles of the load with base economic scenario, and median load with conservative (blue) and aggressive (red) economic scenarios. The actual monthly peaks and energy of 2011 are labeled as black dots.

In practice, the 90th percentile is often used to represent a severe scenario that may happen one out of ten times. It does not mean that the load will never exceed this bound. Among the 12 monthly peaks shown in Fig. 5, the actual peak of May 2011 does exceed the 90th percentile line, which is reasonable considering the definition of the 90th percentile.

Sometimes the extreme estimates are unrealistic, because the given temperature scenario can be out of range of the training data. For instance, in Fig. 5, the extreme scenario of Jan 2011 exceeds 6000 MW, which is driven by an extremely cold year in the 1980s. Since the 90th percentile derived from the 30 scenarios is not sensitive to the extreme value, it is still reliable and practical to use such a 90th percentile curve for planning purposes.

VI. Load Normalization

Due to the variation in climate from year to year, most utilities conduct some form of weather normalization processes to esti-

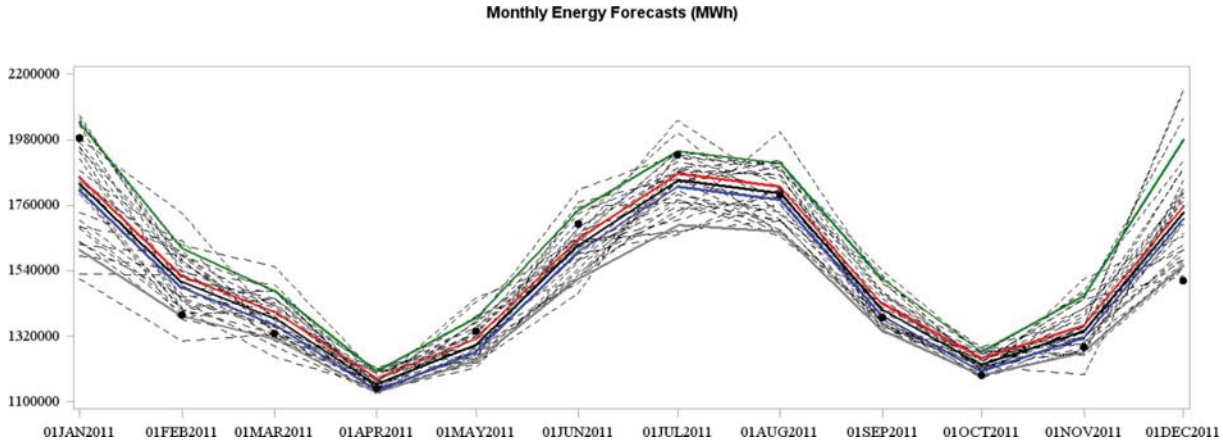


Fig. 4. Ex ante forecasts of 2011 monthly energy.

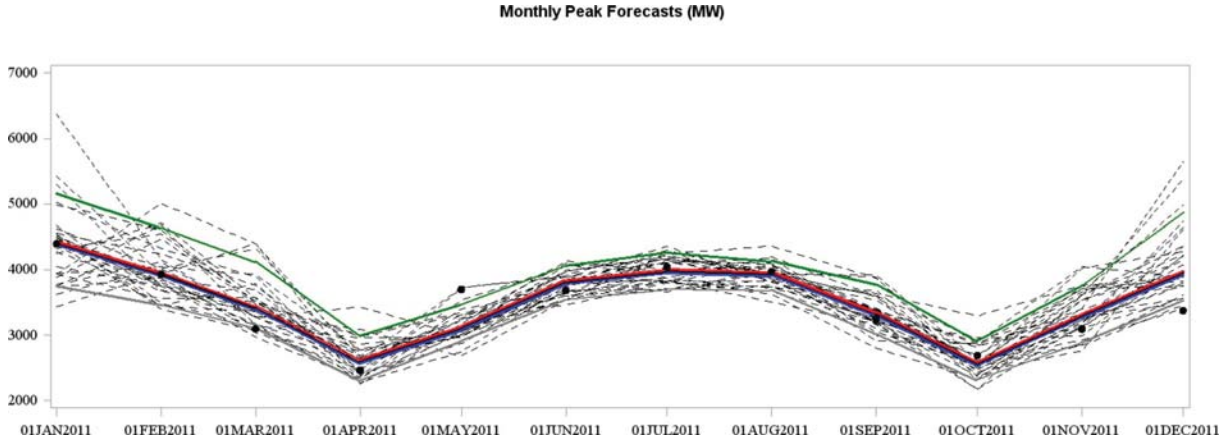


Fig. 5. Ex ante forecasts of 2011 monthly peak ($30 + 5$ scenarios).

mate the normalized load profile. There are two business needs for such processes: 1) understanding the load growth *without* the impact of climate change; 2) understanding the variation of the load *with* the impact of climate change. Due to the nonlinear relationship between load and weather [1], a normal weather profile usually does not lead to a normal load profile. Comparing with the conventional term *weather normalization*, a more accurate description to the process of estimating the load profile without impact of climate change should have been *load normalization against weather*.

Similar to creating weather scenarios for LTLF as discussed in Section V-A, there are three components that should be clearly specified in the load normalization process for a given year y : 1) how to model the system; 2) how many years of temperature history to use; 3) how to extract normalized peak and energy. The second and third components can be treated the same way as discussed in Section V-A, while the first one is slightly different.

When normalizing the historical load of a given year y, we should identify a model that concurrently best represents the system status in the year y, and has strong predictive power to answer the "what-if" questions. Since all the information in-

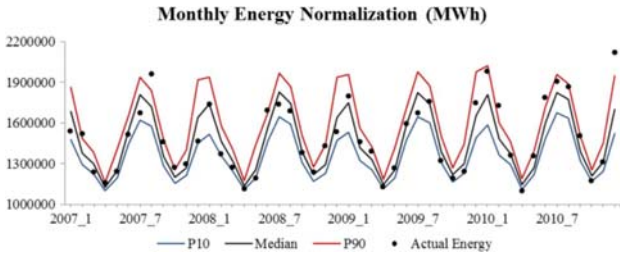


Fig. 6. Monthly energy normalization (2007–2010).

cluding load, temperature, and economy of the year y is available for load normalization, we can use the model L_y, which is identified using the data through the end of year y.

Figs. 6 and 7 present the load normalization results for monthly energy and peaks from 2007 to 2010, where the 10th percentile, median, and 90th percentile load profiles are colored in blue, black, and red respectively. The actual peaks are labeled as black dots. As shown in Fig. 6, the actual monthly energy of December 2010 is above the 90th percentile line. This is due to 3 consecutive very cold weeks, which rarely happened in the past several decades.

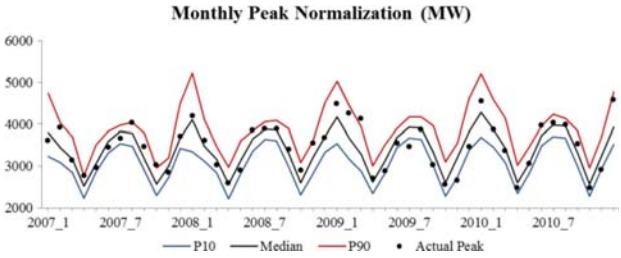


Fig. 7. Monthly peak normalization (2007–2010).

VII. Conclusion

In this paper, we presented a practical approach to LTLF. We modernized predictive modeling, weather normalization, and probabilistic forecasting with MLR models and hourly information. Through a case study at NCEMC, we showed how this method can create superior accuracy and defensibility of the forecast results over the classical approach based on monthly data. In particular, we proposed the concept of load normalization, and demonstrated a simulation approach to normalizing the load against weather.

In future work, as an expansion of the proposed methodology, we would like to further explore the following directions: 1) incorporation of high resolution spatial information; 2) how data cleansing could help improve long term load forecasts; 3) understanding how the forecast errors of explanatory variables contribute to the error of ex ante forecasts.

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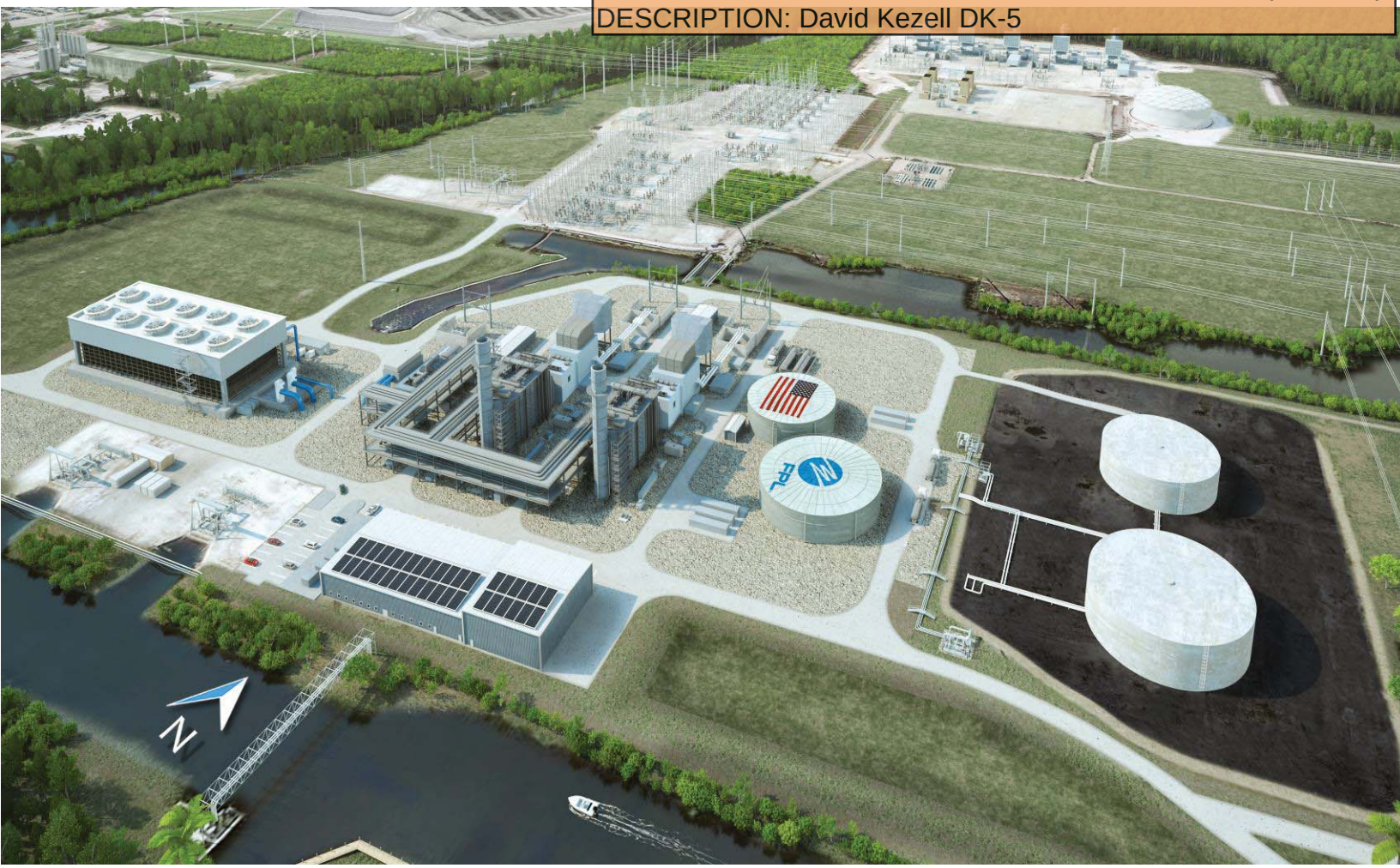
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FPL

SITE CERTIFICATION APPLICATION
DANIA BEACH ENERGY CENTER

VOLUME I OF III

Submitted by:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

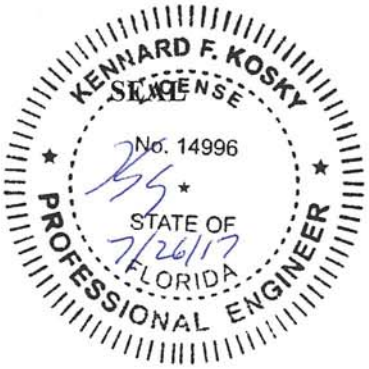
July 2017

17-73823

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***Board of Professional Engineers**
Certification of Authorization No. 00001670



VOLUME I

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7.0 ECONOMIC AND SOCIAL EFFECTS OF PLANT CONSTRUCTION AND OPERATION

The purpose of this chapter is to identify the direct and indirect economic costs and social effects of the Project based on both temporary (construction) and long-term (operation) time periods.

Direct effects are those that are the result of the construction or operation of the DBEC. Indirect effects are those that are the result of changes in the livelihood of the people and business interests in the vicinity of a project, such as increased spending by construction and operation personnel. Many of these effects are difficult to measure and qualitative assumptions are often made to assess the relative values of anticipated costs and benefits.

This chapter is divided into two parts: benefits and costs. Section 7.1 addresses the economic and social benefits of the Project, including analyses of the direct and indirect effects of construction and operation of DBEC. Section 7.2 addresses the economic and social costs of the Project and includes analyses of the temporary and long-term indirect costs involving construction and operation of DBEC. An analysis of the fiscal and economic impacts of the DBEC is provided in Appendix 10.7.3. All costs and benefits are based on 2017 dollar values unless otherwise indicated.

7.1 Economic and Social Benefits

The DBEC is anticipated to benefit the City of Dania Beach, Broward County, and the State of Florida by providing significant economic output, requiring relatively few costs accrued to the local government, and creating a positive downstream effect spurring community growth and opportunity throughout the region.

Direct and indirect economic benefits from construction include construction workforce jobs, purchase and rental of equipment and materials, housing and living expenses for construction workers, and indirect employment. Direct and indirect economic benefits from operation include capital expenditures, operation and maintenance expenditures, employment and property tax revenues.

7.1.1 Economic Benefits

FPL estimates that the total Project capital cost will be approximately $888 million to modernize the existing power plant. Principal components include the power block ($764 million); transmission interconnection and integration ($21 million); and allowance for funds used during construction ($103 million).

7.1.1.1 Benefits of Construction

Onsite construction activities of DBEC are anticipated to begin in 2020 and conclude in mid-2022. The construction activities are anticipated to result in a total economic output of approximately $310 million

Form 1 Attachment 2

Compliance with Antidegradation Policy

The Lauderdale Plant Industrial Wastewater Facility (IWWF/NPDES) permit modification to the existing permit FL0001503 (Major) is consistent with the antidegradation permitting requirements (62-4.242 F.A.C.) and the antidegradation policy for surface water quality (62-302.300 F.A.C.) for the following reasons:

1. The Project is in the public interest, as required by Section 62-4.242(1)(b)1 F.A.C.; and the Project is clearly important to and beneficial to the public health, safety and welfare. As discussed in Public Service Commission filings, the modernization project:

   - Will provide a reliable base load generating capacity in a region where demand is the highest.
   - Will improve fuel efficiency at the Lauderdale site, and on a FPL system-wide basis.
   - Will improve the environmental profile of the Lauderdale site by lowering emission rates.
   - Will result in a lower cost supply of electricity for FPL's customers, and
   - Will create new jobs and tax revenue for Florida's economy.

2. While the facility modification will provide approximately 25 percent more power, the permit modification does not propose a new or an expanded surface water discharge. To accomplish this, the DBEC (Unit 7) cooling system will use a hybrid design -- once-through steam cycle cooling, with an auxiliary cooling system that is designed to evaporate between 0.5 percent and 1.0 percent of the once-through cooling water flow and the existing cooling pond to dissipate heat.

3. Consequently, there is no new or expanded discharge for the following reasons. First, there is no change in the industrial activity. The proposed industrial activity (i.e., fossil-fuel electric generation) is exactly the same as under the existing permit. Second, for the same meteorological conditions (rainfall, cloud cover, temperature and dew point), the annual average daily flow (AADF) from Outfall D-001 to the South Fork of New River (WBID 3277A) will be less than or equal to the existing discharge rate. Third, pollutant loads, including the thermal or heat load, from the modernized facility through D-001 to South Fork New River will be less than or equal to that of the existing facility. All existing effluent limitations for Outfall D-001 (flow, temperature, TDS, pH, copper and Whole Effluent Toxicity test results) will be met by the modernized facility.

4. The permit modification will not result in any material or measurable water quality degradation.

5. The facility modification will not adversely affect conservation of fish and wildlife, including endangered or threatened species, or their habitats. The cooling water intake withdrawal rate (design intake flow) from the Dania Cutoff canal and the intake through-screen velocity will be unchanged. As discussed above, the thermal load to the South Fork New River will not exceed the existing thermal load. Therefore, the permit modification will have no adverse effect from impingement or entrainment on fish or shellfish; and there will be no adverse effect from the thermal discharge to the South Fork New River. In other words, there will be no water quality degradation related to CWA Sections 316(a) or 316(b). Based on conditions in the existing IWWF/NPDES permit, the facility is in the process of evaluating existing impacts from

impingement and entrainment. When the Best Technology Available (BTA) determination is final, the facility will implement any required changes to address existing impacts.

6. The modernization project will not adversely affect endangered or threatened species, or their habitat. The only state or federally listed species known to occupy the waters adjacent to the modernized facility is the West Indian manatee (*Trichechus manatus*). The cooling water discharge canal and quarry areas are used by manatees as a warm-water refuge during the winter months. FPL will construct a thermal refuge to protect manatees seeking warm water during cold weather conditions. The refuge will be available during the Unit 7 project construction phase, when the thermal discharge from the plant is temporarily discontinued and critical cold weather conditions are possible.

7. The permit modification is not inconsistent with any applicable Surface Water Improvement and Management Plan that has been adopted by the South Florida Water Management District.

8. The facility does not discharge to or degrade any Outstanding Florida Waters.

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Carlos Lopez-Cantera
Lt. Governor

Noah Valenstein
Secretary

PERMITTEE

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Authorized Representative:
James Frauen, Vice President of Power Delivery
and Technical Services

Air Permit No. 1070025-028-AC (PSD-FL-443)
Expires: March 31, 2024
Seminole Generating Station
Facility ID No. 1070025
Seminole Combined-Cycle Facility

PROJECT

This is the final air construction permit, which authorizes the replacement of one existing coal-fired unit with a new natural gas-fired two-on-one combined cycle unit. The proposed work will be conducted at the existing Seminole Generating Station, which is an electric power plant categorized under Standard Industrial Classification No. 4911. The existing facility is in Putnam County at 890 North Highway 17 in Palatka, Florida. The UTM coordinates are Zone 17, 438.8 kilometers (km) East, and 3289.2 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

(DRAFT)

For: Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 71
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: David Kezell DK-6

DRAFT

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Construction Permit package was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on the date indicated below to the following persons.

James Frauen, SECI: JFrauen@seminole-electric.com
Chris Weber, SECI: CWeber@seminole-electric.com
Chris Brew, SECI: CBrew@seminole-electric.com
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EPA Region 4 NSR/PSD: NSRsubmittals@epa.gov
Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(DRAFT)

DRAFT

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (DRAFT)

A. Natural Gas-Fired Combustion Turbines with Duct-Fired HRSGs (EU Nos. 017 and 018)

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
017	Natural Gas-Fired Combustion Turbine with Duct-Fired HRSG
018	Natural Gas-Fired Combustion Turbine with Duct-Fired HRSG

The CT proposed for the project is the General Electric (GE) 7HA.02 turbine. Each CT will utilize inlet evaporative air cooling. Emissions from each turbine will be controlled using dry low-NO_X (DLN) combustion, oxidation catalyst, and selective catalytic reduction (SCR).

Each combustion turbine generator (CTG) will have a nominal electrical output of 384 MW. Each turbine will be connected to a heat recovery steam generator (HRSG) with duct burners. Steam generated in the two HRSGs will be routed to a common steam turbine (ST), with a nominal generating capacity of 415 MW. The total gross nominal electrical generating capacity for the unit is 1,183 MW, and the net nominal generating capacity is approximately 1,050 MW.

The nominal design heat input rate to each turbine is 3,514 MMBtu/hr, based on an ambient air temperature of 59 degrees Fahrenheit (°F), evaporative cooling, 14.7 pounds per square inch (psi) pressure, the higher heating value (HHV) of the fuel, and 100% load. Each duct burner will have a nominal heat input rating of 250 MMBtu/hr (HHV).

Each HRSG will have a stack height of 199 ft and an inner stack diameter of 23.5 ft. Each stack will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_X emissions as well as flue gas oxygen or carbon dioxide content.

{Note: Actual heat input rate varies depending upon gas turbine characteristics, ambient conditions, and inlet air cooling. A predictive emissions monitoring system (PEMS) may be used in lieu of CEMS, pending EPA approval of an alternative monitoring system petition per 40 CFR Part 75 Subpart E and 40 CFR Part 60. If the permittee wishes to change the method of compliance with the requested state-issued and NSPS NO_X limits from a CEMS to a PEMS, another air construction permit will be necessary.}

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determination of the Best Available Control Technology (BACT) was conducted for volatile organic compounds (VOC). [Rule 62-210.200 (BACT), F.A.C.]

2. NSPS Requirements: These units shall comply with the applicable NSPS in 40 CFR 60, including: Subpart A (General Provisions), Subpart KKKK (Standards of Performance for Stationary Gas Turbines), and Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units). See Appendices Subpart A, KKKK, and TTTT of this permit. The applicant's requested standards for NO_X and the fuel sulfur specifications are as stringent as, or more stringent than, the NO_X and sulfur dioxide (SO_2) limits imposed by the applicable NSPS Subpart KKKK provisions. Some separate reporting and monitoring may be required by the individual subparts. [Rule 62-204.800(8)(b), F.A.C.; and NSPS 40 CFR 60, Subparts A, KKKK, and TTTT]

   {Permitting note: These units are not subject to the NESHAP in 40 CFR 63, Subpart YYYY, for stationary combustion turbines. Subpart YYYY does not apply to turbines that fire only natural gas.}

EQUIPMENT DESCRIPTION

3. Combustion Turbines: The permittee is authorized to install, tune, operate, and maintain two GE 7HA.02 CTs with a nominal generating capacity of 384 MW each and an inlet air filtration system with inlet air cooling. The CTs will be designed for operation in combined-cycle mode, with one shared steam turbine. The CTs may also operate in simple-cycle mode but may not bypass pollution controls. [Application 1070025-028-AC; Design]

4. Heat Recovery Steam Generators (HRSGs): The permittee is authorized to install, operate and maintain two HRSGs, associated duct burners and exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the two CTGs and deliver steam to the steam turbine-electrical generator (STG). The

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Carlos Lopez-Cantera
Lt. Governor

Noah Valenstein
Secretary

PERMITTEE

Florida Power & Light Company (FPL)
700 Universe Boulevard
Juno Beach, FL 33408

Authorized Representative:
Mr. Michael W. Sole, Vice President

Air Permit No. 0110037-017-AC (PSD-FL-442)
Expires: December 31, 2023
Lauderdale Plant
Facility ID No. 0110037
Dania Beach Energy Center

PROJECT

This is the final air construction permit, which authorizes the construction and operation of a net 1,200-megawatt (MW) nominal 2-on-1 combined cycle electrical generating facility within the existing Lauderdale Site, and will be known as the "Dania Beach Energy Center" (DBEC). The proposed work will be conducted on 134 acres within the existing 392-acre Lauderdale Plant, which is an electric utilities facility categorized under Standard Industrial Classification No. 4911. The existing facility is in Broward County, 2 miles West of Ravenswood Road and can be accessed from Southwest 42nd Street and Griffin Road, Fort Lauderdale, Florida. The UTM coordinates are: Zone 17, 580.2 km East and 2883.3 km North. Latitude is: 26° 04' 05" North; and, Longitude is: 80° 11' 54" West.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 72
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: David Kezell DK-7

Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Construction Permit package was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on the date indicated below to the following persons.

Michael W. Sole, FPL: Michael.Sole@fpl.com
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FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS

A. Combined Cycle Unit 7 (EU Nos. 055 & 056)

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
055	Unit 7A – One nominal 430 MW combustion turbine with HRSG
056	Unit 7B – One nominal 430 MW combustion turbine with HRSG

CT proposed for this project is the General Electric (GE) 7HA combustion turbine. Each CT will utilize evaporative cooling and wet compression. Emissions from each turbine will be controlled using dry low-NOx (DLN) combustion and selective catalytic reduction (SCR). The nominal heat input rate to each gas turbine is 4,015.4 million British thermal units per hour (MMBtu/hour) when firing natural gas and 3,603.6 MMBtu/hour when firing distillate oil (based on a compressor inlet air temperature of 75° F, the higher heating value (HHV) of each fuel, at baseload).

Each HRSG will have a stack height of approximately 149 feet and an inner stack diameter of approximate 25.6 feet. Each stack will be equipped with a continuous emissions monitoring systems (CEMS) to measure and record NO_X emissions as well as flue gas oxygen or carbon dioxide content.

{Permitting Note: In accordance with Rule 62-212.400(PSD), F.A.C., the above emission unit is subject to Best Available Control Technology (BACT) determinations for the following pollutants: carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The final BACT determinations are presented in Appendix E of this permit. These emissions units are regulated under the federal Acid Rain Program; and, NSPS Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) of 40 CFR 60, adopted and incorporated by reference in Rule 62-204.800(8)(b)82., F.A.C. The requested limits for NO_X assure compliance with Rule 62-296.570, F.A.C. (RACT).}

SHUTDOWN UNITS

1. Shutdown Units: The following units are required to permanently shut down as a part of the PSD project: Units 4 and 5 (CTs 4A, 4B, 5A, and 5B; EU Nos. 035 - 038). [Rule 62-212.400(12), F.A.C. and Application No. 0110037-017-AC]

EQUIPMENT SPECIFICATIONS

2. Combustion Turbines & HRSGs: The permittee is authorized to install, tune, operate, and maintain two GE 7HA CTs with a nominal generating capacity of 430 MW each with inlet air cooling (i.e. evaporative cooling and wet compression). The CTs will be designed for operation in combined-cycle mode with two HRSGs and one steam turbine generator and will have dual-fuel capability (natural gas and ULSD fuel oil). Each CT may also operate in simple cycle mode without the steam turbine generator. Each HRSG exhaust stack shall be approximately 149 feet tall and 25.6 feet in diameter. [Rule 62-4.070(3), F.A.C. and Application No. 0110037-017-AC]

CONTROL TECHNOLOGY

3. Combustion Technology: The permittee shall install, operate and maintain the dry-low NO_X (DLN) combustion system or its equivalent on each CT to control NO_X emissions from the CT when firing natural gas. Prior to the initial emissions performance tests required for the CT, the DLN combustors or its equivalent and automated gas turbine control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or determined best practices.
[Rule 62-4.070(3), F.A.C. and Design; Application No. 0110037-017-AC]



Independent Statistics & Analysis
U.S. Energy Information Administration

Capital Cost Estimates for Utility Scale Electricity Generating Plants

November 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 73
PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.(Rebuttal)
DESCRIPTION: David Kezell DK-8



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Introduction

The current and future projected cost and performance characteristics of new electric generating capacity are critical inputs into the development of energy projections and analyses. The construction and operating costs, along with the performance characteristics of new generating plants, play an important role in determining the mix of capacity additions that will serve future demand for electricity. These parameters also help to determine how new capacity competes against existing capacity, and the response of the electric generators to the imposition of environmental controls on conventional pollutants or any limitations on greenhouse gas emissions.

EIA commissioned an external consultant to develop up-to-date cost and performance estimates for utility-scale electric generating plants for AEO2013.[1] This information allowed EIA to compare the costs of different power plant technologies on a standardized basis and was a key input enhancement to the National Energy Model System (NEMS). For the AEO 2016 development, EIA commissioned the same consultant group to update the cost and performance estimates for a select set of the technologies evaluated in the original 2012 study. This paper summarizes the results of the findings and discusses how EIA used the updated information to analyze the development of new capacity in the electric power sector.

Developing updated estimates: key design considerations

The focus of the 2016 update was to gather current information on the "overnight" construction costs, operating costs, and performance characteristics for a wide range of generating technologies.[2] The estimates were developed through costing exercises, using a common methodology across technologies. Comparing cost estimates developed on a similar basis using the same methodology is of particular importance to ensure modeling consistency.

Each technology is represented by a generic facility of a specific size and configuration, in a location that does not have unusual constraints or infrastructure requirements. Where possible, costs estimates were based on information on system design, configuration, and construction derived from actual or planned projects known to the consultant, using generic assumptions for labor and materials rates. When this information was not available, the project costs were estimated using a more generic technology representation and costing models that account for the current labor and materials rates necessary to complete the construction of a generic facility as well as consistent assumptions for the contractual relationship between the project owner and the construction contractor.

The specific overnight costs for each type of facility were broken down to include:

- **Civil and structural costs:** allowance for site preparation, drainage, the installation of underground utilities, structural steel supply, and construction of buildings on the site
- **Mechanical equipment supply and installation:** major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators,

[1] U.S. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants 2013
[2] The term “overnight” refers to the cost of the project as if no interest were incurred during its construction.

condensers, photovoltaic modules, combustion turbines, wind turbines, and other auxiliary equipment

- **Electrical and instrumentation and control:** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities
- **Project indirect costs**: engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency[3]
- **Owners costs:** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system

Non-fuel operations and maintenance (O&M) costs associated with each of the power plant technologies were evaluated as well. The O&M costs that do not vary significantly with a plant's electricity generation are classified as fixed, including salaries for facility staff and maintenance that is scheduled on a calendar basis. The costs incurred to generate electricity are classified as variable such as the cost of consumable materials and maintenance that may be scheduled based on the number of operating hours or start-stop cycles of the plant. The heat rates[4] were also evaluated for the appropriate technologies. It should be noted that all estimates provided in this report are broad in scope. A more in-depth cost assessment would require a more detailed level of engineering and design work, tailored to a specific site.

Findings

Table 1 summarizes updated cost estimates for generic utility-scale generating technologies, including four powered by coal, six by natural gas, three by solar energy, and one each by wind, biomass, uranium, and battery storage. EIA does not model all of these generating plant types, but included them in the study in order to present consistent cost and performance information for a broad range of generating technologies and to aid in the evaluation for potential inclusion of new or different technologies or technology configurations in future analyses.

The specific technologies represented in the NEMS model for*AEO2016* that use the cost data from this report are identified in the last column of Table 1.

Table 2 compares the updated overnight cost estimates to those developed for the 2013 report. To facilitate comparisons, the costs are expressed in 2016 dollars.[5] Notable changes include:

- **Ultra Supercritical Coal (USC) with and without carbon capture and storage (USC/CCS).** USC with carbon capture and storage was added for this study to help meet EPA's 111b new source performance standard for carbon emissions. While USC without carbon capture cannot be built under current regulations, inclusion of this technology maintains the capability to analyze policy alternatives that may exclude 111b requirements.

[3] Fees for contingency include contractor overhead costs, fees, profit, and construction.
[4] Heat Rate is a measure of generating station thermal efficiency commonly stated as Btu per kilowatthour.
[5] U.S. Energy Information Administration, Annual Energy Outlook 2016, Table 20, GDP chain-type price index

- **Conventional Natural Gas Combined Cycle (NGCC) and Advanced Natural Gas Combined Cycle (ANGCC):** The updated overnight capital cost for conventional and advanced NGCC plants remained level relative to the cost in the 2013 study. The capacity of the NGCC unit increased from 400 MW in the 2013 study to 429 MW, while the capacity of the ANGCC unit increased from 620 MW to 702 MW for ANGCC to reflect trends toward larger installations for this technology.
- **Onshore Wind**: Overnight costs for onshore wind decreased by approximately 25 percent relative to the 2013 study, primarily due to lower wind turbine prices. EIA adjusted regional cost factors for wind plants from those reported in this report for inclusion in AEO 2016[hyper link to Table 8.2]. The regional factors in this report primarily account for regional variation in labor and materials costs, but subsequent evaluation of the regional variation in wind plant costs found that other factors, such as typical plant size, may account for a larger share of the observed regional differences in cost for the wind plants.
- **Solar Photovoltaic:** The overnight capital costs for solar photovoltaic technologies decreased by 67 percent for the 20 MW fixed tilt photovoltaic systems from the costs presented in the 2013 study. Solar photovoltaic single-axis tracking systems were introduced in this report (including both a 20 MW and 150 MW system configurations). There is not a significant difference in Capital costs between fixed-tilt and single-axis-tracking systems. The overall decreases in costs can be attributed to a decline in the component costs and the construction cost savings for the balance of plant systems.

  As previously noted, costs are developed using a consistent methodology that includes a broad project scope and includes indirect and owners costs. The cost figures will not necessarily match those derived in other studies that employ different approaches to cost estimation.

EIA's analysis of technology choice in the electric power sector

EIA's modeling employs a net present value (NPV) capital budgeting methodology to evaluate different investment options for new power plants. Estimates of the overnight capital cost, fixed and variable operations and maintenance costs, and plant heat rates for generic generating technologies serve as a starting point for developing the total cost of new generating capacity. However, other parameters also play a key role in determining the total capital costs. Because several of these factors are dynamic, the realized overall capital cost for given technologies can vary based on a variety of circumstances. Five of the most notable parameters are:

- **Financing:** EIA determines the cost of capital required to build new power plants by calculating a weighted average cost of capital using a mix of macro-economic parameters determined through EIA's modeling and an assumed capital structure for the electric power industry.
- **Lead Time:** The amount of time needed to build a given type of power plant varies by technology. Projects with longer lead times increase financing costs. Each year of construction represents a year of additional interest charges before the plant is placed in service and starts generating revenue. Furthermore, plants with front-weighted construction and development profiles will incur higher interest charges during construction than plants where most of the construction expenditures occur at the end of the development cycle.

- **Inflation of material and construction costs:** The projected relationship between the rate of inflation for the overall economy and key drivers of plant costs, such as materials and construction, are important elements impacting overall plant costs. A projected economy-wide inflation rate that exceeds the projected inflation rate for materials and construction costs results in a projected decline in real (inflation-adjusted) capital costs and vice versa.
- **Resource Supply:** Technologies such as wind, geothermal, or hydroelectric must be sited in suitable locations to take advantage of the particular resource. In order to capture the site specific costs associated with these technologies, EIA develops upward sloping supply curves for each of these technologies. These curves assume that the lowest-cost, most-favorable resources will be developed first, and when only higher-cost, less-favorable sites remain, development costs will increase and/or project performance will decrease.
- **Learning by doing:** The overnight capital costs developed for the report serve as an input to EIA's long term modeling and represent the cost of construction for a project that could begin as early as 2015. However, these costs are assumed to decrease over time in real terms as equipment manufacturers, power plant owners, and construction firms gain more experience with certain technologies. The rate at which these costs decline is often referred to as the learning rate.

  EIA determines learning rates at the power plant component level, not for the power plant technology itself because some technologies share the same component types. It is assumed that the knowledge and experienced gained through the manufacture and installation of a given component in one type of power plant can be carried over to the same component in another type of plant. As an example, the experience gained through the construction of natural gas combustion turbine plants can be leveraged to influence the overall cost of building a Natural Gas Combined Cycle unit, which in part, includes the components of a combustion turbine natural gas plant. Other technologies, such as nuclear power and pulverized coal (PC) plants without CCS, do not share component systems, and their learning rates are determined solely as a function of the amount of capacity built over time.

  Technologies and their components are represented in the NEMS model at various stages of maturity. EIA classifies technologies into three such stages: mature, evolutionary, and revolutionary. The initial learning rate is evaluated for each technology. The technology classification determines how the rate of cost reduction changes as each technology progresses through the learning function. Generally, overnight costs for technologies and associated components decline at a specified rate based on a doubling of new capacity. The cost decline is fastest for revolutionary technologies and slower for evolutionary and mature technologies.[6]

[6] U.S. Energy Information Administration, Electricity Market Module Assumptions Document, Table 8.3.

The capacity additions used to influence learning are primarily developed from NEMS results. However, external capacity additions from international projects are also included for some technologies, to account for additional learning from such projects. For power plant technologies with multiple components, the capacity additions are weighted by the contribution of each component to the overall plant construction cost.[7]

Table 3 classifies the status of each technology and component as modeled in *AEO2016*

The NEMS model also assumes that efficiency for all fossil-fueled plants improves as a result of learning by doing. The power plant heat rates provided by the consultant are intended to represent the characteristics of a plant that starts construction in 2015 referred to as "first-of-a-kind." NEMS assumes that the heat rate for all fossil fueled technologies declines over time to a level referred to as an "nth-of-a-kind" heat rate.[8] The magnitude of heat rate improvement depends on the current state of the technology, with revolutionary technologies seeing a more significant decline in heat rate than mature technologies. Heat rate improvements are independent of capacity expansion. Fixed and variable O&M are not assumed to achieve learning-related savings. The performance of wind plants, as measured by capacity factor, is also assumed to improve as a result of learning by doing.[9]

Impact of location on power plant capital costs

The estimates provided in this report are representative of a generic facility located in a region without any special issues that would alter its cost. However, the cost of building power plants in different regions of the United States can vary significantly. The report includes location-based cost adjustment tables for each technology in 64 metropolitan areas. These adjustments were made to reflect the impact of remote location costs, costs associated with seismic design that may vary by region, and labor wage and productivity differences by region. In order to reflect these costs in EIA's modeling, these adjustments were aggregated to represent the 22 Electricity Market Module regions. EIA also assumes that the development of certain technologies is not feasible in given regions for geographic, logistical, or regulatory reasons. The regional cost adjustments and development restrictions are summarized in Table 4.

Subsequent peer review of these results indicated that the regional factors used for wind plants do not adequately reflect observed regional variation of wind plant costs, which appear to be substantially determined by factors other than those considered above. In particular, EIA found a significant regional variation in typical plant size that generally correlated with regional variation in installation costs. Therefore, EIA does not use the regional factors included in this report for its analysis of wind technologies. Regional factors used for AEO 2016 and related analyses can be found in Table 8.2 of the AEO 2016 Assumptions document, and are also shown in Table 4.

[7] U.S. Energy Information Administration, Electricity Market Module Assumptions Document, Table 8.4.
[8] U.S. Energy Information Administration, AEO 2016 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, Table 8.2.
[9] U.S. Energy Information Administration, Renewable Fuels Module

Summary

The estimates provided by the consultant for this report are key inputs for EIA electric market projections, but they are not the sole driver of electric generation capacity expansion decisions. The evolution of the electricity mix in each of the 22 regions modeled in *AEO2016* is sensitive to many factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, whether wholesale power markets are regulated or competitive, the existing generation mix, additional costs associated with environmental control requirements, and future electricity demand.

Users interested in additional details regarding these updated cost estimates should review the consultant study prepared by Leidos Engineering, LLC in Appendix B.

Table 1. Updated estimates of power plant capital and operating costs

	Plant Characteristics		Plant Costs (2016$)			
Technology	**Nominal Capacity (MW)**	**Heat Rate (Btu/kWh)**	**Overnight Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Variable O&M ($/MWh)**	**NEMS Input**
Coal						
Ultra Supercritical Coal (USC)[10]	650	8,800	3,636	42.1	4.6	N
Ultra Supercritical Coal with CCS (USC/CCS)[11]	650	9,750	5,084	70	7.1	Y
Pulverized Coal Conversion to Natural Gas (CTNG)	300	10,300	226	22	1.3	N
Pulverized Coal Greenfield with 10-15 percent	300	8,960	4,620	50.9	5	N
Pulverized Coal Conversion to 10 percent biomass –	300	10,360	537	50.9	5	Y
Natural Gas						
Natural Gas Combined Cycle (NGCC)	702	6,600	978	11	3.5	Y
Advanced Natural Gas Combined Cycle (ANGCC)[13]	429	6,300	1,104	10	2	Y
Combustion Turbine (CT)	100	10,000	1,101	17.5	3.5	Y
Advanced Combustion Turbine (ACT)	237	9,800	678	6.8	10.7	Y
Reciprocating Internal Combustion Engine (RICE)	85	8,500	1,342	6.9	5.85	N
Uranium						
Advanced Nuclear (AN)	2,234	N/A	5,945	100.28	2.3	Y
Biomass						
Biomass (BBFB)	50	13,500	4,985	110	4.2	N
Wind						
Onshore Wind (WN)	100	N/A	1,877	39.7	0	Y
Solar						
Photovoltaic – Fixed	20	N/A	2,671	23.4	0	N
Photovoltaic – Tracking	20		2,644	23.9	0	N
Photovoltaic – Tracking	150	N/A	2,534	21.8	0	Y
Storage						
Battery Storage (BES)	4	N/A	2,813	40	8	N

[10] USC coal without CCS is not compliant with 111b new source standards for carbon emissions and cannot be built in the AEO2016 forecast.
[11] Ultra Supercritical Coal with 30% CCS
[12] Represents capital cost to retrofit existing coal plants to operate with 10% biomass fuel.
[13] "Advanced"-higher capital cost with reduced operating costs

Table 2. Overnight cost comparison with 2013 estimates

	Overnight Capital Cost (2016 $/kW)		
	2016 Report	**2013 report**	**% Difference**
Coal			
Single Unit Advanced PC	N/A	$3,453	N/A
Dual Unit Advanced PC	N/A	$3,121	N/A
Single Unit Advanced PC with CCS	N/A	$5,561	N/A
Dual Unit Advanced PC with CCS	N/A	$5,026	N/A
Single Unit IGCC	N/A	$4,681	N/A
Dual Unit IGCC	N/A	$4,026	N/A
Single Unit IGCC with CCS	N/A	$7,020	N/A
Ultra Supercritical Coal (USC)	$3,636	N/A	5%[14]
Ultra Supercritical Coal with CCS (USC/CCS)	$5,084	N/A	N/A
Pulverized Coal Conversion to Natural Gas (CTNG)	$226	N/A	N/A
Pulverized Coal Greenfield with 10-15 percent biomass (GCBC)	$4,620	N/A	N/A
Pulverized Coal Conversion to 10 percent biomass Co-Firing 30 MW (CTCB)	$537	N/A	N/A
Natural Gas			
Conventional CC	$978	$976	0.3%
Advanced CC	$1,104	$1,088	1%
Advanced CC with CCS	N/A	$2,229	N/A
Conventional CT	$1,101	$1,035	6%
Advanced CT	$678	$719	(6%)
Fuel Cells	N/A	$7,562	N/A
Reciprocating Internal Combustion Engine (RICE)	$1,342	N/A	N/A
Uranium			
Dual Unit Nuclear	$5,945	$5,883	1%
Biomass			
Biomass CC	N/A	$8,702	N/A
Biomass BFB	$4,985	$4,377	12%
Wind			
Onshore Wind	$1,877	$2,354	(25%)
Offshore Wind	N/A	$6,628	N/A

[14] Comparison of costs of coal units without carbon control, despite difference in generation performance (ultra supercritical vs supercritical)

Table 2. Overnight cost comparison with 2013 estimates (cont.)

	Overnight Capital Cost (2016 $/kW)		
	2016 Report	2013 report	% Difference
Solar			
Solar Thermal	N/A	$5,390	N/A
Solar Photovoltaic (20 MW)	$2,671	$4,450	(67%)
Solar Photovoltaic (150 MW)	N/A	$4,120	N/A
Solar Photovoltaic -Tracking (20 MW)	$2,644	N/A	N/A
Solar Photovoltaic - Tracking (150 MW)	$2,534	N/A	N/A
Geothermal – Dual Flash	N/A	$6,641	N/A
Geothermal – Binary	N/A	$4,640	N/A
Municipal Solid Waste			
Municipal Solid Waste	N/A	$8,843	N/A
Hydroelectric			
Conventional Hydroelectric	N/A	$3,123	N/A
Pumped Storage	N/A	$5,626	N/A
Battery Storage (4 MW)	2,813	N/A	N/A

Table 3. Status of technologies and components modeled by EIA

	Revolutionary	Evolutionary	Mature
Pulverized Coal			X
Pulverized Coal with CCS			
- Non-CCS portion of Pulverized Coal Plant			X
- CCS	X		
Integrated Gasification Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Gasifier		X	
- Balance of Plant			X
Conventional Natural Gas Combined Cycle			
- Conventional Combustion Turbine			X
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle with CCS			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
- CCS	X		
Conventional Natural Gas Combustion Turbine			
- Conventional Combustion Turbine			X
- Balance of Plant			X
Advanced Natural Gas Combustion Turbine			
- Advanced Combustion Turbine		X	
- Balance of Plant			X
Advanced Nuclear	X		
Biomass			
- Pulverized Coal			X
- Fuel Preparation		X	
Geothermal		X	
Municipal Solid Waste/Landfill Gas			X
Conventional Hydroelectric			X
Wind			
- Onshore/Common Components			X
- Offshore Components	X		
Solar Thermal	X		
Solar PV			
- Modules (Utility and End Use)		X	
- Utility Balance of Plant		X	

Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region[15]

EMM Region	PC	IGCC	PC w/CCS	Conv. CT	Adv. CT	Conv. CC	Adv. CC	Adv. CC w/CCS	Fuel Cell	Nuclear	Biomass	MSW	On-shore Wind	Off-shore Wind	Solar Thermal	Solar PV
1 (ERCT)	0.91	0.92	0.92	0.93	0.95	0.91	0.92	0.9	0.96	0.96	0.93	0.93	0.95	0.92	0.86	0.87
2 (FRCC)	0.92	0.93	0.94	0.93	0.93	0.91	0.92	0.92	0.97	0.97	0.94	0.94	N/A	N/A	0.89	0.9
3 (MROE)	1.01	1.01	0.99	0.99	1.01	0.99	0.99	0.97	0.99	1.01	0.99	0.98	0.99	0.97	N/A	0.96
4 (MROW)	0.95	0.96	0.96	0.98	1.00	0.97	0.97	0.96	0.98	0.98	0.96	0.96	1.03	1.01	N/A	0.95
5 (NEWE)	1.1	1.09	1.05	1.16	1.2	1.16	1.15	1.08	1.01	1.05	1.04	1.02	1.06	1.03	N/A	1.03
6 (NYCW)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.5	1.14	N/A	1.26	1.26	N/A	1.29	N/A	N/A
7 (NYLI)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.5	1.14	N/A	1.26	1.26	1.25	1.29	N/A	1.45
8 (NYUP)	1.11	1.1	1.05	1.17	1.22	1.16	1.16	1.06	1.00	1.07	1.03	1.00	1.01	0.99	N/A	0.98
9 (RFCE)	1.15	1.14	1.09	1.21	1.25	1.21	1.21	1.12	1.02	1.08	1.07	1.03	1.05	1.03	N/A	1.05
10 (RFCM)	0.98	0.98	0.98	1.01	1.02	1.00	1.00	0.99	0.99	0.99	0.98	0.98	1.00	0.98	N/A	0.97
11 (RFCW)	1.05	1.04	1.02	1.05	1.06	1.04	1.04	1.02	1.00	1.03	1.02	1.00	1.02	1.01	N/A	1.00
12 (SRDA)	0.92	0.93	0.93	0.95	0.96	0.93	0.93	0.92	0.97	0.96	0.93	0.94	0.96	1.00	N/A	0.89
13 (SRGW)	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.04	1.02	1.03	1.03	1.03	1.04	1.00	N/A	1.05
14 (SRSE)	0.92	0.93	0.93	0.95	0.97	0.93	0.94	0.92	0.97	0.96	0.93	0.94	0.96	0.93	N/A	0.89
15 (SRCE)	0.93	0.94	0.94	0.94	0.95	0.93	0.93	0.92	0.97	0.97	0.94	0.94	0.96	1.00	N/A	0.89
16 (SRVC)	0.89	0.91	0.91	0.91	0.93	0.88	0.89	0.88	0.96	0.95	0.91	0.91	0.95	0.92	N/A	0.84
17 (SPNO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
18 (SPSO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
19 (AZNM)	1.00	1.00	0.99	1.03	1.04	1.02	1.02	1.00	0.99	1.00	1.00	0.99	1.03	1.00	0.99	0.99
20 (CAMX)	N/A	N/A	1.12	1.24	1.29	1.25	1.24	1.15	1.03	N/A	1.08	1.06	1.12	1.05	1.13	1.11
21 (NWPP)	1.01	1.01	1.00	1.02	1.03	1.01	1.01	0.99	0.99	1.01	1.00	0.98	1.05	1.02	0.99	0.99
22 (RMPA)	0.99	0.99	0.97	1.02	1.05	1.01	1.01	0.96	0.98	1.01	0.97	0.95	1.03	N/A	0.93	0.93

Note: Geothermal and Hydroelectric plants are not included in the table because EIA uses site specific cost estimates for these technologies which include regional factors.

[15] The regional tables in the report were aggregated to the appropriate Electricity Market Module region in order to represent regional cost factors in NEMS

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SECI's responses to Staff's First Set of Interrogatories, Nos. 1, 2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 19, 20, 21, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 34.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 1, 2, 4, 5, 14, & 30)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 74
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Julia A. Diazgranados (1-5, 7, 14, 29-32)David Wagner (8, 16a, 17)Jason

1. **Please complete the following table regarding the projected system annual revenue requirement costs for capital, O&M, fuel, and emissions for each portfolio, listed below, over the 33 year period in nominal and net present value. Provide all requested data electronically in MS Excel format with all formulae intact.**
   - **b. SGS 2x1 Portfolio**
   - **c. CPP/CC Portfolio**
   - **d. Limited Build Risk: Shady Hills Portfolio**
   - **e. No Build Risk: All PPA Portfolio**

RESPONSE: See Attachment Q-1.

2. **Please complete the following table regarding the timeline of planned units, retirements, and purchased power agreements (PPAs) for each portfolio, listed below, considered over the 33 year period.**
   - **b. SGS 2x1 Portfolio**
   - **c. CPP/CC Portfolio**
   - **d. Limited Build Risk: Shady Hills Portfolio**
   - e. **No Build Risk: All PPA Portfolio**

RESPONSE: See Attachment Q-2.

3. Please provide the anticipated life span of the SGS coal units.

RESPONSE: Seminole estimates that SGS has a useful life through 2047.

4. Please provide Seminole's current and projected system summer and winter net capacity in MW and percent (to two decimal places) by primary fuel type assuming implementation of the CPP/CC portfolio for the years 2018-2051, including both owned generation and purchased power agreements in a table formatted similar to that of Schedules 6.1 and 6.2 of the Utility's Ten-Year Site Plan. Omit primary fuel types not used. Provide a description of the capacity sources in the "Other" category, should they exist.

RESPONSE: See Attachment Q-4.

5. Please provide the current and projected amount of summer and winter capacity of each primary fuel type that is generated by sources with dual-fuel capabilities, in MW and percent of system capacity, assuming implementation of the CPP/CC portfolio for the years 2018-2051, including both own generation and purchased power agreements in a table formatted similar to that of Schedules 6.1 and 6.2 of the Utility's Ten-Year Site Plan. Omit primary fuel types not used. Identify alternative fuel types used and an estimated duration of fuel at full capacity. Provide a description of the capacity sources in the "Other" category, should they exist.

RESPONSE: See Attachment Q-5 for information formatted similar to Ten-Year Site Plan Schedules 6.1 and 6.2. The following table identifies the number of hours of operation at full capacity utilizing Ultra LS Diesel fuel (the only alternative fuel type used by Seminole).

	MGS	Oleander	Hardee
Max Hrs. of Operation (Summer)	115	73	157
Max Hrs. of Operation (Winter)	103	68	133

7. **Please provide, on a system-wide basis, the actual annual fuel usage (in MWh) and average fuel price (in nominal $/MMBTU) for natural gas utilized by Seminole in the period 2016 through 2017. Also, please provide the forecasted annual fuel usage (in MWh) and forecasted annual average fuel price (in nominal $/MMBTU) for natural gas forecasted to be used by Seminole in the period 2018 through 2032. To complete your response, please populate Table 1 below.**

RESPONSE:

Table 1: Average Fuel Price (Includes Fixed and Variable Transportation Charges) and Consumption Comparison

Year		Natural Gas	
		MWh	$/MMBTU
Actual	2016	5,254,585	3.983
	2017	5,223,842	4.331
Projected	2018	5,907,640	4.686
	2019	6,168,608	4.464
	2020	6,554,213	4.404
	2021	6,530,551	4.393
	2022	6,678,985	5.022
	2023	8,890,057	4.776
	2024	9,105,236	4.819
	2025	9,503,828	4.823
	2026	9,762,185	4.873
	2027	9,923,697	4.947
	2028	10,094,125	5.009
	2029	10,270,507	5.090
	2030	10,486,844	5.152
	2031	10,683,773	5.816
	2032	10,818,529	5.877

8. Please identify and discuss expected industry trends and factors for natural gas that will affect Seminole during the period 2018 through 2032.

RESPONSE: Seminole has identified four key factors/trends for natural gas that will affect it during the period of 2018 through 2032. These factors are (1) strong demand growth for natural gas from the industrial sector and electric power sectors, (2) growth in liquefied natural gas (LNG) export facilities and liquefaction capacity in the United States, (3) continued growth in low-cost, unconventional gas production in the United States, and (4) continued development of natural gas pipeline infrastructure connecting key production areas with the existing pipeline grid and/or market areas in North America. The trends in growing demand for natural gas from the industrial and electric power sectors, along with the growth for LNG export, are being driven primarily by the relatively low price environment in the United States since 2009. Although the power sector will continue to see some of that growth negated by increasing renewable generation over the near term, some power companies, including Seminole, are accelerating plans to transition their older coal-fired generating resources over to more efficient, gas-fired units as a cost-effective alternative. The forward NYMEX curve for gas prices also reflects this continued expectation of ample supply to feed the growing demand with the calendar-year average price remaining below $3.00/mmBtu through 2025 and rising to only $3.35/mmBtu by 2030[1]. Gas production growth, primarily from shale gas and associated gas from tight oil plays, is the key reason for the low price environment and such continued growth will be dependent on adequate oil and gas resources, producer efficiency and drilling technology. Lastly, as natural gas demand has increased, or in some cases developed in areas where gas was not previously available, pipeline infrastructure has developed to connect these unconventional production regions with new markets. Seminole sees this trend continuing during the early part of the forecast period and infrastructure developing beyond the first five years will be dependent on the geographical characteristics of future supply and demand centers.

[1] NYMEX forward natural gas prices based on closing prices for January 23, 2018.

9. Please provide the dates for the last actual data point (as opposed to forecasted data point) of each of the input variables used in the econometric models and forecasts identified in Seminole's response to Staff's First Request for Production of Documents, Nos. 10, 11, and 13, if not otherwise evident in the response to the requests.

RESPONSE: See the file labeled "170266- Staff's 1st POD Nos. 10,11,13-Data Sources."

10. What are the preparation dates for each of the models and forecasts appearing in response to Staff's First Request for Production of Documents, Nos. 10, 11, and 13.

RESPONSE: The preparation dates for each of the referenced models and forecasts for the base scenario is June 29, 2017. For severe and mild scenarios, the preparation dates for demand and energy are August 3, 2017 and August 4, 2017, respectively.

Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

11. Please refer to pages 16-17, Section 3.3.3. Please explain whether or not the Tillman Solar Center LLC Solar/PV generating facility and the Cooperative Solar facility will be operated in the winter season. If so, please provide their winter capacities. If not, please provide an explanation.

RESPONSE: Both the Tillman Solar Center and the Cooperative Solar facility will be operated during all hours of the year, subject to normal facility outage and maintenance needs. Similar to the balance of the year, production will not be constrained/restricted during the winter season; Seminole will take all MWh produced.

When commercial, the expected MWh output annually for the Tillman Solar Facility is 108,046 MWh, assuming a facility capacity rating of 40 MW. A monthly breakdown of expected energy output from the Tillman Solar Center is provided in the table on below. Note that the expected energy output is lowest during the months December-February, which are the typical winter peaking months for Seminole's system.

Month	Estimated Facility Energy Production (MWh)	
January	(a)	6,820
February	(b)	7,299
March	(c)	9,562
April	(d)	10,592
May	(e)	11,648
June	(f)	10,460
July	(g)	10,551
August	(h)	10,156
September	(i)	8,506
October	(j)	8,939
November	(k)	7,308
December	(l)	6,205
Total	(m)	108,046

The Cooperative Solar facility is budgeted to provide approximately 5,122 MWh to Seminole's system in 2018, assuming a facility capacity rating of 2.2 MW. A monthly breakdown of expected energy output from the Cooperative Solar facility is provided in the table below. Note that the expected energy output is lowest during the months of December - February, which are the typical winter peaking months for Seminole's system.

Month	Generation (MWh)
Jan	318.2
Feb	361.9
Mar	403.8
Apr	550.1
May	569.1
Jun	513
Jul	496.5
Aug	467.1
Sep	420.8
Oct	421
Nov	322
Dec	278.8
Total	5122.3

Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

12. Please refer to page 30, Table 5. Detail what is included in the "Other Owner's Costs and Contingency" category.

RESPONSE: The "Other Owner's Costs and Contingency" category includes the cost associated with a variety of anticipated activities, carried out directly by Seminole or indirectly by consultants that Seminole would hire, that will support the execution of the SCCF project. Among those anticipated activities are:

- establishing an on-site camera system to visually document project progress over time,
- in-factory quality assurance oversight of manufactured components,
- legal services,
- site construction management services,
- owner's engineering support services,
- training of owner's operations and maintenance staff during commissioning,
- internal project management services,
- a performance bond (optional).

This category also includes owner's contingency reserve for any currently unidentified and unknown potential costs that may be associated with scope increases, changing regulatory requirements, schedule delays, or other unanticipated challenges.

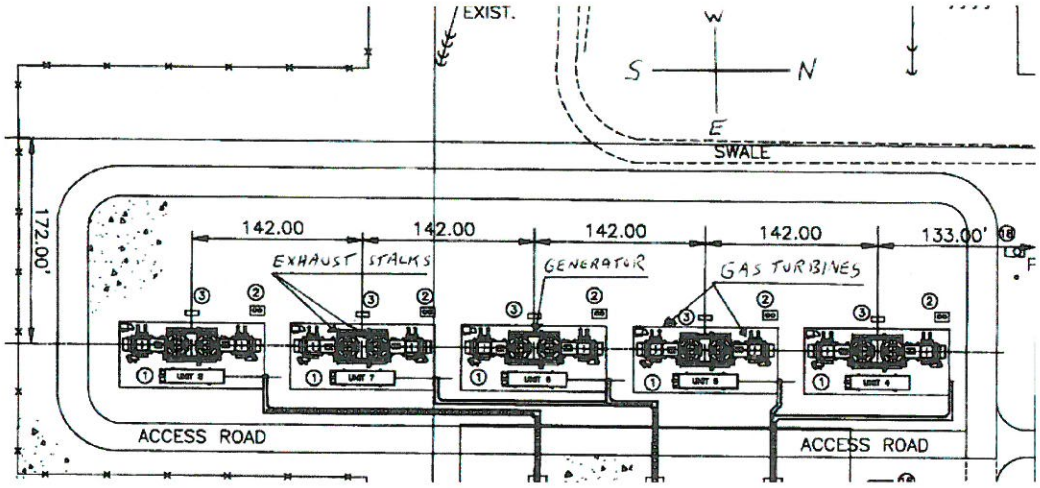
Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

13. Please refer to pages 50-51, Section 6.2.1. Please explain whether or not upgrading the Midulla Generating Station's combustion turbine units to combined cycle configurations was evaluated as a self-build alternative for its feasibility in meeting Seminole's demand. If not, please provide an explanation.

RESPONSE: Seminole considered, but did not evaluate in detail, the conversion of the Midulla Generating Station (MGS) simple cycle combustion turbines into combined cycle configurations. Seminole believes that such a project would be technically difficult, if not impossible, and commercially infeasible for the following reasons:

- Each Pratt & Whitney FT-8 Twin Pack combustion turbine set is configured such that two separate gas turbines are connected to a single generator that sits in line with and in between the gas turbines. There are five Twin Packs at MGS for a total of 10 simple cycle gas turbines. This two-turbines-on-one, shared-generator configuration of these aeroderivative combustion turbines is particularly designed for the fast response and flexible output generally desired in peaking assets.
- Each of the five twin packs were originally installed in a single straight line as shown in the drawing and photograph below.
- Upgrading to combined cycle operation would require the installation of multiple heat recovery steam generators (HRSGs) to capture the heat energy in the exhaust gasses in the form of steam and at least one, but likely more, steam turbine generators (STG) to convert that steam into electrical energy.
- In order to add HRSGs to the FT-8s one would have to either 1) build them vertically in line with the existing exhaust stacks or 2) horizontally on land further to the west (up on the drawing). Building them vertically would be cost prohibitive, if technically possible, as they are very heavy and supporting all the additional weight would require a complete redesign and reconstruction of the existing foundations below the FT8s. Building them horizontally would require extending elevated ductwork from the cylindrical portion of each exhaust stack to HRSGs and new stacks installed to the west of the existing FT8s. Space is limited to the west by existing 230 kV transmission lines serving the existing combined cycle facility at MGS and would potentially require their relocation. Such relocation would also run into space constraints.
- The gas turbines run on an individual basis so combining the exhaust gasses from two turbines into one HRSG would cause the HRSG to run in a thermodynamically inefficient operating condition if only one turbine were operating. Hence, five HRSGs may be possible but ten HRSGs would allow better size optimization.
- Additionally, at least one steam turbine generator (STG) would be required to be installed in this tight space. Again, from a thermodynamic standpoint, more than a single STG that is sized to accept steam generated from ten gas turbines is highly impractical if feasible at all. Adding more STGs would improve the operation but add significantly more cost.

- Furthermore, transmission constraints at the MGS site represent another financial impediment to this combined cycle conversion concept. In fact, Seminole evaluated adding a sixth FT-8 Twin Pack peaking unit at MGS in the 2007 timeframe and discovered that the additional 62 MW from this unit would result in a requirement to upgrade multiple transmission lines in order to reliably interconnect the sixth unity to the transmission system. This made adding another peaking unit cost prohibitive. A steam turbine generator sized to accept steam from the five (5) existing peaking units would likely generate well over 100 MW and result in a minimum of the same required upgrades, in addition to the possibility of new overloads due to additional generation in the Hardee/Polk area load pocket since 2007, *e.g.* TECO Polk Expansion just north of MGS.
- In summary, the capital cost of upgrading MGS's combustion turbine units to combined cycle configurations with the consequential transmission system impact cost and the inherent operational inefficiencies would result in a commercially uncompetitive facility.





Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

14. Please refer to page 109. Provide a reserve margin calculation in the format of Schedule 7.1 and 7.2 of the Utility's Ten-Year Site Plan for each portfolio, listed below, considered over the 33 year period. Provide all requested data electronically in MS Excel format with all formulae intact.

a. SGS 2x1 Portfolio
b. CPP/CC Portfolio
c. Limited Build Risk: Shady Hills Portfolio
d. No Build Risk: All PPA Portfolio
e. Provide the Utility's 2018-2027 reserve margin calculation in the format of Schedule 7 of the Utility's Ten-Year Site Plan without including any planned units or planned purchases. Provide all requested data electronically in MS Excel format with all formulae intact.

RESPONSE: See Attachment Q-14.

15. Please refer to page 112. Provide data in the format of Schedule 9 of the Utility's Ten-Year Site Plan for the Seminole Combined Cycle Facility.

RESPONSE:

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	SGS CC Facility
2	Capacity	
	a. Summer (MW):	1108
	b. Winter (MW):	1116
	c. ISO (MW):	1122
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing	
	a. Field construction start-date (1):	December 2019
	b. Commercial in-service date:	December 2022
5	Fuel	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	
6	Air Pollution Control Strategy	Dry Low-NOx burners, SCR, and Oxidation Catalyst
7	Cooling Method:	Wet Cooling Tower with Forced Draft Fans
8	Total Site Area:	SGS
9	Construction Status:	Planned
10	Certification Status:	Planned
11	Status With Federal Agencies	N/A
12	Projected Unit Performance Data	
	Planned Outage Factor (POF):	4.00
	Forced Outage Factor (FOF):	3.00
	Equivalent Availability Factor (EAF):	93.00
	Resulting Capacity Factor (%):	79%
	Average Net Operating Heat Rate (ANOHR):	6328 Btu/kWh (HHV) - ISO Rating
13	Projected Unit Financial Data ($2022)	
	Book Life (Years):	30
	Total Installed Cost (In-Service Year $/kW)(2):	648
	Direct Construction Cost ($/kW):	608
	AFUDC Amount ($/kW):	40
	Escalation ($/kW):	Included in values above
	Fixed O&M ($/kW-Yr):	15
	Variable O&M ($/Run Hour):	0
	Variable O&M ($/MWH):	0.114
	K Factor:	N/A

NOTES:

(1) Assumes thirty-six months of construction.

(2) Calculated at ISO rating.

Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

16. Please refer to pages 20-34, Section 4.0.

a. In terms of quality and function, are there any differences between the natural gas used in the proposed SCCF and SHCCF? Will both SCCF and SHCCF use the same type of natural gas which come from the same supplier?

RESPONSE: The SCCF and SHCCF will both receive natural gas supply from the FGT system and as such, the gas quality will be similar and conform to the specifications contained in FGT's FERC approved tariff.

b. What is the function of the "dew point fuel heaters" (page 32) to be used in SHCCF, and how often it will be used?

RESPONSE: Hydrocarbon condensation occurs due to a drop in natural gas temperature – particularly following pressure reduction or when the gas expands through a control valve. To eliminate concerns of these phenomena at Shady Hills, incoming natural gas is directed through an electric heater to raise the gas temperature dew point in accordance with OEM recommendations (approximately 50 degrees Fahrenheit above the dew point of these hydrocarbons). This prevents liquid hydrocarbons from forming and entering the turbine's combustion system where they could cause harm to the equipment.

The Shady Hills dew point heater is controlled via an outlet temperature control. The actual heating is accomplished using electricity provided within the plant's expected auxiliary (parasitic) load. This dew point heater is only used during a turbine start.

A "performance heater" is also included in the plant design which uses hot water from the plant to heat the fuel gas to the combustion turbine during normal operation. When the plant reaches sufficient load and high temperature feedwater is available for heating, this downstream performance heater is placed into service and the startup dew point heater is shut down.

c. Please explain why only the proposed SHCC, but not SCCF, needs the dew point fuel heaters for the purpose of control the regulated SO2 and PM air emissions.

RESPONSE: SCCF will utilize dew point heaters as well. By mitigating the possibility of liquids precipitating from the cooled natural gas, the heaters help to control the formation of unusual combustion product compounds (potentially SO2 or particulates from sulfur compounds) that could be generated by having liquids entrained in the natural gas supply.

d. On page 24, Seminole explains that the proposed SCCF will achieve the control of CO and VOCs emission through use of oxidation catalyst system.

How will the proposed SHCCF achieve the control of CO and VOCs emission?

RESPONSE: GE's 7HA.02 combustion turbine is a high efficiency unit that allows for low CO and VOC emissions. CO and VOC emissions are formed by incomplete combustion of fuel, and the 7HA.02 combustor technology uses high combustion temperatures, adequate excess air, and good fuel/air mixing during combustion to minimize CO and VOC formation. Good combustion practices will limit CO and VOC formation to levels that are consistent with BACT emission limits for CO and VOC that were adopted by the FDEP for the FPL Okeechobee Clean Energy Center (OCEC); Permit No. 0930117-001-AC/PSD-FL-434 and Dania Beach Energy Center (DBEC); Permit No. 0110037-017-AC/PSD-FL-442. The CO and VOC emission limits that will be requested for SHCCF will be substantially similar to the emission limits established as Best Available Control Technology (BACT) for CO and VOC emissions for OCEC and DBEC by FDEP.

Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

17. **Please refer to pages 56-57, please provide explanation of, and the rationale on, how the Natural Gas High Price Forecast and Natural Gas Low Price Forecast were derived versus the Natural Gas Base Price Forecast.**

RESPONSE: Seminole utilizes a statistics based approach to develop alternate (i.e. high/low) gas price projections for scenario analysis and planning evaluations. Seminole uses a process similar to that used by the EIA to establish its confidence interval around forecasted gas prices in its Short-Term Energy Outlook[1]. Seminole's process is based on the following assumptions:

- Alternate gas curves form a statistical confidence interval around Seminole's base case forward curve
- Alternate gas curves use a 68% confidence interval (represents +/- one standard deviation)

For the volatility inputs required in the analysis, Seminole uses implied volatility from the NYMEX options market and extrapolates a volatility forward curve beyond the horizon of available NYMEX data.

[1] October 2009 Short-Term Energy Outlook Supplement: Energy Price Volatility and Forecast Uncertainty https://www.eia.gov/outlooks/steo/special/pdf/2009_sp_05.pdf

Interrogatory Nos. 11-19 pertain to Exhibit No. MPW-2, sponsored by Witness Michael P. Ward II.

19. Please refer to page 33 for the following questions.

a. Who will construct the "new interconnection with FGT" to supply the natural gas to the SHCCF?

RESPONSE: The new gas interconnection facilities will be constructed in part or in whole by FGT. Any portion not constructed by FGT will be constructed by Shady Hills Energy Center, LLC.

b. If the new interconnection discussed in 16(a) will be built by Seminole:

- **Has the associated costs been included in the economic analysis presented in Figure 13 on page 65?**
- **If your response to the above is no, please explain why not.**

RESPONSE: As stated above, the new interconnection with FGT will not be built by Seminole.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

20. Please refer to pages 66-71, Section 7.0. Please explain whether or not energy-storage technologies such as batteries, pumped hydropower, flywheels, thermal storage, synthetic fuels, and compressed air, including any other modalities, were evaluated for their feasibility to shift peak demand and flatten Seminole's demand curve. If not, please provide an explanation.

RESPONSE: Seminole did not specifically evaluate any of the listed technologies for their feasibility to shift peak demand on its system. However, through the issuance of its RFP, Seminole sought input from the wholesale power markets to identify viable commercial alternatives to serve the energy demands of its member systems. Seminole did receive several proposals for solar with battery storage and evaluated those proposals in its review process. In its evaluation process, Seminole chose to focus on conventional solar offerings due to the combination of economic savings and the challenges with battery proposals meeting longer summer peaks.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

21. Please refer to pages 66-71, Section 7.0. Please explain whether or not distributed renewable generation was evaluated for its feasibility in meeting Seminole's baseload, intermediate, and peaking capacity demands. If not, please provide an explanation.

RESPONSE: Seminole did not specifically evaluate distributed renewable generation for its feasibility to meet Seminole's future capacity needs. However, through the issuance of its RFP, Seminole sought input from the wholesale power markets to identify viable commercial alternatives to serve the capacity demands of its member systems. Seminole and its members are committed to renewable generation, with almost 4% of its member's energy requirements expected to come from renewable resources in 2018.

Additionally, a provision to Seminole's Member Wholesale Power Contract provides each member the flexibility to install owned or leased distributed renewable generation not to exceed five percent of their average annual peak demand for the three prior calendar years. This provision also provides Members the ability to own or lease dispatchable peak shaving generators, and to utilize net metering for member-consumers. The Members ability to own or lease distributed renewable generation is accounted for in the load forecast. Likewise, behind-the meter solar generation is reflected in model training data and implied in Seminole's load forecast. Future expectations of additional behind-the-meter solar adoption are forecasted separately and are netted from energy and demand forecasts.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

23. Please refer to page 69, Table 18. Please explain why some conservation and DSM programs are only available to member-customers of select Member cooperatives.

a. Is there a strategy in place to increase program adoption by Member cooperatives?

RESPONSE: Seminole's Members are member-consumer owned, individual retail suppliers of end-use electricity. Members determine individually which conservation and DSM programs to implement. As the wholesale provider of electricity, Seminole provides Members with information, education and training resources related to conservation and DSM programs by facilitating the Energy Efficiency Working Group (EEWG). Seminole coordinates and implements programs based on Member request.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

24. Please refer to pages 70-71, Section 7.2. Please provide an estimate of the benefits to Seminole's demand and to Seminole's member-customers that implementation of the Smart Thermostat measure will yield. As part of this response, describe how these benefits are realized.

RESPONSE: The estimated demand savings for the smart thermostat program reflected in the Advanced Energy and Tierra Resource Consultants (AE/Tierra) analysis was 0.14 kW per participant and the projected number of participants in the first year was 1517 homes. The total demand savings was 212 kW. The benefits to member-customers include an estimated annual savings of 366 kWh and $50.36 per home. Benefits from smart thermostats are generally realized by utilizing temperature setbacks during unoccupied times resulting in lower HVAC energy use and costs for participants. The projections presented in the AE/Tierra analysis are not based on the full use of the demand response features of a smart thermostat. Seminole is currently investigating a smart thermostat pilot program which will utilize such demand response features. Utilizing demand response should increase demand savings and program costs. Implementation of the pilot program will enable Seminole to estimate the benefits to Seminole's demand.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

25. Please refer to page 47, Table 15. Please explain how Seminole developed its "Base," "Low," and "High" scenarios/sensitivities of the "Net Energy for Load," "Summer Net Firm Demand," and "Winter Net Firm Demand," forecasts shown in Table 15.

RESPONSE: Seminole forecasts delivery-point metered energy and Member-coincident demand. Forecasts of Member demand coincident with Seminole are derived by applying coincident factors to Member-maximum demand forecasts. Out of model adjustments are then applied, including adding back Member-specified forecasts for non-weather sensitive large loads, netting the expected amount of load generated by the Southeastern Power Authority (SEPA), and netting the projected incremental amount of distributed renewable generation behind the meter. Next, Member forecasts are then disaggregated by a projected ratio of Member load by transmission-supplier area, re-aggregated to transmission-supplier total, scaled up by transmission supplier losses, and then aggregated to Seminole total. Finally, firm sales are added and the demonstrated capacities of distributed diesel generators are netted. This process creates Seminole's Net Energy for Load and Net Firm Demand.
The Base, High and Low scenarios represent load outcomes if the future distribution of temperatures is similar to the past distribution; all other exogenous parameters are equal. Seminole developed Net Energy for Load forecast scenarios utilizing the 50^{th}, 10^{th} and 90^{th} percentile ranks of temperature distributions, respectively. Low and High forecast scenarios of seasonal Net Firm Demand are developed the same way, however the Base forecast scenario of Net Firm Demand utilizes the average of the temperature distribution.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

26. Please refer to page 47, Table 15, "Winter Net Firm Demand – Base". What are the factors/drivers accounting for the forecasted 5-year average annual growth rate of positive 1.8 percent, given the most recent 4-year historical "AAGR '13-'17," is negative 1.7 percent? As in, what is behind the change in trend from decreasing winter demand to increasing winter demand?

RESPONSE: Weather is one of the primary drivers for changes in winter demand year over year. Due to the volatility of winter weather, interpreting the actual AAGR can be unclear, and can obscure load trends due to population, income, price of electricity or the adoption of energy efficient technologies. The AAGR statistic for future projections of winter demand is subject to less volatility, since weather parameters in the model are constant every year and only the growth parameters are modeled to be dynamic.

Examining the average of winter demand per consumer over the course of several years can reduce noise due to weather volatility. Over the five year period from 2013 through 2017, average winter demand per consumer was approximately 4.42 kW. Seminole estimates average winter demand per consumer to average approximately 4.42 kW over the next 5-year and 10-year period.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

27. **Please refer to pages 45 and 47, featuring Tables 13 and 15, respectively. Table 13 shows that the average annual growth rate (AAGR) for total sales is expected to decrease significantly in the 2018-2022 period compared to the AAGR for the 2012-2016 period (2.7% versus 1.3%, a 1.4% decline). Table 15 shows that the AAGR for winter net firm demand is expected to increase significantly in the 2018-2022 period compared to the AAGR for the 2012-2016 period (-1.7% versus 1.8%, a 3.6% increase). What is the cause for the expected opposing change in growth rates for sales (decreasing) and winter net firm demand (increasing). If the cause is evident in data otherwise provided by Seminole in response to staff discovery, please identify such discovery item responses.**

RESPONSE: These differences reflect consumer electricity use behavior, which are significantly driven by changes in weather. The high average annual growth of approximately 2.7% in total sales from 2012 through 2016 is due in part to an abnormally hot summer in 2016. During that year, member-consumers used an above-average amount of electricity to cool their homes and businesses. The abnormally warm weather continued into the 2016/2017 winter, which caused consumers to use significantly less electricity for heating than normal. In fact, demand during the winter of 2016/2017 was the lowest since at least 2007. The cause is evident in input data sets provided in response to staff discovery items POD-11 and POD-13.

Future expectations of load growth are modeled with weather parameters that are constant through time, (i.e. future weather is not modeled to fluctuate year-over-year). Given constant weather parameters modeled in the future, load growth is expected to be a function of dynamic parameters including population growth, economic growth, and growth in energy efficient technology adoption. After these explanatory parameters have been accounted for, time series techniques including autocorrelation methods (AR) and moving averages (MA) are employed to enhance model fit and increase near-term forecast accuracy. Choice of ARMA variables are based on efficiency gains to the overall training period and recent history through holdout and backcast analysis.

Interrogatory Nos. 20-28 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Kyle D. Wood.

28. Please refer to page 47, Table 15. Why is the average annual growth rate (AAGR) for summer net firm demand decreasing from 2.9% for 2012-2016 to 1.2 percent for 2018-2022 while the AAGR for winter net firm demand is expected to increase during those periods from -1.7% to 1.8%? If the cause is evident in data otherwise provided by Seminole in response to staff discovery, please identify such discovery item responses.

RESPONSE: Refer to answers to Interrogatories #26 and #27 and the additional information below.

In the near term, seasonal demands are projected to follow recent trends, which have been significantly influenced by consecutive years of warm weather. Future summer net firm demand also includes 15 MW of firm sales through 2020; without these firm sales the AAGR for summer net firm demand is 1.3% from 2018-2022. Overall, average demand per consumer was projected to be approximately 0.4 kW lower (8.2% decrease) in the winter and 0.2 kW (5.6% decrease) in the summer than the prior 10-year seasonal average.

On January 18, 2018, Seminole recorded the 2017/2018 estimated-actual winter net firm demand to be approximately 3,853 MW. Given this preliminary information, the 2018-2022 AAGR for winter net firm demand is expected to be -1.4%.

Interrogatory No. 29 pertains to the direct testimony of Witness Julia Diazgranados.

29. Please refer to page 10, lines 8-10. If the Seminole Generating Station (SGS) coal units are still high-performing assets, please explain why it is more cost effective to retire one of the units and to build/purchase additional capacity to meet the Utility's needs.

RESPONSE: The SGS coal units are still high-performing assets for the class of generation they are in (sub-critical coal units) and deliver a significant amount of our base energy. In addition, they are a reliable source that provides Seminole with fuel diversity. However, the cost of maintaining and satisfying environmental requirements make the coal units a less attractive option given the high efficiencies of the new models of CC and the low natural gas price projections.

a. Please explain if the SGS unit selected for retirement will be maintained for potential operation in the future or if it will be dismantled.

RESPONSE: The selection of which unit will be taken out of service and the determination as to maintaining it for potential future use, dismantling or leave in place has not yet been made.

Interrogatory Nos. 30-32 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Julia Diazgranados.

30. Please refer to pages 61 and 65.

a. **Please explain why Seminole based the Various Carbon Tax used in its sensitivity analyses of economic evaluation on Minnesota PSC Carbon tax assumptions.**

RESPONSE: As Seminole's evaluation process moved toward the consideration of sensitivity analyses, Seminole approached its Independent Evaluator, Sedway Consulting, to inquire about what other utilities around the country were assuming in their power procurement activities with regard to future potential costs of greenhouse gas (GHG) emissions. Although Sedway Consulting was aware of several confidential forecasts (that obviously could not be provided as they were confidential), the IE noted that the Minnesota PSC had public directives that could form an adequate basis for Seminole's sensitivity analyses. Thus, Sedway Consulting provided Seminole with this public information.

b. **Please provide all the details of Minnesota PSC Carbon Tax assumptions.**

RESPONSE: The Minnesota Public Utilities Commission (MPUC) had established an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation of $9/ton to $34/ton for CO2 emitted in 2019 and thereafter. It did so in its April 28, 2014 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06, in Docket No. E-999/CI-07-1199.

c. **Referring page 61, please provide the rationale on the following assumptions:**
- **Low Carbon Tax starting at $9.00/ton,**
- **Mid Carbon Tax starting at $21.50/ton, and**
- **High Carbon tax starting at $43.00/ton.**

RESPONSE: Please note that the reference in the testimony to $43.00/tons the High Carbon Tax starting value was a scrivener's error; the correct value for the High Carbon Tax starting value used in the analyses is $34.00/ton. The low and high values come from the MPUC information described in the response to part b above. The $21.50/ton mid value has been a generally accepted mid-range value for use in Minnesota generation planning and power procurement analyses.

d. Please **provide the projected High, Mid and Low Carbon Taxes for the period 2018 through 2051.**

RESPONSE: See Attachment Q-30.

e. **Please identify which of the Carbon Tax scenario (Low, Mid or High) was used in deriving Figure 13 "Summary of Updated Economic Analysis" on page 65.**

RESPONSE: None. Given that the base economics were derived with the assumption that there would not be a carbon tax, Seminole performed the three Carbon Tax scenarios.

f. **Has Seminole performed the economic analysis in which zero Carbon Tax was assumed? If not, please explain the reason, and provide an analysis similar to that shown in Figure 13 on page 65 assuming zero Carbon Tax.**

RESPONSE: Yes, only the low, mid, and high carbon tax sensitivity analyses contain a carbon tax component. All other sensitivities, including the base, do not include a carbon tax assumption.

Interrogatory Nos. 30-32 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Julia Diazgranados.

31. Please identify which of the Natural Gas Price Forecasts (Base, High or Low) was used in deriving Figure 13 Summary of Updated Economic Analysis presented on page 65.

RESPONSE: The Portfolio Summaries in Figure 13 used the base natural gas price forecast in deriving the total Member revenue requirements.

Interrogatory Nos. 30-32 pertain to the sections of the Need Study, filed in Exhibit No. MPW-2, that are sponsored by Witness Julia Diazgranados.

32. Has Seminole performed an economic analysis in which High Natural Gas Price with zero Carbon Tax scenario was assumed? If not, please explain the reason, and provide an analysis similar to that shown in Figure 13 on page 65 assuming zero Carbon Tax with High Natural Gas Price Forecast.

RESPONSE: Seminole performed an economic analysis for Optimistic (high load and low natural gas prices) and Pessimistic (low load and high natural gas prices) which represent the book-ends of the best and worst case scenarios for Member rates. Therefore, Seminole did not believe it was necessary to run economic analysis on the different components since Member rates would fall somewhere in the middle.

Portfolio Summaries
High Natural Gas - Economic Analysis Results
(millions of $)

	SGS 2x1 Portfolio	CPP/CC Portfolio	Limited Build Risk: Shady Hills Portfolio	No Build Risk: All PPA Portfolio
Resources	-SGS 2x1 -Multiple PPA	-SGS 2x1 -Shady Hills 1x1 -Multiple PPA	-Shady Hills 1x1 -Multiple PPA	-Multiple PPA
Total Member Revenue Requirements - Years 2018-2027 (millions of $)				
Nominal	13,282	13,398	13,074	**12,997**
NPV @ 6.0%	9,638	9,712	9,499	**9,429**
Total Member Revenue Requirements - Years 2018-2051 (millions of $)				
Nominal	**69,334**	70,608	70,173	69,685
NPV @ 6.0%	**24,680**	25,030	24,818	24,662

Interrogatory No. 34 pertains to the direct testimony of Witness Ankur Mathur, filed in Docket No. 20170267-EC.

34. Please refer to page 5, lines 1-8. Describe how successful these tolling agreements are/were and identify any issues encountered.

RESPONSE: These tolling agreements have been successful, when considering (a) the ability to provide a stable source of revenue that supports financing for the underlying power projects, and (b) the ability to provide a reliable, cost-effective source of capacity, energy and ancillary services for each off-takers supply portfolio.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 1-5, 7, 14, 29-32 of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados
Julia Diazgranados

Director of Treasury & Planning
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Kezell, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 12, 13, 15, and 16c of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Kezell

Director of Engineering & Capital Development
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
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Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF CONNECTICUT)
)
COUNTY OF FAIRFIELD)

Before me, the undersigned authority, personally appeared Ankur Mathur, 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. 16b, 16d, 19, and 34 of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Ankur Mathur

Vice President, Shady Hills Energy Center, LLC
Title

Notary Public
State of Connecticut

My commission Expires:

DENISA PLETENIKOVA
Notary Public-Connecticut
My Commission Expires
October 31, 2020

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Jason Peters, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 11, 20, 21, and 33 of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Jason Peters

Portfolio Director
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
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Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Wagner, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 6, 8, 16a, 17, and 18 of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Wagner

Portfolio Director
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
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NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle D. Wood, 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. 9, 10, 21-28 of The Florida Public Service Commission's First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle D. Wood

Manager of Load Forecasting and Member Analytics
Title

Rebecca Witherow
Notary Public
State of Florida

My commission Expires: June 20, 2021

REBECCA WITHEROW
Notary Public – State of Florida
Commission # GG 077134
My Comm. Expires Jun 20, 2021
Bonded through National Notary Assn.

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SECI's responses to Staff's First Set of Interrogatories, No. 18.

(CONFIDENTIAL DN. 01988-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 75
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Wagner

76

SECI's responses to Staff's First Set of Interrogatories, No. 33.

(CONFIDENTIAL DN. 01988-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 76
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Jason Peters (33)

77

SECI's responses to Staff's Second Set of Interrogatories, No. 35, 36.

(CONFIDENTIAL DN. 01826-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 77
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Kezell (35)Ankur Mathur (36)

78

SECI's responses to Staff's Second Set of Interrogatories, Nos. 37, 38, 40, 41.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 78
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Julia A. Diazgranados (37)David Kezell (38)Michael P. Ward II (40)

37. Please refer to Seminole's response to Staff's First Set of Interrogatories, Question No. 2. Please explain why Seminole includes generic combined cycle and combustion turbine additions in the "No Build Risk: All PPA Portfolio".

RESPONSE: Seminole has included generic units in all four of the portfolios to back fill as PPAs expire.

38. Please refer to Witness Ward's testimony, Exhibit MPW-2, pages 50-51. Please explain whether or not upgrading Seminole Generating Station Units 1 and 2 to improve their efficiency or output was evaluated as a self-build alternative for its feasibility in meeting Seminole's demand. If so, please provide the results of this evaluation. If not, please provide an explanation.

RESPONSE: Various projects have been implemented over the years on the SGS coal units to improve their heat rate. As new technologies emerge that have potential for application at SGS they are evaluated on a case-by-case basis to determine their advisability. There were no new SGS Unit 1 and Unit 2 improvement evaluations done as part of Seminole's self-build alternatives for meeting new demand. The SGS coal units could not be feasibly or cost-effectively retrofitted to achieve the amount of additional capacity required to meet Seminole's projected need.

40. Please refer to Witness Ward's testimony, Exhibit MPW-2, page 65. Please explain why Seminole selected the least cost portfolio based on Total Member Revenue Requirements for Years 2018-2051 instead of basing the selection on Total Member Revenue Requirements for Years 2018-2027.

RESPONSE: Seminole selected the most cost-effective, risk managed resource plan based on analyzing both the total revenue requirements for the years 2018-2051 as well as the total revenue requirements for the years 2018-2027. This along with the non-economic considerations included in the portfolio scorecard assessment resulted in the selection of the CPP/CC Portfolio. While the No Build Risk-All PPA Portfolio has a lower CPVRR of approximately $136 million in the 2018-2027 time period in comparison to the CPP/CC Portfolio during the same time period, the No Build Risk-All PPA Portfolio has the additional risk and uncertainty associated with having to go back into the market for replacement resources as the PPAs expire. It should also be noted that for the first few years, up to 2021, both portfolios have the same resource mix.

It is an industry standard practice to evaluate new generation facilities over a reasonable life expectancy. Most natural gas generating facilities have a life of 30 plus years. Because Seminole was evaluating new generation facilities (both owned and PPAs), we believed it prudent to have a study period that would cover the life expectancy of these units. Traditionally, revenue requirements for cooperative owned generation decline over the life of the facility whereas PPA pricing is usually flat or even escalating.

The portfolio scorecard assessments, which factored in operational flexibility for both real time and fuel, and strategic considerations, were also drivers; and as noted above, economics, not only for the 30+ years but also the 10 years were considered. In the end the CPP/CC Portfolio had the best scorecard ranking of all the portfolios making it the most cost effective, risk-managed alternative.

41. Please refer to Witness Ward's testimony, Exhibit MPW-2, page 66. Please describe Seminole's responsibilities in the facilitation of the Energy Efficiency Working Group.

RESPONSE: Seminole is committed to a comprehensive energy management program, which encourages the efficient use of electric energy. Seminole implements its commitment through the joint Energy Efficiency Working Group (EEWG) with its Members. Seminole assists its Members in the development and implementation of comprehensive energy conservation programs through training, technical assistance, and informational programs. Seminole conducts cost effectiveness studies regarding various approaches to energy management, including but not limited to demand side management, energy efficiency programs, and distributed energy resources.

The focus of Seminole's responsibilities in the EEWG is to facilitate information sharing on successful energy conservation and energy efficiency programs, to evaluate demand-side management/conservation programs, and to expand consumer education programs and information related to energy efficiency and energy conservation. Seminole coordinates and hosts the group meetings at least two times per year. Seminole also facilitates training and education efforts for Member staff, including classes on infrared thermal imaging, heating, ventilation, and air conditioning (HVAC) analysis, whole-home duct and envelope tightness analysis, and most recently, a solar photovoltaic workshop held in conjunction with the Florida Solar Energy Center. Seminole also coordinates with Members on consumer education by providing energy efficiency videos, and energy efficiency information and materials that can be made available to consumers in both English and Spanish.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 37 and 39 of Staff's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of her knowledge, information and belief.

Julia Diazgranados

Director of Treasury & Planning
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
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Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Kezell, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 35 and 38 of Staff's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Kezell

Director, Engineering and Capital Development
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
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NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Michael Ward, who

( ) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 40 of Staff's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Michael Ward

Vice President of Strategic Initiatives
Title

Stephanie H. Saxby
Notary Public
State of Florida

My commission Expires:



AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle D. Wood, 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. 41 of the Public Service Commission's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle D. Wood

Manager of Load Forecasting & Analytics
Title

Rebecca Witherow
Notary Public
State of Florida

My commission Expires: June 20, 2021

REBECCA WITHEROW
Notary Public - State of Florida
Commission # GG 077134
My Comm. Expires Jun 20, 2021
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79

SECI's responses to Staff's Third Set of Interrogatories, Nos. 42, 44, 46, 48, 49, 50, 51, 52, 53, 54, 55, 57, 59, 60, 61, 62.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 44 & 62)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 79
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Thomas Hines (42, 44)Alan S. Taylor (46, 48-51)David Kezell (52,

42. **Please refer to Witness Hines' testimony, Exhibit TH-2, page 8 of 20. Please provide the percent of member-consumers that have dispatchable demand response by class, including residential, commercial, industrial, and "other" member-consumers.**

RESPONSE: The percent of member-consumers that have dispatchable demand response by Seminole Member and customer class is shown in the table below.

Seminole Member	% of Member Consumers with Dispatchable Demand Response			
	Residential	Commercial	Industrial	Other
Central Florida	0%	0%	0%	0%
Clay	0%	0%	0%	0%
Glades	0%	0%	0%	0%
Peace River	0%	0%	0%	0%
Sumter	0%	0.2%	0%	0%
Suwanee	0%	0%	0%	0%
Talquin	0%	0%	0%	0%
Tri County	0%	0%	0%	0%
Withlacoochee	0%	0%	0%	0%

44. **Please refer to Witness Hines' testimony, Exhibit TH-3, page 12 of 25. Please provide Utility Cost Test (UCT) and Ratepayer Impact Measure (RIM) Test results collectively evaluating all of Seminole's Members' existing residential energy audit programs, excluding the LED direct install program.**

RESPONSE: The Utility Cost Test (UCT) and Ratepayer Impact Measure (RIM) Test results are included in Attachment Q-44. Savings were only evaluated for Talquin EMC's energy audit program since they were the only Member who had completed a billing analysis to track savings from audit program participants.

a. Is Seminole responsible for administering the energy audits? If not, who is?

RESPONSE: The Seminole Members are responsible for administering energy audits.

46. **Please refer to Witness Taylor's testimony, Exhibit AST-1 Document 2, page 6 of 23, Table A-3, row 16. What form(s) of energy storage (ES) is the I-1 proposal?**

RESPONSE: The bidder indicated that the exact technology was yet to be determined but suggested that it would probably be a lithium-ion battery facility.

48. Please refer to Witness Taylor's testimony, Exhibit AST-1 Document 2, pages 8-9 of 23. Please explain why Seminole decided on a 40 MW solar PV proposal as opposed to solar proposals of other capacities.

RESPONSE: In its May 31, 2017 request for best-and-final offers from the two semi-finalist counterparties, Seminole remained open to reviewing offers of any size up to 75 MW but indicated that it was most interested in seeing prices for projects that were 50 MW or less in size. This seemed to be a threshold in Seminole's modeling results beyond which the economy-of-scale $/MWh price benefits did not justify the increased total contract costs, particularly in light of the fact that solar projects were not expected to provide any contributing capacity toward Seminole's winter-peaking needs. In addition, Seminole was concerned about the potential operational impacts of a larger project on its system. Seminole also recognized that there would be geographic diversity benefits of acquiring smaller projects in different locations relative to one large project that might crowd out the potential for additional projects in the future. In response to Seminole's May 2017 request, Coronal provided the lowest-priced RFP offer at the Tillman site and indicated that it would honor this price for a project that was anywhere within the 40 MW to 75 MW range. Thus, the Tillman offer provided an opportunity for a Seminole to assess the impact of a low-price mid-size project on its system, and Seminole therefore selected the Tillman 40 MW offer as the focus of negotiations.

49. Please refer to Witness Taylor's testimony, Exhibit AST-1 Document 2, pages 17 and 20 of 23. On page 17, it is stated that proposal A-11 "continued to be evaluated" in the RFP process. On page 20, proposal A-11 is not found in Table A-12. Please reconcile this.

RESPONSE: Proposal A-11 did continue to be evaluated for some time but was ultimately set aside before the results depicted in Table A-1 were reviewed. There were several reasons for it being set aside: (1) it was a new CT resource and thus had development risks, (2) there were existing CT resources (specifically, the L-1 CT proposals) that had superior levelized net cost quantitative values with no development risk, and (3) there were other existing peaking resources that had similar levelized net cost quantitative values (e.g., the Shady Hills CTs and DEF Peaking System Sale) and had additional quantitative and qualitative characteristics that are not reflected in the levelized net cost information. Specifically, there were transmission benefits associated with the former and annual MW quantity optionality associated with the latter.

50. Please refer to Witness Taylor's testimony, Exhibit AST-1 Document 2, pages 20 and 22-23 of 23. On page 20, Table A-12 shows the term of the Southern Company System proposal as 3 years. On pages 22-23, Tables A-13 to A-15 show the term of the same proposal as 5 years. Please reconcile this.

RESPONSE: There were two attractive System Sale offers from Southern Company Services in the final analysis – a 3-year offer and a 5-year offer. The 3-year offer was the better of the two (on a levelized net cost basis) and was therefore depicted in Table A-12; however, the 5-year offer was a better fit with Seminole's needs and the portfolios of resources depicted in Table A-13 and A-15 and was thus included in the final portfolios.

51. Please refer to Seminole's response to Staff's First Set of Interrogatories, Question No. 2 and Witness Taylor's testimony, Exhibit AST-1, Document 2, Tables A-13 to A-15, on pages 22-23 of 23. For the portfolios indicated below, please reconcile any differences in optionality, capacity, in-service dates, term length, and inclusion/exclusion into the portfolio between Seminole's response to Question 2 and Tables A-13 to A-15 for each applicable project.

a. Clean Power Plan (CPP)
b. SGS 2x1
c. Limited Build

RESPONSE: The information provided in Tables A-13 to A-15 of Witness Taylor's testimony, Exhibit AST-1, Document 2 (i.e., Sedway Consulting's Independent Evaluation Report) reflects the information that was known at the time of the July 12, 2017 Board of Trustees meeting where the decision was made about moving ahead with a final portfolio. Subsequent to that meeting, refinements were made to the CPP portfolio to better match Seminole's needs and/or address issues that arose in the negotiations with the finalist bidders. Those refinements are reflected in the Seminole response to Question 2. Thus, the Shady Hills CT PPA was reduced from a 23-year term to a 15-year term (2024-2039), and the DEF Intermediate and Peaking System Sales were combined (i.e., their intermediate and peaking characteristics were persevered but the minimum capacity in Seminole's response shows 100 MW, whereas it was actually 50 MW of intermediate and 50 MW of peaking, with a combined maximum limit of 450 MW). In addition, Seminole was able to negotiate a half-year extension of its current Oleander PPA (i.e., through the end of 2021), which – in combination with other annual capacity optionality adjustments for other resources in the CPP portfolio – obviated the need for the 5-year Offer L-1 in that portfolio. Sedway Consulting used 172 MW as the winter capacity for Offer L-1 because that is what the bidder provided in its offer spreadsheet information. Also, it is important to note that several of the offers in Tables A-13 to A-15 are depicted with their maximum capacities; however, they actually had adjustable quantities that varied by year in Sedway Consulting's detailed portfolio analyses.

52. Please refer to Witness Kezell's direct testimony, pages 7-9 of 12. Please explain if the SCCF can be retrofitted with dual-fuel capabilities in the future. If so, please provide an estimate of the expense.

RESPONSE: Yes, the SCCF can be retrofitted with dual-fuel capabilities in the future. Doing so would come at a substantially higher cost than that described on pages 7-9 of 12 of Witness Kezell's direct testimony. That previously submitted cost estimate represented the differential cost to design, build, and operate a dual-fuel facility versus a single fuel (natural gas only) facility from the beginning of the conceptual design phase. Once the facility has already been designed and built, the cost to retrofit in a distillate oil firing capability is higher. Such a retrofit project is estimated as follows:

Capital Estimate for Retrofitting the SCCF with Distillate Oil Firing Capability

Anticipated Original Equipment Manufacturer (OEM) Scope	Cost / unit	Quantity	Installed Cost
Furnish and install all "on turbine" modifications (combustors, piping, etc.)	$ 10,000,000	2	$ 20,000,000
Furnish and install all controls modifications			
Furnish Two (2) high pressure fuel oil pump skids			
Furnish Two (2) high pressure demin water pump skids			
Furnish and install Filter skids for fuel oil and for demin			
Furnish and install all piping downstream of the filter skids			
			$ 20,000,000
Anticipated Scope by Others	**Cost / unit**	**Quantity**	**Installed Cost**
4 Million Gallon Fuel Oil Storage Tank	$ 6,000,000	1	$ 6,000,000
Foundations for Tanks and Pumps	$ 1,000,000	1	$ 1,000,000
Secondary Containment	$ 500,000	1	$ 500,000
Distillate Oil Unloading Station	$ 250,000	1	$ 250,000
New 2 Million Gallon SS Demineralized Water Tank	$ 4,500,000	1	$ 4,500,000
Piping from tanks to pumps and from pumps to filter skids, and Electrical	$ 800,000	1	$ 800,000
Balance of Plant (e.g. demin) Impacts	$ 1,000,000	1	$ 1,000,000
2,000 Gallon Waste Water Tank	$ 25,000	1	$ 25,000
Overhead and Profit at 15%			$ 2,111,250
Contingency at 10%			$ 1,407,500
			$ 17,593,750
Total Installed Cost			**$ 37,593,750**

53. Please refer to Witness Ward's testimony, Exhibit MPW-2, pages 33-34 of 153. Please explain if the SHCCF will be equipped with dual-fuel capabilities. If not, please explain if the SHCCF can be retrofitted with dual-fuel capabilities in the future, and provide an estimate of the expense.

RESPONSE: SHCCF will not be equipped with dual-fuel capabilities. There is no provision in the Tolling Agreement that would obligate SHEC to incorporate any future plant alterations for dual-fuel capabilities.

54. Please refer to Witness Ward's testimony, Exhibit MPW-2, page 47 of 153, Table 15, and page 49 of 153, graph titled "Seminole Gap Chart", which are sponsored by Witness Kyle D. Wood and Witness Julia Diazgranados, respectively. Staff observes that the forecasted values shown on Table 15, when multiplied by a reserve margin of 15 percent, do not equal the annual values shown on the Seminole Gap Chart. Please provide a reconciliation of the two data sets.

RESPONSE: Table 15 reflects the peak demands net of 67 MW of distributed generation. Seminole models the distributed generation as a resource within in the production cost model. Therefor Seminole adds the 67 MW along with associated losses (approximately 2%) back to the peak demand prior to calculating reserves.

55. Please refer to Witness Ward's testimony, Exhibit MPW-2, page 47 of 153, Table 15, which is sponsored by Witness Kyle D. Wood. Please explain further the footnote that states "all values exclude Southeastern Power Administration."

RESPONSE: Seminole's Members Central Florida Electric Cooperative (E.C.), Suwannee Valley E.C., Talquin E.C., Tri-County E.C. contract with the Southeastern Power Administration (SEPA) for a portion of their power requirements. In total, SEPA provides 25.8 MW of Seminole coincident demand requirements and approximately 1% of total energy requirements. These amounts are shown in "CONFIDENTIAL-170266-Staff's 1st POD Nos. 11-13-Out of Model," which was previously provided in response to Staff's First Request for Production Nos. 11, 12, and 13. Specifically, see tabs "LFS17 Budget Energy SeciMthly" and "LFS17 Budget Demand SeciMthly".

57. Please refer to the Seminole's response to Staff's First Set of Interrogatories, Question No. 18(c). Please describe the effects on the construction timeline and cost of the SCCF project if removing the coal unit at SGS from service was delayed.

RESPONSE: There is no direct effect on the construction timeline nor on the cost of the SCCF simply due to a delay in removing an SGS coal unit from service as the SCCF construction and commissioning is independent of the removal from service of one of the coal units. The coal unit's removal from service, on the other hand, is contingent upon successful construction and commissioning of the SCCF. If, however, a circumstance such as a delay in the construction of the natural gas line which is anticipated to fuel the SCCF is experienced, then there would be effects on both the construction timeline and the cost of the SCCF. The construction timeline of the SCCF would likely be impacted on a day-for-day basis by a delay in the gas line's availability. The cost for the SCCF would also be increased by such a delay as the EPC Contractor, as well as other on-site project participants, would need to extend their time on site and hence, their costs would increase. Finally, there would be an increase in the interest paid during construction to account for the relatively longer period that construction loans would be in use.

59. Please refer to Seminole's Responses to Staff's First Production of Documents (POD), No. 10, Workbook titled: "CONFIDENTIAL-170266-Staff's 1st POD No.10-# of Cust. Model", Sheet titled: "Meters_Regression&Coefficients", for the following requests.

a. **Please provide a full description of each of the model names listed on this sheet (in Column C).**

RESPONSE: See "Attachment Q-59-Description of Variable and Model Names.xlsx"

b. **Please provide a full description of each of the variable names listed on this sheet (in Column D).**

RESPONSE: See "Attachment Q-59-Description of Variable and Model Names.xlsx"

60. Please refer to Seminole's Responses to Staff's First POD, No. 11, Workbook titled: "CONFIDENTIAL-170266-Staff's 1st POD No. 11-Base Model", Sheet titled: "Energy_Regression&Coefficients", for the following requests.

a. Please provide a full description of each of the model names listed on this sheet (in Column C).

RESPONSE: See "Attachment Q-60-Description of Variable and Model Names.xlsx"

b. Please provide a full description of each of the variable names listed on this sheet (in Column D).

RESPONSE: See "Attachment Q-60-Description of Variable and Model Names.xlsx"

61. Please refer to Seminole's Responses to Staff's First POD, No. 11, Workbook titled: "CONFIDENTIAL-170266-Staff's 1st POD No. 11-Base Model", Sheet titled: "Energy_Total_Actuals&Prediced [*sic*]", for the following requests.

a) Please provide qualitative explanations for both the year-to-year change in consumption from January 1, 2010, to January 1, 2017, and the projected change in consumption from March 1, 2017, to January 1, 2022, for Clay County Electric Cooperative.

2010 to 2011

The winter months of 2010 were historically extreme in terms of both heating degree days and minimum temperatures. In contrast, the winter months of 2011 were considerably more mild. Further, the summer months of 2010 were more extreme than the summer months in 2011 in terms of cooling degree days. The primary cause of the large decrease in Energy Purchases from 2010 to 2011 was the stark contrast in weather severity between these two years. Estimated population growth in CEC's service territory was slightly negative, but commercial consumer growth continued to increase, albeit slightly, since the Great Recession. Due to the on going effects of the Great Recession, housing stock growth flattened and gross domestic product had declined. There was a large decrease in real income per household during this period, which would have led to more careful energy consumption to in order reduce household expenditure.

2011 to 2012

2012 was more mild than 2011 in terms of both CDD and HDD. As weather is a primary driver of energy sales, there was a reduction in total sales from the prior year. Additionally, estimated population growth was very minor, relative to population growth in past periods. Further reduction in the real income per household contributed to reduced sales growth.

2012 to 2013

2013 was similar to 2012, with slightly more HDD, and slightly less CDD. Overall, there was a very slight reduction in Total Degree Days from the prior year, as well as a slight reduction in energy sales. Stagnating growth in estimated population did little to boost energy sales.

2013 to 2014

There was a noticeable increase in CDD from the prior year, as well as a large increase in HDD. This increase in weather severity from the prior year contributed to an increase in total energy sales, despite very little growth in estimated population.

2014 to 2015

There was a noticeable increase in CDD from the prior year, as well as a noticeable decrease in HDD. While Total Degree Days decreased from the prior year, there was a greater proportion of CDD to HDD. This led to a small increase in total sales from the prior year. Further contributing to this increase in sales was an increased level of estimated population growth that hadn't been seen in several years.

2015 to 2016

There was a noticeable increase in both CDD and HDD from the prior year. This overall increase in relative weather severity and positive growth in the estimated population both contributed to growth in sales from the prior period.

2017 through 2018

Actual temperatures in January and February of 2017 were very mild, which lowered energy usage per consumer. Weather for the projected period through 2017 and 2018 were assumed to return to normal conditions. Therefore, the remaining change in energy is due to estimated population growth in the service territory, albeit slightly lower than the prior year. Economic growth in the statistical area is expected to increase at the highest rate since the Great Recession during this period. According to the FDOT, construction on the northwestern, first segment of the First Coast Expressway (Blanding Boulevard/SR 21 in Clay County north to I-10/US 90 in Duval County) began in 2013 and should be completed in its entirety in early 2018 with some sections opening as soon as late 2017. This expressway is expected to positively impact Clay's service territory, as well as continued expansion around Jacksonville.

2018 through 2019

Population growth is projected to marginally increase and economic growth is expected to continue. Another segment of the First Coast Expressway in Clay County may begin as early as 2019 according to the FDOT. Reductions in end-use appliance energy intensity are expected to continue to reduce total usage.

2019 through 2020

During this time period, the U.S. Energy Information Administration (EIA) projects strong gains in technology improvements for general service lighting, driven by enactments set forth from the Energy Independence and Security Act of 2007. Furthermore, decreasing prices in efficient lighting are expected to advance adoption, especially as light-emitting diodes (LED) bulbs

approach price parody with compact fluorescent lamps (CLFs) during this time. Population growth is projected to marginally increase and economic growth is expected to continue.

2020 through 2021

Strong gains in energy efficiency and the saturation of energy efficient technologies are expected to continue to reduce consumer electricity consumption during this period. Population growth in the Member service territory is projected to increase at a marginally slower rate than the prior, while economic growth in expected to maintain at a similar level as the prior year.

b) Please provide qualitative explanations for both the year-to-year change in consumption from January 1, 2010, to January 1, 2017, and the projected change in consumption from March 1, 2017, to January 1, 2022, for Withlacoochee River Electric Cooperative.

2010 to 2011

The winter months of 2010 were historically extreme in terms of both heating degree days and minimum temperatures. In contrast, the winter months of 2011 were considerably more mild. Further, the summer months of 2010 were more extreme than the summer months in 2011 in terms of cooling degree days. The primary cause of the large decrease in Energy Purchases from 2010 to 2011 was the stark contrast in weather severity between these two years. Additionally, growth in the estimated population was lower than it had been in recent history, which did little to boost sales growth. There was a large decrease in real income per household during this period, which would have led to more careful energy consumption to in order reduce household expenditure.

2011 to 2012

2012 was more mild than 2011 in terms of both CDD and HDD. As weather is a primary driver of energy sales, there was a reduction in total sales from the prior year. Growth in the estimated population was even lower than the prior year, which did little to boost sales growth. Further reduction in the real income per household contributed to reduced sales growth.

2012 to 2013

2013 was similar to 2012, with slightly more CDD, and slightly less HDD. Growth in estimated population was historically low. Overall, there was very little change in both TOTAL DEGREE

DAYS and total energy sales. Further reduction in the real income per household contributed to reduced sales growth.

2013 to 2014

There was a noticeable increase in CDD from the prior year, as well as a large increase in HDD. This increase in weather severity from the prior year contributed to an increase in total energy sales. An uptick in estimated population growth further-contributed to the growth in energy sales.

2014 to 2015

There was a noticeable increase in CDD from the prior year, as well as a large decrease in HDD. While TOTAL DEGREE DAYS remained relatively unchanged from the prior year, there was a greater proportion of CDD to HDD. This, along with continued growth in the estimated population, led to a noticeable increase in total sales from the prior year.

2015 to 2016

There was a slight increase in CDD and a large increase in HDD from the prior year. This overall increase in relative weather severity contributed to a growth in sales. The highest growth in estimated population seen in recent years further-contributed to the increased sales growth.

2017 through 2018

Actual temperatures in January and February of 2017 were very mild, which lowered energy usage per consumer. Weather for the projected period through 2017 and 2018 were assumed to return to normal conditions. The remaining change in energy is due to estimated population growth in the service territory. Population growth in Withlacoochee River's (WREC) service territory is tied to the economic expansion of northern Tampa and Pasco County, which is one of the fastest growing areas in the United States. In 2017, the Florida Hospital Center Ice opened, adding a new large load to WREC's territory. Economic growth in Withlacoochee River's statistical area is projected to be at its highest level since the Great Recession.

2018 through 2019

Population growth in the service territory is projected to marginally increase above the rate of growth from the prior year. Reductions in end-use appliance energy intensity are expected to continue.

2019 through 2020

During this time period, the U.S. Energy Information Administration (EIA) projects strong gains in technology improvements for general service lighting, driven by enactments set forth from the Energy Independence and Security Act of 2007. Furthermore, decreasing prices in efficient lighting are expected to advance adoption, especially as light-emitting diodes (LED) bulbs approach price parody with compact fluorescent lamps (CLFs) during this time. Population growth in WREC's service territory is projected to maintain at the same rate of growth as the prior year.

2020 through 2021

Strong gains in energy efficiency and the saturation of energy efficient technologies are expected to continue to reduce consumer electricity consumption during this period. Population growth in the Member service territory is projected to increase at a marginally slower rate than the prior year.

c) Please provide qualitative explanations for both the year-to-year change in consumption from January 1, 2010, to January 1, 2017, and the projected change in consumption from March 1, 2017, to January 1, 2022, for Sumter Electric Cooperative.

2010 to 2011

The winter months of 2010 were historically extreme in terms of both heating degree days and minimum temperatures. In contrast, the winter months of 2011 were considerably more mild. Further, the summer months of 2010 were more extreme than the summer months in 2011 in terms of cooling degree days. The primary cause of the large decrease in Energy Purchases from 2010 to 2011 was the stark contrast in weather severity between these two years. Additionally, the increase in estimated population over the prior year was small, relative to recent years, which also contributed to a decrease in sales growth. There was a large decrease in real income per household during this period, which would have led to more careful energy consumption to in order reduce household expenditure.

2011 to 2012

2012 was more mild than 2011 in terms of both CDD and HDD. As weather is a primary driver of energy sales, there was a reduction in total sales from the prior year. This was another relatively slow growth year in terms of estimated population, which contributed to reduced sales growth.

2012 to 2013

2013 was similar to 2012, with slightly less CDD and HDD. Despite the slight decrease in Total Degree Days, increasingly strong, steady growth in estimated population contributed to overall growth in energy sales from the prior year.

2013 to 2014

There was a noticeable increase in CDD from the prior year, as well as a large increase in HDD. This increase in weather severity from the prior year contributed to an increase in total energy sales. This was a high-growth year in terms of estimated population, which contributed to the increased sales growth.

2014 to 2015

There was a noticeable increase in CDD from the prior year, as well as a noticeable decrease in HDD. While Total Degree Days decreased from the prior year, there was a greater proportion of CDD to HDD. This led to an overall increase in total sales from the prior year. This was another high-growth year in terms of estimated population, which contributed to the increased sales growth.

2015 to 2016

There was a noticeable increase in both CDD and HDD from the prior year. This overall increase in relative weather severity contributed to an increase in growth in sales.

2017 through 2018

Actual temperatures in January and February of 2017 were very mild, which lowered energy usage per consumer. Weather for the projected period through 2017 and 2018 were assumed to return to normal conditions. Therefore, the remaining change in energy is due to estimated population growth in the service territory. Economic growth in the statistical area is expected to be strong, especially health care, construction and the service industry, which attracts a range of population demographics to the area. Sumter County one of the fastest growing areas in the United States. In early 2017, the Villages announced its plans to develop as many as 20,000 new homes in the Wildwood area. This development is expected to significantly impact population growth in the Member service territory.

2018 through 2019

Population growth is projected to marginally increase above the rate of growth from the prior year and economic growth activity is projected to be around the highest levels since the Great

Recession. Reductions in end-use appliance energy intensity are expected to continue to reduce total usage.

2019 through 2020

During this time period, the U.S. Energy Information Administration (EIA) projects strong gains in technology improvements for general service lighting, driven by enactments set forth from the Energy Independence and Security Act of 2007. Furthermore, decreasing prices in efficient lighting are expected to advance adoption, especially as light-emitting diodes (LED) bulbs approach price parody with compact fluorescent lamps (CFLs) during this time. Population in the Member service area is projected to reach its highest rate of growth during this time period.

2020 through 2021

Strong gains in energy efficiency and the saturation of energy efficient technologies are expected to continue to reduce consumer electricity consumption during this period. Population growth in the Member service territory is projected to increase at a marginally slower rate than the prior year.

62. Has Seminole performed a forecast error rate analysis (forecast to actual) of its 2017 Winter Peak Load Forecast, Summer Peak Forecast, and Net Energy for Load? If so, please provide the results of the analysis for three, four, and five years prior to 2017.

RESPONSE: Seminole conducted a forecast error rate analysis of its 2017 Winter Peak Load Forecast, Summer Peak Forecast, and Net Energy for Load for three, four, and five years prior to 2017. The summary results of this analysis are provided in Exhibit No. (KDW-4) "Historical Seminole Error Rates based on Corrected Sotkiewicz Approach" of Kyle Wood's rebuttal to Paul Sotkiewicz's testimony. The detailed results are provided in PDF and Excel format in:

1. Attachment Q-62a-Forecast Error Analysis based on Corrected Sotkiewicz Approach
2. Attachment Q-62b-NET ENERGY FOR LOAD
3. Attachment Q-62c-SUMMER NET FIRM DEMAND
4. Attachment Q-62d-WINTER NET FIRM DEMAND

AFFIDAVIT

STATE OF COLORADO)
)
COUNTY OF BOULDER)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 54 of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados

Julia Diazgranados

Director of Treasury & Planning
Title

Notary Public
State of Colorado

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF ARIZONA

COUNTY OF MARICOPA

Before me, the undersigned authority, personally appeared Thomas Hines, who

( ) is personally known to me, or

(X) produced Arizona Driver's License as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 42, 43, 44, and 45, of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Thomas Hines

Principal, Tetra Resource Consultants
Title

Laura Aguirre
Notary Public
Maricopa County, Arizona
My Comm. Expires 11-12-2021

Laura Aguirre
Notary Public
State of Arizona

My commission Expires: 11/12/2021

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Kezell, 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. 52, 56 and 57 of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Kezell

Director, Engineering and Capital Development
Title

Notary Public
State of Florida

My commission Expires:

MARITZA DE JESUS
Notary Public - State of Florida
Commission # GG 091581
My Comm. Expires Apr 6, 2021
Bonded through National Notary Assn.

AFFIDAVIT

STATE OF CONNECTICUT)
) NORWALK
COUNTY OF FAIRFIELD)

(x) is personally known to me, or

( ) produced

On this 8th day of March 2018, before me personally appeared Ankur Mathur, to me known, and known to me personally to be the person who executed the foregoing certificate, and further, who, being by me duly sworn, deposes and says that the foregoing answers to Interrogatory No. 53 of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Name: Ankur Mathur
Title: Vice President
Shady Hills Energy Center, LLC

Notary Public
State of Connecticut

My commission Expires:

DENISA PLETENIKOVA
Notary Public-Connecticut
My Commission Expires
October 31, 2020

AFFIDAVIT

STATE OF COLORADO)
)
COUNTY OF BOULDER)

Before me, the undersigned authority, personally appeared Alan Taylor, who

( ) is personally known to me, or

( ) produced Colorado drivers license as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 46, 47, 48, 49, 50, and 51, of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

JENNAH QAZI
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164039824
MY COMMISSION EXPIRES 10/18/20

Alan Taylor

PRESIDENT
Title

Notary Public
State of Colorado

My commission Expires: 10/18/2020

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle Wood, 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. 55, 59, 60, 61, 62 of Staff's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle Wood

Manager - Load Forecasting & Energy Analysis
Title

Lisa M. Weiskopf
Notary Public
State of Florida

My commission Expires:

LISA M. WEISKOPF
MY COMMISSION # FF 942048
EXPIRES: February 2, 2020
Bonded Thru Notary Public Underwriters

80

SECI responses to Staff's Third Set of Interrogatories, No. 58.

(CONFIDENTIAL DN 02223-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 80
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Jason Peters (58)

81

SECI's responses to Staff's Fourth Set of Interrogatories, Nos. 63, 64, 65, 66.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 63)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 81
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Kyle D. Wood

63. Please refer to Seminole's Responses to Staff's First Request for Production, No. 13, (confidential) Workbook titled "CONFIDENTIAL-170266-Staff's 1st POD No. 13-Base Model," Sheets titled: "WDemand_Regression&Coefficienct[sic]" and "WDemand_Input_Data" for the following requests.

a) **In reference to Sheet "WDemand_Regression&Coefficienct[sic]," is it correct that the variables "JAN2017" and "MAR1998" listed in column D are used as binary independent variables in the Withlacoochee River Electric Cooperative kW and Suwannee Valley Electric Cooperative kW models?**

RESPONSE: Yes, that is correct.

b) **Why are these variables included in each of the models?**

RESPONSE: Seminole took a conservative approach to forecasting the winter-season demand model by employing the monthly load factor forecast for January as an independent variable in place of the winter-season load factor forecast. This was a level-shift downward for all Member's winter demand forecasts since: (1) the relationship between demand and load factor in the regression equation is negative; (2) the monthly load factor forecast for January is higher than the winter-season load factor forecast; (3) the load factor forecast is a constant value or is nearly a constant value per Member.

The level-shift downward the Withlacoochee River Electric Cooperative's (WREC) winter demand forecast was approximately 78 MW, which accounted for nearly half (nearly 50%) of the entire reduction to all Member forecasts in aggregate. In order to not over emphasize the conservative approach to WREC's winter demand forecast, binaries where added to account for the two hottest winter seasons in the training data.

The Suwannee Valley Winter Demand forecast model was originally designed with Withlacoochee's forecast model specification and these binaries were not omitted. The effects of these binaries were not significant and increased Suwannee Valley's forecast by less than 1 MW through the forecast horizon.

c) **Assuming "JAN2017" corresponds to an observation from January 2017 and "MAR1998" corresponds to an observation from March 1998, what event, if any, is associated with these specific observations to warrant creating binary variables for those months in particular?**

RESPONSE: These binaries account for the two hottest winter seasons in the training data.

d) In reference to Sheet "WDemand_Input_Data," please list the observations for which the "MAR1998" variable would take a value other than "0" and explain why it would take that value.

RESPONSE: The software used for load forecasting only reads date values in the form of "01JanYEAR" for models with only 1 observation per year. The binary was named "MAR1998" since this is the actual date when the winter season peak demand was observed. Furthermore, the training data does reflect observations from March 1998, despite the date labeled on the output table. The only observation for which the "MAR1998" variable would take a value other than "0" is the winter season of 1998.

e) Please provide definitions and sources for the following variables found throughout the Workbook by filling in the chart below.

Variable	Definition	Source
AVGPEAKTEMP3	Average of temperatures during Member coincident peak demand and two hours preceding peak demand	AccuWeather, Power Billing System
CDD_Intensity_Index_SEA_Class	Cooling Degree Day Monthly Index by Month of Season Peak, Multiplied by End-Use Cooling Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Year	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
CDD_Intensity_Index_SEA_Weighted	Cooling Degree Day Monthly Index by Month of Season Peak, Multiplied by End-Use Cooling Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Month	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
Coincident_Factor		Power Billing System
Days	Number of Days in Month	NA
HDD_Intensity_Index_SEA_Class	Heating Degree Day Monthly Index by Month of Season Peak, Multiplied by End-Use Heating Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Year	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
HDD_Intensity_Index_SEA_Weighted	Heating Degree Day Monthly Index by Month of Season Peak, Multiplied by	AccuWeather, Itron, Seminole-Member Residential Appliance

	End-Use Heating Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Month	Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
kW	Member coincident demand in kilowatts	Power Billing System
Load_Factor	Total energy in kilowatts /(Member coincident demand in kilowatts*Number of hours in a given month)	Power Billing System
MAX_Intensity_Index_SEA_Class	Maximum Temperature Monthly Index by Month of Season Peak, Multiplied by End-Use Cooling Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Year	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
MAX_Intensity_Index_SEA_Weighted	Maximum Temperature Monthly Index by Month of Season Peak, Multiplied by End-Use Cooling Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Month	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
Max_TMP	Maximum Temperature	AccuWeather
Mean_CC	Mean Cloud Cover	AccuWeather
Mean_FLK	Mean Feels Like Temperature	AccuWeather
Mean_TMP	Mean Temperature	AccuWeather
Mean_WCL	Mean Wind Chill	AccuWeather
MIN_Intensity_Index_SEA_Class	Minimum Temperature Monthly Index by Month of Season Peak, Multiplied by End-Use Heating Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Year	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
MIN_Intensity_Index_SEA_Weighted	Minimum Temperature Monthly Index by Month of Season Peak, Multiplied by End-Use Heating Appliance Energy Intensity Annual Index, Weighted by Rate Class Sales per Month	AccuWeather, Itron, Seminole-Member Residential Appliance Saturation Survey, Bureau of Labor Statistics, RUS Form-7, Power Billing System
Min_TMP	Minimum Temperature	AccuWeather

MINIMUM	Minimum Temperature	AccuWeather
RealIncome_per_HH	Real Income per Household	Moody's
TMP_CoopCoinMA3	Average of temperatures during Member coincident peak demand and two hours preceding peak demand	AccuWeather, Power Billing System

f) Please provide all observations for the following variables in Excel format, which were defined on Sheet "WDemand_Regression&Coefficienct[sic]" but are not listed on Sheet "WDemand_Input_Data" for all the dates and cooperatives listed in columns B and C of "WDemand_Input_Data."

1. **AVGPEAKTEMP3**
2. **CDD**
3. **DAYS**
4. **JAN2017**
5. **MAR1998**
6. **MAX_TMP**
7. **Mean_CC**
8. **Mean_FLK**
9. **Mean_TMP**
10. **Mean_WCL**
11. **Min_TMP**
12. **MINIMUM**
13. **TMP_CoopCoinMA3**

RESPONSE: The observations for the variables listed above are provided in attachment "170266-Staff's 4th ROGs No. 63 - base_winter_load_factor_model.xlsx", with the exception of "JAN2017" and "MAR1998", which are binaries produced in SAS® software. Also, note the Winter Load Factor forecast is not an input to the Winter Demand model. Seminole input the Monthly Load Factor forecast model output into the Winter Season Demand forecast model. The input data, model statistics and results to both Winter Season and Monthly Load Factor forecast models are provided in attachment "170266-Staff's 3rd ROGs No. 63-base_winter_load_factor_model.xlsx" and "170266-Staff's 3rd ROGs No. 63-base_monthly_load_factor_model.xlsx", respectively.

g) **In reference to Sheet "WDemand_Regression&Coefficienct[sic]," please provide the rationale for taking a logarithmic transformation of the variable "Bebr_Population_base" in the kW model for Sumter Electric Cooperative.**

RESPONSE: The logarithmic transformation of population growth is a data driven and conservative approach to modeling demand. If population were regressed on demand in level form, the relationship would be linear. Therefore, if population in level form increases by 1 unit every period, demand would increase by x units every period. When population is transformed into natural logarithmic form as it is in this model, 1 unit increases in population every period increases demand at a marginally decreasing rate.

h) **In reference to Sheet "WDemand_Regression&Coefficienct[sic]," please provide the rationale for taking a square root transformation of the variable "Bebr_Population_base" in the kW model for Withlacoochee River Electric Cooperative.**

RESPONSE: The square root transformation of population growth is a data driven and conservative approach to modeling demand. If population were regressed on demand in level form, the relationship would be linear. Therefore, if population in level form increases by 1 unit every period, demand would increase by x units every period. When population is transformed into square root form as it is in this model, 1 unit increases in population every period increases demand at a marginally decreasing rate.

i) **In reference to Sheet "WDemand_Regression&Coefficienct[sic]," please specify which model, "PRECO_LFS17COPY4" or "PRECO_LFS17COPY6," was used in predicting the Peace River Electric Cooperative kW demand numbers listed in Sheet "WDemand_Actuals&Prediced[sic]."**

RESPONSE: "PRECO_LFS17COPY4" and "PRECO_LFS17COPY6" are combined by weighted root-mean-square error. Model "PRECO_LFS17COPY4" accounts for 54.602% of the weight and model "PRECO_LFS17COPY6" accounts for 45.398% of the weight.

j) **In reference to Sheet "WDemand_Regression&Coefficienct[sic]," please provide the rationale for taking logarithmic transformations of the variable "Consumers_LFS17" in the kW models for Clay County Electric Cooperative, Central Florida Electric Cooperative, and Suwannee Valley Electric Cooperative. Please explain why this variable was not transformed in the models for Glades Electric Cooperative, Talquin Electric Cooperative, and Tri-County Electric Cooperative.**

RESPONSE: The choice of logarithmic transformation of population in the regression model is a data driven and conservative approach to modeling demand. The difference between regressing population in natural log form versus level form is marginal. However, through data

driven analysis, regressing population with the logarithmic transformation proves to be an efficient estimator to the model. For Glades, Talquin, and Tri-County the variable was not transformed based on data driven analyses. Furthermore, the transformation had little to no impact on the forecast model.

k) Please provide the rationale for excluding the variable "Consumers_LFS17" from the Withlacoochee River Electric Cooperative kW model.

RESPONSE: Population is an efficient growth driver in the Withlacoochee model and provides very similar data driven results compared to consumer data. Furthermore, it was discovered that that consumer data had shifted from trend due to changes in accounting methods between the end of 2016 and the beginning of 2017, which required data cleansing. Given these considerations, population is a reasonable alternative to the consumer variable.

l) In reference to Sheet "WDemand_Input_Data," please provide the formulas depicting how the following variables that are influenced by temperature are forecasted for future years.

1. **HDD**
2. **HDD_Intensity_Index_Weighted**
3. **HDD_Intensity_Index_SEA_Class**
4. **HDD_Intensity_Index_SEA_Weighted**
5. **CDD_Intensity_Index_SEA_Class**
6. **CDD_Intensity_Index_SEA_Weighted**
7. **Any other variables that are created based on temperature forecasts.**

RESPONSE:

1) Seminole uses hourly data for 25 weather stations throughout Florida along with aggregated hourly Member-level load values in a regression framework to optimally select weather stations for each Member using the approach detailed in: Tao Hong, Pu Wang and Laura White, "Weather station selection for electric load forecasting," International Journal of Forecasting, vol.31, no.2, pp 286-295, April-June 2015.

2) "Virtual Station" hourly weather data values are created for each Member by averaging the observations from that Member's optimally selected station list over a rolling 30-year horizon.

3) "Expand" procedure used in SAS Software on hourly virtual station dataset to create by-Member variables for:

3, 12, 24 and 48 hour moving averages of hourly temperatures
3, 12, and 24 hour weighted moving averages of hourly temperatures
Exponentially weighted moving averages of hourly temperatures with smoothing factors of $\alpha = 0.2, 0.3$, and 0.4

4) For hourly virtual station temperatures, and the various moving averages of those temperatures created in (3), Cooling Degree Hour and Heating Degree Hour variables are created using 61 °F as the cutoff for HDH and 72 °F as the cutoff for CDH.

5) Hourly virtual station temperatures are summed by day. Daily summed temperatures are to create Degree Day variables using 61 °F as the cutoff for HDD and 72 °F as the cutoff for CDD, while Total Degree Days are defined as the sum of CDD and HDD:

HDD = (MAX(0,(61*24) - Sum_TMP)) / 24
CDD = (MAX(0, Sum_TMP - (72-24))) / 24
TDD = HDD+CDD;

6) A monthly dataset is produced from the hourly data with the Mean, Sum, Min and Max of all weather variables generated via SAS® Functions.

7) Both Median-normal and Average -normal datasets are produced from the monthly dataset created in (6). For future years (out to 2060), normal monthly weather statistics are set as the median and average monthly values of the past 30 years, respectively.

8) CDD, HDD, MIN, and MAX Index variables are created by dividing the respective weather variable for each year and month by the corresponding month from a base year of 2009 (using the median normal monthly dataset).

9) CDD, HDD, MIN and MAX Seasonal Index variables are created by dividing the respective variable for each year and month by the corresponding month from a base year of 2009 (using the average normal monthly dataset).

10) Itron data is used to create the variables Heating, Cooling, Base, and Total Intensity Class.

11) HDD and MIN Intensity Index Class variables are created by multiplying Heating Intensity Class (10) by HDD and MIN Indices (8). CDD and MAX Intensity Index Class variables are created by multiplying Cooling Intensity Class (10) by CDD and MAX Indices (8).

12) HDD and MIN Intensity Index Seasonal Class variables are created by multiplying Heating Intensity Class (10) by HDD and MIN Seasonal Indices (9). CDD and MAX Intensity Index Seasonal Class variables are created by multiplying Cooling Intensity Class (10) by CDD and MAX Seasonal Indices (9).

13) Binary variables are created for each month.

14) HDD, CDD, MIN and MAX Intensity Index Class variables from (11) are interacted with monthly binaries (13) to create new variables HDD, CDD, MIN and MAX Intensity Index Seasonal Class variables from (12) are interacted with monthly binaries (13) to create new variables.

15) A variable "weight" is created by taking the proportion of monthly rate-class sales to total monthly sales, by Member. For future years, this is the forecasted rate-class sales to total monthly sales, by Member.

16) The weight variable (15) is interacted with Intensity Class variables (10) to created Heating, Cooling, Base and Total Intensity Class Weighted.

17) The weight variable (15) is interacted with HDD, CDD, MIN and MAX Intensity Index Class Variables to create new variables. The weight variable (15) is interacted with HDD, CDD, MIN and MAX Intensity Index Seasonal Class Variables to create new variables.

18) The weight variable (15) is interacted with HDD, CDD, MIN and MAX Intensity Index Class Variables and Monthly Binaries (13) to create new variables. The weight variable (15) is interacted with HDD, CDD, MIN and MAX Intensity Index Seasonal Class Variables and Monthly Binaries (13) to create new variables.

Variable Name	**Variable Description**	**Energy Variable Created In:**	**Demand Variable Created In:**
APR_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, April binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
AUG_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, August binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
Avg_Relative_Humidity	Average Relative Humidity	Step 7: Using Median Values	Step 7: Using Mean Values
AVGPEAKTEMP3	Three-hour moving average of Temperatures	Step 7: Using Median Values	Step 7: Using Mean Values
CDD	Cooling Degree Days	Step 7:	Step 7:

		Using Median Values	Using Mean Values
CDD_Intensity_ Index_Class	CDD Index interacted with Cooling Intensity Index and weighted by class sales by year	Step 8: Using Median Values	Step 8: Using Mean Values
CDD_Intensity_ Index_Weighted	CDD Index interacted with Cooling Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
DEC_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, December binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
DEC_HDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, December binary, and weighted by class sales by month	Step 18: Using Median Values	Step 18: Using Mean Values
DEC_MIN_Index_Class_Weighted	Minimum Temperature Index interacted with Heating Intensity Index, December binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
FEB_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, February binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
FEB_HDD_Index_Class_Weighted	HDD Index interacted with Heating Intensity Index, February binary, and weighted by class sales by month	Step 18: Using Median Values	Step 18: Using Mean Values
FEB_HDD_Intensity_Index_Class	HDD Index interacted with Heating Intensity Index, February binary, and weighted by class sales by month	Step 14: Using Median Values	Step 14: Using Mean Values
FEB_MIN_Index_Class_Weighted	Minimum Temperature Index interacted with Heating Intensity Index, February binary and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
HDD	Heating Degree Days	Step 7: Using Median	Step 7: Using Mean

		Values	Values
HDD_Intensity_Index_SEA_Weighted	HDD Index interacted with Heating Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
HDD_Intensity_Index_Weighted	HDD Index interacted with Heating Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
JAN_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, January binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
JAN_HDD_Intensity_Index_Class	HDD Index interacted with Heating Intensity Index, January binary, and weighted by class sales by year	Step 14: Using Median Values	Step 14: Using Mean Values
JUL_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, July binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
MAR_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, March binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
MAR_HDD_Index_Class_Weighted	HDD Index interacted with Heating Intensity Index, March binary, and weighted by class sales by month	Step 18: Using Median Values	Step 18: Using Mean Values
MAR_HDD_Intensity_Index_Class	HDD Index interacted with Heating Intensity Index, March binary, and weighted by class sales by year	Step 14: Using Median Values	Step 14: Using Mean Values
MAR_MIN_Index_Class_Weighted	Minimum Temperature Index interacted with Heating Intensity Index, March binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
MAX_Intensity_Index_SEA_Weighted	Maximum Temperature Index interacted with Heating Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
MAX_Intensity_	Maximum Temperature Index weighted by class	Step 17:	Step 17:

Index_Weighted	sales by month	Using Median Values	Using Mean Values
Max_TMP	Max Temperature	Step 7: Using Median Values	Step 7: Using Mean Values
MAY_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, May binary and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
Mean_CC	Mean Cloud Cover	Step 7: Using Median Values	Step 7: Using Mean Values
Mean_FLK	Mean Feels Like Temperature	Step 7: Using Median Values	Step 7: Using Mean Values
Mean_TMP	Mean Temperature	Step 7: Using Median Values	Step 7: Using Mean Values
Mean_WCL	Mean Wind Chill	Step 7: Using Median Values	Step 7: Using Mean Values
MIN_Intensity_Index_SEA_Weighted	Minimum Temperature Index interacted with Heating Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
MIN_Intensity_Index_Weighted	Minimum Temperature Index interacted with Heating Intensity Index and weighted by class sales by month	Step 17: Using Median Values	Step 17: Using Mean Values
Min_TMP	Minimum Temperature	Step 7: Using Median Values	Step 7: Using Mean Values
MINIMUM	Minimum Temperature	Step 7: Using Median	Step 7: Using Mean

		Values	Values
NOV_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, November binary and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
NOV_HDD_Index_Class_Weighted	HDD Index interacted with Heating Intensity Index, November binary and weighted by class sales by month	Step 18: Using Median Values	Step 18: Using Mean Values
NOV_HDD_Intensity_Index_Class	HDD Index interacted with Heating Intensity Index, November binary and weighted by class sales by year	Step 14: Using Median Values	Step 14: Using Mean Values
NOV_MIN_Index_Class_Weighted	Minimum Temperature Index interacted with Heating Intensity Index, November binary and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
OCT_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, October binary and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
Precipitation	Precipitation (Water Equivalent Inches)	Step 7: Using Median Values	Step 7: Using Mean Values
SEP_CDD_Index_Class_Weighted	CDD Index interacted with Cooling Intensity Index, September binary, and weighted by class sales by month	Step 18: Using Median values	Step 18: Using Mean values
TMP_CoopCoinMA3	Three-hour moving average of Temperatures	Step 7: Using Median Values	Step 7: Using Mean Values

64. Please refer to the Seminole Need Study, Exhibit MPW-2, page 36 of 153. Why did Seminole Electric Cooperative use a 30 year weather normal weather calculation to forecast energy and demand rather than a shorter time period (e.g. 15, 20 or 25 years) or with differential weighting (weighting more current weather observations more than earlier weather observations)?

RESPONSE: Seminole bases its normal weather calculation on the National Oceanic and Atmospheric Administration Center (NOAA) derivation of "Climate Normals." NOAA uses three decades of weather data to derive "Climate Normals."

65. Please refer to the Seminole Need Study, Exhibit MPW-2, page 36 of 153. What are the weather stations represented in each Member cooperative's weather data?

RESPONSE: See the table below.

Cooperative	Station Code	Airport
Central Florida	K40J	Perry-Foley Airport
Central Florida	KCTY	Cross City Airport
Central Florida	KGNV	Gainesville Regional Airport
Central Florida	KLEE	Leesburg Regional Airport
Central Florida	KOCF	Ocala International Airport – Jim Taylor Field
Central Florida	KVVG	The Villages
Clay	KGNV	Gainesville Regional Airport
Clay	KJAX	Jacksonville International
Clay	KLEE	Leesburg Regional Airport
Clay	KOCF	Ocala International Airport – Jim Taylor Field
Clay	KSGJ	St. Augustine Airport
Clay	KVQQ	Cecil Field Airport
Clay	KVVG	The Villages
Glades	KBOW	Barow Municipal
Glades	KOBE	Okeechobee County Airport
Glades	KPGD	Punta Gorda Charlotte County
Glades	KRSW	Fort Myers South West Florida International
Glades	KVRB	Vero Beach Regional
Peace River	KBOW	Barow Municipal

Peace River	KPGD	Punta Gorda Charlotte County
Peace River	KSRQ	Sarasota Bradenton International
Sumter	KBOW	Barow Municipal
Sumter	KGNV	Gainesville Regional Airport
Sumter	KLEE	Leesburg Regional Airport
Sumter	KOCF	Ocala International Airport – Jim Taylor Field
Sumter	KSFB	Orlando Sanford Airport
Sumter	KVVG	The Villages
Suwannee Valley	K40J	Perry-Foley Airport
Suwannee Valley	KBGE	Bainbridge Decatur County Industrial Air Park
Suwannee Valley	KCTY	Cross City Airport
Suwannee Valley	KGNV	Gainesville Regional Airport
Suwannee Valley	KJAX	Jacksonville International
Suwannee Valley	KLEE	Leesburg Regional Airport
Suwannee Valley	KTLH	Tallahassee Regional Airport
Suwannee Valley	KVLD	Valdosta Regional Airport
Suwannee Valley	KVQQ	Cecil Field Airport
Talquin	K40J	Perry-Foley Airport
Talquin	KAAF	Apalachicola Regional Airport
Talquin	KBGE	Bainbridge Decatur County Industrial Air Park
Talquin	KMAI	Marianna Municipal Airport
Talquin	KTLH	Tallahassee Regional Airport
Talquin	KVLD	Valdosta Regional Airport

Tri-County	K40J	Perry-Foley Airport
Tri-County	KBGE	Bainbridge Decatur County Industrial Air Park
Tri-County	KCTY	Cross City Airport
Tri-County	KJAX	Jacksonville International
Tri-County	KTLH	Tallahassee Regional Airport
Tri-County	KVLD	Valdosta Regional Airport
Withlacoochee	KBKV	Gainesville Regional Airport
Withlacoochee	KBOW	Barow Municipal
Withlacoochee	KLEE	Leesburg Regional Airport
Withlacoochee	KOCF	Ocala International Airport – Jim Taylor Field
Withlacoochee	KSRQ	Sarasota Bradenton International
Withlacoochee	KVDF	Vandenberg Airport
Withlacoochee	KVVG	The Villages

66. What is the method of calculating and source of SEC's price data as appears in its response to Staff First Request for Production of Documents, Nos. 11 and 13?

RESPONSE:

Seminole's "March 2017 Financial Forecast" is the source for the Average Member Wholesale Rate. The Average Member Wholesale Rate calculation is shown below.

$$Average\ Member\ Wholesale\ Rate = \frac{(Member\ Revenue\ Requirements)}{Energy\ Sales}$$

The Average Member Wholesale Rate is converted into a three year moving average ("Price_3YrMA") as shown in the calculation below.

$$Price_3YrMA_t = \frac{(Price_t + Price_{t-1} + Price_{t-2})}{3}$$

Price_3YrMA is converted into real terms using the annual Consumer Price Index (CPI). The annual CPI is the average of monthly CPI per year. Price_3YrMA is converted into real terms as shown in the calculation below.

$$RealPrice_3YrMA_t = \left(Price_3YrMA_{2016} \left(\frac{(Price_3YrMA_t / Price_3YrMA_{2016})}{(CPI_t / CPI_{2016})} \right) \right)$$

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle Wood, 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. 63, 63a, 63b, 63c, 63d, 63e, 63f, 63g, 63h, 63i, 63j, 63k, 63l, 64, 65, 66 of Staff's Fourth Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle Wood

Title

Notary Public
State of Florida

My commission Expires:

LISA M. WEISKOPF
MY COMMISSION # FF 942048
EXPIRES: February 2, 2020
Bonded Thru Notary Public Underwriters

82

SECI's responses to Staff's Fifth Set of Interrogatories, No. 67.

(CONFIDENTIAL DN. 02190-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 82
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Kezell

83

SECI's responses to Staff's Fifth Set of Interrogatories, No. 68.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 68)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 83
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Julia A. Diazgranados

68. Please refer to the rebuttal testimony of Witness Taylor, page 2, lines 11-12, and to Seminole's response to Staff's First Set of Interrogatories, Question No. 1, Attachment "170266-Staff's 1st INTs No. 1 Attachment Q-1". According to the response to Staff's First Set of Interrogatories, the Annual Revenue Requirements in Net Present Value terms for the CPP/CC Portfolio are $9 million, $8 million, and $7 million greater than the No Build Risk: All PPA Portfolio for the years 2018, 2019, and 2020, respectively. Please reconcile this with Witness Taylor's rebuttal testimony, which indicates that all Portfolios were the same for the pre-2021 time period.

RESPONSE: Witness Taylor's rebuttal testimony is correct; all of the portfolios had the same resource mix prior to 2021. After further evaluation in response to staff's interrogatory, Seminole has discovered a model glitch within the PaR model. This issue has to do with unit start cost and how it is reported out of PaR. There are three start cost variables; "start cost without fuel", "start cost fuel" and "total start cost" which is the summation of the two prior variables. Normally, the model will produce the two detail variables, but occasionally only the "total start cost" variable is produced. This issue has been reported to ABB but at this time they do not have a fix.

In the No Build Risk: All PPA Portfolio the single variable, "total start cost", was provided. This variable had not been mapped into our new financial forecast model resulting in missed cost. Upon mapping of the variable and rerunning the financial forecast model we now see the cost for the first three years in line with the other portfolios. Seminole is providing revised Exhibit No.___(JAD-6) and a revised table to Staff's Interrogatory No. 1 for the No Build Risk: All PPA Portfolio (see "REVISED Attachment Q-1-No Build Risk All PPA Portfolio").

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, 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. 68 of The Florida Public Service Commission's Fifth Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados

Julia Diazgranados

Director of Treasury and Planning
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

84

SECI's responses to Staff's Sixth Set of Interrogatories, 69, 70.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 84
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Kyle D. Wood

69. Please refer to the Rebuttal Testimony of Seminole Witness Kyle D. Wood, page 2, line 5, through page 3, line 24. Please discuss how Seminole's member cooperatives load data and customer data interact with Seminole's new forecasting methodology. Specifically, how does Seminole's new forecasting methodology incorporate information from its member cooperatives?

RESPONSE: The consumer data Members provide Seminole is the actual dependent variable in the consumer forecast model. Seminole uses the consumer model as a data driven approach to assess the explanatory efficiency of independent variables, such as population, housing stock etc., with respect to consumer growth. This information provides Seminole with a basis for selecting independent variables that explain growth in energy and demand forecast models. The consumer actual and forecast data may be used as an independent variable in the energy and demand forecast models, as well.

The end-use sales data Members provide to Seminole are used to derive rate class energy forecast models. The energy model is a top down reconciliation however, meaning rate class models are reconciled to match the total forecast output. In addition, Member sales data are used to derive rate-class weighted energy efficiency variables used in total energy and total demand forecast models.

Last, Members provide Seminole with the number of end-use solar installations and the capacity ratings associated with those installations for Seminole's behind-the-meter distributed solar generation forecast. Members also notify Seminole when a new, Member-owned solar generation facility is expected to come online so that Seminole can incorporate the expected output into the behind-the-meter solar forecast, as well.

PETITIONERS RESPONSES TO
STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 69-70)
INTERROGATORY NO. 70
DOCKET NOS. 20170266-EC, 20170267-EC
PAGE 1 OF 1

70. Please refer to the Rebuttal Testimony of Seminole Witness Wood, page 5, lines 14-17. Please clarify if the term "biannually" is being used to imply a 6 month period, or a two-year period (i.e. biennial).

RESPONSE: Mr. Wood's testimony intended to refer to use of a two-year period (i.e. biennial). Seminole will file an errata to substitute the word "biennially" for "biannually."

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle Wood, 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. 69 and 70 of Staff's Sixth Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle Wood

Manager of Load Forecasting and Member Analytics

Title

Maritza De Jesus

Notary Public
State of Florida

My commission Expires:

MARITZA DE JESUS
Notary Public - State of Florida
Commission # GG 091581
My Comm. Expires Apr 6, 2021
Bonded through National Notary Assn.

85

SECI's responses to Staff's First Request for Production of Documents, Nos. 2, 8, 10, 11, 13, 14, 15, 16, 17, 18.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 2, 8, 10,*11, *13, 14, 16, 17, 18)

***CONFIDENTIAL DN. 02379-2018**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 85
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Kezell (2), Thomas Hines (5,7, 8), Kyle D. Wood (10, 11, 13-18)

2. Please refer to pages 51-52, Section 6.2.2. Produce the study conducted by a third party environmental consultant assessing the environmental licensing considerations associated with locating a new potential site in Putnam and Gilchrist Counties.

RESPONSE: See the document entitled "170266-Staff's 1st POD No. 2- Site Selection Report."

8. Please refer to page 70, section 7.2. Please produce the analyses of the "additional [DSM] measures" evaluated by AE/Tierra, including the calculations of the Rate Impact Measure ("RIM") tests performed.

RESPONSE: Please see the documents entitled "170266-Staff's 1st POD No. 8-Cost Effect." and "170266-Staff's 1st POD No. 8-DSM Measures."

Please refer to pages 39, 41, and 43 (Tables 16, 8, and 10 respectively) for Production of Documents Nos. 10-11.

10. With regards to the forecasts of Average Number of Customers, please provide documentation of all aspects of the models and forecasts development, in electronic format (Excel), for all nine members of Seminole Electric Cooperative. This should include the model assumptions (rationale for variable selection and model specification), the regression equation(s), the input data sets, the input data sources, the predicted data sets, the model output (variable coefficients, all statistical analyses), the forecast data sets, and any out-of-model adjustments (plus any associated rationale, source, and calculation for each such adjustment).

RESPONSE: See the document labeled "170266- Staff's 1st POD Nos. 10,11,13-Data Sources" for explanation of data sources used in the analysis. See the document labeled "CONFIDENTIAL-170266-Staff's 1st POD No.10-# of Cust. Model" for regression equations, input data sets, predicted data sets, model output, and forecast data sets. Model assumptions are inherent in model output. The remaining analysis was performed in SAS and cannot be readily replicated or downloaded into Excel. The document labeled "CONFIDENTIAL-170266-Staff's 1st POD No.10-# of Cust. Model" contains confidential third-party information which Seminole is only authorized to share with the Public Service Commission under the terms of an agreement with that third party. Such third-party confidential information will be redacted from any copy of this document disclosed to Intervenors. Confidential files will be submitted with a separate Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.0006 F.A.C.

Please refer to pages 39, 41, and 43 (Tables 16, 8, and 10 respectively) for Production of Documents Nos. 10-11.

11. With regards to Seminole's forecasts of Average Consumption Per Customer, please provide documentation of all aspects of the models and forecasts development, in electronic format (Excel), for all nine members of SEC. This should include the model assumptions (rationale for variable selection and model specification), the regression equation(s), the input data sets, the input data sources, the predicted data sets, the model output (variable coefficients, all statistical analyses), the forecast data sets, and any out-of-model adjustments (plus any associated rationale, source, and calculation for each such adjustment).

RESPONSE: See the documents listed below-

1. CONFIDENTIAL-170266- Staff's 1st POD No. 11-Base Model
2. CONFIDENTIAL-170266- Staff's 1st POD No. 11-High Model
3. CONFIDENTIAL-170266- Staff's 1st POD No. 11-Low Model

These documents contain confidential third-party information which Seminole is only authorized to share with the Public Service Commission under the terms of an agreement with that third party. Such third-party confidential information will be redacted from any copy of these documents disclosed to Intervenors.

See also the document labeled "CONFIDENTIAL-170266-Staff's 1st POD Nos. 11-13-Out of Model." See also the document labeled "170266- Staff's 1st POD Nos. 10,11,13-Data Sources" for explanation of data sources used in the analysis. Model assumptions are inherent in model output. The remaining analysis was performed in SAS and cannot be readily replicated or downloaded into Excel. Confidential files will be submitted with a separate Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.0006 F.A.C.

13. With regards to Seminole's forecast of winter seasonal peak demand, please provide documentation of all aspects of the models and forecasts development, in electronic format (Excel), for all nine members of Seminole Electric Cooperative. This should include the model assumptions (rationale for variable selection and model specification), the regression equation(s), the input data sets, the input data sources, the predicted data sets, the model output (variable coefficients, all statistical analyses), the forecast data sets, and any out-of-model adjustments (plus any associated rationale, source, and calculation for each such adjustment).

RESPONSE: See the documents listed below for regression equations, input data sets, predicted data sets, model output, and forecast data sets.

1. CONFIDENTIAL-170266-Staff's 1st POD No. 13-Base Model
2. CONFIDENTIAL-170266-Staff's 1st POD No. 13-High Model
3. CONFIDENTIAL-170266-Staff's 1st POD No. 13-Low Model

These documents contain confidential third-party information which Seminole is only authorized to share with the Public Service Commission under the terms of an agreement with that third party. Such third-party confidential information will be redacted from any copy of these documents disclosed to Intervenors.

See also the document labeled "CONFIDENTIAL-170266-Staff's 1st POD Nos. 11-13-Out of Model. See also the document labeled "170266- Staff's 1st POD Nos. 10,11,13-Data Sources" for explanation of data sources used in the analysis. Model assumptions are inherent in model output. The remaining analysis was performed in SAS and cannot be readily replicated or downloaded into Excel. Confidential files will be submitted with a separate Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.0006 F.A.C.

14. Please refer to page 31. Please provide documentation in electronic format (Excel) showing the aggregation of all Member actuals and forecasts of customers, energy, and demand (Seminole's maximum demand) for 2007 through 2027, consistent with the as-filed study.

RESPONSE: See the documents listed below:

1. 170266-Staff's 1st POD No.14-Member Customers and Sales
2. 170266-Staff's 1st POD No. 14-Member NEL and Net Firm Demand

15. If any updates (actuals or projections) to the input variables in the models or forecasts included in response to Staff's First Request for Production of Documents, Item No. 13, are in Seminole's possession, please provide such updates.

RESPONSE: There are no updated input variables in the models or forecasts.

16. Please refer to page 5, lines 15-18. Please provide a copy of the source document used in the 2017 through 2026 average annual population growth projections referred to in this section of testimony.

RESPONSE: See the document labeled "170266-Staff's 1st POD No. 16-EDR Demo Est Conference."

17. Please refer to page 5, lines 20-22. Please provide a copy of the report *The Florida Economic Overview* referenced in this section of testimony.

RESPONSE: See the document labeled "170266-Staff's 1st POD No. 17-EDR FL EconomicOverview."

18. Please refer to page 11, lines 15-17. Please provide a copy of the *2016 Member Residential Appliance Saturation Survey* referred to in this section of testimony.

RESPONSE: See the document labeled "CONFIDENTIAL-170266-Staff's 1st POD No. 18-Survey Appendix B" Confidential files will be submitted with a separate Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.0006 F.A.C.

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SECI's responses to Staff's First Request for Production of Documents, No. 6.

(CONFIDENTIAL DN. 01988-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 86
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Michael P. Ward, II

87

SECI's responses to Staff's First Request for Production of Documents, No. 12.

(CONFIDENTIAL DN. 01988-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 87
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Kyle D. Wood

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SECI's responses to Staff's Third Request for Production of Documents, Nos. *21, 22.

***CONFIDENTIAL DN. 02379-2018.**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 88
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Kyle D. Wood

21. Please refer to Seminole's responses to Staff First Request for Production Nos. 11, 12, and 13. Please provide Seminole's development of its price variable for all periods shown in Excel format with formulas intact.

RESPONSE: The Seminole price variable is derived in SAS by Member by rate class by month. The SAS input and output data are attached. The calculation in SAS is provided below.

SAS Input

"170266-Staff's 3rd PODs No. 21 - CPIU LFS17 wIndex.xlsx"

"170266-Staff's 3rd PODs No. 21 - Itron - SECI Prices LFS17"

SAS Output

"170266-Staff's 3rd PODs No. 21 – Seminole Price - SAS Output by Member by Rate Class by Month"

Calculation in SAS

RealPrice_2016=Price_3YrMA/(cpi_Ave2016);

22. Please refer to Seminole's response to Staff's First Request for Production of Documents. Nos. 11 and 13. Please provide the development of Seminole's weather data for all periods shown in Excel format with formulas intact.

RESPONSE: Seminole is unable to produce the development of weather in Excel. The weather development is performed in SAS® software.

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SECI's responses to Quantum's First Set of Interrogatories, No. 2.

(CONFIDENTIAL DN. 02397-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 89
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Kezell

90

SECI's responses to Quantum's First Set of Interrogatories, Nos. 5, 14, 15, 16, 17, 18, 19, 21, 22, 23, 24, 25, 26.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 17)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 90
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Julia A. Diazgranados (5, 15, 26)Jason Peters (14, 25)David Wagner

5. What are the expected capacity factors of the SCCF and the SHCCF?

RESPONSE: See table below.

a. Please provide capacity factors for both plants.

RESPONSE: The following capacity factors were derived from production cost modeling.

SEMINOLE ELECTRIC COOPERATIVE, INC.
DOCKET NO. 20170266-EC, DOCKET NO. 20170267-EC
QUANTUM'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 5
PAGE 1 OF 1

	Capacity Factor	
	SCCF	SHCCF
2021		7%
2022	5%	76%
2023	76%	54%
2024	77%	57%
2025	77%	56%
2026	79%	58%
2027	78%	58%
2028	80%	60%
2029	80%	61%
2030	80%	61%
2031	79%	62%
2032	80%	63%
2033	80%	62%
2034	81%	64%
2035	80%	63%
2036	79%	62%
2037	79%	62%
2038	80%	63%
2039	79%	62%
2040	81%	64%
2041	81%	64%
2042	82%	65%
2043	82%	65%
2044	82%	66%
2045	82%	66%
2046	83%	68%
2047	82%	67%
2048	72%	67%
2049	72%	68%
2050	75%	69%
2051	74%	62%

14. Please state whether Seminole or Shady Hills will be required to pay (i) the Variable O&M costs and (ii) the Fixed O&M costs of the SHCCF.

RESPONSE: Shady Hills Energy Center, L.L.C., is responsible for the variable and fixed O&M costs of the SHCCF.

15. Please indicate whether the updated fuel price forecast in Table 17 of the Seminole Need Study was used to choose the portfolio or the initial fuel price forecast in Table 16 of the Seminole Need Study?

RESPONSE: The fuel price forecast in Table 16 of the Seminole Need Study was used in determining the portfolio of choice. Additional analysis was performed with the fuel price forecast in Table 17 of the Seminole Need Study and the use of the updated forecast did not change the preferred portfolio.

16. Please provide the methodology for forecasting gas prices beyond the horizon covered by the NYMEX forward curve.

RESPONSE: For projecting natural gas prices beyond the horizon of the NYMEX forward curve, Seminole escalates the gas price annually by the rate of increase for the applicable year forecasted by the Energy Information Administration ("EIA") in the reference case of its Annual Energy Outlook ("AEO").

17. Does the gas price forecast include the basis differential for delivery to the SCCF and SHCCF?

RESPONSE: The price forecast includes a basis differential from the NYMEX/Henry Hub gas price projection to account for geographic differences in the cost of gas supply and variable transportation costs for delivery to the Florida market area.

a. How was this basis derived? Please provide data and formulas supporting the delivery basis in the price forecast

RESPONSE: The geographic basis (i.e., FGT Zone 3) is added to the NYMEX/Henry Hub price projection. That value is divided by one minus the assumption for the pipeline fuel loss factor and the pipeline usage charge is added to the result to achieve the gas price forecast incorporating the basis differential elements described above.

This calculation for both the natural gas forecast and the updated forecast is contained in the spreadsheet labeled "170266-Quantum's 1st POD No. 1- ROG 17a- Gas Price Formulas" to be provided in response to Intervenor's First Request for Production of Documents.

18. Does the gas price forecast account for the operation of the Sabal Trail pipeline and deliveries of gas from the Marcellus and Utica shale regions via Transco and Sabal Trail? If yes, please explain.

RESPONSE: The gas price forecast is primarily driven by the NYMEX forward curve, which takes into account all available information on natural gas production and pipeline infrastructure.

19. Is there an assumed inflation rate used in projecting gas prices out beyond the horizon the NYMEX forward curve? If so, what is this rate? If the rate varies by year, please state the assumed escalation rate for each year of Seminole's analysis period.

RESPONSE: The following table contains the escalation rates by year as described in response to question 16 above. For years beyond the horizon of the EIA forecasted gas price (2051), Seminole uses the average annual escalation rate for the last five years of the available EIA data. Variations in the annual escalation rate in Seminole's forecasts are attributed directly to the variations in the EIA forecast and are driven by the underlying factors incorporated into their price forecasting methodology.

Base Natural Gas Price Forecast - Escalation	
Year	Escalation Rate (from EIA 2017 Annual Energy Outlook for 2030+)
2018	NYMEX Price
2019	NYMEX Price
2020	NYMEX Price
2021	NYMEX Price
2022	NYMEX Price
2023	NYMEX Price
2024	NYMEX Price
2025	NYMEX Price
2026	NYMEX Price
2027	NYMEX Price
2028	NYMEX Price
2029	NYMEX Price
2030	3.1%
2031	4.2%
2032	2.1%
2033	0.5%
2034	1.4%
2035	3.7%
2036	1.5%
2037	1.9%
2038	1.5%
2039	2.5%
2040	1.7%
2041	2.4%
2042	3.9%
2043	4.7%

2044	3.1%
2045	3.5%
2046	3.4%
2047	3.6%
2048	4.4%
2049	3.1%
2050	3.6%
2051	3.6%

21. Please explain why, in spite of the economic expansion that has taken place since the end of the last recession (2009), why the Seminole load forecast shows increasing load (total GWh and peak MW) but the history from 2009-2016 has shown declining load.

RESPONSE: A former Member of Seminole, Lee County Electric Cooperative (LCEC), discontinued purchasing power from Seminole in 2014. The first phase of LCEC's withdrawal from the Seminole system began in 2010. The significant reduction in Seminole's load due to LCEC's departure must be considered when interpreting the results of the load forecast with respect to historical figures. Tables 6 through 15 in the Need Determination Study report Seminole's load history including and excluding LCEC.

22. What is the historic forecast error for Seminole's load forecasts over the past 10 years?

OBJECTION/RESPONSE: Seminole objects to this interrogatory insofar as it calls for the creation of data or information that Seminole otherwise does not possess or otherwise would require Seminole to perform analyses that have not been performed to date because there is no such requirement under the applicable rules and law. Subject to and without waiving such objection, Seminole is in the process of preparing an analysis of forecast error, which will be produced upon completion.

a. What is the historic forecast error in the primary driver for demand cited by Seminole (population growth) over the past 10 years?

OBJECTION: Seminole objects to this interrogatory insofar as it calls for the creation of data or information that Seminole otherwise does not possess or otherwise would require Seminole or non-party to this proceeding perform or have another entity to perform analyses that have not been performed to date because there is no such requirement under the applicable rules and law.

b. Please identify the historic economic forecast error provided by Moody's over the past 10 years for Seminole's load forecast?

OBJECTION/RESPONSE: Moody's has not provided Seminole with the historic economic forecast error over the past 10 years. Seminole objects to this interrogatory insofar as it calls for the creation of data or information that Seminole does not possess or otherwise would require Seminole to analyses that have not been performed to date because there is no such requirement under the applicable rules and law.

23. Please provide the low and high load growth forecast sensitivities used in the economic analysis? How much lower/higher is this load forecast than the base load forecast? How were these sensitivities derived?

RESPONSE: See Determination of Need Study Table 14 and 15 (MPW-2 page 46-47) and the following documents, which were previously produced to Quantum in response to Staff's First Request for Production of Documents:

1. CONFIDENTIAL-170266- Staff's 1st POD No. 11-Base Model
2. CONFIDENTIAL-170266- Staff's 1st POD No. 11-High Model
3. CONFIDENTIAL-170266- Staff's 1st POD No. 11-Low Model
4. CONFIDENTIAL-170266-Staff's 1st POD No. 13-Base Model
5. CONFIDENTIAL-170266-Staff's 1st POD No. 13-High Model
6. CONFIDENTIAL-170266-Staff's 1st POD No. 13-Low Model
8. 170266-Staff's 1st POD No. 14-Member NEL and Net Firm Demand

In 170266-Staff's 1st POD No. 14-Member NEL and Net Firm Demand, the load growth forecast sensitivities can be subtracted from or divided by the base forecast in a given year to determine how much lower/higher the forecast sensitivity is than the base load forecast.

The base, high and low scenarios represent load outcomes if the future distribution of temperatures is similar to the past distribution; all other exogenous parameters are equal. Seminole developed Net Energy for Load forecast scenarios utilizing the 50th, 10th and 90th percentile ranks of temperature distributions, respectively. Low and High forecast scenarios of seasonal Net Firm Demand are developed the same way, however the Base forecast scenario of Net Firm Demand utilizes the average of the temperature distribution.

24. What are the historic load factors for the Seminole system?

RESPONSE: See the following document, which was previously produced to Quantum in response to Staff's First Request for Production of Documents:

1. 170266-Staff's 1st POD No. 14-Member NEL and Net Firm Demand

ANNUAL LOAD FACTOR = NET ENERGY FOR LOAD X 1000 / (MAXIMUM NET FIRM DEMAND X NUMBER OF HOURS PER YEAR)

Where Net Energy for Load in GWh and Net Firm Demand in MW;

Where Maximum Net Firm Demand = Summer or Winter Net Firm Demand, whichever is greater per year.

25. Please list all non-economic criteria used in evaluating offers to Seminole and the weighting each was given?

RESPONSE: Areas of review for non-economic criteria in Seminole's evaluation included contract terms, fuel supply, transmission, key model assumptions, environmental, regulatory compliance, counterparty/credit, and legal. Generally, each of these areas had several subcategories within the area of review. The Seminole evaluation team rated each category on the potential impact and likelihood of that impact occurring. In this portion of the analysis, Seminole did not weight any category with a specific percentage; the concept was to identify risks of concern in each proposal. Seminole did roll up its review of non-economic criteria into a scorecard to evaluate the final portfolios against each other.

a. What factors go into the risk rating? What weights were given to each factor?

RESPONSE: The evaluation of the items listed above composed the risk rating in the scorecard. Seminole applied the evaluated risk of each proposal to the MW value of the proposal in the applicable portfolio to generate a weighted risk rating. This weighted risk rating then determined the score of 1-10 given to the portfolio. 10% of the weighted scorecard value was given to the risk rating.

b. What factors go into the strategic rating? What weights were given to each factor?

RESPONSE: Seminole's strategic rating category evaluated the benefit of the proposal (and applicable portfolio) in regards to any flexibility/diversity/optionality provided by the portfolio. Example criteria included the ability of the proposal to minimize carbon emissions exposure to Seminole's portfolio, reduce/extend the term at Seminole's option, diversification of the geographic location of Seminole's resources, and others. 20% of the weighted scorecard value was given to the strategic rating.

c. What factors go into the operational flexibility rating?

RESPONSE: Seminole's operational flexibility ratings (regarding fuel and real time) evaluated the benefit of the proposal (and applicable portfolio) in regards to any flexibility provided in the day to day operation of the resources in the portfolio. Example criteria included the ability of the proposal to provide fuel from multiple gas pipelines, have multiple fuels, be available within 30 minutes for Seminole's intraday needs, and others. A total of 20% of the weighted scorecard value was given to the two operational ratings.

26. Did Seminole consider any "optionality" to choose a smaller self-build portfolio, smaller generation tolling agreements, non-generation, or shorter duration alternatives in the event the load stayed flat or continued to decline?

RESPONSE: Seminole considered and incorporated optionality in all portfolios.

a. If so, what were the economic and non-economic values to those options?

RESPONSE: The economic value is determined through production cost modeling. The non-economic and economic value is inherent in the optionality and the flexibility it provides to Seminole with the ability to shape capacity to specific annual needs.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(X) 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, 5, 8, 13, 15, and 26 of Quantum Pasco Power, L.P.'s First Set of Interrogatories (NOS. 1-26) to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados
Julia Diazgranados

Director of Treasury & Planning
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Jason Peters, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 7, 9-12, 14, and 25 of Quantum Pasco Power, L.P.'s First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Jason Peters

Manager Director

Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Wagner, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 6, 16, 17, 18 and 19 of Quantum Pasco Power, L.P.'s First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Wagner

Portfolio Director
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle D. Wood, 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. 20-24 of Quantum Pasco Power, L.P.'s First Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle D. Wood

Manager of Load Forecasting & Member Analytics

Title

Rebecca Witherow

Notary Public
State of Florida

My commission Expires: June 20, 2021

REBECCA WITHEROW
Notary Public – State of Florida
Commission # GG 077134
My Comm. Expires Jun 20, 2021
Bonded through National Notary Assn.

91

SECI's responses to Quantum's Second Set of Interrogatories, Nos. 36, 37, 39, 40, 42, 43, 44, 50.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 91
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Michael P. Ward II (36-37, 39)Julia A. Diazgranados (40, 42-44, 50c)Alan

36. Does Seminole believe that it can feasibly and cost-effectively operate SGS Unit 1 through the entire Study Period, i.e., from the present through 2051?

RESPONSE: From an engineering perspective, Seminole believes that it can feasibly operate SGS Unit 1 through the entire Study Period. However, the analyses presented in Seminole's pre-filed testimony and need study indicate that the most cost-effective alternative for meeting Seminole's needs includes taking one of the SGC coal units out of service commensurate with the commercial operation of the Seminole Combined Cycle Facility in approximately 2023.

a. If no, why not?

RESPONSE: See response to Interrogatory No. 36 above.

b. If no, please state when, i.e., through what year in the future, Seminole believes it can feasibly and cost-effectively continue to operate SGS Unit 1.

RESPONSE: See response to Interrogatory No. 36 above.

37. Does Seminole believe that it can feasibly and cost-effectively operate SGS Unit 2 through the entire Study Period, i.e., from the present through 2051?

RESPONSE: From an engineering perspective, Seminole believes that it can feasibly operate SGS Unit 2 through the entire Study Period. However, the analyses presented in Seminole's pre-filed testimony and need study indicate that the most cost-effective alternative for meeting Seminole's needs includes taking one of the SGC coal units out of service commensurate with the commercial operation of the Seminole Combined Cycle Facility in approximately 2023.

c. If no, why not?

RESPONSE: See response to Interrogatory No. 37 above.

d. If no, please state when, i.e., through what year in the future, Seminole believes it can feasibly and cost-effectively continue to operate SGS Unit 2.

RESPONSE: See response to Interrogatory No. 37 above.

39. If Seminole were to remove only one of its coal-fired generating units from service, as represented in the Clean Power Plan ("CPP") described in the Petition and in the Sedway Report, which of the units, i.e., either SGS Unit 1 or SGS Unit 2, would Seminole remove from service?

RESPONSE: Seminole is currently evaluating which unit to remove from service.

40. Which unit was assumed to be removed from service in developing the cost projections and cost-effectiveness analyses described in Ms. Diazgranados's testimony and in the Sedway Report?

RESPONSE: SGS Unit 1.

42. Please identify the projected generation of SGS Unit 1 (i.e., the existing coal unit) and SGS Unit 2 for each year of the Study Period, assuming that both units would remain in service until retired.

RESPONSE:

	SGS U1	SGS U2
	GWh	
2018	3,856	3,589
2019	3,377	4,076
2020	3,651	3,520
2021	3,146	3,857
2022	3,442	3,320
2023	2,964	3,580
2024	3,500	3,369
2025	3,127	3,816
2026	3,627	3,478
2027	3,300	3,987
2028	3,382	3,225
2029	3,089	3,682
2030	3,496	3,312
2031	2,808	3,345
2032	3,200	3,015
2033	2,851	3,396
2034	3,200	3,004
2035	2,849	3,396
2036	3,251	3,071
2037	2,883	3,416
2038	3,251	3,060
2039	2,725	3,241
2040	2,997	2,822
2041	2,715	3,182
2042	3,108	2,915
2043	2,794	3,306
2044	3,178	2,949
2045	2,846	3,373
2046	3,222	3,005
2047	2,870	3,422
2048	3,317	3,124
2049	2,975	3,524
2050	3,393	3,193
2051	3,050	3,612

43. Please identify the projected generation of whichever of Seminole's coal units Seminole would leave in service in the Clean Power Plan scenario, for each year of the Study Period.

RESPONSE:

	SGS U1	SGS U2
	GWh	
2018	3,841	3,576
2019	3,351	4,044
2020	3,622	3,494
2021	3,175	3,863
2022	3,215	3,088
2023	3,058	
2024	2,768	
2025	3,094	
2026	2,815	
2027	3,216	
2028	2,902	
2029	3,274	
2030	2,957	
2031	3,302	
2032	2,990	
2033	3,374	
2034	2,998	
2035	3,396	
2036	3,067	
2037	3,391	
2038	2,780	
2039	3,144	
2040	2,801	
2041	3,152	
2042	2,852	
2043	3,228	
2044	2,925	
2045	3,268	
2046	2,946	
2047	3,256	
2048	2,732	
2049	3,025	
2050	2,743	
2051	3,317	

44. Please identify each of the PPAs that Seminole included in the All-PPA Portfolio referenced in Exhibit JAD-6 to the testimony of Julia Diazgranados.

RESPONSE:

- SCS Base - 350 MW - 50 MW
- LS Power (Santa Rosa) - 231 MW
- DEF Winter Peaking - 50 MW to 600 MW
- DEF System Intermediate & Peaking Mix - 100 MW to 450 MW
- Tillman Solar Center - 40 MW
- Oleander Peaking CTs - 364 MW
- Shady Hills Peaking CTs – 519 MW

50. Did Sedway evaluate the cost-effectiveness of the All-PPA Portfolio?

RESPONSE: No.

a. If so, please provide the results of any such analysis or analyses, and all workpapers relating to such analyses.

RESPONSE: .Sedway Consulting did not evaluate the cost-effectiveness of the All-PPA Portfolio represented in Seminole Witness Julia Diazgranados' testimony.

b. If not, please explain why not.

RESPONSE: The All-PPA Portfolio represented in Seminole Witness Julia Diazgranados' testimony was not a portfolio that was developed for presentation to Seminole's Board of Trustees for the final selection decision in July, 2017. Also, it was not a portfolio that was compliant with the selection criteria that Seminole and Sedway Consulting had agreed to early in the RFP project (which limited imported capacity from outside of peninsular Florida for reliability reasons). Sedway Consulting was free to develop its own portfolios for its own evaluation, and did so; however, all of the portfolios that Sedway Consulting developed and evaluated were compliant with the established selection criteria

c. If not, please (i) identify who prepared the analyses shown in Exhibit JAD-6 and (ii) identify all documents, including workpapers, that relate to such analyses.

RESPONSE:

(i) Julia Diazgranados

(ii) Documents from which the answer can be derived will be provided pursuant to Fla. R. Civ. P. 1.340(c) under the terms of the Confidentiality Agreement between Seminole and Quantum Pasco Power.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Michael Ward, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 35-37, 39, and 51 of Quantum Pasco Power, LP's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Michael Ward

Vice President of Strategic Initiatives
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 27-34, 38, 40-47, and 50c of Quantum Pasco Power, LP's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados
Julia Diazgranados

Director of Treasury and Planning
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF COLORADO)
)
COUNTY OF BOULDER)

Before me, the undersigned authority, personally appeared Alan Taylor, who

( ) is personally known to me, or

(X) produced Colorado Driver's License as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 50a and 50b of Quantum Pasco Power, LP's Second Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Alan Taylor

PRESIDENT
Title

Notary Public
State of Colorado

My commission Expires: 10/13/2020

DYLAN LEVI TUCKER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164039302
MY COMMISSION EXPIRES 10/13/20

92

SECI's responses to Quantum's Third Set of Interrogatories, Nos. 56, 57, 76, 77, 81, 82.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 92
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Julia A. Diazgranados (56-57, 77)Alan S. Taylor (76)Kyle D. Wood (81-82)

56. a. Who specified the power purchase agreements ("PPAs") that were included in the All-PPA Portfolio?

RESPONSE: System Optimizer was utilized to select which PPAs should be considered for the All PPA Portfolio. The RFP evaluation team further optimized the PPAs identified by System Optimizer to provide an appropriate balance between economics, operational considerations, and risk management. The members of the evaluation team included the following: Michael Ward, David Kezell, Robert DeMelo, Lewis Snyder, David Wagner, Tim Rogers, Jason Peters, Tim Nasello, Julia Diazgranados, Brian Broadstock, Daniel Noia, and Mark Anderson.

b. Please explain in detail the basis upon which the PPAs included in the All-PPA Portfolio were chosen.

RESPONSE: See response to Interrogatory No. 56a above.

57. a. Did Seminole evaluate or analyze any portfolio in which it was assumed that Seminole would meet all of its needs for the Study Period, or any period shorter than the Study Period, only with PPAs in addition to the power produced by Seminole's SGS Unit 1 and Unit 2 and Seminole's Midulla Generating Station Units 1 through 8? If so, please identify each such portfolio and state exactly what PPAs were assumed to be included in each such portfolio.

RESPONSE: Yes, that would be the All PPA Portfolio. An Alternate All PPA Portfolio was evaluated but was eliminated due to the revenue requirements being higher than the All PPA Portfolio presented in the Seminole Need Study. The following table shows the PPAs included in each of these portfolios.

Portfolio Summaries – All PPA
Initial Economic Analysis Results
(millions of $)

	Alternate No Build Risk: All PPA Portfolio (30 year System Optimizer)	No Build Risk: All PPA Portfolio (10 year System Optimizer)
Resources	-LS Power - Santa Rosa -Shady Hills 3x0 -SCS Base -FPL Int. -FPL Pk. -Oleander 2x0 -Quantum Pasco	-LS Power - Santa Rosa -Shady Hills 3x0 -SCS Base -DEF Int. -DEF Pk. -Oleander 2x0
Total Member Revenue Requirements - Years 2018-2027 (millions of $)		
Nominal	12,173	12,096
NPV @ 6.0%	8,850	8,798
Total Member Revenue Requirements - Years 2018-2051 (millions of $)		
Nominal	62,923	61,695
NPV @ 6.0%	22,438	22,198

b. If the only such portfolio evaluated was the All-PPA Portfolio, please so state.

RESPONSE: See response to Interrogatory No. 57a above.

76. a. Did Sedway evaluate any portfolios not identified in the Sedway Report?

RESPONSE: Yes. In its independent evaluation role, Sedway Consulting had full latitude to develop and investigate any portfolios it wished to evaluate in an effort to identify the least-cost portfolio for Seminole's customers.

b. If so, please identify and state the exact specifications of each such portfolio.

RESPONSE: Sedway Consulting explored the selection of different combinations of competing top-ranked resources in an effort to identify the least-cost portfolio for Seminole's customers. A full portfolio analysis was conducted for one particular resource that was labeled as O-1 in the tables in Sedway Consulting's Independent Evaluation Report. This resource displaced some of the available capacity associated with the Southern Company System sale that was labeled as Q-1 in the same report.

c. If so, please provide the results of any such portfolio thus evaluated in the same formats shown in Tables A-13 through A-15.

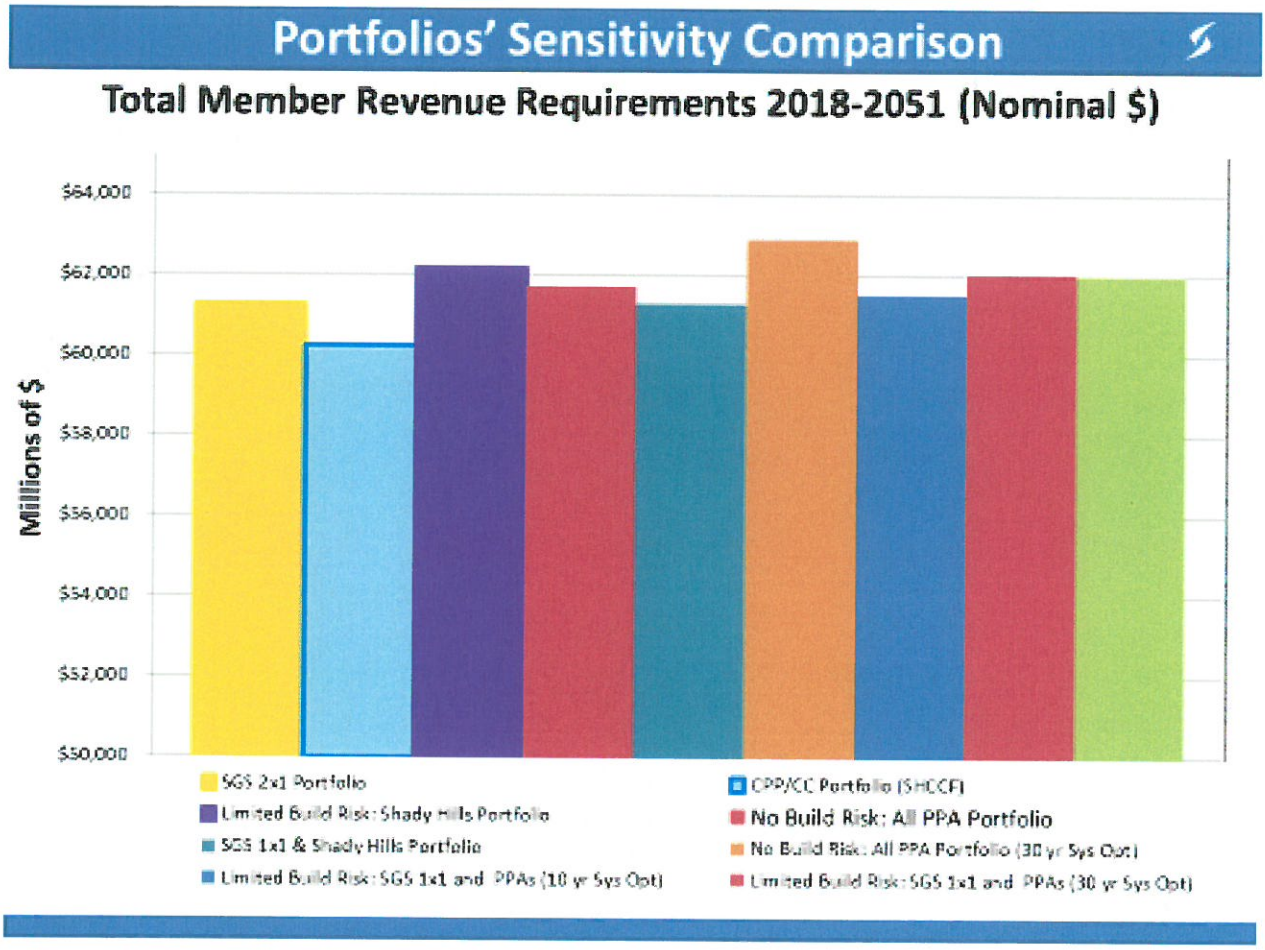
RESPONSE: See CONFIDENTIAL Attachment 76c.

77. Did Seminole evaluate any portfolios other than the four portfolios identified in Figure 11 and Figure 13 of the Seminole Need Study? If so, please provide the results of any such portfolio thus evaluated in the same formats shown in Figure 11, Figure 12, and Figure 13 of the Seminole Need Study.

RESPONSE: Seminole developed revenue requirements based on the initial economic assumptions for the following additional portfolios. Only the final portfolios had risk assessments performed, therefore these portfolios do not have a portfolio risk assessment in a form like Figure 12.

Portfolio Summaries For Additional Portfolios (millions of $)

	SGS 1x1 & Shady Hills Portfolio	No Build Risk: All PPA Portfolio (30 yr. Sys Opt)	Limited Build Risk: SGS 1x1 and PPAs (10 yr. Sys Opt)	Limited Build Risk: SGS 1x1 and PPAs (30 yr. Sys Opt)	Limited Build Risk: SHCCF and PPAs (30 yr. Sys Opt)
Resources	-SGS 1x1 -Shady Hills 1x1 -SCS Base -DEF Int. -Shady Hills 3x0	-LS Power - Santa Rosa -Shady Hills 3x0 -SCS Base -FPL Int. -FPL Pk. -Oleander 2x0 -Quantum Pasco	-SGS 1x1 -SCS Base -DEF Pk. -Shady Hills 3x0 -Oleander 2x0	-SGS 1x1 -SCS Base -FPL Int. -FPL Pk. -Santa Rosa -Shady Hills 3x0 -Oleander 1x0	-Shady Hills 1x1 -SCS Base -FPL Int. -FPL Pk. -Santa Rosa -Shady Hills 3x0 -Oleander 1x0
Total Member Revenue Requirements - Years 2018-2027 (millions of $)					
Nominal	12,540	12,173	12,335	12,386	12,265
NPV @ 6%	8,563	8,850	8,414	9,010	8,932
Total Member Revenue Requirements - Years 2018-2051 (millions of $)					
Nominal	61,306	62,923	61,518	62,055	62,081
NPV @ 6%	22,254	22,438	22,279	22,328	22,247


Portfolios' Sensitivity Comparison
Total Member Revenue Requirements 2018-2051 (Nominal $)
Millions of $
$64,000
$62,000
$60,000
$58,000
$56,000
$54,000
$52,000
$50,000
SGS 2x1 Portfolio
Limited Build Risk: Shady Hills Portfolio
SGS 1x1 & Shady Hills Portfolio
Limited Build Risk: SGS 1x1 and PPAs (10 yr Sys Opt)
CPP/CC Portfolio (SHCCF)
No Build Risk: All PPA Portfolio
No Build Risk: All PPA Portfolio (30 yr Sys Opt)
Limited Build Risk: SGS 1x1 and PPAs (30 yr Sys Opt)

81. Please explain why Seminole uses data provided by Moody Analytics for its projections and analyses.

RESPONSE: Moody's Analytics is a well-recognized resource for economic analysis, real-time updates of the economy, and long term forecasts for a number of macro-economic indicators. Seminole subscribes to Moody's specifically for Florida-county, monthly-interval forecasts of economic indicators for load forecast models. In addition, Moody's provides Seminole access to webinars regarding important economic events and Seminole subscribes to written reports on the Florida economy. Finally, Seminole has access to Moody's economists to discuss forecast methodology and assumptions.

82. a. Does Seminole use any publicly available data, e.g., from the U.S. Energy Information Administration, for the same projections and analyses for which Seminole uses Moody Analytics data?

RESPONSE: Yes.

b. If so, please identify all such publicly available sources from which Seminole uses data for such purposes.

RESPONSE: Seminole uses publically available population projections by county published online by the University of Florida Bureau of Business and Economic Research (BEBR). Seminole also requests quarterly population projections, based on BEBR's 5-year interval projections, from the Florida Office of Economic and Demographic Research.

c. If so, please identify all documents reflecting or showing the results of any such analyses.

RESPONSE: Please see Petitioners' response to Staff's Request for Production No. 19 and the documents produced in response to that Request.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Julia Diazgranados, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 53-57, 61a, 61b, 61d, 61e, 62, 63, 65, 66, 77, 78, and 83 of Quantum Pasco Power, LP's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Julia Diazgranados

Julia Diazgranados

Director of Treasury & Planning

Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF COLORADO)
)
COUNTY OF BOULDER)

Before me, the undersigned authority, personally appeared Alan Taylor, who

( ) is personally known to me, or

(✓) produced Colorado Driver's License as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 58-60, 61c, 69-71, 76, and 79 of Quantum Pasco Power, LP's Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Alan Taylor

Alan Taylor

PRESIDENT

Title

Notary Public
State of Colorado

My commission Expires: 10/07/20

Erick Gilberto Giron Salguero
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164046418
MY COMMISSION EXPIRES 10/07/20

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared Kyle D. Wood, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 81-82 of Quantum Pasco Power, L.P.'s Third Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

Kyle D. Wood

Manager of Load Forecasting & Member Analytics
Title

Rebecca Witherow
Notary Public
State of Florida

My commission Expires: June 20, 2021

REBECCA WITHEROW
Notary Public – State of Florida
Commission # GG 077134
My Comm. Expires Jun 20, 2021
Bonded through National Notary Assn.

93

SECI's responses to Quantum's Fourth Set of Interrogatories, Nos. 85, 86.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 93
PARTY: STAFF'S EXHIBITS
DESCRIPTION: David Kezell

85. As of the filing of its response to this Interrogatory, does Seminole have a finally executed EPC contract for the SCCF? If so, please provide the EPC contract in response to Quantum's document production requests accompanying this Interrogatory. If not, please state the approximate date on which Seminole expects to have such finally executed EPC contract.

RESPONSE: No, Seminole does not have a finally executed EPC contract for the SCCF as of the date of the filing of this response. Seminole expects to have a finally executed contract by April 12, 2018.

86. Does Seminole expect that the EPC contract will include provisions for change orders that could increase the cost of the SCCF to Seminole?

RESPONSE: Yes, Seminole does expect that the EPC contract will include provisions for change orders that could increase, or decrease, the cost of the SCCF to Seminole.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me, the undersigned authority, personally appeared David Kezell, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 85 and 86 of Quantum Pasco Power, LP's Fourth Set of Interrogatories to Seminole Electric Cooperative, Inc., in Docket No. 20170266-EC are true and correct to the best of his knowledge, information and belief.

David Kezell

Director, Engineering and Capital Development
Title

Notary Public
State of Florida

My commission Expires: June 5, 2019

SHERRIE L. MATTHEWS
MY COMMISSION EXPIRES
June 5, 2019
#FF 221129
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

94

SECI's responses to Quantum's First Request for Production of Documents, No. 2.

(CONFIDENTIAL DN. 02397-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 94
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Michael P. Ward, II

95

Quantum's Responses to Staff's First Set of Interrogatories, Nos. 1, 2, 3.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 95
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Paul M. Sotkiewicz, Ph.D.

RESPONSES TO INTERROGATORIES

1. Please refer to witness Sotkiewicz's testimony, page 9, lines 7-19. Please state whether the forecasting error rate analysis presented in this section of testimony includes the values related to serving Lee County Electric Cooperative (LCEC). If the error rates are exclusive of values related to LCEC, please specify how and by what amount the associated data was extricated from the analysis.

Response

The forecasting error rate analyses 3, 4, and 5 years out include forecasts and actual values for winter and summer peak and total GWh of energy consumed include LCEC through the end of 2013 after which Seminole no longer served LCEC load.

The forecasting error rate analyses 3, 4, and 5 years out for the years 2014, 2015, and 2016 *do not include* LCEC load in the forecasts and actual values for winter and summer peak and total GWh of energy consumed as Seminole no longer served LCEC load starting January 1, 2014.

The above referenced inclusions and exclusions were based on Dr. Sotkiewicz's knowledge of the Florida electric industry and on the information presented in Seminole's Ten Year Site Plans ("TYSPs") that Dr. Sotkiewicz analyzed in preparing his testimony.

At the time that Dr. Sotkiewicz prepared his testimony, Dr. Sotkiewicz understood that it was generally and publicly known, at

least as early as 2008, and as stated by Seminole itself in the 2008 TYSP, that LCEC would cease receiving bulk power service from Seminole as of January 1, 2014. No more specific information was generally available regarding any schedule on which LCEC would "transition" out of receiving service from Seminole. Accordingly, at the time he prepared his testimony, he relied on Seminole's TYSPs based on the reasonable assumption that Seminole's forecasts, presented to the PSC as Seminole's plan, included LCEC's loads (demands and energy requirements) in the 2005, 2006, and 2007 TYSPs, and excluded LCEC's loads starting in 2014 in the TYSPs submitted in 2008 and thereafter. Thus, for example, the forecasts for 2010 presented in 2005, 2006, and 2007, would have included LCEC loads, and Dr. Sotkiewicz believed that the actual loads in 2010 would likewise have included LCEC loads. Similarly, the forecasts for 2016 presented in the 2009, 2010, and 2011 TYSPs, having been prepared after 2008, would have excluded LCEC loads, and the actual loads served in the forecast years 2014-2016 would also have excluded the LCEC loads. Thus, based on this understanding, Dr. Sotkiewicz believed that the error analyses comparing forecast vs. actual Seminole loads properly included the LCEC loads for forecasts made before 2008 and the actual loads for the forecast years in his analyses, and properly excluded the LCEC forecast loads starting in 2014 for forecasts made beginning with the 2008 TYSP and the actual loads for the forecast years in his

analyses.

In further re-reviewing the TYSPs, Dr. Sotkiewicz discovered a footnote in the 2010 plan, and repeated in the 2011, 2012, and 2013 TYSPs, that indicates that Seminole would only be serving "approximately 70 percent" of the LCEC load starting in 2010. There were not similar footnotes in the 2008 or 2009 plans to indicate this transition. Moreover, since Seminole does not break out its peak and total energy forecasts or actual values by member Cooperative, it would have been impossible to know how to make any adjustments based on the above referenced footnote. Going even further, starting with the 2014 TYSP, Seminole makes reference to the fact that actual values through 2013 include LCEC and makes no mention of any adjustments that were made per the above referenced footnote regarding "approximately 70 percent", leading any reader or analyst to conclude that the actuals include the entirety of the LCEC total energy consumption and peak loads. What is known is that Seminole ceased serving all LCEC's loads as of January 1, 2014, and that the load forecasts in Seminole's TYSPs for 2009 and later years either did, or should have, accounted for that fact. Accordingly, it would be meaningful to examine the errors for the forecasts for 2014, 2015, and 2016 on a 3-years-out, 4-years-out, and 5-years-out basis. Those results are presented here.

Winter Peak Demand Forecast vs. Actual:

	5 Years Out	4 Years Out	3 Years Out
Average MW Error:	1,179 MW	1,055 MW	904 MW
Average % Error:	36.4%	32.6%	27.9%

Summer Peak Demand Forecast vs. Actual:

	5 Years Out	4 Years Out	3 Years Out
Average MW Error:	594 MW	441 MW	270 MW
Average % Error:	19.2%	14.3%	8.8%

Net Energy for Load Forecast vs. Actual:

	5 Years Out	4 Years Out	3 Years Out
Average GWH Error:	2,599 GWH	1,967 GWH	1,408 GWH
Average % Error:	18.4%	14.0%	10.0%

2. Please refer to witness Sotkiewicz's testimony, page 11, lines 17-19. Please specify how Seminole could "correct its forecasting methodologies", and what specific steps or actions should Seminole be taking in altering its forecasting methodologies.

Response

At the time of writing his testimony, Dr. Sotkiewicz did not have the details of Seminole's actual load forecasting methodology used throughout the 2005 to 2017 period but for the broad set of data and outlines provided in the Ten Year Site Plans.

As of this response, Intervenors and Dr. Sotkiewicz have received more information regarding the Seminole load forecasting methodology, but he has been unable to analyze it all. Once Dr. Sotkiewicz has been able to go through the Seminole load forecasting methodology provided, he can offer broad based recommendations.

3. Please refer to witness Sotkiewicz's testimony, Exhibit PS-2, page 1, Exhibit PS-3, page 1, and Exhibit PS-4, page 1.

a. Please indicate whether the data in rows 2014, 2015, and 2016 reflect LCEC's forecast usage data (i.e. MWs, GWhs), but excludes Lee County Electric Cooperative's actual usage data.

Response

No. Seminole knew as early as the 2008 Ten Year Site Plan, and stated as such in the 2008 Ten Year Site Plan, that LCEC would not be served by Seminole beginning January 1, 2014. Seminole's 2008 TYSP at page 11. From the information provided in the Seminole Ten Year Site Plans, Dr. Sotkiewicz believes and understands that there were no LCEC forecast usage data included in any of Seminole's forecasts for 2014, 2015, or 2016, and that the actual usage data for those years correspondingly does not include any LCEC usage values.

b. If Quantum's response to 3(a) is "Yes", please identify all such LCEC's usage data for those years and Quantum's source for that data.

Response

Not applicable.

c. If Quantum's response to 3(b) is "No", please fully explain whether the differences and percentage differences shown in rows 2014, 2015, and 2016 are correct or overstated and why.

Response

The 5-years-out forecast values for 2014 shown in Seminole's 2009 TYSP (pages 20, 22, and 24) do not include LCEC forecast usage values for 2014 since Seminole knew as far back as the 2008 Ten Year Site Plan that it would no longer be serving LCEC load beginning January 1, 2014. Similarly, the 5-years-out forecast values for 2015 shown in Seminole's 2010 TYSP (pages 21, 23, and 25) do not include LCEC forecast usage values for 2015 since Seminole knew as far back as the 2008 Ten Year Site Plan that it would no longer be serving LCEC load beginning January 1, 2014. And continuing the pattern, the forecast values for 2016 do not include LCEC forecast usage values for 2014 since Seminole knew as far back as the 2008 Ten Year Site Plan that it would no longer be serving LCEC load beginning January 1, 2014.

Moreover, the actual values for total energy (GWh) usage, and winter and summer peaks do not include LCEC values as indicated in each of the 2014-2017 Ten Year Site Plans as Seminole has indicated that only the actual values through 2013 include LCEC with the implication that any subsequent years (2014-2016) do not include LCEC.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Alachua)

Before me, the undersigned authority, personally appeared Dr. Paul M. Sotkiewicz, who ___ is personally known to me or X produced identification (Identification Produced driver's license), who being duly sworn, deposes and says that he provided the answers to interrogatory numbers 1-3 from the Florida Public Service Commission Staff's First Set of Interrogatories to Michael Tulk, Patrick Daly, and Quantum Pasco Power, L.P. in PSC Docket Nos. 20170266-EC and 20170267-EC, and that the responses are true and correct to the best of his knowledge, information and belief.

Paul M. Sotkiewicz

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid of this 14 day of March, 2018.

Notary Public
State of Florida, at Large

CHARLENE FERTEL
Notary Public - State of Florida
Commission # GG 112127
My Comm. Expires Jun 6, 2021

My Commission Expires:

06/06/2021

96

Quantum's Responses to Staff's First Request for Production of Documents, No. 1.

(Additional files contained on Staff's Hearing Exhibits CD Nos. 1)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 96
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Paul M. Sotkiewicz, Ph.D.

RESPONSES TO REQUEST FOR PRODUCTION OF DOCUMENTS

1. Please provide any work papers used in developing Exhibits PS-2, PS-3, and PS-4, of witness Paul M. Sotkiewicz's testimony, in Excel format with formulas intact and cells unlocked.

Response: The requested Excel spreadsheets are attached.

Respectfully submitted this 28th day of February 2018.

Robert Scheffel Wright
schef@gbwlegal.com
John T. LaVia, III
jlavia@gbwlegal.com
Gardner, Bist, Bowden, Bush,
Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, Florida 32308
Telephone (850) 385-0070
Facsimile (850) 385-5416

Attorneys for Intervenors

97

Deposition of Kyle D. Wood, Exhibits Nos. 1, 2, 3, 4.

(Additional files contained on Staff's Hearing Exhibits CD. Exhibits Nos. 1, 2, 4)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 97
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Kyle D. Wood

2017 Need Study Compared to 2017 and 2016 Ten Year Site Plan (TYSP)
Net Energy for Load and Net Firm Demand Forecasts
Seminole Electric Cooperative, Inc.

NET ENERGY FOR LOAD
2017 Need Study Compared to 2017 TYSP

Year	2017 Need Study	2017 TYSP	Difference	Difference%
2017	14,125	14,175	-50	-0.4%
2018	14,601	14,548	53	0.4%
2019	14,820	14,871	-51	-0.3%
2020	14,948	15,087	-139	-0.9%
2021	15,094	15,316	-222	-1.5%
2022	15,306	15,531	-225	-1.5%
2023	15,543	15,773	-230	-1.5%
2024	15,774	16,016	-242	-1.5%
2025	15,990	16,264	-274	-1.7%
2026	16,216	16,490	-274	-1.7%

NET ENERGY FOR LOAD
2017 Need Study Compared to 2016 TYSP

Year	2017 Need Study	2016 TYSP	Difference	Difference%
2017	14,125	14,249	-124	-0.9%
2018	14,601	14,566	35	0.2%
2019	14,820	14,870	-50	-0.3%
2020	14,948	15,133	-185	-1.2%
2021	15,094	15,370	-276	-1.8%
2022	15,306	15,602	-296	-1.9%
2023	15,543	15,815	-272	-1.8%
2024	15,774	16,026	-252	-1.6%
2025	15,990	16,224	-234	-1.5%

WINTER NET FIRM DEMAND
2017 Need Study Compared to 2017 TYSP

Year	2017 Need Study	2017 TYSP	Difference	Difference%
2017/2018	3,398	3,523	-125	-3.7%
2018/2019	3,466	3,593	-127	-3.7%
2019/2020	3,531	3,646	-115	-3.3%
2021/2022	3,588	3,701	-113	-3.2%
2022/2023	3,643	3,750	-107	-2.9%
2023/2024	3,699	3,803	-104	-2.8%
2024/2025	3,749	3,857	-108	-2.9%
2025/2026	3,802	3,911	-109	-2.9%
2026/2027	3,857	3,962	-105	-2.7%
2027/2028	3,909	4,013	-104	-2.6%

WINTER NET FIRM DEMAND
2017 Need Study Compared to 2016 TYSP

Year	2017 Need Study	2016 TYSP	Difference	Difference%
2017/2018	3,398	3,539	-141	-4.1%
2018/2019	3,466	3,596	-130	-3.8%
2019/2020	3,531	3,649	-118	-3.3%
2021/2022	3,588	3,698	-110	-3.1%
2022/2023	3,643	3,744	-101	-2.8%
2023/2024	3,699	3,787	-88	-2.4%
2024/2025	3,749	3,827	-78	-2.1%
2025/2026	3,802	3,866	-64	-1.7%
2026/2027	3,857	3,904	-47	-1.2%

SUMMER NET FIRM DEMAND
2017 Need Study Compared to 2017 TYSP

Year	2017 Need Study	2017 TYSP	Difference	Difference%
2017	3,090	3,045	45	1.5%
2018	3,140	3,104	36	1.2%
2019	3,187	3,163	24	0.8%
2020	3,238	3,207	31	1.0%
2021	3,251	3,241	10	0.3%
2022	3,297	3,290	7	0.2%
2023	3,343	3,341	2	0.0%
2024	3,388	3,391	-3	-0.1%
2025	3,430	3,441	-11	-0.3%
2026	3,474	3,487	-13	-0.4%

SUMMER NET FIRM DEMAND
2017 Need Study Compared to 2016 TYSP

Year	2017 Need Study	2016 TYSP	Difference	Difference%
2017	3,090	3,082	8	0.3%
2018	3,140	3,143	-3	-0.1%
2019	3,187	3,201	-14	-0.4%
2020	3,238	3,257	-19	-0.6%
2021	3,251	3,291	-40	-1.2%
2022	3,297	3,336	-39	-1.2%
2023	3,343	3,377	-34	-1.0%
2024	3,388	3,419	-31	-0.9%
2025	3,430	3,457	-27	-0.8%

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Net Energy for Load (GWh)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL)			(FORECAST - ACTUAL) / ACTUAL		
				3 Years Out	*4 Years Out*	*5 Years Out*	*3 Years Out*	*4 Years Out*	*5 Years Out*
	2003 LFS	Dec.2002	2005 TYSP	-365	-97	1,028	-2.12%	-0.55%	5.93%
	2005 LFS	Dec.2004	2006 TYSP	1,625	2,248	1,869	9.38%	12.88%	10.77%
*	2005 LFS	Dec.2004	2007 TYSP	1,584	2,205	1,824	9.14%	12.63%	10.52%
	2007 LFS	Dec.2006	2008 TYSP	933	3,065	4,150	5.38%	19.11%	26.32%
	2008 LFS	Dec.2007	2009 TYSP	1,945	2,787	3,528	12.13%	17.67%	22.31%
	2009 LFS	Dec.2008	2010 TYSP	2,331	2,859	2,358	14.78%	18.08%	17.02%
	2010 LFS	Dec.2009	2011 TYSP	2,678	1,974	2,108	16.94%	14.25%	14.95%
	2011 LFS	Dec.2010	2012 TYSP	1,066	1,286	1,435	7.69%	9.12%	9.92%
	2012 LFS	Dec.2011	2013 TYSP	952	963	1,557	6.75%	6.65%	10.87%
	2013 LFS	Dec.2012	2014 TYSP	823	1,414		5.69%	9.87%	
	2014 LFS	Dec.2013	2015 TYSP	-57			-0.40%		
			AVERAGE	**1,229**	**1,870**	**2,206**	**7.76%**	**11.97%**	**14.29%**
			***AVERAGE** (Excluding Duplicate)*	**1,193**	**1,833**	**2,254**	**7.62%**	**11.90%**	**14.76%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002				
	2003				
1 Year Out	2004				
2 Years Out	2005	16,766	16,295	-471	-2.81%
3 Years Out	2006	17,233	16,868	-365	-2.12%
4 Years Out	2007	17,669	17,572	-97	-0.55%
5 Years Out	2008	17,332	18,360	1,028	5.93%

2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)
Adjusted for LCEC

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	17,669	18,134	465	2.63%
3 Years Out	2008	17,332	18,957	1,625	9.38%
4 Years Out	2009	17,453	19,701	2,248	12.88%
5 Years Out	2010	17,346	19,215	1,869	10.77%

Note: 2010 Forecast Value Reduced by 1,299 GWh to Account for LCEC.

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2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)
Adjusted for LCEC

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	17,669	18,095	426	2.41%
3 Years Out	2008	17,332	18,916	1,584	9.14%
4 Years Out	2009	17,453	19,658	2,205	12.63%
5 Years Out	2010	17,346	19,170	1,824	10.52%

Note: 2010 Forecast Value Reduced by 1,299 GWh to Account for LCEC.

2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006				
	2007				
1 Year Out	2008				
2 Years Out	2009	17,453	18,812	1,359	7.79%
3 Years Out	2010	17,346	18,279	933	5.38%
4 Years Out	2011	16,037	19,102	3,065	19.11%
5 Years Out	2012	15,769	19,919	4,150	26.32%

2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007				
	2008				
1 Year Out	2009				
2 Years Out	2010	17,346	17,344	-2	-0.01%
3 Years Out	2011	16,037	17,982	1,945	12.13%
4 Years Out	2012	15,769	18,556	2,787	17.67%
5 Years Out	2013	15,812	19,340	3,528	22.31%

2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008				
	2009				
1 Year Out	2010				
2 Years Out	2011	16,037	17,480	1,443	9.00%
3 Years Out	2012	15,769	18,100	2,331	14.78%
4 Years Out	2013	15,812	18,671	2,859	18.08%
5 Years Out	2014	13,854	16,212	2,358	17.02%

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2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009				
	2010				
1 Year Out	2011				
2 Years Out	2012	15,769	17,884	2,115	13.41%
3 Years Out	2013	15,812	18,490	2,678	16.94%
4 Years Out	2014	13,854	15,828	1,974	14.25%
5 Years Out	2015	14,104	16,212	2,108	14.95%

2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010				
	2011				
1 Year Out	2012				
2 Years Out	2013	15,812	17,403	1,591	10.06%
3 Years Out	2014	13,854	14,920	1,066	7.69%
4 Years Out	2015	14,104	15,390	1,286	9.12%
5 Years Out	2016	14,471	15,906	1,435	9.92%

2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011				
	2012				
1 Year Out	2013				
2 Years Out	2014	13,854	14,620	766	5.53%
3 Years Out	2015	14,104	15,056	952	6.75%
4 Years Out	2016	14,471	15,434	963	6.65%
5 Years Out	2017	14,325	15,882	1,557	10.87%

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2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012				
	2013				
1 Year Out	2014				
2 Years Out	2015	14,104	14,794	690	4.89%
3 Years Out	2016	14,471	15,294	823	5.69%
4 Years Out	2017	14,325	15,739	1,414	9.87%

2014 LOAD FORECAST STUDY
2015 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2013	2013				
	2014				
1 Year Out	2015				
2 Years Out	2016	14,471	14,050	-421	-2.91%
3 Years Out	2017	14,325	14,268	-57	-0.40%

Summer Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	4 Years Out	5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	4 Years Out	5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	-172	-241	112	-4.74%	-6.28%	3.09%
	2005 LFS	Dec.2004	2006 TYSP	216	176	382	5.95%	4.60%	10.77%
*	2005 LFS	Dec.2004	2007 TYSP	211	171	377	5.81%	4.47%	10.63%
	2007 LFS	Dec.2006	2008 TYSP	314	378	769	8.85%	10.35%	22.43%
	2008 LFS	Dec.2007	2009 TYSP	293	645	704	8.02%	18.82%	19.74%
	2009 LFS	Dec.2008	2010 TYSP	590	582	549	17.21%	16.32%	17.78%
	2010 LFS	Dec.2009	2011 TYSP	463	412	557	12.98%	13.34%	18.44%
	2011 LFS	Dec.2010	2012 TYSP	164	329	218	5.31%	10.89%	6.72%
	2012 LFS	Dec.2011	2013 TYSP	254	69	288	8.41%	2.13%	9.25%
	2013 LFS	Dec.2012	2014 TYSP	-43	177		-1.33%	5.68%	
	2014 LFS	Dec.2013	2015 TYSP	-92			-2.95%		
			AVERAGE	**200**	**270**	**440**	**5.78%**	**8.03%**	**13.20%**
			AVERAGE (Excluding Duplicate)	**199**	**281**	**447**	**5.77%**	**8.43%**	**13.53%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002				
	2003				
1 Year Out	2004				
2 Years Out	2005	3,539	3,324	-215	-6.08%
3 Years Out	2006	3,632	3,460	-172	-4.74%
4 Years Out	2007	3,839	3,598	-241	-6.28%
5 Years Out	2008	3,630	3,742	112	3.09%

2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)
Adjusted for LCEC

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	3,839	3,655	-184	-4.79%
3 Years Out	2008	3,630	3,846	216	5.95%
4 Years Out	2009	3,824	4,000	176	4.60%
5 Years Out	2010	3,548	3,930	382	10.77%

Note: 2010 Forecast Value Reduced by 227 MW to Account for LCEC.

2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)
Adjusted for LCEC

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	3,839	3,691	-148	-3.86%
3 Years Out	2008	3,630	3,841	211	5.81%
4 Years Out	2009	3,824	3,995	171	4.47%
5 Years Out	2010	3,548	3,925	377	10.63%

Note: 2010 Forecast Value Reduced by 227 MW to Account for LCEC.

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2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006				
	2007				
1 Year Out	2008				
2 Years Out	2009	3,824	3,920	96	2.51%
3 Years Out	2010	3,548	3,862	314	8.85%
4 Years Out	2011	3,653	4,031	378	10.35%
5 Years Out	2012	3,428	4,197	769	22.43%

2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007				
	2008				
1 Year Out	2009				
2 Years Out	2010	3,548	3,787	239	6.74%
3 Years Out	2011	3,653	3,946	293	8.02%
4 Years Out	2012	3,428	4,073	645	18.82%
5 Years Out	2013	3,566	4,270	704	19.74%

2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008				
	2009				
1 Year Out	2010				
2 Years Out	2011	3,653	3,883	230	6.30%
3 Years Out	2012	3,428	4,018	590	17.21%
4 Years Out	2013	3,566	4,148	582	16.32%
5 Years Out	2014	3,088	3,637	549	17.78%

2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009				
	2010				
1 Year Out	2011				
2 Years Out	2012	3,428	3,910	482	14.06%
3 Years Out	2013	3,566	4,029	463	12.98%
4 Years Out	2014	3,088	3,500	412	13.34%
5 Years Out	2015	3,021	3,578	557	18.44%

2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010				
	2011				
1 Year Out	2012				
2 Years Out	2013	3,566	3,740	174	4.88%
3 Years Out	2014	3,088	3,252	164	5.31%
4 Years Out	2015	3,021	3,350	329	10.89%
5 Years Out	2016	3,243	3,461	218	6.72%

2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011				
	2012				
1 Year Out	2013				
2 Years Out	2014	3,088	3,194	106	3.43%
3 Years Out	2015	3,021	3,275	254	8.41%
4 Years Out	2016	3,243	3,312	69	2.13%
5 Years Out	2017	3,114	3,402	288	9.25%

2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012				
	2013				
1 Year Out	2014				
2 Years Out	2015	3,021	3,101	80	2.65%
3 Years Out	2016	3,243	3,200	-43	-1.33%
4 Years Out	2017	3,114	3,291	177	5.68%

2014 LOAD FORECAST STUDY
2015 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2013	2013				
	2014				
1 Year Out	2015				
2 Years Out	2016	3,243	2,963	-280	-8.63%
3 Years Out	2017	3,114	3,022	-92	-2.95%

Winter Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2015
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	(FORECAST - ACTUAL) 4 Years Out	(FORECAST - ACTUAL) 5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	(FORECAST - ACTUAL) / ACTUAL 4 Years Out	(FORECAST - ACTUAL) / ACTUAL 5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	79	457	348	1.87%	11.35%	8.24%
	2005 LFS	Dec.2004	2006 TYSP	581	266	-139	13.76%	5.61%	-2.75%
*	2005 LFS	Dec.2004	2007 TYSP	575	259	-146	13.62%	5.47%	-2.89%
	2007 LFS	Dec.2006	2008 TYSP	-388	552	1,161	-7.69%	12.79%	29.63%
	2008 LFS	Dec.2007	2009 TYSP	192	731	1,096	4.45%	18.66%	29.57%
	2009 LFS	Dec.2008	2010 TYSP	688	1,049	992	17.56%	28.30%	30.62%
	2010 LFS	Dec.2009	2011 TYSP	1,047	951	698	28.24%	29.35%	19.43%
	2011 LFS	Dec.2010	2012 TYSP	693	461	885	21.39%	12.83%	26.76%
	2012 LFS	Dec.2011	2013 TYSP	356	715	1,128	9.91%	21.62%	37.38%
	2013 LFS	Dec.2012	2014 TYSP	559	960	238	16.90%	31.81%	6.18%
	2014 LFS	Dec.2013	2015 TYSP	498	-265		16.50%	-6.88%	
	2015 LFS	Dec.2014	2016 TYSP	-314			-8.15%		
			AVERAGE	**381**	**558**	**626**	**10.70%**	**15.54%**	**18.22%**
			AVERAGE (Excluding Duplicate)	**363**	**588**	**712**	**10.43%**	**16.54%**	**20.56%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2016.

2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002-03				
1 Year Out	2003-04				
2 Years Out	2004-05				
3 Years Out	2005-06	4,225	4,304	79	1.87%
4 Years Out	2006-07	4,026	4,483	457	11.35%
5 Years Out	2007-08	4,221	4,569	348	8.24%

2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)
Adjusted for LCEC

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004-05				
1 Year Out	2005-06				
2 Years Out	2006-07				
3 Years Out	2007-08	4,221	4,802	581	13.76%
4 Years Out	2008-09	4,738	5,004	266	5.61%
5 Years Out	2009-10	5,047	4,908	-139	-2.75%

Note: 2009/2010 Forecast Value Reduced by 305 MW to Account for LCEC.

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2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)
Adjusted for LCEC

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004-05				
1 Year Out	2005-06				
2 Years Out	2006-07				
3 Years Out	2007-08	4,221	4,796	575	13.62%
4 Years Out	2008-09	4,738	4,997	259	5.47%
5 Years Out	2009-10	5,047	4,901	-146	-2.89%

Note: 2009/2010 Forecast Value Reduced by 305 MW to Account for LCEC.

2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006-07				
1 Year Out	2007-08				
2 Years Out	2008-09				
3 Years Out	2009-10	5,047	4,659	-388	-7.69%
4 Years Out	2010-11	4,315	4,867	552	12.79%
5 Years Out	2011-12	3,918	5,079	1,161	29.63%

2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007-08				
1 Year Out	2008-09				
2 Years Out	2009-10				
3 Years Out	2010-11	4,315	4,507	192	4.45%
4 Years Out	2011-12	3,918	4,649	731	18.66%
5 Years Out	2012-13	3,707	4,803	1,096	29.57%

2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008-09				
1 Year Out	2009-10				
2 Years Out	2010-11				
3 Years Out	2011-12	3,918	4,606	688	17.56%
4 Years Out	2012-13	3,707	4,756	1,049	28.30%
5 Years Out	2013-14	3,240	4,232	992	30.62%

2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009-10				
1 Year Out	2010-11				
2 Years Out	2011-12				
3 Years Out	2012-13	3,707	4,754	1,047	28.24%
4 Years Out	2013-14	3,240	4,191	951	29.35%
5 Years Out	2014-15	3,593	4,291	698	19.43%

2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010-11				
1 Year Out	2011-12				
2 Years Out	2012-13				
3 Years Out	2013-14	3,240	3,933	693	21.39%
4 Years Out	2014-15	3,593	4,054	461	12.83%
5 Years Out	2015-16	3,307	4,192	885	26.76%

2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011-12				
1 Year Out	2012-13				
2 Years Out	2013-14				
3 Years Out	2014-15	3,593	3,949	356	9.91%
4 Years Out	2015-16	3,307	4,022	715	21.62%
5 Years Out	2016-17	3,018	4,146	1,128	37.38%

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2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012-13				
1 Year Out	2013-14				
2 Years Out	2014-15				
3 Years Out	2015-16	3,307	3,866	559	16.90%
4 Years Out	2016-17	3,018	3,978	960	31.81%
5 Years Out	2017-18	3,853	4,091	238	6.18%

2014 LOAD FORECAST STUDY
2015 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2013	2013-14				
1 Year Out	2014-15				
2 Years Out	2015-16				
3 Years Out	2016-17	3,018	3,516	498	16.50%
4 Years Out	2017-18	3,853	3,588	-265	-6.88%

2015 LOAD FORECAST STUDY
2016 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2014	2014-15				
1 Year Out	2015-16				
2 Years Out	2016-17				
3 Years Out	2017-18	3,853	3,539	-314	-8.15%

Winter Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2015
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL)			(FORECAST - ACTUAL) / ACTUAL		
				3 Years Out	*4 Years Out*	*5 Years Out*	*3 Years Out*	*4 Years Out*	*5 Years Out*
	2003 LFS	Dec.2002	2005 TYSP	79	457	348	1.87%	11.35%	8.24%
	2005 LFS	Dec.2004	2006 TYSP	581	266	-139	13.76%	5.61%	-2.75%
*	2005 LFS	Dec.2004	2007 TYSP	575	259	-146	13.62%	5.47%	-2.89%
	2007 LFS	Dec.2006	2008 TYSP	-388	552	1,161	-7.69%	12.79%	29.63%
	2008 LFS	Dec.2007	2009 TYSP	192	731	1,096	4.45%	18.66%	29.57%
	2009 LFS	Dec.2008	2010 TYSP	688	1,049	992	17.56%	28.30%	30.62%
	2010 LFS	Dec.2009	2011 TYSP	1,047	951	698	28.24%	29.35%	19.43%
	2011 LFS	Dec.2010	2012 TYSP	693	461	885	21.39%	12.83%	26.76%
	2012 LFS	Dec.2011	2013 TYSP	356	715	1,128	9.91%	21.62%	37.38%
	2013 LFS	Dec.2012	2014 TYSP	559	960	238	16.90%	31.81%	6.18%
	2014 LFS	Dec.2013	2015 TYSP	498	-265		16.50%	-6.88%	
	2015 LFS	Dec.2014	2016 TYSP	-314			-8.15%		
			AVERAGE	**381**	**558**	**626**	**10.70%**	**15.54%**	**18.22%**
			***AVERAGE** (Excluding Duplicate)*	**363**	**588**	**712**	**10.43%**	**16.54%**	**20.56%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2016.

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2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002-03				
1 Year Out	2003-04				
2 Years Out	2004-05				
3 Years Out	2005-06	4,225	4,304	79	1.87%
4 Years Out	2006-07	4,026	4,483	457	11.35%
5 Years Out	2007-08	4,221	4,569	348	8.24%

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2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)
Adjusted for LCEC

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004-05				
1 Year Out	2005-06				
2 Years Out	2006-07				
3 Years Out	2007-08	4,221	4,802	581	13.76%
4 Years Out	2008-09	4,738	5,004	266	5.61%
5 Years Out	2009-10	5,047	4,908	-139	-2.75%

Note: 2009/2010 Forecast Value Reduced by 305 MW to Account for LCEC.

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2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)
Adjusted for LCEC

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004-05				
1 Year Out	2005-06				
2 Years Out	2006-07				
3 Years Out	2007-08	4,221	4,796	575	13.62%
4 Years Out	2008-09	4,738	4,997	259	5.47%
5 Years Out	2009-10	5,047	4,901	-146	-2.89%

Note: 2009/2010 Forecast Value Reduced by 305 MW to Account for LCEC.

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2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006-07				
1 Year Out	2007-08				
2 Years Out	2008-09				
3 Years Out	2009-10	5,047	4,659	-388	-7.69%
4 Years Out	2010-11	4,315	4,867	552	12.79%
5 Years Out	2011-12	3,918	5,079	1,161	29.63%

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2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007-08				
1 Year Out	2008-09				
2 Years Out	2009-10				
3 Years Out	2010-11	4,315	4,507	192	4.45%
4 Years Out	2011-12	3,918	4,649	731	18.66%
5 Years Out	2012-13	3,707	4,803	1,096	29.57%

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2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008-09				
1 Year Out	2009-10				
2 Years Out	2010-11				
3 Years Out	2011-12	3,918	4,606	688	17.56%
4 Years Out	2012-13	3,707	4,756	1,049	28.30%
5 Years Out	2013-14	3,240	4,232	992	30.62%

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2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009-10				
1 Year Out	2010-11				
2 Years Out	2011-12				
3 Years Out	2012-13	3,707	4,754	1,047	28.24%
4 Years Out	2013-14	3,240	4,191	951	29.35%
5 Years Out	2014-15	3,593	4,291	698	19.43%

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2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010-11				
1 Year Out	2011-12				
2 Years Out	2012-13				
3 Years Out	2013-14	3,240	3,933	693	21.39%
4 Years Out	2014-15	3,593	4,054	461	12.83%
5 Years Out	2015-16	3,307	4,192	885	26.76%

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2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011-12				
1 Year Out	2012-13				
2 Years Out	2013-14				
3 Years Out	2014-15	3,593	3,949	356	9.91%
4 Years Out	2015-16	3,307	4,022	715	21.62%
5 Years Out	2016-17	3,018	4,146	1,128	37.38%

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2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012-13				
1 Year Out	2013-14				
2 Years Out	2014-15				
3 Years Out	2015-16	3,307	3,866	559	16.90%
4 Years Out	2016-17	3,018	3,978	960	31.81%
5 Years Out	2017-18	3,853	4,091	238	6.18%

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2014 LOAD FORECAST STUDY
2015 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2013	2013-14				
1 Year Out	2014-15				
2 Years Out	2015-16				
3 Years Out	2016-17	3,018	3,516	498	16.50%
4 Years Out	2017-18	3,853	3,588	-265	-6.88%

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2015 LOAD FORECAST STUDY
2016 TEN YEAR SITE PLAN
WINTER PEAK DEMAND (MW)

	WINTER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2014	2014-15				
1 Year Out	2015-16				
2 Years Out	2016-17				
3 Years Out	2017-18	3,853	3,539	-314	-8.15%

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Summer Net Firm Demand (MW)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	(FORECAST - ACTUAL) 4 Years Out	(FORECAST - ACTUAL) 5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	(FORECAST - ACTUAL) / ACTUAL 4 Years Out	(FORECAST - ACTUAL) / ACTUAL 5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	-172	-241	112	-4.74%	-6.28%	3.09%
	2005 LFS	Dec.2004	2006 TYSP	216	176	382	5.95%	4.60%	10.77%
*	2005 LFS	Dec.2004	2007 TYSP	211	171	377	5.81%	4.47%	10.63%
	2007 LFS	Dec.2006	2008 TYSP	314	378	769	8.85%	10.35%	22.43%
	2008 LFS	Dec.2007	2009 TYSP	293	645	704	8.02%	18.82%	19.74%
	2009 LFS	Dec.2008	2010 TYSP	590	582	549	17.21%	16.32%	17.78%
	2010 LFS	Dec.2009	2011 TYSP	463	412	557	12.98%	13.34%	18.44%
	2011 LFS	Dec.2010	2012 TYSP	164	329	218	5.31%	10.89%	6.72%
	2012 LFS	Dec.2011	2013 TYSP	254	69	288	8.41%	2.13%	9.25%
	2013 LFS	Dec.2012	2014 TYSP	-43	177		-1.33%	5.68%	
	2014 LFS	Dec.2013	2015 TYSP	-92			-2.95%		
			AVERAGE	**200**	**270**	**440**	**5.78%**	**8.03%**	**13.20%**
			***AVERAGE** (Excluding Duplicate)*	**199**	**281**	**447**	**5.77%**	**8.43%**	**13.53%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

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2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002				
	2003				
1 Year Out	2004				
2 Years Out	2005	3,539	3,324	-215	-6.08%
3 Years Out	2006	3,632	3,460	-172	-4.74%
4 Years Out	2007	3,839	3,598	-241	-6.28%
5 Years Out	2008	3,630	3,742	112	3.09%

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2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)
Adjusted for LCEC

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	3,839	3,655	-184	-4.79%
3 Years Out	2008	3,630	3,846	216	5.95%
4 Years Out	2009	3,824	4,000	176	4.60%
5 Years Out	2010	3,548	3,930	382	10.77%

Note: 2010 Forecast Value Reduced by 227 MW to Account for LCEC.

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2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)
Adjusted for LCEC

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	3,839	3,691	-148	-3.86%
3 Years Out	2008	3,630	3,841	211	5.81%
4 Years Out	2009	3,824	3,995	171	4.47%
5 Years Out	2010	3,548	3,925	377	10.63%

Note: 2010 Forecast Value Reduced by 227 MW to Account for LCEC.

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2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006				
	2007				
1 Year Out	2008				
2 Years Out	2009	3,824	3,920	96	2.51%
3 Years Out	2010	3,548	3,862	314	8.85%
4 Years Out	2011	3,653	4,031	378	10.35%
5 Years Out	2012	3,428	4,197	769	22.43%

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2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007				
	2008				
1 Year Out	2009				
2 Years Out	2010	3,548	3,787	239	6.74%
3 Years Out	2011	3,653	3,946	293	8.02%
4 Years Out	2012	3,428	4,073	645	18.82%
5 Years Out	2013	3,566	4,270	704	19.74%

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2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008				
	2009				
1 Year Out	2010				
2 Years Out	2011	3,653	3,883	230	6.30%
3 Years Out	2012	3,428	4,018	590	17.21%
4 Years Out	2013	3,566	4,148	582	16.32%
5 Years Out	2014	3,088	3,637	549	17.78%

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2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009				
	2010				
1 Year Out	2011				
2 Years Out	2012	3,428	3,910	482	14.06%
3 Years Out	2013	3,566	4,029	463	12.98%
4 Years Out	2014	3,088	3,500	412	13.34%
5 Years Out	2015	3,021	3,578	557	18.44%

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2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010				
	2011				
1 Year Out	2012				
2 Years Out	2013	3,566	3,740	174	4.88%
3 Years Out	2014	3,088	3,252	164	5.31%
4 Years Out	2015	3,021	3,350	329	10.89%
5 Years Out	2016	3,243	3,461	218	6.72%

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2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011				
	2012				
1 Year Out	2013				
2 Years Out	2014	3,088	3,194	106	3.43%
3 Years Out	2015	3,021	3,275	254	8.41%
4 Years Out	2016	3,243	3,312	69	2.13%
5 Years Out	2017	3,114	3,402	288	9.25%

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2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012				
	2013				
1 Year Out	2014				
2 Years Out	2015	3,021	3,101	80	2.65%
3 Years Out	2016	3,243	3,200	-43	-1.33%
4 Years Out	2017	3,114	3,291	177	5.68%

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2014 LOAD FORECAST STUDY
2015 TEN YEAR SITE PLAN
SUMMER PEAK DEMAND (MW)

	SUMMER	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2013	2013				
	2014				
1 Year Out	2015				
2 Years Out	2016	3,243	2,963	-280	-8.63%
3 Years Out	2017	3,114	3,022	-92	-2.95%

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Net Energy for Load (GWh)
Historical Seminole Error Rates based on Corrected Sotkiewicz Approach
Load Forecast Studies 2003 through 2014
Adjusted for Lee County Electric Cooperative, Inc.

	LFS	Forecast Origin	TYSP	(FORECAST - ACTUAL) 3 Years Out	(FORECAST - ACTUAL) 4 Years Out	(FORECAST - ACTUAL) 5 Years Out	(FORECAST - ACTUAL) / ACTUAL 3 Years Out	(FORECAST - ACTUAL) / ACTUAL 4 Years Out	(FORECAST - ACTUAL) / ACTUAL 5 Years Out
	2003 LFS	Dec.2002	2005 TYSP	-365	-97	1,028	-2.12%	-0.55%	5.93%
	2005 LFS	Dec.2004	2006 TYSP	1,625	2,248	1,869	9.38%	12.88%	10.77%
*	2005 LFS	Dec.2004	2007 TYSP	1,584	2,205	1,824	9.14%	12.63%	10.52%
	2007 LFS	Dec.2006	2008 TYSP	933	3,065	4,150	5.38%	19.11%	26.32%
	2008 LFS	Dec.2007	2009 TYSP	1,945	2,787	3,528	12.13%	17.67%	22.31%
	2009 LFS	Dec.2008	2010 TYSP	2,331	2,859	2,358	14.78%	18.08%	17.02%
	2010 LFS	Dec.2009	2011 TYSP	2,678	1,974	2,108	16.94%	14.25%	14.95%
	2011 LFS	Dec.2010	2012 TYSP	1,066	1,286	1,435	7.69%	9.12%	9.92%
	2012 LFS	Dec.2011	2013 TYSP	952	963	1,557	6.75%	6.65%	10.87%
	2013 LFS	Dec.2012	2014 TYSP	823	1,414		5.69%	9.87%	
	2014 LFS	Dec.2013	2015 TYSP	-57			-0.40%		
			AVERAGE	**1,229**	**1,870**	**2,206**	**7.76%**	**11.97%**	**14.29%**
			***AVERAGE** (Excluding Duplicate)*	**1,193**	**1,833**	**2,254**	**7.62%**	**11.90%**	**14.76%**

Note: Load Forecast Study Conducted Biennially prior to 2008.
Source: Ten Year Site Plans 2005 through 2015.

2003 LOAD FORECAST STUDY
2005 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2002	2002				
	2003				
1 Year Out	2004				
2 Years Out	2005	16,766	16,295	-471	-2.81%
3 Years Out	2006	17,233	16,868	-365	-2.12%
4 Years Out	2007	17,669	17,572	-97	-0.55%
5 Years Out	2008	17,332	18,360	1,028	5.93%

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2005 LOAD FORECAST STUDY
2006 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)
Adjusted for LCEC

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	17,669	18,134	465	2.63%
3 Years Out	2008	17,332	18,957	1,625	9.38%
4 Years Out	2009	17,453	19,701	2,248	12.88%
5 Years Out	2010	17,346	19,215	1,869	10.77%

Note: 2010 Forecast Value Reduced by 1,299 GWh to Account for LCEC.

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2005 LOAD FORECAST STUDY
2007 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)
Adjusted for LCEC

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2004	2004				
	2005				
1 Year Out	2006				
2 Years Out	2007	17,669	18,095	426	2.41%
3 Years Out	2008	17,332	18,916	1,584	9.14%
4 Years Out	2009	17,453	19,658	2,205	12.63%
5 Years Out	2010	17,346	19,170	1,824	10.52%

Note: 2010 Forecast Value Reduced by 1,299 GWh to Account for LCEC.

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2007 LOAD FORECAST STUDY
2008 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2006	2006				
	2007				
1 Year Out	2008				
2 Years Out	2009	17,453	18,812	1,359	7.79%
3 Years Out	2010	17,346	18,279	933	5.38%
4 Years Out	2011	16,037	19,102	3,065	19.11%
5 Years Out	2012	15,769	19,919	4,150	26.32%

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2008 LOAD FORECAST STUDY
2009 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2007	2007				
	2008				
1 Year Out	2009				
2 Years Out	2010	17,346	17,344	-2	-0.01%
3 Years Out	2011	16,037	17,982	1,945	12.13%
4 Years Out	2012	15,769	18,556	2,787	17.67%
5 Years Out	2013	15,812	19,340	3,528	22.31%

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2009 LOAD FORECAST STUDY
2010 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2008	2008				
	2009				
1 Year Out	2010				
2 Years Out	2011	16,037	17,480	1,443	9.00%
3 Years Out	2012	15,769	18,100	2,331	14.78%
4 Years Out	2013	15,812	18,671	2,859	18.08%
5 Years Out	2014	13,854	16,212	2,358	17.02%

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2010 LOAD FORECAST STUDY
2011 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2009	2009				
	2010				
1 Year Out	2011				
2 Years Out	2012	15,769	17,884	2,115	13.41%
3 Years Out	2013	15,812	18,490	2,678	16.94%
4 Years Out	2014	13,854	15,828	1,974	14.25%
5 Years Out	2015	14,104	16,212	2,108	14.95%

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2011 LOAD FORECAST STUDY
2012 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2010	2010				
	2011				
1 Year Out	2012				
2 Years Out	2013	15,812	17,403	1,591	10.06%
3 Years Out	2014	13,854	14,920	1,066	7.69%
4 Years Out	2015	14,104	15,390	1,286	9.12%
5 Years Out	2016	14,471	15,906	1,435	9.92%

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2012 LOAD FORECAST STUDY
2013 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2011	2011				
	2012				
1 Year Out	2013				
2 Years Out	2014	13,854	14,620	766	5.53%
3 Years Out	2015	14,104	15,056	952	6.75%
4 Years Out	2016	14,471	15,434	963	6.65%
5 Years Out	2017	14,325	15,882	1,557	10.87%

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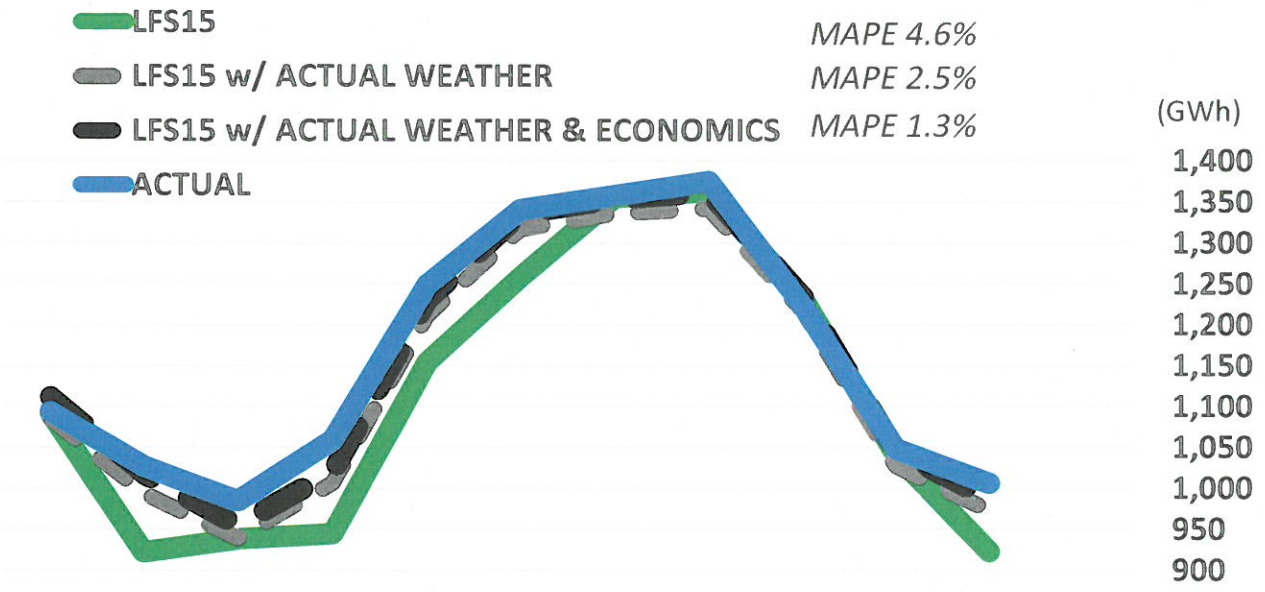
2013 LOAD FORECAST STUDY
2014 TEN YEAR SITE PLAN
NET ENERGY FOR LOAD (GWh)

	YEAR	ACTUAL	FORECAST	(FCST - ACT)	(FCST - ACT) / ACT
Forecast Origin December 2012	2012				
	2013				
1 Year Out	2014				
2 Years Out	2015	14,104	14,794	690	4.89%
3 Years Out	2016	14,471	15,294	823	5.69%
4 Years Out	2017	14,325	15,739	1,414	9.87%

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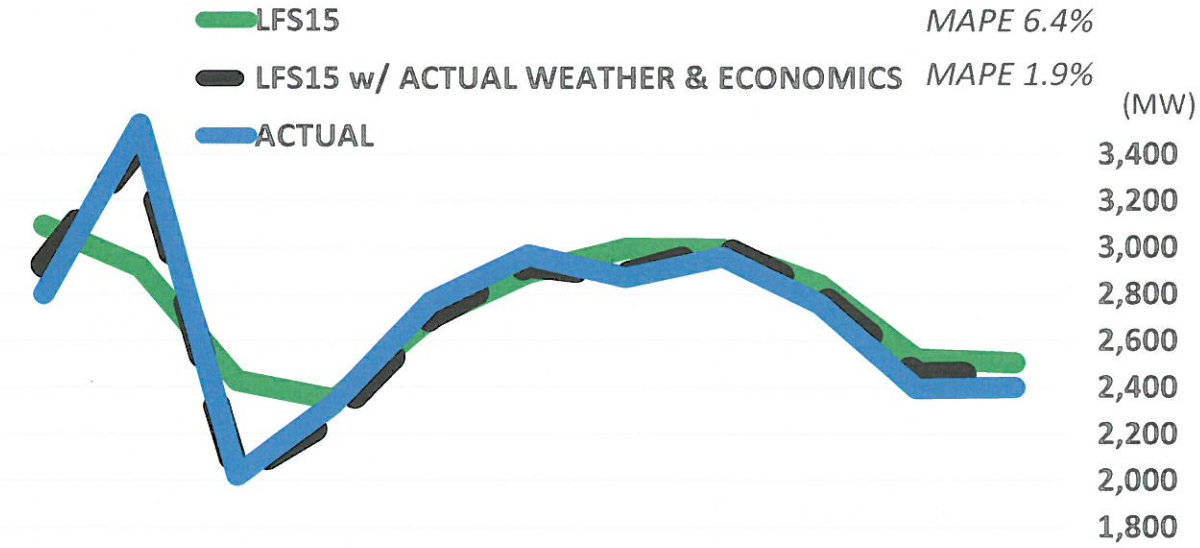
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2015 Energy



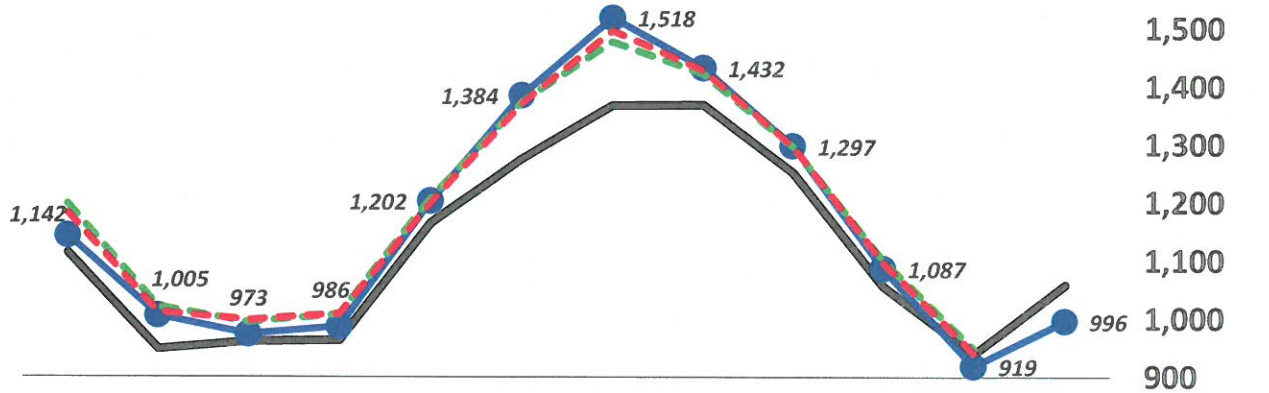
JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
-1.63%	0.80%	2.93%	3.62%	1.48%	0.34%	0.27%	0.92%	-0.84%	0.14%	1.70%	LFS15 Backcast Actual Weather & Economics

2015 Demand



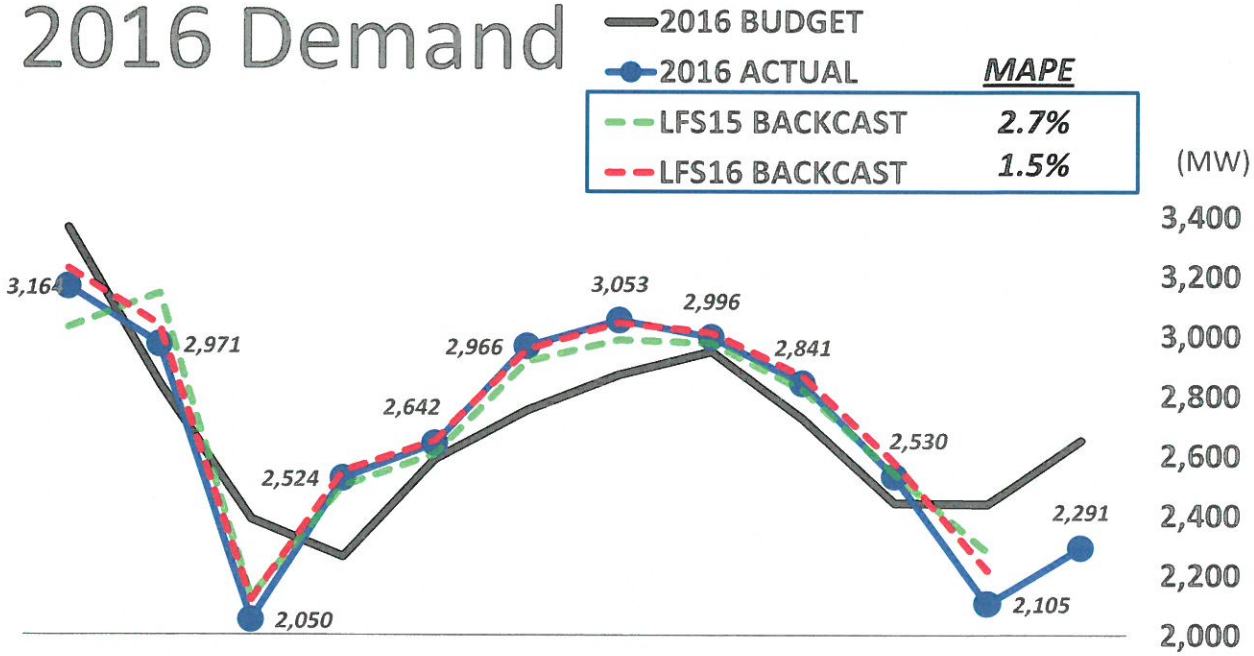
JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
-4.36%	2.42%	-0.19%	2.56%	2.24%	1.28%	-0.37%	-1.24%	-1.41%	-2.37%	-2.42%	LFS15 Backcast Actual Weather & Economics

2016 Energy



JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
-4.7%	-1.5%	-2.1%	-2.1%	-0.4%	0.9%	2.8%	0.7%	0.1%	-1.3%	-3.2%		LFS15 Backcast
-3.4%	-0.6%	-2.5%	-2.2%	0.2%	1.0%	1.5%	0.3%	0.1%	-0.9%	-2.3%		LFS16 Backcast

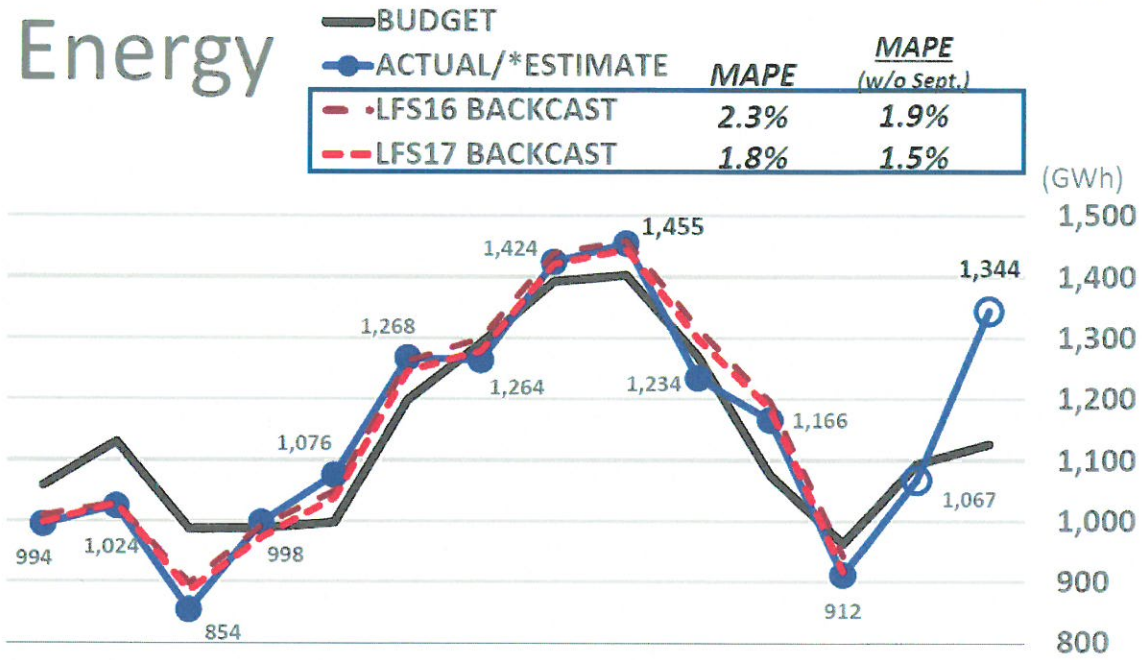
2016 Demand



JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
4.3%	-5.8%	-3.7%	1.0%	1.4%	1.7%	2.1%	0.7%	0.7%	-0.4%	-8.3%		LFS15 Backcast
-1.4%	-2.3%	-3.4%	-0.9%	-0.2%	0.5%	-0.1%	-0.3%	-0.7%	-1.8%	-5.4%		LFS16 Backcast

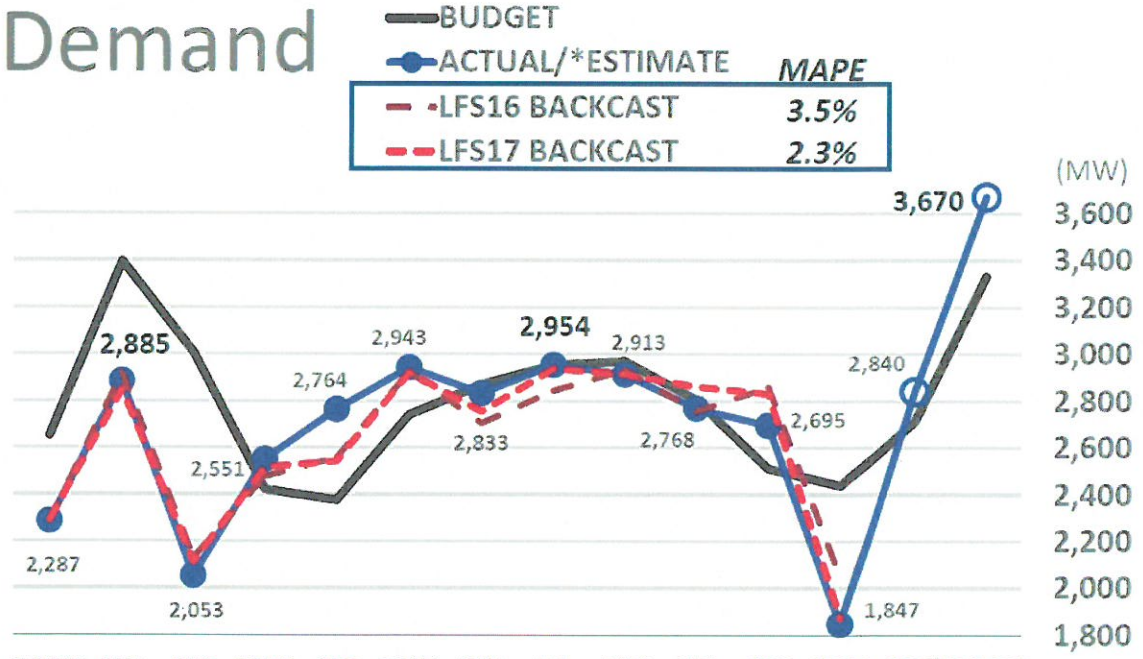
December 2016 is an Estimated-Actual
Note: In Sample Fit through February 2016

Energy



DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*	
-1.5%	-0.5%	-5.1%	0.6%	2.5%	0.4%	-2.9%	-1.0%	-0.3%	-6.6%	-2.5%	-3.4%		LFS16 Backcast
-0.3%	-0.4%	-3.7%	2.5%	3.5%	1.7%	-1.2%	0.2%	0.7%	-5.2%	-1.6%	-0.6%		LFS17 Backcast

Demand



DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*	
-0.1%	-1.2%	-3.7%	2.9%	7.5%	0.6%	4.5%	3.7%	-0.7%	0.5%	-6.1%	-10.9%		LFS16 Backcast
-0.1%	1.3%	-2.8%	1.4%	8.1%	0.8%	2.8%	0.5%	0.0%	-3.4%	-5.0%	-1.5%		LFS17 Backcast

*December 2017 and January 2018 are Estimated-Actual
Note: In sample fit through February 2017.

ENERGY (kWh)

DATE	LFS16 BACKCAST (thru NOV17)	LFS17 FS BACKCAST	LARGE LOADS and SAWMILL	SEPA	Billing Energy Adj	LFS16 BUDGET BACKCAST	LFS17 BUDGET BACKCAST
DEC	**1,011,479,417**	**999,612,389**	9,914,158	12,221,327	16,629	**1,009,188,876.34**	**997,321,848.54**
JAN	**1,028,615,062**	**1,027,728,603**	10,421,401	9,745,199	14,916	**1,029,306,179.63**	**1,028,419,720.93**
FEB	**901,753,042**	**889,354,839**	6,084,298	10,259,848	12,383	**897,589,875.28**	**885,191,671.80**
MAR	**993,643,672**	**974,441,131**	9,453,870	11,006,808	14,342	**992,105,076.60**	**972,902,535.18**
APR	**1,051,814,725**	**1,040,573,647**	8,784,988	11,690,872	14,346	**1,048,923,187.53**	**1,037,682,109.43**
MAY	**1,265,215,896**	**1,249,180,128**	9,553,364	12,603,880	18,273	**1,262,183,652.99**	**1,246,147,885.29**
JUN	**1,302,963,500**	**1,281,671,218**	9,030,397	12,038,665	21,135	**1,299,976,366.47**	**1,278,684,084.57**
JUL	**1,443,368,330**	**1,425,485,823**	9,298,306	13,574,174	19,503	**1,439,111,964.46**	**1,421,229,457.66**
AUG	**1,462,360,788**	**1,448,427,123**	9,831,687	13,195,561	19,346	**1,459,016,259.85**	**1,445,082,594.55**
SEP	**1,319,504,882**	**1,302,318,818**	7,860,970	12,034,317	16,883	**1,315,348,418.44**	**1,298,162,354.04**
OCT	**1,199,675,351**	**1,188,930,886**	8,831,318	13,260,501	14,034	**1,195,260,201.68**	**1,184,515,737.18**
NOV	**953,579,002**	**927,877,225**	2,153,320	12877906		**942,854,415.53**	**917,152,638.51**

NON-COIN DEMAND (kW)

DATE	LFS16 BACKCAST (thru NOV17)	LFS17 FS BACKCAST	LARGE LOADS and SAWMILL	LFS16 BUDGET BACKCAST (NON-COIN)	LFS17 BUDGET BACKCAST (NON-COIN)	PBS Actual Billing - SUM Member Non-Coin PBS0670	ACTUAL NET BILLED DEMAND PBS0470	CoinFactor	LFS16 BUDGET BACKCAST (SECI-COIN)	LFS17 BUDGET BACKCAST (SECI-COIN)
DEC	**2,441,973**	**2,443,769**	13,914	**2,455,887**	**2,457,683**	2,454	2,287	93.19%	**2,288,556.19**	**2,290,229.82**
JAN	**3,011,522**	**2,939,448**	12,805	**3,024,327**	**2,952,253**	2,990	2,885	96.49%	**2,918,096.86**	**2,848,554.47**
FEB	**2,253,670**	**2,234,761**	12,204	**2,265,874**	**2,246,965**	2,185	2,053	93.98%	**2,129,402.32**	**2,111,632.19**
MAR	**2,605,657**	**2,647,015**	17,565	**2,623,222**	**2,664,580**	2,702	2,551	94.43%	**2,477,004.10**	**2,516,056.82**
APR	**2,643,077**	**2,626,271**	15,802	**2,658,879**	**2,642,073**	2,874	2,764	96.19%	**2,557,521.34**	**2,541,356.00**
MAY	**3,040,773**	**3,035,418**	13,556	**3,054,329**	**3,048,974**	3,073	2,943	95.76%	**2,924,823.43**	**2,919,695.48**
JUN	**2,866,372**	**2,920,057**	13,378	**2,879,750**	**2,933,435**	3,017	2,833	93.89%	**2,703,722.97**	**2,754,126.44**
JUL	**3,005,750**	**3,105,466**	11,346	**3,017,096**	**3,116,812**	3,134	2,954	94.27%	**2,844,077.72**	**2,938,075.41**
AUG	**3,146,580**	**3,126,567**	13,050	**3,159,630**	**3,139,617**	3,139	2,913	92.81%	**2,932,555.90**	**2,913,981.18**
SEP	**2,872,060**	**2,982,744**	11,932	**2,883,992**	**2,994,676**	2,897	2,768	95.54%	**2,755,314.49**	**2,861,060.00**
OCT	**2,958,446**	**2,929,013**	13,913	**2,972,359**	**2,942,926**	2,803	2,695	96.17%	**2,858,393.33**	**2,830,088.84**
NOV	**2,249,106**	**2,056,197**	12,642	**2,261,748**	**2,068,839**	2,035	1,843	90.58%	**2,048,688.25**	**1,873,951.55**

	ENERGY 2017 Actual Billing MWh	LFS16 Backcast	ENERGY Diff	Diff%	LFS17 Backcast	ENERGY Diff	Diff%
DEC16	994,371	**1,009,189**	-14,818	-1.49%	**997,322**	-2,951	-0.30%
JAN	1,024,395	**1,029,306**	-4,911	-0.48%	**1,028,420**	-4,025	-0.39%
FEB	853,849	**897,590**	-43,741	-5.12%	**885,192**	-31,343	-3.67%
MAR	997,635	**992,105**	5,530	0.55%	**972,903**	24,733	2.48%
APR	1,075,653	**1,048,923**	26,730	2.49%	**1,037,682**	37,971	3.53%
MAY	1,267,851	**1,262,184**	5,668	0.45%	**1,246,148**	21,704	1.71%
JUN	1,263,925	**1,299,976**	-36,052	-2.85%	**1,278,684**	-14,759	-1.17%
JUL	1,424,305	**1,439,112**	-14,807	-1.04%	**1,421,229**	3,075	0.22%
AUG	1,454,878	**1,459,016**	-4,138	-0.28%	**1,445,083**	9,795	0.67%
SEP	1,234,257	**1,315,348**	-81,092	-6.57%	**1,298,162**	-63,906	-5.18%
OCT	1,166,094	**1,195,260**	-29,166	-2.50%	**1,184,516**	-18,422	-1.58%
NOV	911,509	**942,854**	-31,346	-3.44%	**917,153**	-5,644	-0.62%
DEC*	1,067,255						
JAN18*	**1,344,131**						

	DEMAND 2017 Actual Billing MWh	LFS16 Backcast	DEMAND Diff	Diff%	LFS17 Backcast	DEMAND Diff	Diff%
DEC16	2,287	**2,289**	-2	-0.07%	**2,290**	-3	-0.15%
JAN	2,885	**2,918**	-33	-1.16%	**2,849**	36	1.25%
FEB	2,053	**2,129**	-76	-3.71%	**2,112**	-58	-2.85%
MAR	2,551	**2,477**	74	2.90%	**2,516**	35	1.37%
APR	2,764	**2,558**	207	7.48%	**2,541**	223	8.06%
MAY	2,943	**2,925**	18	0.60%	**2,920**	23	0.78%
JUN	2,833	**2,704**	129	4.55%	**2,754**	78	2.77%
JUL	2,954	**2,844**	110	3.73%	**2,938**	16	0.55%
AUG	2,913	**2,933**	-19	-0.67%	**2,914**	-1	-0.03%
SEP	2,768	**2,755**	13	0.45%	**2,861**	-93	-3.37%
OCT	2,695	**2,858**	-163	-6.06%	**2,830**	-135	-5.01%
NOV	1,847	**2,049**	-202	-10.92%	**1,874**	-27	-1.46%
DEC*	2,840						
JAN18*	**3,670**						

	ENERGY LFS17 BUDGET	DEMAND LFS17 BUDGET
DEC16	**1,058,183**	**2,652**
JAN	**1,130,118**	**3,394**
FEB	**986,845**	**3,005**
MAR	**987,848**	**2,422**
APR	**997,448**	**2,376**
MAY	**1,198,160**	**2,740**
JUN	**1,291,391**	**2,870**
JUL	**1,392,117**	**2,954**
AUG	**1,402,662**	**2,969**
SEP	**1,269,713**	**2,805**
OCT	**1,075,657**	**2,512**
NOV	**962,933**	**2,438**
DEC*	**1,093,500**	**2,712**
JAN18*	**1,126,270**	**3,331**

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	2018 BUDGET		2018 ACTUAL		2017 BUDGET		2017 ACTUAL						2016 BUDGET	2016 BUDGET	2016 ACTUAL	
MONTH	ENERGY (MWH)	DEMAND (MW-Months)	ENERGY (MWH)	DEMAND (MW-Months)	ENERGY (MWH)	DEMAND (MW-Months)	ACTUAL / PROJECTED ENERGY (MWh)	ANNUAL GROWTH	ACTUAL VS. BUDGET	ACTUAL DEMAND (MW-Months)	ANNUAL GROWTH	ACTUAL VS. BUDGET	DEMAND (MW-Months)	ENERGY (MW-Months)	ENERGY (MWH)	DEMAND (MW-Months)
January	1,126,270	3,331	**1,344,131**	**3,670**	1,130,118	3,394	**1,024,395**	-10.3%	-9.4%	**2,885**	-8.8%	-15.0%			1,142,437	3,164
February					986,845	3,005	**853,849**	-15.1%	-13.5%	**2,053**	-30.9%	-31.7%			1,005,223	2,971
March					987,848	2,422	**997,635**	2.5%	1.0%	**2,551**	24.5%	5.3%			973,031	2,050
April					997,448	2,376	**1,075,653**	9.0%	7.8%	**2,764**	9.5%	16.3%			986,491	2,524
May					1,198,160	2,740	**1,267,851**	5.5%	5.8%	**2,943**	11.4%	7.4%			1,202,080	2,642
June					1,291,391	2,870	**1,263,925**	-8.7%	-2.1%	**2,833**	-4.5%	-1.3%			1,384,448	2,966
July					1,392,117	2,954	**1,424,305**	-6.2%	2.3%	**2,954**	-3.2%	0.0%			1,518,138	3,053
August					1,402,662	2,969	**1,454,878**	1.6%	3.7%	**2,913**	-2.8%	-1.9%			1,431,689	2,996
September					1,269,713	2,805	**1,234,257**	-4.9%	-2.8%	**2,768**	-2.6%	-1.3%			1,297,243	2,841
October					1,075,657	2,512	**1,166,094**	7.3%	8.4%	**2,695**	6.5%	7.3%			1,086,613	2,530
November					962,933	2,438	**911,509**	-0.8%	-5.3%	**1,847**	-12.3%	-24.3%			918,730	2,105
December					1,093,500	2,712	**1,067,255**	7.3%	-2.4%	**2,840**	24.2%	4.7%	2,652	1,058,183	994,371	2,287

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ENERGY

	MAPE	MAPES DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
LFS16 Backcast	2.3%	***-1.5%***	***-0.5%***	***-5.1%***	***0.6%***	***2.5%***	***0.4%***	***-2.9%***	***-1.0%***	***-0.3%***	***-6.6%***	***-2.5%***	***-3.4%***	***LFS16 Backcast***
LFS17 Backcast	1.8%	***-0.3%***	***-0.4%***	***-3.7%***	***2.5%***	***3.5%***	***1.7%***	***-1.2%***	***0.2%***	***0.7%***	***-5.2%***	***-1.6%***	***-0.6%***	***LFS17 Backcast***
		1.5%	0.5%	5.1%	0.6%	2.5%	0.4%	2.9%	1.0%	0.3%	6.6%	2.5%	3.4%	
		0.3%	0.4%	3.7%	2.5%	3.5%	1.7%	1.2%	0.2%	0.7%	5.2%	1.6%	0.6%	

MAPE wo Sept
1.9%
1.5%

DEMAND

	MAPE	MAPES DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
LFS16 Backcast	3.5%	***-0.1%***	***-1.2%***	***-3.7%***	***2.9%***	***7.5%***	***0.6%***	***4.5%***	***3.7%***	***-0.7%***	***0.5%***	***-6.1%***	***-10.9%***	***LFS16 Backcast***
LFS17 Backcast	2.3%	***-0.1%***	***1.3%***	***-2.8%***	***1.4%***	***8.1%***	***0.8%***	***2.8%***	***0.5%***	***0.0%***	***-3.4%***	***-5.0%***	***-1.5%***	***LFS17 Backcast***
		0.1%	1.2%	3.7%	2.9%	7.5%	0.6%	4.5%	3.7%	0.7%	0.5%	6.1%	10.9%	
		0.1%	1.3%	2.8%	1.4%	8.1%	0.8%	2.8%	0.5%	0.0%	3.4%	5.0%	1.5%	

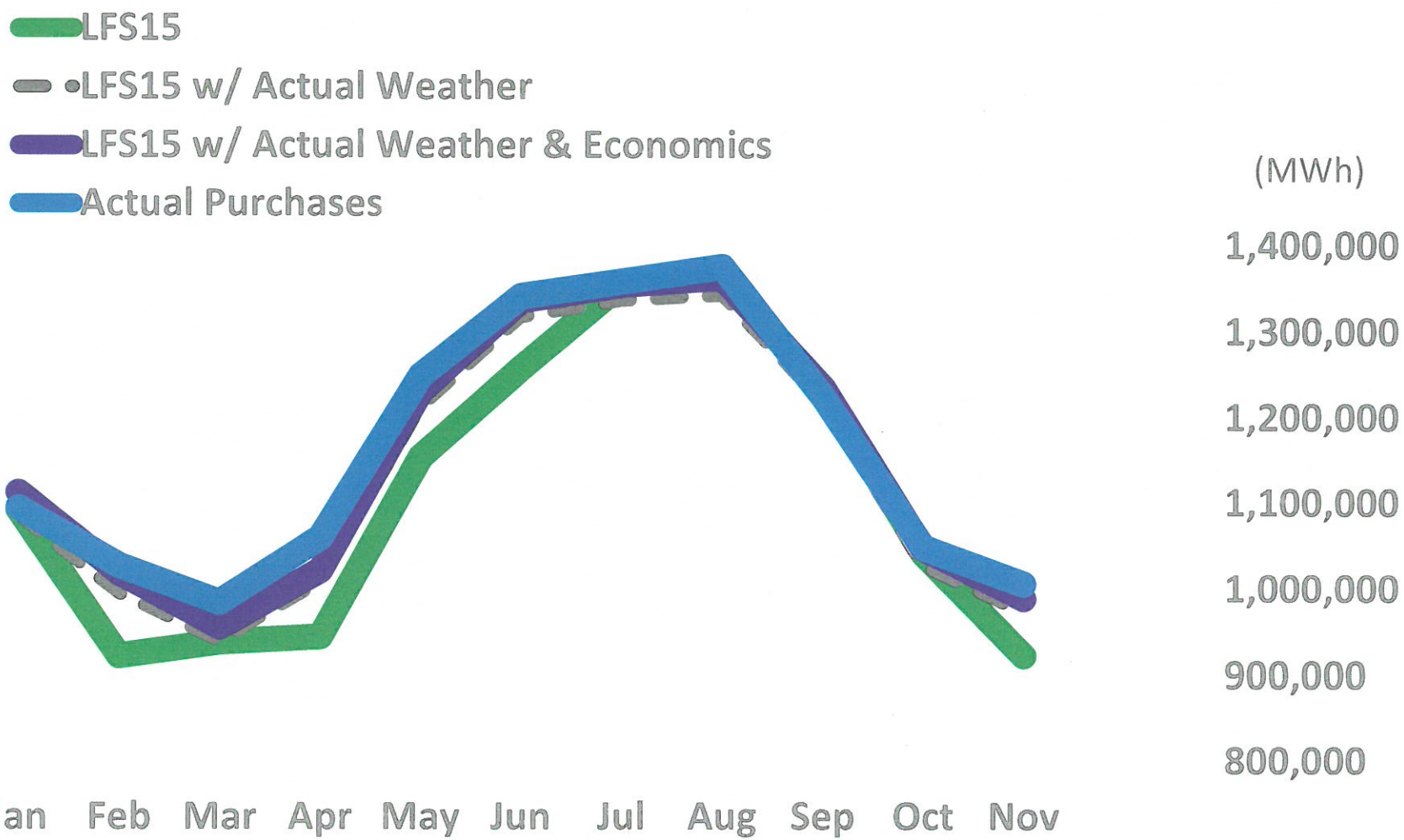
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MONTH	Cooperative	Month	Actual Purchases	LFS15	LFS15 w/ Actual Weather	LFS15 w/ Actual Weather & Economics	Actual Purchases	LFS15	LFS15 w/ Actual Weather	LFS15 w/ Actual Weather & Economics	APE - SECI LFS15	APE - SECI LFS15 w/Wea	APE - SECI LFS15 w/Wea & Eco	Deviation from Backcast (%)
1	Central Florida	Jan	41,297,349	41,154,926	40,934,381	42,355,732	1,085,451,585	1,091,261,878	1,085,037,597	1,101,223,044	0.2%	0.6%	1.6%	-1.6%
2	Central Florida	Feb	38,723,255	32,732,714	36,224,902	37,629,652	1,028,044,869	921,188,389	960,884,916	1,017,824,795	10.2%	3.1%	0.8%	0.8%
3	Central Florida	Mar	34,361,837	32,786,714	32,182,736	33,575,761	983,543,142	937,219,889	936,844,053	954,694,611	4.7%	4.6%	2.9%	2.9%
4	Central Florida	Apr	37,037,424	31,992,544	34,292,702	35,407,618	1,068,818,345	943,437,673	1,006,884,346	1,029,592,275	10.9%	4.9%	3.6%	3.9%
5	Central Florida	May	47,247,462	41,269,627	44,941,533	45,912,908	1,248,308,454	1,102,936,941	1,211,571,042	1,229,864,663	7.7%	2.9%	1.5%	1.6%
6	Central Florida	Jun	51,130,159	46,063,424	48,752,955	50,027,143	1,348,206,128	1,256,583,873	1,316,770,998	1,335,623,132	8.2%	1.8%	0.3%	0.3%
7	Central Florida	Jul	50,216,181	49,180,177	48,835,877	50,116,481	1,357,395,950	1,354,578,466	1,338,646,278	1,353,528,141	0.2%	1.6%	0.3%	0.3%
8	Central Florida	Aug	49,319,569	48,959,479	48,336,172	50,388,840	1,374,328,971	1,361,963,934	1,341,983,926	1,361,668,836	0.9%	2.4%	0.9%	0.9%
9	Central Florida	Sep	43,458,383	43,590,109	43,024,089	44,474,518	1,224,163,954	1,232,890,263	1,217,329,907	1,234,422,736	0.7%	0.5%	0.6%	0.6%
10	Central Florida	Oct	36,703,389	35,630,719	34,910,424	36,276,712	1,048,122,727	1,041,993,056	1,027,366,969	1,046,634,764	0.7%	2.0%	0.1%	0.1%
11	Central Florida	Nov	34,644,291	32,883,697	34,503,188	35,918,849	1,005,562,252	971,819,048	973,500,115	988,453,179	8.3%	2.7%	1.7%	1.7%
12	Central Florida	Dec	36,319,700	33,008,549			39,336,844	1,042,897,059	948,472,155	1,073,388,049	6.8%	2.5%	1.3%	
1	Clay	Jan	260,983,935	260,732,791	261,015,296	264,433,776								
2	Clay	Feb	242,110,837	211,365,018	232,650,966	240,418,382								
3	Clay	Mar	219,716,845	215,968,291	213,387,702	217,492,295								
4	Clay	Apr	234,600,716	215,828,143	225,969,428	229,008,221								
5	Clay	May	281,182,896	264,188,355	278,852,100	281,919,273								
6	Clay	Jun	310,604,802	291,225,716	312,857,242	318,494,443								
7	Clay	Jul	324,852,731	319,327,011	315,002,496	318,158,729								
8	Clay	Aug	318,618,710	319,178,288	313,765,422	316,807,977								
9	Clay	Sep	277,894,521	265,594,149	282,949,868	286,133,892								
10	Clay	Oct	233,644,908	234,966,592	230,136,954	234,886,723								
11	Clay	Nov	235,404,582	211,467,946	222,326,122	226,615,723								
12	Clay	Dec		245,834,892	214,004,342	248,710,893								
1	Glades	Jan	28,830,607	29,188,143	28,683,754	28,949,883								
2	Glades	Feb	25,200,994	25,279,906	25,793,409	25,978,879								
3	Glades	Mar	31,254,419	27,621,843	28,049,713	28,239,868								
4	Glades	Apr	32,754,611	28,167,308	29,677,208	29,704,238								
5	Glades	May	33,065,068	31,217,586	32,053,107	32,004,292								
6	Glades	Jun	30,940,147	29,019,366	29,424,382	29,554,556								
7	Glades	Jul	31,228,278	29,286,767	29,974,791	29,267,037								
8	Glades	Aug	31,234,356	29,512,048	29,122,268	29,677,058								
9	Glades	Sep	29,083,401	27,510,946	27,234,312	27,715,211								
10	Glades	Oct	28,349,061	25,863,715	25,997,181	26,301,041								
11	Glades	Nov	27,302,478	23,642,603	25,259,062	24,995,039								
12	Glades	Dec		27,298,946	27,379,814	27,913,254								
1	Peace River	Jan	50,081,813	50,512,125	49,832,388	50,512,513								
2	Peace River	Feb	47,109,691	45,489,681	47,250,158	48,133,521								
3	Peace River	Mar	53,715,272	48,559,815	49,908,087	50,394,237								
4	Peace River	Apr	58,589,387	51,502,945	54,584,062	56,396,933								
5	Peace River	May	68,229,114	61,767,200	63,356,977	64,038,309								
6	Peace River	Jun	67,342,294	64,026,790	63,882,202	64,403,427								
7	Peace River	Jul	67,490,231	67,351,167	65,693,975	65,977,069								
8	Peace River	Aug	69,888,966	68,170,943	68,173,910	67,462,818								
9	Peace River	Sep	66,649,447	64,647,082	63,005,966	64,127,379								
10	Peace River	Oct	58,834,052	58,333,070	57,969,131	59,427,327								
11	Peace River	Nov	56,677,859	49,752,389	53,126,546	54,773,140								
12	Peace River	Dec		52,558,582	51,380,694	53,562,051								
1	Sumter	Jan	250,606,201	252,613,562	253,363,347	255,099,654								
2	Sumter	Feb	238,507,147	230,274,229	232,485,977	234,196,328								
3	Sumter	Mar	241,666,522	225,567,065	229,926,974	228,963,820								
4	Sumter	Apr	261,852,319	231,759,281	245,881,928	244,996,202								
5	Sumter	May	301,282,617	277,867,084	288,747,488	290,126,793								
6	Sumter	Jun	323,588,790	300,726,386	312,484,150	314,097,604								
7	Sumter	Jul	319,371,888	323,554,147	317,529,539	320,177,535								
8	Sumter	Aug	329,874,638	325,686,252	320,410,069	322,969,608								
9	Sumter	Sep	300,332,295	296,400,892	294,250,744	296,196,928								
10	Sumter	Oct	260,651,158	253,203,759	250,219,962	251,309,274								
11	Sumter	Nov	246,256,853	219,414,514	233,496,253	233,998,622								
12	Sumter	Dec		240,026,404	227,313,995	244,410,715								
1	Suwannee Valley	Jan	35,896,645	34,443,267	33,825,252	35,511,516								
2	Suwannee Valley	Feb	33,998,328	28,909,709	31,331,631	33,064,335								
3	Suwannee Valley	Mar	29,561,493	28,656,658	27,888,678	28,664,446								
4	Suwannee Valley	Apr	30,611,867	28,315,063	30,038,292	30,279,294								
5	Suwannee Valley	May	41,935,774	35,687,312	38,332,521	38,889,865								
6	Suwannee Valley	Jun	44,352,127	39,999,115	42,961,489	43,553,047								
7	Suwannee Valley	Jul	45,602,898	43,808,770	44,204,814	45,350,077								
8	Suwannee Valley	Aug	43,265,867	42,699,596	42,991,223	43,682,552								
9	Suwannee Valley	Sep	35,600,727	36,933,038	36,392,221	36,847,332								
10	Suwannee Valley	Oct	29,373,478	30,858,863	30,063,035	30,671,396								
11	Suwannee Valley	Nov	30,621,901	28,849,863	29,438,074	29,680,817								
12	Suwannee Valley	Dec		34,209,320	28,795,255	34,025,132								
1	Talquin*	Jan	93,342,781	93,384,140	91,988,002	95,259,036								
2	Talquin	Feb	88,062,201	74,559,373	83,628,952	86,483,133								
3	Talquin	Mar	68,508,204	70,797,571	67,878,445	70,443,140								
4	Talquin	Apr	68,481,004	65,430,080	68,257,628	71,201,320								
5	Talquin	May	84,885,601	79,564,092	86,066,387	88,430,411								
6	Talquin	Jun	93,102,252	89,677,471	96,612,968	98,243,996								
7	Talquin	Jul	103,115,903	98,983,233	101,908,779	104,978,950								
8	Talquin	Aug	99,836,141	99,062,772	100,922,680	103,629,111								
9	Talquin	Sep	82,766,976	86,767,299	82,938,740	85,306,671								
10	Talquin	Oct	70,266,523	72,534,885	69,156,953	71,411,246								
11	Talquin	Nov	69,337,891	74,265,791	71,467,565	73,545,135								
12	Talquin*	Dec		67,152,913	70,446,240	69,643,608								
1	Tri-County	Jan	29,763,637	29,580,904	28,582,460	28,764,854								
2	Tri-County	Feb	25,070,345	22,110,559	23,609,534	23,957,531								
3	Tri-County	Mar	22,177,589	22,441,842	22,068,814	21,837,964								
4	Tri-County	Apr	22,901,416	21,581,080	22,569,194	22,333,847								
5	Tri-County	May	29,122,611	26,580,471	28,987,531	27,946,189								
6	Tri-County	Jun	31,824,680	29,466,027	31,282,497	30,867,973								
7	Tri-County	Jul	33,589,794	31,727,082	31,940,099	32,496,073								
8	Tri-County	Aug	31,985,447	31,266,877	31,371,058	31,364,782								
9	Tri-County	Sep	26,913,736	27,604,415	27,127,829	26,712,645								
10	Tri-County	Oct	22,934,891	23,380,750	22,849,530	22,906,488								
11	Tri-County	Nov	22,488,943	22,298,606	22,901,926	22,111,448								
12	Tri-County	Dec		26,183,763	22,459,866	25,162,475								
1	Withlacoochee R	Jan	305,868,915	302,644,000	299,012,798	308,438,080								
2	Withlacoochee R	Feb	289,282,055	280,469,200	280,919,661	288,052,995								
3	Withlacoochee R	Mar	282,541,061	264,819,900	268,562,884	275,082,481								
4	Withlacoochee R	Apr	311,327,619	288,861,529	295,156,964	301,266,607								
5	Withlacoochee R	May	363,365,311	334,736,646	352,003,418	360,590,243								
6	Withlacoochee R	Jun	387,536,680	366,457,578	378,429,124	385,780,943								
7	Withlacoochee R	Jul	381,730,068	381,340,022	381,947,568	387,012,190								
8	Withlacoochee R	Aug	400,294,957	397,434,629	389,000,263	395,448,338								
9	Withlacoochee R	Sep	361,317,428	363,782,542	361,006,108	366,866,153								
10	Withlacoochee R	Oct	308,386,297	306,280,706	306,062,784	313,349,557								
11	Withlacoochee R	Nov	293,418,466	259,325,437	280,672,386	287,726,407								
12	Withlacoochee R	Dec		291,435,096	272,214,539	308,422,500								

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
-1.63%	0.80%	2.93%	3.62%	1.46%	0.34%	0.27%	0.92%	-0.84%	0.14%	1.70%	LFS15 Backcast Actual Weather & Economics

2015 Energy



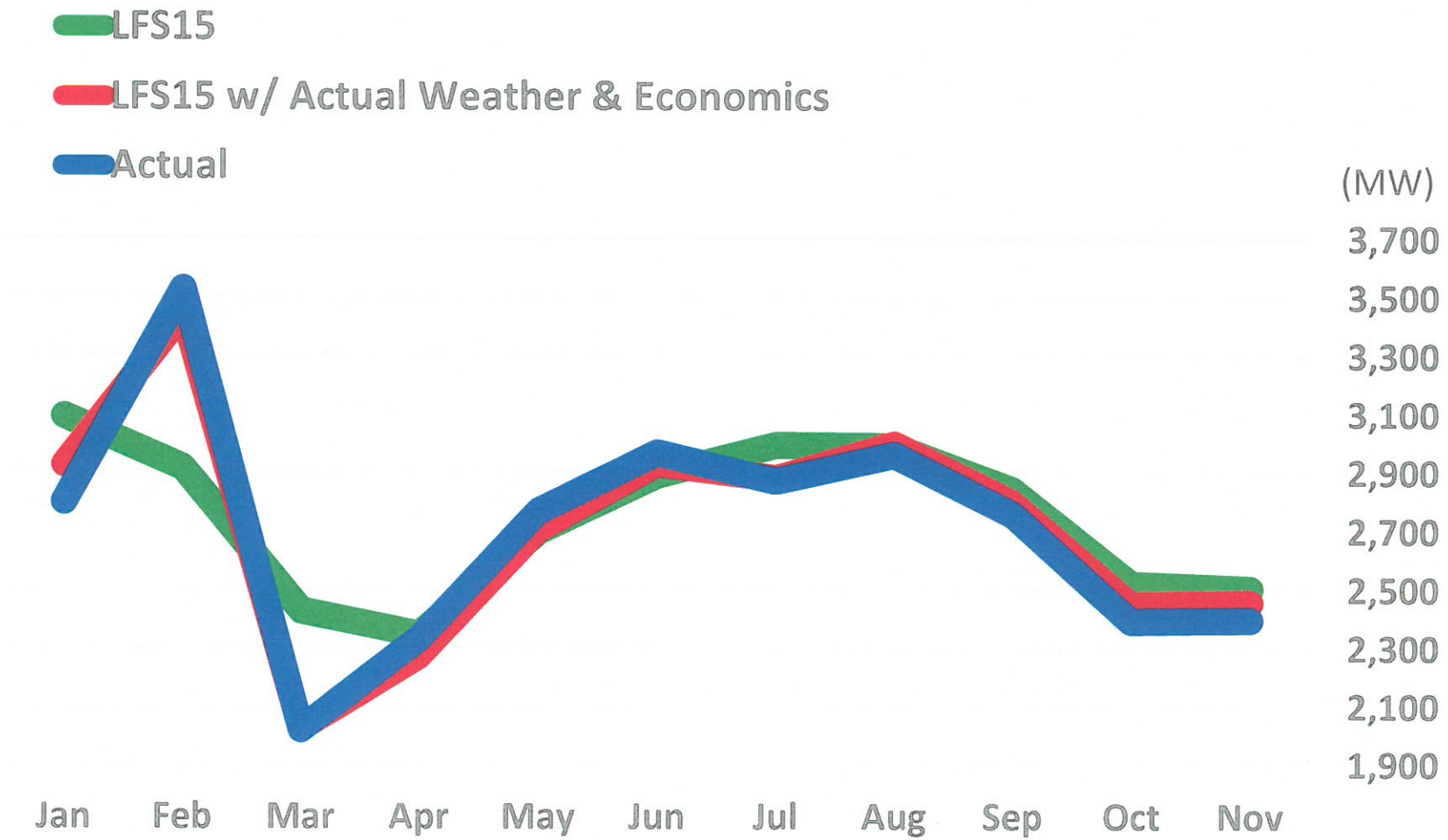
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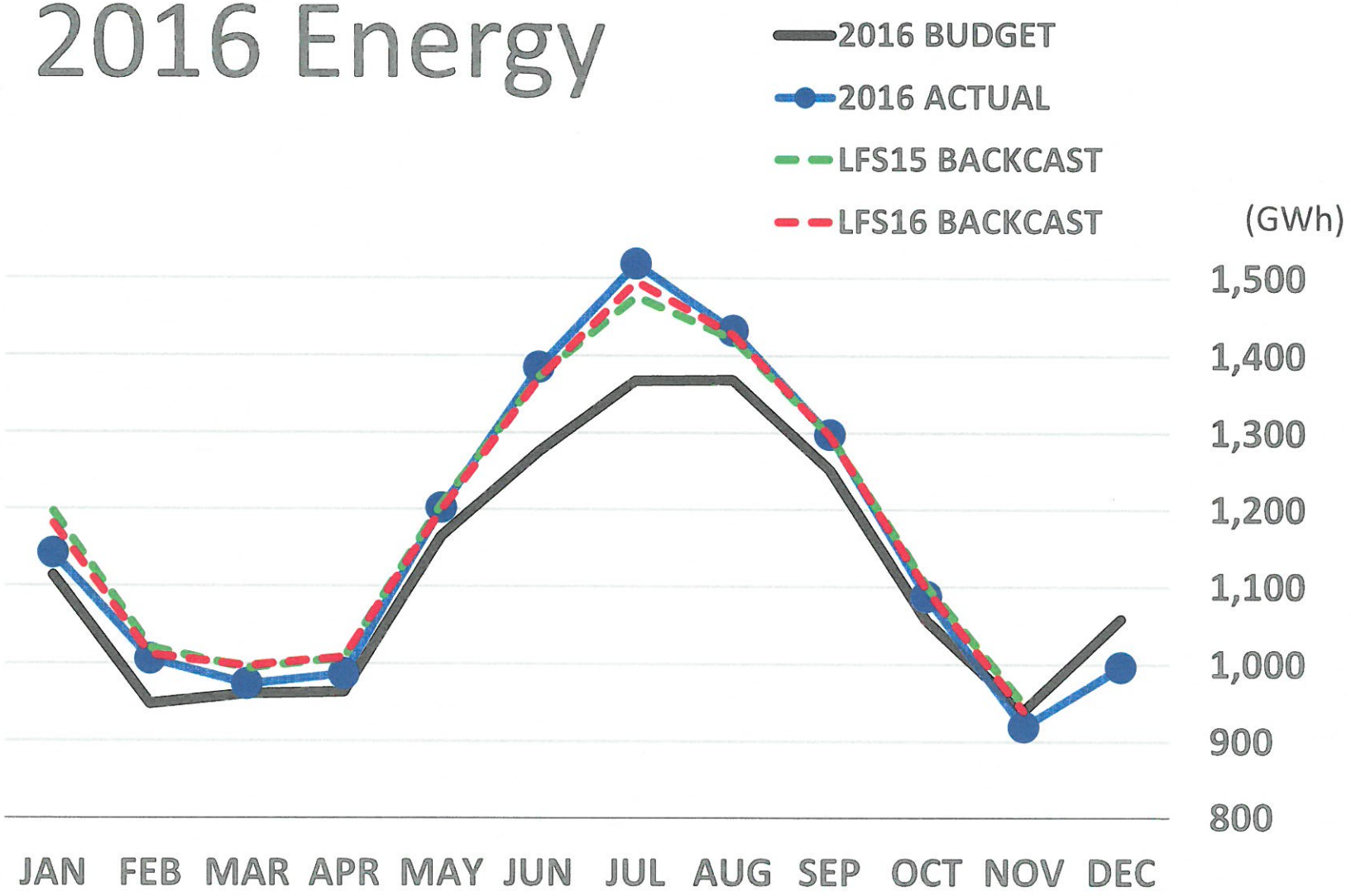
Date		Actual	LFS15 w/ Actual Weather & Economics	LFS15	Difference% - Backcast	Difference% - LFS15	MAPE - Backcast	MAPE - LFS15
1-Jan-15	Jan	**2,796,521**	**2,923,923**	**3,089,970**	-4.4%	-9.5%	4.6%	9.5%
1-Feb-15	Feb	**3,525,630**	**3,442,228**	**2,913,544**	2.4%	21.0%	2.4%	21.0%
1-Mar-15	Mar	**2,019,502**	**2,023,441**	**2,425,782**	-0.2%	-16.7%	0.2%	16.7%
1-Apr-15	Apr	**2,331,958**	**2,273,640**	**2,344,802**	2.6%	-0.5%	2.5%	0.5%
1-May-15	May	**2,765,157**	**2,704,628**	**2,696,483**	2.2%	2.5%	2.2%	2.5%
1-Jun-15	Jun	**2,966,044**	**2,928,576**	**2,888,898**	1.3%	2.7%	1.3%	2.7%
1-Jul-15	Jul	**2,869,321**	**2,879,868**	**2,992,935**	-0.4%	-4.1%	0.4%	4.1%
1-Aug-15	Aug	**2,959,154**	**2,996,336**	**2,989,980**	-1.2%	-1.0%	1.3%	1.0%
1-Sep-15	Sep	**2,756,832**	**2,796,271**	**2,838,905**	-1.4%	-2.9%	1.4%	2.9%
1-Oct-15	Oct	**2,392,516**	**2,450,553**	**2,519,720**	-2.4%	-5.0%	2.4%	5.0%
1-Nov-15	Nov	**2,397,614**	**2,457,167**	**2,503,303**	-2.4%	-4.2%	2.5%	4.2%
1-Dec-15	Dec		2,750,074	2,669,186				
		29,780,249	**29,876,630**	**30,204,322**	**-0.3%**	**-1.4%**	**1.9%**	**6.4%**

2015 Demand


LFS15
LFS15 w/ Actual Weather & Economics
Actual
(MW)
3,700
3,500
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1,900
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov

	2016 Actual Billing MWh	LFS15 Backcast			LFS16 Backcast		
Jan	1,142,437	1,196,193	*-53,756*	*-4.7%*	1,181,163	*-38,725*	*-3.4%*
Feb	1,005,223	1,020,138	*-14,915*	*-1.5%*	1,011,573	*-6,350*	*-0.6%*
Mar	973,031	993,766	*-20,735*	*-2.1%*	997,206	*-24,175*	*-2.5%*
Apr	986,491	1,006,900	*-20,408*	*-2.1%*	1,008,255	*-21,764*	*-2.2%*
May	1,202,080	1,206,466	*-4,386*	*-0.4%*	1,199,327	*2,753*	*0.2%*
Jun	1,384,448	1,372,664	*11,785*	*0.9%*	1,370,580	*13,869*	*1.0%*
Jul	1,518,138	1,475,932	*42,206*	*2.8%*	1,495,359	*22,779*	*1.5%*
Aug	1,431,689	1,420,994	*10,695*	*0.7%*	1,427,066	*4,622*	*0.3%*
Sep	1,297,243	1,296,281	*963*	*0.1%*	1,296,203	*1,040*	*0.1%*
Oct	1,086,613	1,100,533	*-13,920*	*-1.3%*	1,096,728	*-10,115*	*-0.9%*
Nov	918,730	948,370	*-29,639*	*-3.2%*	939,924	*-21,193*	*-2.3%*

2016 Energy



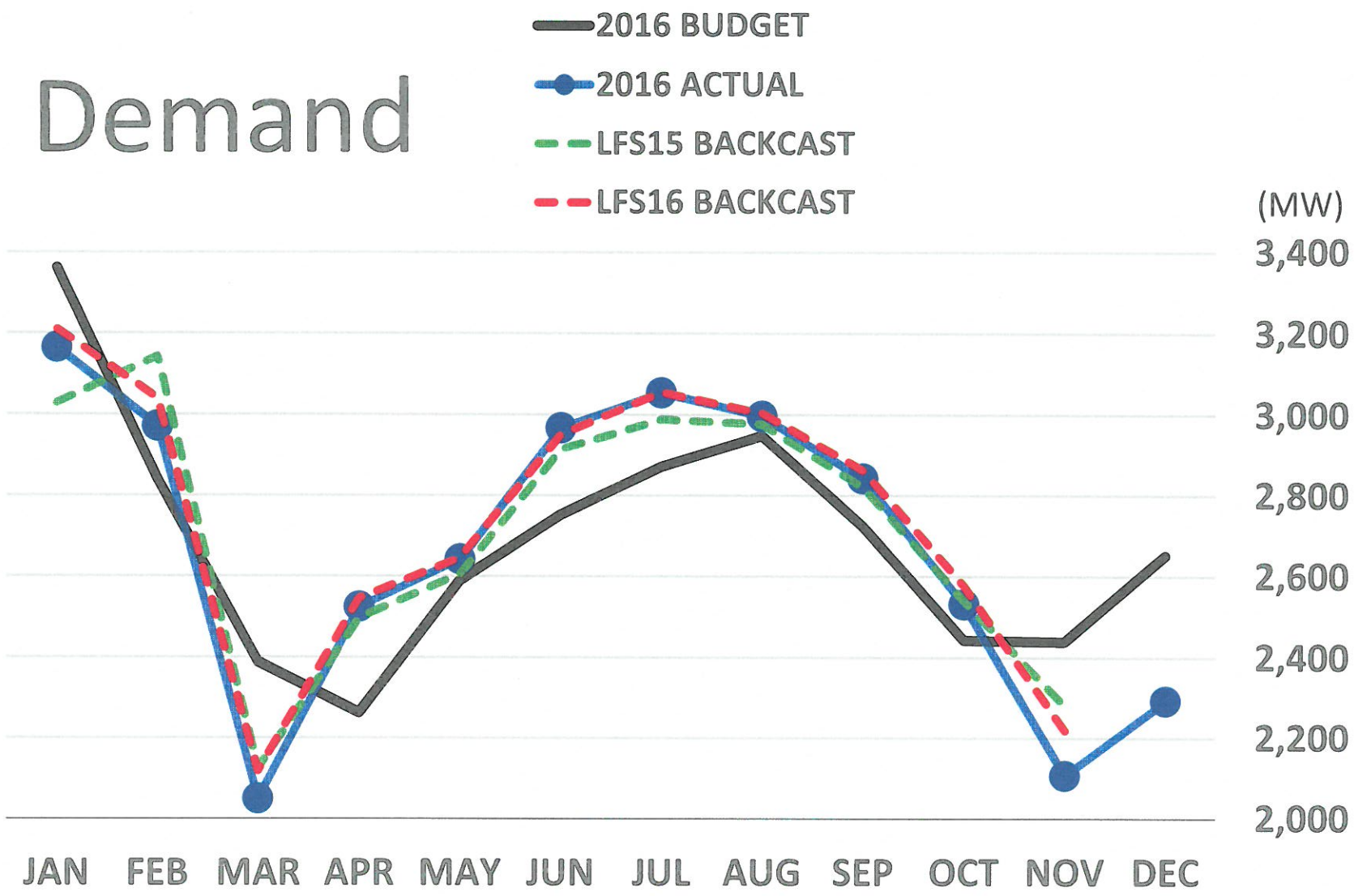
ENERGY: SECI-8 Billing (Metered Sales to Members Net of SEPA Net of INT-2).

***2015 BACKCAST:** Actual weather through November 2016. Economy and population forecasts from Spring 2015 vintage. Actual load data through Dec. 2014.

****2016 BACKCAST:** All explainatory variables, including load, up-to-date through November 2016. Lastest UF BEBR population forecast vintage as of Jan. 2016.

	2016 Actual Billing MW		LFS15 Backcast			LFS16 Backcast	
Jan	**3,164**	**3,028**	*136*	*4.3%*	**3,209**	*-45*	*-1.4%*
Feb	**2,971**	**3,142**	*-171*	*-5.8%*	**3,039**	*-69*	*-2.3%*
Mar	**2,050**	**2,125**	*-75*	*-3.7%*	**2,119**	*-69*	*-3.4%*
Apr	**2,524**	**2,498**	*26*	*1.0%*	**2,546**	*-22*	*-0.9%*
May	**2,642**	**2,605**	*36*	*1.4%*	**2,646**	*-4*	*-0.2%*
Jun	**2,966**	**2,915**	*52*	*1.7%*	**2,951**	*15*	*0.5%*
Jul	**3,053**	**2,987**	*65*	*2.1%*	**3,055**	*-2*	*-0.1%*
Aug	**2,996**	**2,976**	*20*	*0.7%*	**3,004**	*-8*	*-0.3%*
Sep	**2,841**	**2,820**	*21*	*0.7%*	**2,862**	*-21*	*-0.7%*
Oct	**2,530**	**2,540**	*-9*	*-0.4%*	**2,576**	*-46*	*-1.8%*
Nov	**2,105**	**2,279**	*-174*	*-8.3%*	**2,218**	*-113*	*-5.4%*
Total	**29,841**	**29,915**	***74***	***0.2%***	**30,224**	***383***	***1.3%***

Demand



Demand: SECI-8 Billing (Metered Sales to Members Net of SEPA Net of INT-2).
***2015 BACKCAST:** Actual weather through November 2016. Economy and population forecasts from Spring 2015 vintage. Actual load data through Dec. 2014.
****2016 BACKCAST:** All explainatory variables, including load, up-to-date through November 2016. Lastest UF BEBR population forecast vintage as of Jan. 2016.

ENERGY (kWh)

DATE	LFS16 BACKCAST (thru NOV17)	LFS17 FS BACKCAST	LARGE LOADS and SAWMILL	SEPA	Billing Energy Adj	LFS16 BUDGET BACKCAST	LFS17 BUDGET BACKCAST
DEC	**1,011,479,417**	**999,612,389**	9,914,158	12,221,327	16,629	**1,009,188,876.34**	**997,321,848.54**
JAN	**1,028,615,062**	**1,027,728,603**	10,421,401	9,745,199	14,916	**1,029,306,179.63**	**1,028,419,720.93**
FEB	**901,753,042**	**889,354,839**	6,084,298	10,259,848	12,383	**897,589,875.28**	**885,191,671.80**
MAR	**993,643,672**	**974,441,131**	9,453,870	11,006,808	14,342	**992,105,076.60**	**972,902,535.18**
APR	**1,051,814,725**	**1,040,573,647**	8,784,988	11,690,872	14,346	**1,048,923,187.53**	**1,037,682,109.43**
MAY	**1,265,215,896**	**1,249,180,128**	9,553,364	12,603,880	18,273	**1,262,183,652.99**	**1,246,147,885.29**
JUN	**1,302,963,500**	**1,281,671,218**	9,030,397	12,038,665	21,135	**1,299,976,366.47**	**1,278,684,084.57**
JUL	**1,443,368,330**	**1,425,485,823**	9,298,306	13,574,174	19,503	**1,439,111,964.46**	**1,421,229,457.66**
AUG	**1,462,360,788**	**1,448,427,123**	9,831,687	13,195,561	19,346	**1,459,016,259.85**	**1,445,082,594.55**
SEP	**1,319,504,882**	**1,302,318,818**	7,860,970	12,034,317	16,883	**1,315,348,418.44**	**1,298,162,354.04**
OCT	**1,199,675,351**	**1,188,930,886**	8,831,318	13,260,501	14,034	**1,195,260,201.68**	**1,184,515,737.18**
NOV	**953,579,002**	**927,877,225**	2,153,320	12877906		**942,854,415.53**	**917,152,638.51**

NON-COIN DEMAND (kW)

DATE	LFS16 BACKCAST (thru NOV17)	LFS17 FS BACKCAST	LARGE LOADS and SAWMILL	LFS16 BUDGET BACKCAST (NON-COIN)	LFS17 BUDGET BACKCAST (NON-COIN)	PBS Actual Billing - SUM Member Non-Coin PBS0670	ACTUAL NET BILLED DEMAND PBS0470	CoinFactor	LFS16 BUDGET BACKCAST (SECI-COIN)	LFS17 BUDGET BACKCAST (SECI-COIN)
DEC	**2,441,973**	**2,443,769**	13,914	**2,455,887**	**2,457,683**	2,454	2,287	93.19%	**2,288,556.19**	**2,290,229.82**
JAN	**3,011,522**	**2,939,448**	12,805	**3,024,327**	**2,952,253**	2,990	2,885	96.49%	**2,918,096.86**	**2,848,554.47**
FEB	**2,253,670**	**2,234,761**	12,204	**2,265,874**	**2,246,965**	2,185	2,053	93.98%	**2,129,402.32**	**2,111,632.19**
MAR	**2,605,657**	**2,647,015**	17,565	**2,623,222**	**2,664,580**	2,702	2,551	94.43%	**2,477,004.10**	**2,516,056.82**
APR	**2,643,077**	**2,626,271**	15,802	**2,658,879**	**2,642,073**	2,874	2,764	96.19%	**2,557,521.34**	**2,541,356.00**
MAY	**3,040,773**	**3,035,418**	13,556	**3,054,329**	**3,048,974**	3,073	2,943	95.76%	**2,924,823.43**	**2,919,695.48**
JUN	**2,866,372**	**2,920,057**	13,378	**2,879,750**	**2,933,435**	3,017	2,833	93.89%	**2,703,722.97**	**2,754,126.44**
JUL	**3,005,750**	**3,105,466**	11,346	**3,017,096**	**3,116,812**	3,134	2,954	94.27%	**2,844,077.72**	**2,938,075.41**
AUG	**3,146,580**	**3,126,567**	13,050	**3,159,630**	**3,139,617**	3,139	2,913	92.81%	**2,932,555.90**	**2,913,981.18**
SEP	**2,872,060**	**2,982,744**	11,932	**2,883,992**	**2,994,676**	2,897	2,768	95.54%	**2,755,314.49**	**2,861,060.00**
OCT	**2,958,446**	**2,929,013**	13,913	**2,972,359**	**2,942,926**	2,803	2,695	96.17%	**2,858,393.33**	**2,830,088.84**
NOV	**2,249,106**	**2,056,197**	12,642	**2,261,748**	**2,068,839**	2,035	1,843	90.58%	**2,048,688.25**	**1,873,951.55**

ENERGY

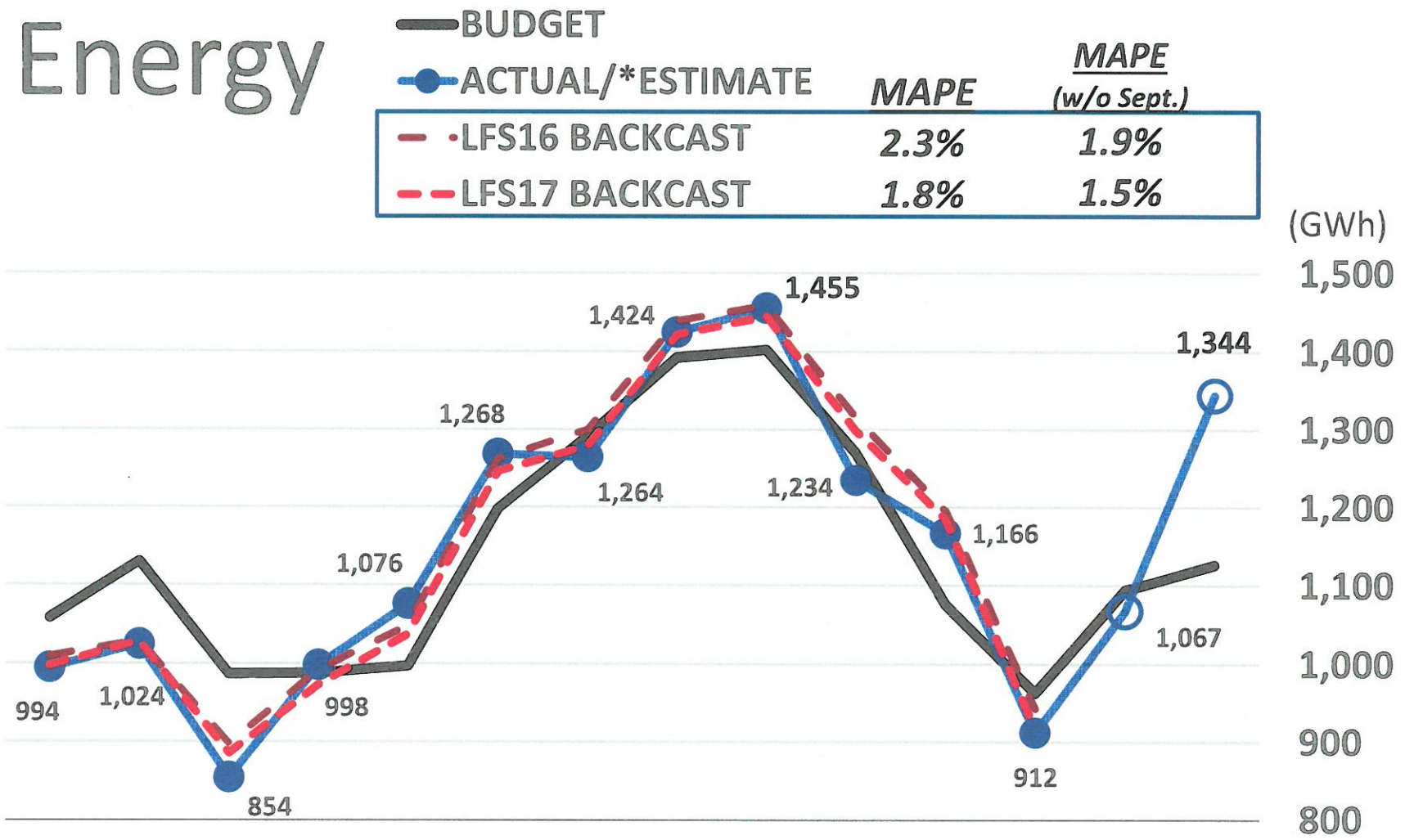
	MAPE	MAPES DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
LFS16 Backcast	2.3%	***-1.5%***	***-0.5%***	***-5.1%***	***0.6%***	***2.5%***	***0.4%***	***-2.9%***	***-1.0%***	***-0.3%***	***-6.6%***	***-2.5%***	***-3.4%***	***LFS16 Backcast***
LFS17 Backcast	1.8%	***-0.3%***	***-0.4%***	***-3.7%***	***2.5%***	***3.5%***	***1.7%***	***-1.2%***	***0.2%***	***0.7%***	***-5.2%***	***-1.6%***	***-0.6%***	***LFS17 Backcast***
		1.5%	0.5%	5.1%	0.6%	2.5%	0.4%	2.9%	1.0%	0.3%	6.6%	2.5%	3.4%	
		0.3%	0.4%	3.7%	2.5%	3.5%	1.7%	1.2%	0.2%	0.7%	5.2%	1.6%	0.6%	

MAPE wo Sept
1.9%
1.5%

DEMAND

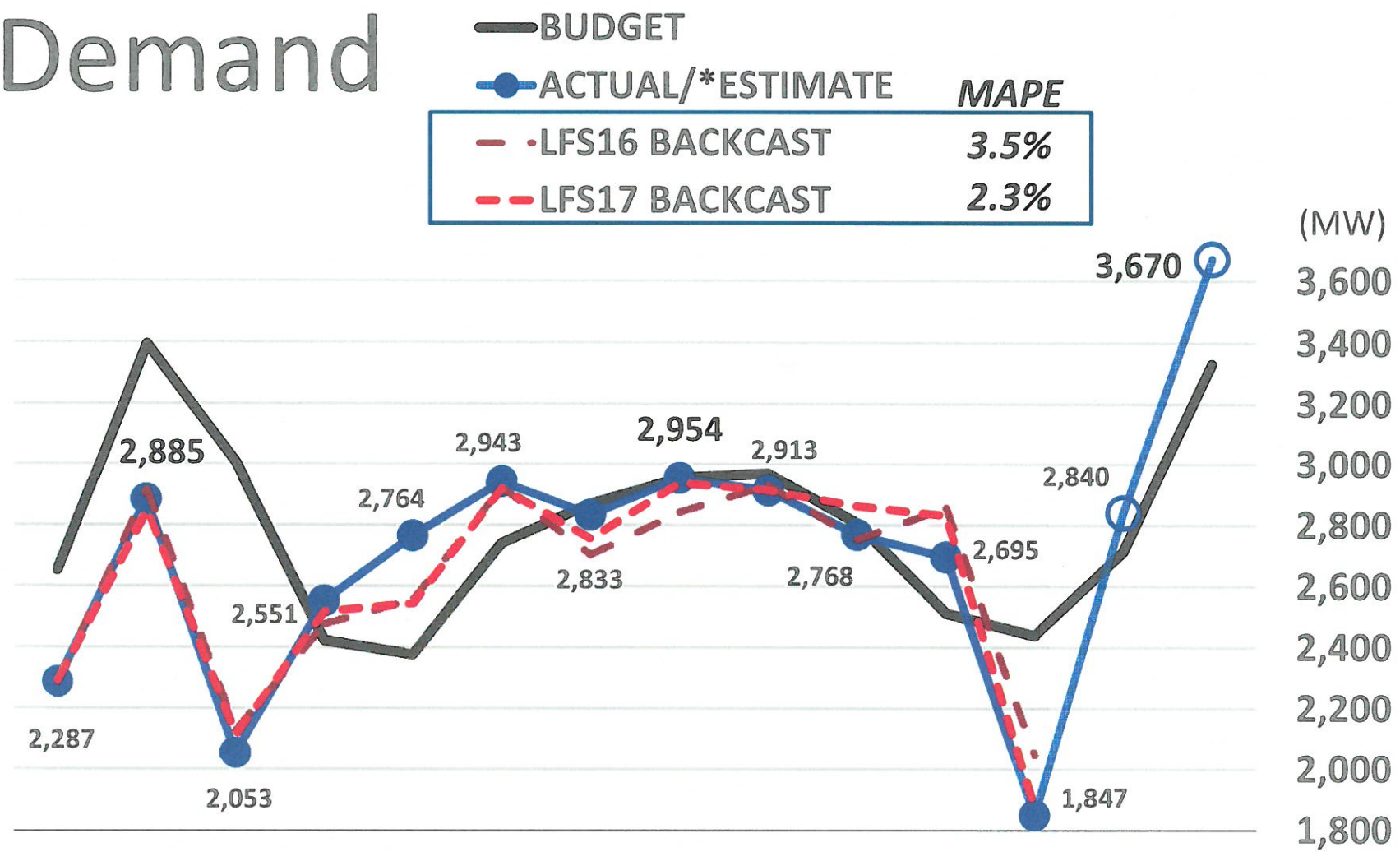
	MAPE	MAPES DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
LFS16 Backcast	3.5%	***-0.1%***	***-1.2%***	***-3.7%***	***2.9%***	***7.5%***	***0.6%***	***4.5%***	***3.7%***	***-0.7%***	***0.5%***	***-6.1%***	***-10.9%***	***LFS16 Backcast***
LFS17 Backcast	2.3%	***-0.1%***	***1.3%***	***-2.8%***	***1.4%***	***8.1%***	***0.8%***	***2.8%***	***0.5%***	***0.0%***	***-3.4%***	***-5.0%***	***-1.5%***	***LFS17 Backcast***
		0.1%	1.2%	3.7%	2.9%	7.5%	0.6%	4.5%	3.7%	0.7%	0.5%	6.1%	10.9%	
		0.1%	1.3%	2.8%	1.4%	8.1%	0.8%	2.8%	0.5%	0.0%	3.4%	5.0%	1.5%	

Energy



DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*	
-1.5%	-0.5%	-5.1%	0.6%	2.5%	0.4%	-2.9%	-1.0%	-0.3%	-6.6%	-2.5%	-3.4%		LFS16 Backcast
-0.3%	-0.4%	-3.7%	2.5%	3.5%	1.7%	-1.2%	0.2%	0.7%	-5.2%	-1.6%	-0.6%		LFS17 Backcast

Demand



DEC16	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC*JAN18*
-0.1%	-1.2%	-3.7%	2.9%	7.5%	0.6%	4.5%	3.7%	-0.7%	0.5%	-6.1%	-10.9%	LFS16 Backcast
-0.1%	1.3%	-2.8%	1.4%	8.1%	0.8%	2.8%	0.5%	0.0%	-3.4%	-5.0%	-1.5%	LFS17 Backcast

98

Deposition of James Maiz.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 98
PARTY: STAFF'S EXHIBITS
DESCRIPTION: James Maiz

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition to determine combined cycle facility, by Seminole Electric Cooperative, Inc.	)	DOCKET NO. 20170266-EC
In Re: Joint Petition to determine need for the Shady Hills combined cycle facility, by Seminole Electric Cooperative, Inc. and Shady Hills Energy Center, LLC	)	DOCKET NO. 20170267-ec
	)	DATED: February 27, 2018

****

ORAL AND TELEPHONIC DEPOSITION OF

JAMES MAIZ

March 6, 2018

****

ORAL AND TELEPHONIC DEPOSITION OF JAMES MAIZ, produced as a witness at the instance of the Petitioner, and duly sworn, was taken in the above-styled and numbered cause on March 7, 2018, from 2:35 p.m. to 3:10 p.m., before Bonnie L. Rodriguez, CSR in and for the State of Texas, reported by machine shorthand, at offices of Rockland Capital, 24 Waterway Avenue, Suite 800, The Woodlands, Texas 77380 pursuant to the Florida Rules of Civil Procedure and the provisions stated on the record.

A P P E A R A N C E S

FOR THE PETITIONER,SEMINOLE ELECTRIC COOPERATIVE, INC., VIA TELEPHONE:

MR. GARY PERKO
Hopping Green & Sams, P.A.
P.O. Box 6526
Tallahassee, Florida 32301
Telephone: (850) 222-7500

FOR THE PUBLIC SERVICE COMMISSION VIA TELEPHONE:

MS. RACHAEL DZIECHCIARZ
Florida Public Service Commission
Office of the General Counsel
2450 Shumard Oak Boulevard
Tallahassee, Florida 32390
E-mail: rdziechc@psc.state.fl.us

FOR THE RESPONDENT, QUANTUM PASCO POWER, L.P., MICHAEL TULK AND PATRICK DALY VIA TELEPHONE:

MR. ROBERT SCHEFFEL WRIGHT
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1300 Thomaswood Drive
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MR. JOHN T. LAVIA, III
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright
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Tallahassee, Florida 32308
E-mail: schef@gbwlegal.com

ALSO PRESENT BY TELEPHONE:

MR. MICHAEL WARD, Seminole Electric Cooperative
MR. PAUL SOTKIEWICZ, EQ Policy
MS. PAKIRA THOMPSON, Staff for Public Service Commission

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JAMES MAIZ

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JAMES MAIZ,

having been duly sworn, testified to the following:

EXAMINATION

BY MR. PERKO VIA TELEPHONE:

Q Could you please state your full name and business address for the record?

A James Andrew Maiz, 24 Waterway Avenue, The Woodlands, Texas 77380.

Q Mr. Maiz, by whom are you currently employed?

A Rockland Capital, LLC.

Q And what is your position at Rockland Capital?

A I'm one of the partners at the firm.

Q And what are your responsibilities in that position?

A Well, we run the business. Rockland Capital is a private equity firm that manages institutionally raised funds and so we oversee the management of those funds.

Q Okay. How would you describe the business that Rockland Capital is in?

A We primarily invest those funds in generating power plants in the independent power space.

Q And one of those power plants that you're

referring to would be the Quantum Pasco Power Facility in Florida; is that correct?

A That's correct.

Q Do you own any other power generation facilities in Florida?

A We do not.

Q Mr. Maiz, it's my understanding that you have been designated by Quantum Power Pasco, LP -- to be prepared to testify on behalf the Quantum Pasco Power about the following subject matter -- I quote -- "Information pertaining to the allegations in Paragraph 11 of the Motion to Intervene of Quantum Pasco Power, L.P. that "at this point in time, Seminole is the only realistic potential counterparty, such that it is highly likely that, absent a reasonable business arrangement with Seminole, the Pasco Facility will be removed from service from the Florida grid."

Is it your understanding that you've been designated by Quantum Pasco Power to testify on its behalf regarding that subject matter?

A Yes.

Q And do you agree to testify --

MR. WRIGHT: Gary?

MR. PERKO: Yes.

MR. WRIGHT: Just to be clear, there is

one word -- not really material but there's a misquote in your notice. You have "reasonable business arrangement," and we're looking at the filed motion. It's "reasonable business agreement."

MR. PERKO: Thanks.

Q (BY MR. PERKO) With that clarification, would your answer still stand, Mr. Maiz?

A Yes.

Q And do you agree to testify on behalf of Quantum Pasco Power, LP, regarding that subject matter?

A I do.

Q What have you done to prepare for this deposition?

A I consulted with -- with Scheff and Jay, my attorneys, and I reviewed the -- the deposition notice -- or I guess I should say the Motion to Intervene and I looked through the materials that we produced for discovery.

Q Do you have those materials that you produced for -- in discovery with you at this time?

A I think I do. I still have mail to download what it is you have sent recently to Jay to cross-check it but I thought I had everything.

Q Okay. That's good. Thank you. Now, with

regard to the Motion to Intervene, did you review that before it was filed in this case?

A I did.

Q And how much time did you spend reviewing that document?

A I - perhaps an hour.

Q Did you provide any input into the -- into the actual text of the document?

A I think I -- I believe I did.

Q Do you recall what portions of it?

A I do not.

Q Did you have any discussions with anyone else other than your counsel about Quantum's intervention prior to the filing of the Motion to Intervene?

MR. WRIGHT: Gary, we're going to object to this as being beyond the scope of inquiry related to Paragraph 11. I'm not going to instruct him not to answer. I think this is, you know, preparatory for predicate but we object to this line of questioning. It's beyond the scope.

MR. PERKO: I'm not going to take long, Scheff. I'm just trying to lay some predicate.

MR. WRIGHT: Okay.

A So I -- I suspect that I suppose spoke to colleagues about the intervention.

Q (BY MR. PERKO) Did you talk Mr. Tulk or Mr. Daly?

MR. WRIGHT: It's beyond the scope. We object. And that is clearly beyond the scope and I will instruct him not to answer on grounds that that's beyond the scope.

MR. PERKO: On grounds that's beyond the scope?

MR. WRIGHT: It's beyond the scope of the deposition notice.

MR. PERKO: Okay.

Q (BY MR. PERKO) Mr. Maiz, can you tell me the relationship between Rockland Capital and Quantum Pasco Power, LP?

A So Rockland Capital manages an institutional fund called Rockland Power Partners 3, and Rockland Power Partners 3 wholly opens Quantum Pasco. So RockLand Capital --

Q When -- I'm sorry.

A I was going to say Rockland Capital has a management agreement with Rockland Power Partners 3 to manage its assets.

Q So Rockland -- I'm sorry, did you say Rockland Pasco Power 3?

A Rockland Power Partners 3 is the name of the

fund.

Q Okay. The Rockland Part -- Rockland Power Partners 3 actually owns Quantum Pasco Power, LP; is that correct?

A Correct.

Q And when did Quantum Power Partners 3 acquire Quantum Pasco Power, LP?

A I believe it was in November of 2016.

Q So it was during -- during the time period that the Seminole RFP was still pending; is that correct?

A Correct.

Q I'd like to refer your attention to one of the documents that your counsel produced in response to production of documents -- our production of documents request to Quantum.

A Okay.

Q And it's -- it was within a series of files, one of which -- the document that I'm referring to is entitled "Rockland Capital Investor Memorandum August 2016," and it begins at Bates Page QuantumResp2SeminolePOD-000013. Do you have that document in front of you?

A I have the investment memorandum, yes.

Q Okay. And did you -- do you recognize this

document?

A I do.

Q Okay. It's my understanding there is confidential information within this -- that's highlighted with the document. I do not intend to recite that or otherwise talk about the specifics, but I would like to talk about a couple of statements in this document.

So if I could refer you to Page 2 of that document on page -- Bates Page 15 of POD-000015. Do you see that?

A I have Page 2, yes.

Q Okay. It states further down there that the Quantum Pasco facility currently has a tolling agreement with TECO; is that correct?

A That's correct.

Q And that agreement expires in December 2018; is that correct?

A That's correct.

Q It also states that the Pasco facility commenced commercial operations in 1993; is that correct?

A To my knowledge --

(Brief interruption.)

A Yes, that's correct.

Q (BY MR. PERKO) It also says that the gas connection at the Pasco facilities is with People's Gas; is that correct?

A That's correct.

Q And the electrical interconnection is with TECO, correct?

A Correct.

Q Okay. If I could refer you to Page 3, it states that the Pasco facility currently has a -- O&M agreement with EthosEnergy. Do you see that?

A I do.

Q It says here that the expiration date is February 2018. Has that contract for agreement been extended?

A I believe it has.

Q Okay. If -- if the Pasco facility were removed in service as you allude to Paragraph 11 of the Motion to Intervene, what would happen to that contract?

MR. WRIGHT: I'm going to object that's beyond the scope.

MR. PERKO: I don't think it's confidential.

MR. WRIGHT: I'm going to object it's beyond to scope but I'll allow him to answer though.

A It would be terminated.

Q (BY MR. PERKO) So the employees of EthosEngery that currently work at the facility would no longer be working at the facility?

MR. WRIGHT: I object to that. That is clearly beyond the scope, Gary. That doesn't have anything to do with our shutting down the plant.

MR. PERKO: Sure, it does. I'm asking the consequences of shutting down the plant. You allege that you will shut the down plant if you don't get a contract with Seminole. It's clearly within the scope.

MR. WRIGHT: I don't agree but I'll let him answer.

A Yes. All of the employees will -- will be let go.

Q (BY MR. PERKO) Okay. On Page 4, if could you look at the first paragraph under the section "Opportunity Overview." That first sentence refers to another power plant that you are acquiring as well as Pasco; is that correct?

A That's correct.

Q And it states that the other facility and "Pasco represent a unique opportunity to Rockland to invest in well-maintained assets with near-term contracted cash flows and essentially salvaged

post-PPA." Do you see that?

A Yes. I see that.

Q What -- what is meant by the term, "essentially salvaged post-PPA"?

A It means that we assumed that at the end of the PPA term that there would be no ongoing basis for operating the power plant and salvage refers to selling the equipment for salvage scrap value.

Q The next sentence says, "The size of the deal, the short-term nature of the contracted cash flows, and limited going concern value post-contract make the auction process well-suited for Rockland." Is that what it says?

A Yes.

Q What was meant by the term, "limited going concern value post-contract" in that statement?

A Again, after the term of the PPA, that it is unlikely that either of these assets would continue operating.

Q The next sentence says, "That said, if a buyer ascribes meaningful value to a re-contracting scenario and incorporates this in their bid (with no contingencies), we will likely not compete on price." What -- what was being conveyed here?

A What we were telling the investment committee

is that if there was a -- another perspective buyer in the auction for these plants, who was willing to assume that they could get a new contract after the existing PPA and they'll willing to pay for that through this auction, that we would probably lose because we were not willing to do that.

Q So is it fair to say that Rockland factored in the risk of not re-contracting into the price that you paid for the Pasco facility?

MR. WRIGHT: I object. It's beyond the scope it has to do with our allegation that we would shut the plant down if we don't get a reasonable business agreement with Seminole. What we did -- the decision-making process that led Quantum and Rockland -- that Rockland to acquire the asset in the first place is not relevant to that.

MR. PERKO: It goes to the -- the relevance and meaning of what you alleged in Paragraph 11, Counsel. Are you instructing the witness not to answer?

MR. WRIGHT: Tell me why you think it's relevant to the allegation.

MR. PERKO: It also goes to cost effectiveness. Are you instructing him not to answer, counsel?

MR. WRIGHT: Not yet if you can tell me why you think it's relevant to our allegation that absent a reasonable business arrangement with Seminole, the Pasco will be removed from service, I'll consider whether to allow him to answer.

MR. PERKO: It goes directly to your assertion that it will be removed from service. I'm trying to understand the import of that obligation.

MR. WRIGHT: What, in your mind, relates that an investment decision made a year and a half to a perspective decision to shut the plant down next December if we don't get a reasonable business agreement with Seminole?

MR. PERKO: Counsel, you made this allegation to explain Quantum Pasco Power, LP's interest in this litigation. This goes directly to that point and why such a removal of service -- what effect that would have Quantum Pasco Power.

MR. WRIGHT: I'm going to object to that on the grounds of relevance because our standing is not an issue by your own specification.

MR. PERKO: It goes to the voracity of the allegation, Counsel. Are you instructing him not to answer?

MR. WRIGHT: No. I'm going to let him

answer, but I object to the relevance of this whole line of questioning because standing -- our standing is not at issue here.

A Okay. Gary, to make I have it right, could you just --

Q (BY MR. PERKO) You can answer.

A Gary, so I can get it right, would you repeat the question one more time.

Q Certainly. Is it fair to say that Rockland factored the risk of not re-contracting the Pasco facility into the price paid for the Pasco facility?

A Yes, it is fair to say that.

Q If you can refer to Page 7 under the heading "Pasco Base Case." Is it fair to say that this states the assumptions that -- the base case assumptions that you made for your decision to acquire the Pasco facility?

A It's -- that's correct.

Q And it essentially states that you assume that the facility would continue to operate under the tolling agreement until -- I'm sorry, and then at the end of the tolling agreement in December 2018, it is assumed that the facility would be decommissioned; is that correct?

A That's correct.

Q Now, on the last sentence of that paragraph,

you state that -- or it states that based on the assumption -- "these assumptions, the investment in Pasco expected to yield a confidential IRR." That --

MR. WRIGHT: Gary, I object to these questions. These all have to do with the investment decision made a year and a half ago. They don't have anything to do with the allegation that we will close the plant down at the end of the December.

MR. PERKO: They absolutely do as to why that affects the interest of your client, which is something that you've alleged, Counsel, and I'm not disputing that your client is -- is -- has standing to participate. But I'm certainly entitled to inquire about the voracity of the allegations in your Motion to Intervene.

MR. WRIGHT: The allegation --

MR. PERKO: I do not --

MR. WRIGHT: The allegation is that absent a reasonable business agreement with Seminole, which obviously means going forward because we don't have one now, the Pasco facility will be removed from service.

The investment decision to acquire the ownership and the facility a year and a half ago does not go to that allegation.

Now, I'm going to let him answer.

MR. PERKO: It goes --

MR. WRIGHT: Gary, I'm going to let him answer. I object on relevance and I will renew that objection any time you ever try to bring this up again.

MR. PERKO: That's fine.

MR. WRIGHT: Okay.

A Okay. So Gary --

Q (BY MR. PERKO) So my question is -- I'm sorry.

A I was going to say, please repeat your question.

Q My question is -- well, my question -- I was just referring you to that sentence. My question is, what is meant by the term IRR? Is that Internal Rate of?

A That's what it means, Internal Rate of Return.

Q Okay. And then it provided a number. I'm not asking you what the number is, but I would ask that, is it fair to say that Rockland concluded that the expected yield of the IRR presented there was reasonable?

MR. WRIGHT: I continue to object on relevance. You can answer, Jim.

A It's low for us, so we were certainly hoping to do better.

Q (BY MR. PERKO) But the overall context of the deal, do you consider it reasonable?

MR. WRIGHT: Same objection as to relevance. Gary, if you can agree that I can maintain my objection to the relevance of these questions, I won't interpose on you; otherwise, I will.

MR. PERKO: Certainly, you can have a standing objection. I don't have much more on this.

A The answer is yes, Gary.

Q (BY MR. PERKO) Now, in the next paragraph, it talks about the Pasco re-contracting case and is it fair to say that you were discussing here the potential effects of the deal assuming that you were to receive a -- or to re-contract for the Pasco facility. It that fair?

A That's fair.

Q And in the last sentence of that paragraph, it states, "Based on these assumptions, under the Recontracting scenario Pasco is expected to yield a confidential IRR." Do you see that?

A I do.

Q And without going into what the number is, is it -- is it fair to say that it's more than twice the IRR for the base case?

A It is.

Q If I can refer you to Page 16. We're almost through here.

A Okay.

Q Under the paragraph headed "Operational/Performance Risk," do you see that?

A I do.

Q It states that, "Given both plants will be approaching the end of their contract terms during Rockland's ownership, Rockland will have to work closely with EthosEnergy (O&M provider for both projects) to monitor morale and workforce attrition, which could negatively impact plant performance." Do you see that?

A I do.

Q Is that a correct statement?

A Well, it was a correct statement and we have done those things.

Q You have done those things? I mean, "the effective morale," were you referring to the employees of EthosEnergy if the plant would shut down?

A That's correct.

Q I think I only have one more reference for this document I'd like to ask you about. It's on Page 32.

A Okay.

Q And it -- it states the historical

performance of the Pasco facility; is that correct?

MR. WRIGHT: Object to relevance. You can answer.

A I'm trying to make sure this is Pasco. Yes, that looks to be correct.

Q Okay. That lists the capacity factors?

A Correct.

Q Do you see it's for 2014, 2015 and 2016 year-to-date?

A Yes.

Q And it states in 2014, it was -- the capacity factor 16.4 percent; is that correct?

A Correct.

MR. WRIGHT: I am continuing my objection, Gary.

MR. PERKO: Understood.

Q (BY MR. PERKO) In 2015, it was 27.7 percent, the capacity factor; is that correct?

A That's correct.

Q And 2016 year-to-date as of that point, it was 8.6 percent capacity factor; is that correct?

A That's correct.

Q And would you consider those levels of capacity factors to be representative of piquing or intermediate low?

A Intermediate.

MR. WRIGHT: Same objection.

Q (BY MR. PERKO) Intermediate?

A Yes.

MR. WRIGHT: These are also -- I think these are also beyond the scope but I'll continue the relevance objection. Go ahead.

MR. PERKO: I'm exploring -- you alleged in Paragraph 11 that it would be removed from service from the Florida grid. I'm exploring what effect that might be.

MR. WRIGHT: Okay. Go ahead.

Q (BY MR. PERKO) I'm finished with that document, I believe. Mr. Maiz, were you able to get an e-mail -- or open an e-mail with another document that I asked counsel to provide to you for the deposition?

A I do have that e-mail.

MR. WRIGHT: Gary, is this -- is this Bates Page 84?

MR. PERKO: Yes.

MR. WRIGHT: Okay. Go ahead, Jim.

A Well --

Q (BY MR. PERKO) Can you -- I'm sorry.

A Bates Page 84, I've got to make sure I have the right one for you guys. Give me some guidance on

it. Which one is it? Describe it.

Q There are a series of e-mails from nFront consulting and this is in the middle of those. It's just one e-mail Bates Page 000084.

A Okay. Is it dated Friday, August 12? Is this the one.

Q Yes, sir, 11:34:21 a.m.?

A Yes, sir, I have that.

Q Do you have it in hard copy?

A I actually don't, so I'm looking at it on my computer screen. I didn't have that with me.

Q Okay. Well, could you explain to me what this document is?

A I -- I believe we had asked nFront to do some transmission analysis for us on Pasco to determine if it provided any critical ancillary benefits to the grid and also how efficient it was to serve different load serving entities in Florida.

Q So is it fair to say that this -- in this e-mail Mr. Kushner of nFront was providing the results of that analysis?

A At least in part, yes.

Q Okay. The second paragraph says, "The analysis indicates that Pasco provides no significant benefit to the transmission system as there are no

voltage issues or thermal overloads in the area with or without the units dispatched."

It goes on to state, "Related to the scope item addressing methods to providing the transmission benefits that Pasco may provide, since there are no regional issue, there is no benefit to be gained by other means." Do you see that?

A I do.

Q Do you have any reason to question the results of the analysis presented there in those two sentences?

A No. That -- that did not surprise me. I would expect that to be the case for most power plants.

Q Okay. Mr. Maiz, you mentioned that the TECO expires in January of 2018 -- I'm sorry, December 2018; is that correct?

A Correct.

Q Were there efforts to -- to extend or renew or replace that agreement with TECO?

A Yes.

Q And do you know why TECO was unwilling to enter or extend a new contract?

A It's my understanding TECO has already set forth how it's going to meet its needs over the next ten years and that did not include Pasco.

Q Do you know why it didn't include Pasco?

A From the point of our ownership forward, the conversations that I've had have led me to believe that their plans were already made before my ownership and did not include Pasco.

Q In response to -- to our interrogatories, it was Quantum Pasco Power's statement that it had responded to an RFP issued Duke Energy Florida October 8th, 2013 and the response was December of 2013. Do you recall that?

A We didn't own it at the time but, yes, I remember providing that response.

Q Do you know why Duke Energy Florida did not select Quantum as a result of that RFP?

A I do not.

Q And have there been any efforts to enter into a contract for the Quantum output with any other Florida utilities, such as Florida Power & Light?

A Not on our behalf. Not -- not since -- not during our ownership.

Q And why is that?

A The analysis that we conducted before we bought the facility, which is largely done by nFront, concluded there were no other opportunities with those other load serving entities.

Q Well, I just have a couple of more questions. Now, is it your understanding that Quantum will receive a contract from Seminole if these needs of terminations are denied?

A That is not my understanding.

Q Okay. And why is that?

A Why is that? I -- I don't -- the two aren't necessarily directly connected.

Q Okay. So is it your understanding that a -- a new process would have to be followed to determine what, if any, power purchase agreements would be entered into by Seminole?

A I do not know what Seminole's process would be.

Q Okay. But it would take some time, would you agree?

A I don't know how long it would take Seminole to do those things. It wouldn't take me long.

Q You're not a regulated electric utility, are you, sir?

A No. No. No. I meant if they --

MR. WRIGHT: I object to that because it presents facts not in evidence, regulating electric facility, but go ahead. You can answer.

A I was not trying to be smart. I was saying

that as an entity, we can respond quickly. I don't know how long it will take Seminole to go through another process.

Q (BY MR. PERKO) Fair enough. And I apologize for any offense. Let me just look through my notes here. I think I may be close to finished.

(Brief pause.)

MR. PERKO: I have nothing further.

MR. WRIGHT: We have no cross and we will read and sign.

MS. DZIECHCIARZ: I have no questions.

(The deposition concluded at 3:10 p.m.)

CHANGES AND SIGNATURE

PAGE	LINE	CHANGE	REASON

I, JAMES MAIZ, have read the foregoing deposition and hereby affix my signature that same is true and correct, except as noted.

_____

JAMES MAIZ

THE STATE OF_____)

THE COUNTY OF_____)

Before me,_____, on this day personally appeared JAMES MAIZ, known to me (or proved to me under oath or through _____) (description of identity card or other document) to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that they executed the same for the purposes and consideration therein expressed.

Given under my hand and seal of office this day of _____, _____.

_____

NOTARY PUBLIC IN AND FOR

THE STATE OF_____

MY COMMISSION EXPIRES:

_____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition to determine combined cycle facility, by Seminole Electric Cooperative, Inc.) DOCKET NO. 20170266-EC

In Re: Joint Petition to determine need for the Shady Hills combined cycle facility, by Seminole Electric Cooperative, Inc. and Shady Hills Energy Center, LLC) DOCKET NO. 20170267-ec

DATED: February 27, 2018

****

REPORTER'S CERTIFICATION

ORAL AND TELEPHONIC DEPOSITION OF JAMES MAIZ

March 6, 2018

I, Bonnie L. Rodriguez, Certified Shorthand Reporter in and for the State of Texas, hereby certify to the following:

That the witness, JAMES MAIZ, was duly sworn by the officer and that the transcript of the oral and telephonic deposition is a true record of the testimony given by the witness;

That the deposition transcript was submitted on _____, to the witness or to the attorney for the witness for examination, signature and return to me by _____;

That the amount of time used by each party at the deposition is as follows:

MR. GARY PERKO - 0 Hours, 35 Minutes

That pursuant to information given to the deposition officer at the time said testimony was taken, the following includes counsel for all parties of record:

MR. GARY PERKO, Attorney for Petitioner

MR. ROBERT SCHEFFELL WRIGHT, Attorney for Respondent

I further certify that I am neither counsel for, related to, nor employed by any of the parties or attorneys in the action in which this proceeding was taken and further that I am not financially or otherwise interested in the outcome of the action.

Further certification requirements pursuant to Rule 203 of TRCP will be certified to after they have occurred.

Certified to by me this 9th day of March,2018.



Bonnie L. Rodriguez, CSR
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FURTHER CERTIFICATION UNDER RULE 203 TRCP

The original deposition/signature page was/was not returned to the deposition officer on _____;

If returned, the attached Changes and Signature page contains any changes and the reasons therefor;

If returned, the original deposition was delivered to _____, Custodial Attorney;

That $_____ is the deposition officer's charges to the Plaintiff for preparing the original deposition transcript and any copies of exhibits;

That the deposition was delivered in accordance with Rule 203.3, and that a copy of this certificate was served on all parties shown herein on _____ and filed with the Clerk.

Certified to by me this_____day of_____, _____.

_____

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March 9, 2018
James Maiz
c/o Robert S. Wright
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL, 32308
rwright@gbwlegal.com
RE: In Re: Petition To Determine Need For Seminole Combined Cycle Facility, By Seminole Electric Cooperative, Inc.
Dear Mr. Wright:
With reference to the deposition of James Maiz taken on 3/6/2018 in connection with the above-captioned case, please be advised that the transcript of the deposition has been completed and is awaiting signature.
Please have your client read the transcript and complete the errata page. Upon completion, please send the signed errata to our office at Two South Biscayne Blvd., Ste. 2250, Miami, FL, 33131, or email it to litsup-fla@veritext.com.

If this is not taken care of, however, within the next 30 days, we shall conclude that the reading and signing of the deposition has been waived and the original, which has already been forwarded to the ordering attorney, may be filed with the Clerk of the Court without further notice.
Sincerely,

Production Department
Veritext Florida

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FLORIDA RULES OF CIVIL PROCEDURE

Rule 1.310

(e) Witness Review. If the testimony is transcribed, the transcript shall be furnished to the witness for examination and shall be read to or by the witness unless the examination and reading are waived by the witness and by the parties. Any changes in form or substance that the witness wants to make shall be listed in writing by the officer with a statement of the reasons given by the witness for making the changes. The changes shall be attached to the transcript. It shall then be signed by the witness unless the parties waived the signing or the witness is ill, cannot be found, or refuses to sign. If the transcript is not signed by the witness within a reasonable time after it is furnished to the witness, the officer shall sign the transcript and state on the transcript the waiver, illness, absence of the witness, or refusal to sign with any reasons given therefor. The deposition may then be used as fully as though signed unless the court holds that the reasons given for the refusal to sign require rejection of

the deposition wholly or partly, on motion under rule 1.330(d)(4).

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Veritext Legal Solutions represents that the foregoing transcript is a true, correct and complete transcript of the colloquies, questions and answers as submitted by the court reporter. Veritext Legal Solutions further represents that the attached exhibits, if any, are true, correct and complete documents as submitted by the court reporter and/or attorneys in relation to this deposition and that the documents were processed in accordance with our litigation support and production standards.

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Deposition of Michael Ward, II, Pages 63, lines 2-14 and Page 64, lines 8-20**

(CONFIDENTIAL DN. 02381-2018)

**Deposition admissible as an exhibit during cross-examination of Mr. Ward, such that Petitioners can conduct redirect with respect to Intervenors' cross-examination, if sought.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 99
PARTY: STAFF'S EXHIBITS
DESCRIPTION: Michael P. Ward II

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 100
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL CPP, CC
Portfolio Revenue Requirement, by General

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 101
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL SGS debt service

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 102
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL 5.10.17
Board P2021 Wrokshop Excerpt

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 103
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL 7.12.17 P2021 Process update and recommended actions

CONFIDENTIAL

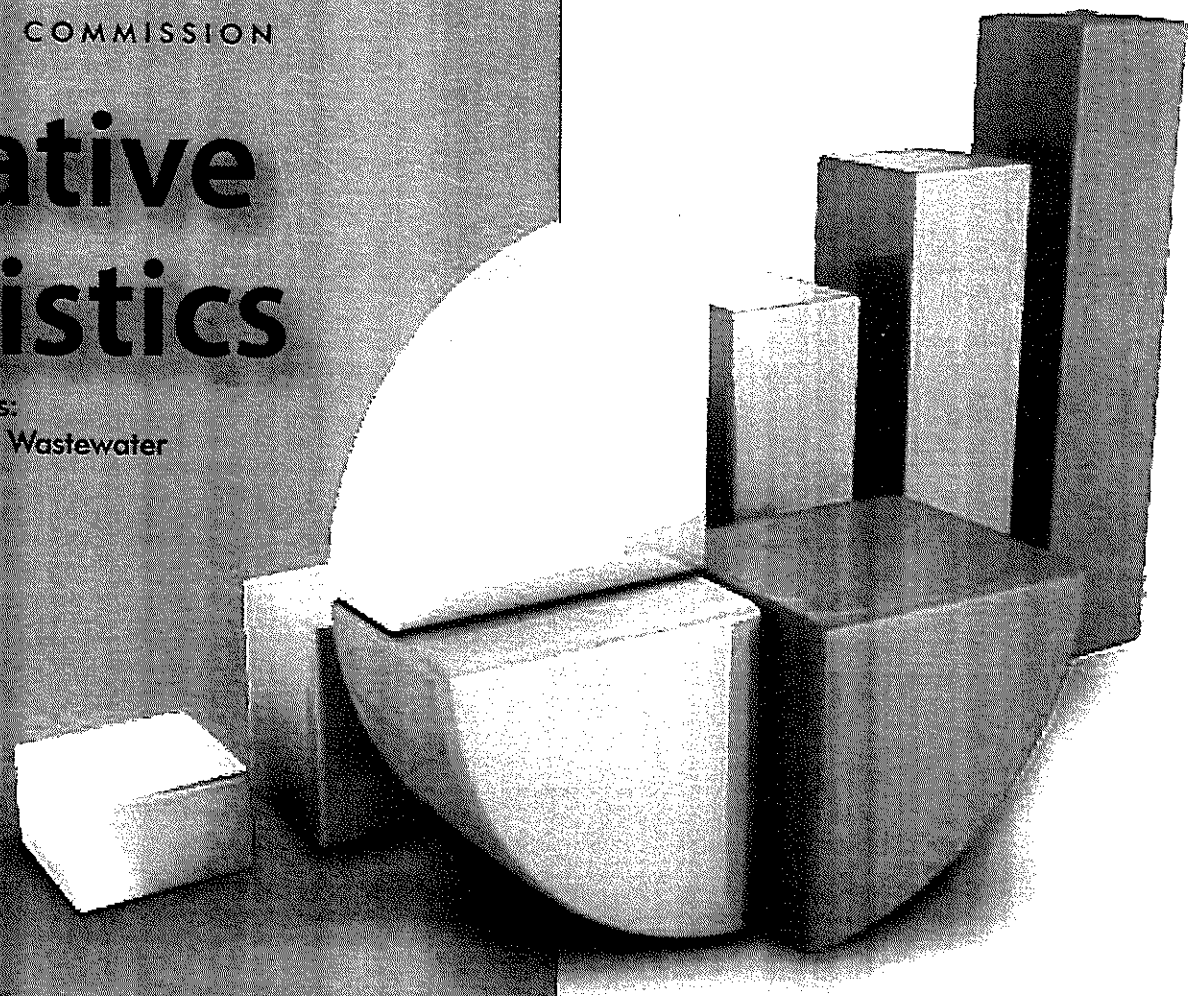
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 104
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL EXH 99, Pages 63 and 64

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 105
PARTY: Quantum, Daly, Tulk
DESCRIPTION: PSC Comparative Rate Statistics for Electric Utilities as of 12.13.16

FLORIDA PUBLIC SERVICE COMMISSION

Comparative Rate Statistics

Regulated Industries:
Electric ◆ Gas ◆ Water & Wastewater



AS OF DECEMBER 31, 2016

This report was prepared by the Florida Public Service Commission
from tariffs filed with the Florida Public Service Commission and information provided by the utilities.

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SECTION A
Regulated Electric Utilities

Investor-Owned Electric Utilities

Typical Electric Bill Comparisons* - Residential Service

December 31, 2016

Utility	Minimum Bill or Customer Charge	KWH					
		100	250	500	750	1,000	1,500
Florida Power & Light Company	$7.87	$16.01	$28.22	$48.59	$68.93	$89.27	$140.61
Duke Energy Florida, LLC	$8.76	$18.73	$33.70	$58.64	$83.55	$108.48	$170.17
Tampa Electric Company	$15.00	$23.85	$37.15	$59.29	$81.43	$103.56	$157.85
Gulf Power Company	$18.60	$29.97	$47.00	$75.41	$103.80	$132.19	$189.00
Florida Public Utilities Company							
Northwest	$14.00	$26.29	$44.71	$75.42	$106.12	$136.83	$210.75
Northeast	$14.00	$26.29	$44.71	$75.42	$106.12	$136.83	$210.75

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as a separate line item. Includes cost recovery clause factors effective December 2016.

Municipal Electric Utilities

Typical Electric Bill Comparisons* - Residential Service

December 31, 2016

Utility	Minimum Bill or Customer Charge	KWH					
		100	250	500	750	1,000	1,500
Alachua	$9.14	$19.58	$35.24	$61.34	$87.44	$113.54	$170.84
Bartow	$8.00	$19.74	$37.35	$66.68	$96.03	$125.36	$184.04
Blountstown	$3.50	$15.39	$33.21	$62.93	$92.64	$122.35	$181.78
Bushnell	$7.40	$18.47	$35.06	$62.73	$90.39	$118.05	$173.38
Chattahoochee	$6.50	$17.07	$32.92	$59.34	$85.76	$112.19	$165.03
Clewiston	$6.50	$16.34	$31.12	$55.72	$80.34	$104.94	$154.16
Fort Meade	$12.96	$24.12	$40.86	$68.76	$96.66	$124.56	$180.36
Fort Pierce	$6.01	$15.93	$30.82	$55.62	$80.43	$107.84	$162.66
Gainesville	$14.25	$25.55	$42.50	$70.75	$99.00	$130.40	$197.40
Green Cove Springs	$12.00	$22.30	$37.75	$63.50	$89.25	$115.00	$168.50
Havana	$6.00	$15.42	$29.56	$53.10	$76.66	$100.20	$147.30
Homestead	$5.60	$16.46	$32.76	$59.92	$87.07	$114.23	$168.55
JEA	$5.50	$15.80	$31.26	$57.00	$82.76	$108.50	$160.00
Jacksonville Beach	$4.50	$15.84	$32.85	$61.21	$89.56	$117.91	$174.62
Key West	$15.03	$25.56	$41.35	$67.68	$94.00	$120.33	$172.98
Kissimmee	$10.17	$19.01	$32.27	$54.37	$76.47	$98.57	$149.10
Lake Worth	$10.53	$20.95	$36.58	$62.63	$88.68	$114.73	$166.83
Lakeland	$9.50	$18.28	$31.44	$53.39	$75.33	$97.27	$143.97
Leesburg	$12.30	$21.58	$35.50	$58.69	$81.89	$105.09	$162.48
Moore Haven	$8.50	$17.79	$31.73	$54.95	$78.18	$101.40	$147.85
Mount Dora	$8.95	$18.91	$33.84	$58.73	$83.63	$108.52	$158.30
New Smyrna Beach	$5.65	$15.57	$30.43	$55.22	$80.00	$104.78	$154.35
Newberry	$7.50	$19.00	$36.25	$65.00	$93.75	$122.50	$180.00
Ocala	$9.33	$19.46	$34.66	$59.99	$85.31	$110.64	$161.30
Orlando	$8.00	$17.80	$32.51	$57.00	$81.51	$106.00	$165.00
Quincy	$6.00	$16.55	$32.38	$58.76	$85.14	$111.51	$164.27
Reedy Creek	$2.85	$12.96	$28.13	$53.39	$78.67	$103.93	$154.47
Starke	$0.00	$10.99	$27.47	$54.95	$82.41	$109.88	$172.60
St.Cloud	$8.32	$18.52	$33.80	$59.29	$84.76	$110.24	$171.61
Tallahassee	$7.41	$17.24	$31.99	$56.57	$81.15	$105.72	$154.88
Vero Beach	$8.33	$19.11	$35.27	$62.21	$89.15	$116.08	$169.96
Wauchula	$9.10	$18.74	$33.20	$57.30	$81.40	$105.50	$153.70
Williston	$8.00	$17.36	$31.41	$54.82	$78.23	$101.64	$148.46
Winter Park	$9.55	$18.85	$32.80	$56.05	$79.30	$102.54	$159.99

* Local taxes, franchise fees, and gross receipts taxes not embedded in rates are excluded. December 2016 Fuel and Purchased Power Costs are included.

Cooperative Electric Utilities

Typical Electric Bill Comparisons* - Residential Service

December 31, 2016

Utility	Minimum Bill or Customer Charge	KWH					
		100	250	500	750	1,000	1,500
Central Florida	$24.00	$34.00	$49.00	$74.00	$99.00	$124.00	$185.50
Choctawhatchee	$26.00	$35.09	$48.72	$71.44	$94.16	$116.87	$162.31
Clay	$20.00	$28.99	$42.48	$64.95	$87.43	$109.90	$164.25
Escambia River	$30.00	$40.60	$56.50	$83.00	$109.50	$136.00	$189.00
Florida Keys	$30.00	$36.72	$46.81	$63.62	$80.43	$97.24	$147.36
Glades	$45.00	$53.35	$65.88	$86.75	$107.63	$128.50	$189.00
Gulf Coast	$30.00	$38.71	$51.78	$73.55	$95.33	$117.10	$160.65
Lee County	$15.00	$23.75	$36.88	$56.15	$79.33	$102.50	$154.20
Okefenoke	$25.00	$34.17	$47.93	$70.85	$93.78	$116.70	$165.90
Peace River	$26.50	$36.51	$51.52	$76.53	$101.54	$126.56	$186.59
Sumter	$20.00	$29.26	$43.15	$66.30	$89.45	$112.60	$168.90
Suwannee Valley	$25.00	$34.60	$49.00	$73.00	$97.00	$121.00	$179.70
Talquin	$30.00	$39.35	$53.38	$76.75	$100.13	$123.50	$181.05
Tri-County	$22.00	$32.50	$48.25	$74.50	$100.75	$127.00	$189.50
West Florida	$24.95	$35.00	$50.07	$75.20	$100.32	$125.44	$185.46
Withlacoochee River	$30.00	$39.00	$52.49	$74.99	$97.48	$119.97	$166.09

* Local taxes, franchise fees, and gross receipts taxes not embedded in rates are excluded. December 2016 Fuel and Purchased Power Costs are included.

Investor-Owned Electric Utilities

Typical Electric Bill Comparisons * - Commercial / Industrial

December 31, 2016

Utility	KW Demand		75	150	500	1,000	2,000
	KWH						
	750	1,500	15,000	45,000	150,000	400,000	800,000
Florida Power & Light Company	$74	$141	$1,513	$3,718	$12,378	$28,928	$56,755
Duke Energy Florida, LLC	$88	$165	$1,315	$3,465	$11,523	$28,682	$57,352
Tampa Electric Company	$89	$160	$1,665	$4,154	$13,777	$33,212	$66,394
Gulf Power Company	$108	$194	$1,714	$4,555	$15,118	$35,991	$71,718
Florida Public Utilities Company							
Northwest	$118	$214	$1,890	$5,256	$17,407	$44,434	$88,738
Northeast	$118	$214	$1,890	$5,256	$17,407	$44,434	$88,738

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as a separate line item. Includes cost recovery clause factors effective December 2016.

Municipal Electric Utilities

Typical Electric Bill Comparisons* - Commercial / Industrial

December 31, 2016

Utility	KW Demand		75	150	500	1,000	2,000
	KWH						
	750	1,500	15,000	45,000	150,000	400,000	800,000
Alachua	$94	$176	$1,814	$4,799	$15,891	$39,846	$79,646
Bartow	$107	$205	$2,054	$5,460	$18,154	$45,434	$90,848
Blountstown	$107	$207	$2,004	$5,997	$19,975	$53,255	$106,503
Bushnell	$100	$193	$1,985	$5,350	$17,780	$44,893	$89,763
Chattahoochee	$92	$177	$2,009	$5,223	$17,353	$44,560	$89,094
Clewiston	$98	$182	$1,713	$4,786	$15,858	$41,018	$81,994
Fort Meade	$111	$206	$1,901	$5,442	$18,042	$44,902	$89,762
Fort Pierce	$88	$171	$1,724	$4,586	$17,184	$41,381	$82,723
Gainesville	$134	$238	$2,388	$6,325	$20,850	$51,250	$102,150
Green Cove Springs	$95	$179	$1,903	$4,970	$16,450	$38,125	$76,025
Havana	$77	$147	$1,419	$4,245	$14,136	$37,686	$75,366
Homestead	$95	$182	$1,919	$5,209	$17,280	$43,898	$87,760
JEA	$82	$156	$1,715	$4,345	$14,286	$35,567	$70,799
Jacksonville Beach	$91	$176	$2,140	$5,751	$19,133	$48,160	$96,304
Key West	$108	$187	$2,011	$5,209	$17,144	$42,744	$85,394
Kissimmee	$86	$160	$1,724	$4,393	$14,513	$35,646	$71,236
Lake Worth	$106	$196	$2,325	$6,124	$20,226	$50,736	$101,392
Lakeland	$77	$142	$1,475	$3,756	$12,826	$30,457	$60,534
Leesburg	$89	$165	$1,791	$4,271	$14,594	$33,498	$69,964
Moore Haven	$88	$168	$1,708	$4,379	$14,519	$35,644	$71,254
Mount Dora	$84	$158	$1,361	$3,675	$12,202	$30,871	$61,721
New Smyrna Beach	$79	$152	$1,855	$4,992	$15,686	$39,606	$79,178
Newberry	$101	$195	$2,007	$5,241	$17,435	$41,045	$82,045
Ocala	$88	$164	$1,618	$4,360	$14,801	$36,678	$73,332
Orlando	$88	$165	$1,602	$4,147	$13,753	$33,247	$66,419
Quincy	$96	$176	$1,451	$3,933	$12,970	$33,152	$61,683
Reedy Creek	$115	$228	$1,535	$4,070	$13,521	$33,824	$67,628
Starke	$102	$195	$1,868	$5,586	$18,599	$49,581	$99,153
St.Cloud	$91	$172	$1,666	$4,313	$14,303	$34,578	$69,078
Tallahassee	$73	$136	$1,806	$4,318	$14,146	$33,331	$66,593
Vero Beach	$95	$181	$1,798	$4,980	$16,507	$42,470	$84,900
Wauchula	$100	$173	$1,720	$4,621	$15,250	$38,735	$77,405
Williston	$88	$161	$1,567	$4,275	$13,970	$35,170	$70,290
Winter Park	$86	$159	$1,394	$3,812	$12,675	$32,247	$64,481

* Local taxes, franchise fees, and gross receipts taxes not embedded in rates are excluded. December 2016 Fuel and Purchased Power Costs are included.

Cooperative Electric Utilities

Typical Electric Bill Comparisons* - Commercial / Industrial

December 31, 2016

Utility	KW Demand		75	150	500	1,000	2,000
	KWH						
	750	1,500	15,000	45,000	150,000	400,000	800,000
Central Florida	$99	$174	$1,925	$4,997	$16,424	$40,549	$80,999
Choctawhatchee	$90	$154	$1,450	$3,809	$11,958	$30,179	$60,315
Clay	$94	$168	$1,567	$4,216	$13,865	$35,390	$67,285
Escambia River	$113	$195	$1,993	$5,240	$17,350	$43,350	$86,650
Florida Keys	$92	$154	$1,431	$4,142	$13,637	$36,226	$72,378
Glades	$126	$198	$2,025	$5,175	$16,900	$42,150	$84,150
Gulf Coast	$99	$166	$1,831	$4,419	$14,635	$35,743	$71,443
Lee County	$86	$153	$1,533	$4,019	$12,369	$30,054	$60,084
Okefenoke	$96	$168	$1,652	$4,159	$13,535	$33,560	$66,980
Peace River	$115	$204	$1,816	$4,579	$14,463	$35,098	$70,046
Sumter	$95	$168	$1,550	$4,108	$13,565	$34,165	$68,275
Suwannee Valley	$102	$179	$1,733	$4,637	$15,460	$38,010	$75,770
Talquin	$100	$181	$1,656	$4,585	$15,470	$35,392	$70,484
Tri-County	$113	$203	$1,935	$4,830	$15,750	$38,750	$77,350
West Florida	$100	$185	$1,759	$4,801	$15,885	$43,708	$87,316
Withlacoochee River	$98	$165	$1,484	$3,931	$13,022	$32,667	$65,299

* Local taxes, franchise fees, and gross receipts taxes not embedded in rates are excluded. December 2016 Fuel and Purchased Power Costs are included.

Investor-Owned Electric Utilities

Miscellaneous Service Charges

December 31, 2016

Utility	Initial Connect (1)	Normal Reconnect (2)	Violation Reconnect (3)	Collection Charge (4)	Late Payment Fee (5)	Returned Check Charge (6) and/or (8)	Temporary Service (7)	
							Underground	Overhead
Florida Power & Light Company	$14.88	$14.88	$17.66	$5.11	$5.00 or 1.5%	$25.00 $30.00 $40.00 or 5%	$175.00	$297.00
Duke Energy Florida, LLC								
During Hours	$61.00	$28.00	$40.00	N/A	$5.00 or 1.5%	$25.00 $30.00 $40.00 or 5%	$227.00	$227.00
After Hours			$50.00					
Tampa Electric Company	$75.00	$28.00	$55.00	$25.00	$5.00 or 1.5%	$25.00 $30.00 $40.00 or 5%	$260.00	$260.00
Gulf Power Company								
During Hours	$27.00	$27.00	$60.00	$30.00	None	$25.00 $30.00 $40.00 or 5%	$110.00	$110.00
After Hours			$80.00					
Florida Public Utilities Company								
During Hours	$61.00	$26.00	$52.00	$16.00	$5.00 or 1.5%	$25.00 $30.00 $40.00 or 5%	$200.00	$230.00
After Hours			$178.00					

(1) Initial connection of service to premises without prior service.

(2) Connection of service to premises with prior service.

(3) Reconnection of service during normal business hours to customer who has been disconnected due to nonpayment or violation of Commission rule, e.g., meter tampering, bad check, etc.

(4) Collection charge made in the event a service representative visits the premises for the purpose of disconnecting for nonpayment, and the customer pays or arranges to pay the past due amount in lieu of disconnection.

(5) Late payment fee is assessed to amounts that are past due. The fee may be either a fixed amount or a percentage of the past due amount, whichever is greater.

(6) Returned check charge is assessed when a check is dishonored by the bank. The charge may be either a fixed amount or a percentage of the dishonored check amount, whichever is greater.

(7) Charge for installing and removing a temporary service drop.

(8) In accordance with Section 68.065, Florida Statutes, the following charges apply to returned checks: $25.00 charge for checks $50.00 or less, $30.00 charge for checks $50.01 - $300.00, and the greater of 5% or $40.00 for checks in excess of $300.00.

Investor-Owned Electric Utilities

Growth and Use Statistics

December 31, 2016

Utility	Residential				Annual Revenues				
	Average Annual Consumption		Number of Customers		Residential			Total Retail Operating	
	kWh	Percent Increase	As of 12/31/2016	Percent Increase	Total Revenue	Percent Increase	Avg. Revenue per kWh Sold (cents)	Revenue	Percent Increase
Florida Power & Light Company	13,699	-1.59%	4,284,159	1.34%	$5,946,128,515	-5.41%	10.13	$10,071,824,537	-5.84%
Duke Energy Florida, LLC	13,126	0.40%	1,543,967	0.49%	$2,413,415,753	-8.08%	11.91	$3,975,806,117	-10.51%
Tampa Electric Company	14,217	-0.13%	651,516	1.82%	$1,035,548,122	-0.45%	11.27	$1,964,465,874	-2.67%
Gulf Power Company	13,515	-1.39%	398,501	1.36%	$715,604,176	-2.56%	13.36	$1,278,534,802	-3.37%
Florida Public Utilities Company									
Northwest	12,054	-1.78%	10,190	0.64%	$19,103,267	-1.64%	15.54	$41,716,456	1.42%
Northeast	12,827	-0.50%	14,155	1.22%	$27,381,621	0.44%	15.15	$48,371,957	9.26%

Municipal & Cooperative Electric Utilities

Growth and Use Statistics

December 31, 2016

Utility	Residential				Annual Revenues				
	Average Annual Consumption		Number of Customers		Residential			Total Retail Operating	
	kWh	Percent Increase	As of 12/31/2016	Percent Increase	Total Revenue	Percent Increase	Avg. Revenue per kWh Sold (cents)	Revenue	Percent Increase
Municipals									
Gainesville Regional Utilities	9,747	2.40%	84,358	0.48%	$106,748,457	-3.34%	13.04	$241,241,112	-3.82%
JEA	13,335	1.03%	401,273	1.90%	$617,415,175	4.38%	11.54	$1,269,995,317	3.50%
City of Lakeland	14,178	0.79%	106,548	2.13%	$161,064,365	-3.22%	10.66	$291,556,519	-5.61%
Orlando Utilities Commission	11,820	-0.73%	169,527	2.53%	$220,839,187	1.13%	11.02	$561,820,616	-0.16%
City of Tallahassee	10,858	-1.50%	99,486	0.80%	$119,556,586	-6.37%	11.07	$250,791,482	-6.97%
Cooperatives									
Clay Electric	14,334	2.39%	153,621	7.70%	$254,639,345	0.14%	11.49	$352,818,919	-0.23%
Lee County Electric	13,708	-0.67%	193,355	1.26%	$273,673,026	-4.36%	10.33	$399,650,603	-2.64%
Withlacoochee River Electric	14,392	1.11%	190,432	1.23%	$317,399,961	-3.49%	11.63	$442,483,600	-3.39%

Note: Above revenues include fuel and purchased power costs.

1,000 kWh Residential Monthly Bills for All Florida Electric Utilities
December 31, 2016

Rank	Utility	Type	Total Bill
1	Florida Power & Light Company	I	$89.27
2	Florida Keys	C	$97.24
3	Lakeland	M	$97.27
4	Kissimmee	M	$98.57
5	Havana	M	$100.20
6	Moore Haven	M	$101.40
7	Williston	M	$101.64
8	Lee County	C	$102.50
9	Winter Park	M	$102.54
10	Tampa Electric Company	I	$103.56
11	Reedy Creek	M	$103.93
12	New Smyrna Beach	M	$104.78
13	Clewiston	M	$104.94
14	Leesburg	M	$105.09
15	Wauchula	M	$105.50
16	Tallahassee	M	$105.72
17	Orlando	M	$106.00
18	Fort Pierce	M	$107.84
19	Duke Energy Florida, LLC	I	$108.48
20	JEA	M	$108.50
21	Mount Dora	M	$108.52
22	Starke	M	$109.88
23	Clay	C	$109.90
24	St. Cloud	M	$110.24
25	Ocala	M	$110.64
26	Quincy	M	$111.51
27	Chattahoochee	M	$112.19
28	Sumter	C	$112.60

Rank	Utility	Type	Total Bill
29	Alachua	M	$113.54
30	Homestead	M	$114.23
31	Lake Worth	M	$114.73
32	Green Cove Springs	M	$115.00
33	Vero Beach	M	$116.08
34	Okefenoke	C	$116.70
35	Choctawhatchee	C	$116.87
36	Gulf Coast	C	$117.10
37	Jacksonville Beach	M	$117.91
38	Bushnell	M	$118.05
39	Withlacoochee River	C	$119.97
40	Key West	M	$120.33
41	Suwannee Valley	C	$121.00
42	Blountstown	M	$122.35
43	Newberry	M	$122.50
44	Talquin	C	$123.50
45	Central Florida	C	$124.00
46	Fort Meade	M	$124.56
47	Bartow	M	$125.36
48	West Florida	C	$125.44
49	Peace River	C	$126.56
50	Tri-County	C	$127.00
51	Glades	C	$128.50
52	Gainesville	M	$130.40
53	Gulf Power Company	I	$132.19
54	Escambia River	C	$136.00
55	Florida Public Utilities Company - Northeast Division	I	$136.83
56	Florida Public Utilities Company - Northwest Division	I	$136.83

I = Investor-owned M = Municipal C = Cooperative

Note: Rates do not include any local taxes, franchise fees, or separately billed gross receipts taxes.

EXHIBIT WITHDRAWN

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 106
PARTY: Quantum, Daly, Tulk
DESCRIPTION: Withlachoochee River Electric Cooperative Billing Statements

Not.

~~CONFIDENTIAL~~

EXHIBIT NO. 107

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: KEZELL / PETERS

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: BATES PAGES SECI001498-SECI001499 AND SECI001500-SECI001501

DOCUMENTS: E-MAILS PRODUCED IN RESPONSE TO QUANTUM'S POD #4

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 107
PARTY: Quantum, Daly, Tulk
DESCRIPTION: Emails produced in resonse to Quantum's 4th POD

From: Lisa Penzer on behalf of p2021 Administrator
To: p2021_docs@spmail.seminole-electric.com
Subject: FW: Market Alternative Team Meeting - Notes from 2/6
Date: Friday, February 17, 2017 8:41:40 AM

From: David Kezell
Sent: Friday, February 10, 2017 8:56 AM
To: Jason Peters - Marketing Employee; Robert DeMelo; Tim Nasello; Brian Broadstock; Joseph Clay; Michael Ward; Julia Diazgranados; Lewis Snyder; David Wagner - Marketing Employee; Michael Maroney; Hannah Long; Tim Rogers; p2021_docs@spmail.seminole-electric.com; p2021 Administrator; Mark Anderson - Marketing Employee; 'alan.taylor@sedwayconsulting.com'
Subject: RE: Market Alternative Team Meeting - Notes from 2/6

Jason,

Thanks for taking a first cut at further quantifying how we will "grade" the various portfolios with respect to the listed criteria. I think this version represents a significant improvement. Here are a few thoughts/questions:

1. Is the intent of having the ratings jump from 10 to 8 (or 7), to 4, to 1, etc. instead of allowing for a 10, 9, 8, 7, . . . 1 rating system to force greater distinction among the portfolios? I'm not sure I understand the logic behind the specific numbering selection and why it is not more granular.
2. Why is the member rate impact rating only looking at 2021 – 2025?
3. What is the effective difference between the Economic Rating and the Member Rate Impact Rating? (Is the former an NPV value and the latter $/kWh?)
4. We should probably have some discussion on the various weightings to make sure that we have consensus there.
5. I still think there are competing aspects of "operational flexibility" that perhaps should be broken out rather than lumped into one category. I would suggest breaking this element into two: fuel flexibility and system flexibility. Weighting could be divided according to potential impact on the business. I also think that fuel diversity could/should be measured as a distinct category

I have an all day meeting scheduled today so I may not make the meeting this afternoon with the E-team. I'll get there as soon as I can if I can wrap up the other meeting early. Thanks for your effort on this.

David

From: Jason Peters - Marketing Employee
Sent: Thursday, February 09, 2017 9:40 AM
To: Robert DeMelo; Tim Nasello; David Kezell; Brian Broadstock; Joseph Clay; Michael Ward; Julia Diazgranados; Lewis Snyder; David Wagner - Marketing Employee; Michael Maroney; Hannah Long; Glenn Spurlock; Tim Rogers; p2021_docs@spmail.seminole-electric.com; p2021 Administrator; Mark Anderson - Marketing Employee; 'alan.taylor@sedwayconsulting.com'
Subject: Market Alternative Team Meeting - Notes from 2/6

Good Morning Team:

I have attached an updated file with my talking points/notes from the meeting FYI.

Additionally, based on team feedback both within and without the meeting, I have attached a new version of the scorecard for your review. Please take a critical look at the "Criteria" section and bring your suggestions for revision/improvement to our next meeting (2/13). Note that I also added a section for the IE and suggested new weightings for the categories. I also provided sample values for 1 portfolio so you can see how it might work.

Finally, Mark A. will be in touch with updated SME assignments tomorrow.

Thank you. J

Jason Peters
Portfolio Director
Office: 813.739.1349
Cell: 813.335.0027



From: Lisa Penzer on behalf of p2021 Administrator
To: p2021_docs@spmail.seminole-electric.com
Subject: FW: Market Alternative Team Meeting - Notes from 1/26
Date: Monday, February 06, 2017 8:24:54 AM

From: David Kezell
Sent: Friday, January 27, 2017 2:50 PM
To: Jason Peters - Marketing Employee; Robert DeMelo; Tim Nasello; Brian Broadstock; Joseph Clay; Michael Ward; Julia Diazgranados; Lewis Snyder; David Wagner - Marketing Employee; Michael Maroney; Hannah Long; Glenn Spurlock; Tim Rogers; p2021_docs@spmail.seminole-electric.com; p2021 Administrator; Mark Anderson - Marketing Employee; 'alan.taylor@sedwayconsulting.com'
Cc: Daniel Noia - Marketing Employee
Subject: RE: Market Alternative Team Meeting - Notes from 1/26

Jason,

I have a few comments/observations/suggestions:

1. The six rating areas and their descriptions seem rather vaguely defined and open to significant subjective interpretation. I would suggest using specific rating metrics for each of the areas that are based on quantifiable elements. For example, for member rate impact one could use a score of 10 for 10% or more rate reduction, a score of 9 for 9-10% reduction, 8 or 8-9% reduction, etc. This way we have a specific, defined, quantified and traceable methodology behind the actual ratings.
2. I think the Member Rate Impact Rating weighting at 10% is too low. Seminole's mission is "to be the preferred provider" and part of our vision is "to be a leading competitor". We will not be preferred if we are not a leading competitor and member rates are the heart of that competitiveness characteristic. At the end of the day, we either focus on getting more competitive or we resign ourselves to the increasing risk of member dissatisfaction and defections. I would suggest that this weighting be increased.
3. I'm not sure that I understand the difference between Member Rate Impact Rating and the Economic Rating. If there is a way of quantifying them separately then perhaps they should remain separate but if we're using the generation planning model output as the measure for both, then perhaps they should be combined.
4. I think there are competing aspects of "operational flexibility" that should be broken out rather than lumped into one category. I would suggest breaking this element into two: fuel flexibility and system flexibility. Weighting could be divided according to potential impact on the business.
5. To my knowledge Seminole has never established an "owned vs. contracted" target. Without a target, grading this element for the various portfolios is almost meaningless. We have to have a basis for scoring. For example if we had a 70% owned, 30% contracted target we could score any portfolio between 69 & 71 owned as a 10, 67-68 & 72-73 as a 9, etc.
6. I think Fuel diversity should be its own category. The rating could easily be quantified based upon the fuel associated with each capacity resource.

I'd be happy to participate in a session to add some quantification rigor to the scorecard.

Thanks,

David

From: Jason Peters - Marketing Employee
Sent: Friday, January 27, 2017 8:15 AM
To: Robert DeMelo; Tim Nasello; David Kezell; Brian Broadstock; Joseph Clay; Michael Ward; Julia Diazgranados; Lewis Snyder; David Wagner - Marketing Employee; Michael Maroney; Hannah Long; Glenn Spurlock; Tim Rogers; p2021_docs@spmail.seminole-electric.com; p2021 Administrator; Mark Anderson - Marketing Employee; 'alan.taylor@sedwayconsulting.com'
Cc: Daniel Noia - Marketing Employee
Subject: Market Alternative Team Meeting - Notes from 1/26

Good Morning:

Attached is a new scorecard draft for the team's review.

Other items of note from the meeting:

1. Mark A. will issue a network transmission request with DEF for the Auburndale CT starting 1/22. I will talk with Calpine about a potential LOI to accommodate this.
2. Mark A. will issue a revised risk template today or Monday. Teams will review their prior ratings and provide any revisions back to Mark by 2/3.
3. SMEs will review risk summary for their areas and provide any feedback by 2/10.
4. I scheduled a risk review meeting with E-team on 3/6. Thanks to Mike W., Mike M. and Robert for volunteering to facilitate the meeting.
5. From our discussions...David's gas assumptions and Julie's initial PaR results are in the T drive for review.

Next meeting is on 2/6. Thanks! J

Jason Peters
Portfolio Director
Seminole Electric Cooperative, Inc.
Office: 813.739.1349
Cell: 813.335.0027



EXHIBIT NO. 108

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: HINES

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: PSC 2017 ANNUAL REPORT ON FEECA ACTIVITIES (EXCERPTS)

DOCUMENTS: COVER PAGE AND PAGES 1-3

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 108
PARTY: Quantum, Daly, Tulk
DESCRIPTION: PSC 2017 Annual Report on FEECA Activities

FLORIDA
PUBLIC
SERVICE
COMMISSION

FEECA

Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act

As Required by Sections 366.82(10), and 377.703(2)(f), and 553.975, Florida Statutes

DECEMBER 2017

Executive Summary

Purpose

Reducing the growth of Florida's peak electric demand and energy consumption became a statutory objective in 1980, with the enactment of the Florida Energy Efficiency and Conservation Act (FEECA). The Florida Energy Efficiency and Conservation Act emphasizes four key areas: reducing the growth rates of weather-sensitive peak demand and electricity usage, increasing the efficiency of the production and use of electricity and natural gas, encouraging demand-side renewable energy systems, and conserving expensive resources, particularly petroleum fuels. Section 366.82(2), F.S., requires the Florida Public Service Commission (FPSC or Commission) to establish goals over a ten year period for the FEECA utilities, and a re-evaluation review every five years. The utilities are required to develop and submit to the Commission for approval, cost-effective demand-side management (DSM) plans to achieve these goals.

The Commission is required by Section 366.82(10), F.S., to provide an annual report to the Florida Legislature and the Governor summarizing the adopted goals and the progress made toward achieving these goals. Similarly, Section 377.703(2)(f), F.S., requires the Commission to file information on electricity and natural gas energy conservation programs with the Department of Agriculture and Consumer Services. Pursuant to Section 366.82(10), F.S., this report on conservation results achieved by the FEECA utilities is due to the Florida Legislature and Governor by March 1, 2018. This report reviews the 2016 annual goal results for each of the seven FEECA electric utilities and fulfills these statutory obligations.

The seven electric utilities currently subject to FEECA are:

- Five Florida Investor-owned utilities (IOUs), ranked in order of sales
  - Florida Power & Light Company (FPL)
  - Duke Energy Florida, LLC (DEF)
  - Tampa Electric Company (TECO)
  - Gulf Power Company (Gulf)
  - Florida Public Utilities Company (FPUC)

- Two municipal utilities, ranked in order of sales
  - JEA
  - Orlando Utilities Commission (OUC)

The Commission regulates the electric rates and energy conservation cost recovery of the five IOUs. In contrast, the Commission does not regulate the rates or conservation program costs of the two municipal utilities for which it sets DSM goals.

Report Layout

This report presents the FEECA utilities' progress towards achieving the Commission-established goals and the Commission's efforts in overseeing these conservation initiatives. This report details these efforts through the following five sections and appendices:

Section 1 provides a brief history of FEECA, and a description of existing tools for increasing conservation throughout the State of Florida.

Section 2 discusses the most recent Commission-established goals set for the FEECA utilities.

Section 3 reviews the utilities' goal achievements and progress towards Low-Income and Research and Development programs.

Section 4 provides an overview of the associated program costs recovered through the Energy Conservation Cost Recovery Clause for 2016.

Section 5 discusses methods the Commission has used to educate consumers about conservation during the prior period, including a list of related web sites.

Appendices 1 and 2 provide a list of the currently-offered conservation programs and a description of each program's purpose.

Goal Setting Process for the Current Period

On November 25, 2014, the Commission approved winter and summer peak demand and annual energy savings goals for the seven FEECA electric utilities beginning in 2015 through 2024. The approved goals were based on the Rate Impact Measure (RIM) cost-effectiveness test. This test was used to ensure that all ratepayers benefit from energy efficiency programs due to downward pressure on electric rates. The Commission identified fewer cost-effective energy efficiency programs as a result of more stringent building codes and appliance efficiency standards. The higher the current efficiency standards and codes, the less opportunity there is for utility-sponsored programs to be cost-effective. Additionally, reduced utility avoided costs resulting from relatively low natural gas prices have contributed to fewer programs being cost-effective. For these reasons, the 2014 approved DSM goals for the FEECA utilities were lower than the Commission-approved goals in 2009. The 2014 goal setting process is discussed further in Section 2.

The November 2014 hearing also resulted in the Commission mandating, in its 2014 Goals Order, that a focus be placed on energy efficiency for low-income consumers. The Commission ordered "When the FEECA utilities file their DSM implementation plans, each plan should address how the utilities will assist and educate their low-income customers, specifically with respect to the measures with a two-year or less payback."[1] Further discussion of the utilities' low-income programs can be found in Section 3.

Following the Commission's establishment of the goals in late 2014, the FEECA utilities filed DSM plans designed to meet the Commission's goals. In mid 2015, the Commission approved each DSM plan. Subsequently, in late 2015, the utilities filed program standards which provide details on how each program will be administered. At the end of 2015, the Commission approved

[1] Order No. PSC-14-0696-FOF-EU, Docket Nos. 130199-EI through 130205-EI, In re: Commission review of numeric conservation goals, issued December 16, 2014.

the program standards, and the utilities implemented the new programs in late 2015 and early 2016. This report covers the first full year of the conservation programs in the utilities' 2015 DSM plans.

2016 Achievements and Related Program Costs

Since FEECA's inception, it is estimated that DSM programs offered by FEECA utilities have reduced summer peak demand by 7,813 megawatts (MW) and winter peak demand by 7,224 MW. In 2016, all of the FEECA utilities met the Commission's Annual goal of total reduction, with four utilities meeting the Commission's energy and demand savings goals for the residential and commercial/industrial (C/I) customer classes. Florida's FEECA electric utilities also performed over 190 thousand residential and commercial energy audits/evaluations and offered 110 residential and commercial programs focused on energy conservation.[2] Additional detail on each utility's performance is described in Section 3.

The Commission has authority by statute to allow investor-owned utilities to recover prudently incurred costs related to conservation.[3] The Commission has implemented this authority through the Energy Conservation Cost Recovery (ECCR) clause. The ECCR clause has been in existence since 1980. For 2016, Florida's investor-owned electric utilities recovered approximately $317 million in conservation program expenditures.

Conclusion

The potential demand and energy savings from utility-sponsored DSM programs are affected by consumer education and behavior, building codes, and appliance efficiency standards. Consumer actions to implement energy efficiency measures outside of utility programs, as well as codes and efficiency standards, create a baseline for a new program's cost-effectiveness and reduce the potential incremental electric demand and energy savings available from DSM programs.

Utilities design DSM programs to encourage conservation that exceeds levels set by current building codes and minimum efficiency standards. The level of savings from these types of programs is uncertain because it requires voluntary participation and in some cases changes in customer behavior. Because all customers pay for the utility conservation programs as a portion of their monthly utility bills, the Commission focuses on ensuring that all customers benefit from utility-sponsored DSM programs. Overall, reducing Florida's electric demand and energy usage relies on customer education, and participation in, utility DSM programs, along with each individual's efforts to save electricity.

Conservation and renewable energy will continue to play an important role in Florida's energy future. The Commission is continuing its efforts to encourage cost-effective conservation that defers the need for new generating capacity and reduces the use of fuel. These initiatives support a balanced mix of resources that reliably and cost-effectively meet the needs of Florida's ratepayers.

[2] 2016 FEECA utility demand-side management annual reports.
[3] Section 366.82(11), F.S.

EXHIBIT NO. 109

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: WOOD / HINES / WAGNER

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: FRCC 2017 LOAD & RESOURCE PLAN (EXCERPTS)

DOCUMENTS: COVER PAGE AND PAGES 31, 47-49

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 109
PARTY: Quantum, Daly, Tulk
DESCRIPTION: FRCC 2017 Load and Resource Plan

FRCC
Florida Reliability Coordinating Council, Inc.

2017
Regional Load & Resource Plan
FRCC-MS-PL-130
Version: 1

3000 Bayport Drive, Suite 600
Tampa, Florida 33607-8410
(813) 289-5644 - Phone
(813) 289-5646 - Fax
www.frcc.com

Classification: Public

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 10

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE					RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSIDE REGION (MW)	OUTSIDE REGION (MW)	REGIONAL IMPORTS (MW)	REGIONAL EXPORTS (MW)	FIRM NON-UTILITY PURCHASES (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	NET FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
2017	49,986	828	424	0	3,881	55,120	47,508	7,612	16%	44,586	10,534	24%
2018	49,484	828	424	0	3,928	54,664	48,042	6,622	14%	45,041	9,623	21%
2019	50,955	828	524	0	3,469	55,776	48,587	7,189	15%	45,533	10,243	22%
2020	51,213	828	624	0	3,484	56,149	48,947	7,202	15%	45,838	10,311	22%
2021	52,168	828	200	0	3,026	56,222	49,498	6,724	14%	46,332	9,890	21%
2022	53,862	828	200	0	3,031	57,921	49,984	7,937	16%	46,794	11,127	24%
2023	55,011	828	200	0	3,033	59,072	50,600	8,472	17%	47,384	11,688	25%
2024	55,619	828	200	0	2,007	58,654	51,264	7,390	14%	48,031	10,623	22%
2025	56,059	828	200	0	1,854	58,941	51,893	7,048	14%	48,658	10,283	21%
2026	56,284	828	200	0	1,717	59,028	52,525	6,503	12%	49,260	9,768	20%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE					RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSIDE REGION (MW)	OUTSIDE REGION (MW)	REGIONAL IMPORTS (MW)	REGIONAL EXPORTS (MW)	FIRM NON-UTILITY PURCHASES (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	NET FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
2017 / 18	52,751	829	424	0	4,154	58,158	44,836	13,322	30%	41,994	16,164	38%
2018 / 19	52,684	829	424	0	3,740	57,677	45,350	12,327	27%	42,462	15,215	36%
2019 / 20	54,505	829	524	0	3,756	59,614	45,769	13,845	30%	42,835	16,779	39%
2020 / 21	54,492	829	624	0	3,755	59,700	46,270	13,430	29%	43,285	16,415	38%
2021 / 22	55,304	829	200	0	3,214	59,547	46,659	12,888	28%	43,659	15,888	36%
2022 / 23	57,437	829	200	0	3,216	61,682	47,096	14,586	31%	44,066	17,616	40%
2023 / 24	57,872	829	200	0	2,661	61,561	47,535	14,026	30%	44,489	17,072	38%
2024 / 25	58,593	829	200	0	1,991	61,613	47,933	13,680	29%	44,881	16,732	37%
2025 / 26	58,832	829	200	0	1,874	61,735	48,356	13,379	28%	45,275	16,460	36%
2026 / 27	59,072	829	200	0	1,854	61,954	48,801	13,153	27%	45,689	16,265	36%

NOTE - COLUMN 11: NET FIRM PEAK DEMAND = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.0
FUEL REQUIREMENTS
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FUEL REQUIREMENTS		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	NUCLEAR		TRILLION BTU	321	310	308	317	316	315	321	316	316	321	316
(2)	COAL		1000 TON	17,543	19,165	15,427	14,060	14,471	14,946	15,099	15,217	15,405	13,769	13,991
	RESIDUAL													
(3)		STEAM	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
	DISTILLATE													
(7)		STEAM	1000 BBL	214	81	73	67	66	49	48	43	45	65	64
(8)		CC	1000 BBL	83	296	41	63	12	14	14	18	17	14	13
(9)		CT	1000 BBL	328	173	71	75	54	50	70	75	79	92	74
(10)		TOTAL:	1000 BBL	625	550	185	205	132	113	132	136	141	171	151
	NATURAL GAS													
(11)		STEAM	1000 MCF	99,950	74,422	67,632	63,471	61,232	54,770	56,556	51,838	55,261	54,828	54,388
(12)		CC	1000 MCF	944,748	930,358	982,550	1,005,642	1,002,622	1,006,737	1,009,172	1,026,073	1,031,561	1,067,817	1,082,158
(13)		CT	1000 MCF	30,940	21,589	21,883	20,865	19,952	22,629	24,094	21,625	27,238	28,919	30,650
(14)		TOTAL:	1000 MCF	1,075,638	1,026,369	1,072,065	1,089,978	1,083,806	1,084,136	1,089,822	1,099,536	1,114,060	1,151,564	1,167,196
(15)	OTHER	PET COKE	1000 TON	1,195	786	748	848	865	808	809	831	840	867	868
		LFG & BIOFUELS	1000 MMBTU	344	366	344	365	387	396	422	432	435	435	444

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.1
ENERGY SOURCES (GWH)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5) ACTUAL	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		GWH	7,816	2,320	3,933	3,127	2,264	2,774	2,854	2,828	2,711	2,703	2,870
(2)	NUCLEAR		GWH	29,052	29,017	28,842	29,686	29,581	29,419	30,038	29,569	29,491	30,046	29,577
(3)	COAL		GWH	38,606	43,019	34,820	31,369	32,771	33,710	33,844	33,948	34,653	30,843	31,423
	RESIDUAL													
(4)		STEAM	GWH	446	154	34	92	10	3	1	1	1	6	8
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL:	GWH	446	154	34	92	10	3	1	1	1	6	8
	DISTILLATE													
(8)		STEAM	GWH	55	22	20	20	19	18	17	15	15	16	16
(9)		CC	GWH	154	271	54	72	32	30	25	25	34	33	30
(10)		CT	GWH	138	80	36	43	24	27	29	32	25	31	22
(11)		TOTAL:	GWH	347	373	110	135	75	75	71	72	74	80	68
	NATURAL GAS													
(12)		STEAM	GWH	9,482	7,508	6,909	6,552	6,286	5,672	5,830	5,391	5,688	5,654	5,600
(13)		CC	GWH	134,967	135,630	144,360	149,693	150,625	150,054	150,188	152,191	153,201	158,493	160,560
(14)		CT	GWH	2,834	1,977	2,072	1,995	1,881	2,107	2,208	1,978	2,520	2,694	2,858
(15)		TOTAL:	GWH	147,283	145,115	153,341	158,240	158,792	157,833	158,226	159,560	161,409	166,841	169,018
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES													
(17)		BIOFUELS	GWH	20	24	24	24	24	24	24	24	24	24	24
(18)		BIOMASS	GWH	885	708	954	1,111	1,121	1,118	1,114	1,148	1,078	1,052	1,095
(19)		HYDRO	GWH	21	14	14	14	14	14	14	14	14	14	14
(20)		LANDFILL GAS	GWH	344	512	475	398	424	432	450	439	453	475	487
(21)		MSW	GWH	1,451	1,432	1,420	1,421	1,428	1,422	1,422	1,422	1,426	1,181	1,085
(22)		SOLAR	GWH	310	888	2,455	2,973	4,093	5,109	6,069	7,026	7,922	8,212	8,458
(23)		WIND	GWH	0	0	0	0	0	0	0	0	0	0	0
(24)		OTHER RENEW.	GWH	14	16	16	16	16	16	16	16	16	16	16
(25)		TOTAL:	GWH	3,045	3,594	5,358	5,957	7,120	8,135	9,109	10,089	10,933	10,974	11,179
(26)	OTHER		GWH	7,448	7,276	6,969	6,911	7,408	7,604	7,669	7,871	7,268	6,947	6,805
(27)	NET ENERGY FOR LOAD		GWH	234,043	230,868	233,407	235,517	238,021	239,553	241,812	243,938	246,540	248,440	250,948

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.2
ENERGY SOURCES (%)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5) ACTUAL	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		%	3.34%	1.00%	1.69%	1.33%	0.95%	1.16%	1.18%	1.16%	1.10%	1.09%	1.14%
(2)	NUCLEAR		%	12.41%	12.57%	12.36%	12.60%	12.43%	12.28%	12.42%	12.12%	11.96%	12.09%	11.79%
(3)	COAL		%	16.50%	18.63%	14.92%	13.32%	13.77%	14.07%	14.00%	13.92%	14.06%	12.41%	12.52%
	RESIDUAL													
(4)		STEAM	%	0.19%	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	0.19%	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(9)		CC	%	0.07%	0.12%	0.02%	0.03%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(10)		CT	%	0.06%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(11)		TOTAL:	%	0.15%	0.16%	0.05%	0.06%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
	NATURAL GAS													
(12)		STEAM	%	4.05%	3.25%	2.96%	2.78%	2.64%	2.37%	2.41%	2.21%	2.31%	2.28%	2.23%
(13)		CC	%	57.67%	58.75%	61.85%	63.56%	63.28%	62.64%	62.11%	62.39%	62.14%	63.80%	63.98%
(14)		CT	%	1.21%	0.86%	0.89%	0.85%	0.79%	0.88%	0.91%	0.81%	1.02%	1.08%	1.14%
(15)		TOTAL:	%	62.93%	62.86%	65.70%	67.19%	66.71%	65.89%	65.43%	65.41%	65.47%	67.16%	67.35%
(16)	NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	RENEWABLES													
(17)		BIOFUELS	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(18)		BIOMASS	%	0.38%	0.31%	0.41%	0.47%	0.47%	0.47%	0.46%	0.47%	0.44%	0.42%	0.44%
(19)		HYDRO	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(20)		LANDFILL GAS	%	0.15%	0.22%	0.20%	0.17%	0.18%	0.18%	0.19%	0.18%	0.18%	0.19%	0.19%
(21)		MSW	%	0.62%	0.62%	0.61%	0.60%	0.60%	0.59%	0.59%	0.58%	0.58%	0.48%	0.43%
(22)		SOLAR	%	0.13%	0.38%	1.05%	1.26%	1.72%	2.13%	2.51%	2.88%	3.21%	3.31%	3.37%
(23)		WIND	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(24)		OTHER RENEW.	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(25)		TOTAL:	%	1.30%	1.56%	2.30%	2.53%	2.99%	3.40%	3.77%	4.14%	4.43%	4.42%	4.45%
(26)	OTHER		%	3.18%	3.15%	2.99%	2.93%	3.11%	3.17%	3.17%	3.23%	2.95%	2.80%	2.71%
(27)	NET ENERGY FOR LOAD		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%



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2017
Regional Load & Resource Plan
FRCC-MS-PL-130
Version: 1

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FRCC-MS-PL-130	2017 Regional Load & Resource Plan	Version 1

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TITLE	NAME	DATE
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FLORIDA RELIABILITY COORDINATING COUNCIL
2017
REGIONAL LOAD & RESOURCE PLAN
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Introduction
FRCC Regional Load & Resource Plan

The Florida Reliability Coordinating Council (FRCC) annual Regional Load & Resource Plan (L&RP) is a collection of historical and forecasted planning information from electric utilities within the FRCC Region and the State of Florida. Data provided by the electric utilities is reflective of data contained in each of their annual Ten Year Site Plan (TYSP) and/or their internal integrated resource planning documents. Section 186.801(1) of the Florida Statutes requires each electric utility within the State of Florida to submit to the Florida Public Service Commission (FPSC) a TYSP that estimates its power-generating needs and the general location of proposed power plant sites[1]. The Statute also states "TYSP shall be reviewed and submitted not less frequently than every 2 years".

There are three components to the L&RP: the Regional section, the State section, and the Merchant section. The Regional and State sections of the L&RP are developed from data collected from the FRCC Load and Resource Database (LRDB). Since Merchants within the FRCC do not have access to the LRDB portal, FRCC Staff collects information from Merchants through an Excel workbook survey.

The L&RP is reviewed by the FRCC Resource Subcommittee (RS), FRCC Transmission Technical Subcommittee (TTS), FRCC Load Forecasting Working Group (LFWG), and the FRCC LRDB users group before it is finalized. FRCC Staff mails copies of the L&RP to the FPSC each year as well as members of certain FRCC committees, subcommittees, working groups, and user groups. The Plan is also posted to the FRCC website.

A high-level summary of information contained in each year's Plan is presented by the FRCC to the FPSC at its annual TYSP Workshop (at a minimum), and is usually expanded to include other items of interest to the Commission. The Workshop is usually scheduled during the month of September each year.

Annual reports that are compiled (in part or whole) from data extracted from the L&RP are the EIA 411 Survey, the FRCC Load & Resource Reliability Assessment Report to the FPSC, and FRCC submissions to NERC including the FRCC Summer Assessments, the FRCC Winter Assessment, and the FRCC Long-Term Reliability Assessment. As new standards are developed, data extracted from the L&RP may be used to compile other reports to fulfill new requirements.

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[1] Some exemptions apply. Refer to FPSC Rule 25-22.071 (Submission and Review of the Ten-Year Site Plans).

FLORIDA RELIABILITY COORDINATING COUNCIL

2017

REGIONAL LOAD & RESOURCE PLAN

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND (MW)					WINTER PEAK DEMAND (MW)					ENERGY	
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2007	46,525				2007 / 08	41,495				2007	232,863	57.1%
2008	44,706				2008 / 09	45,590				2008	226,852	57.9%
2009	46,260				2009 / 10	51,767				2009	225,964	55.8%
2010	45,564				2010 / 11	45,876				2010	233,158	51.4%
2011	44,777				2011 / 12	38,318				2011	223,875	55.7%
2012	43,946				2012 / 13	36,733				2012	220,875	57.4%
2013	44,549				2013 / 14	38,842				2013	221,564	56.8%
2014	45,794				2014 / 15	42,597				2014	224,724	56.0%
2015	45,716				2015 / 16	37,881				2015	234,434	58.5%
2016	47,671				2016 / 17	36,682				2016	234,043	56.0%

YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2017	47,508	474	2,448	44,586	2017 / 18	44,836	459	2,383	41,994	2017	230,868	55.5%
2018	48,042	503	2,498	45,041	2018 / 19	45,350	475	2,413	42,462	2018	233,407	55.5%
2019	48,587	520	2,534	45,533	2019 / 20	45,769	493	2,441	42,835	2019	235,517	55.3%
2020	48,947	540	2,569	45,838	2020 / 21	46,270	515	2,470	43,285	2020	238,021	55.5%
2021	49,498	562	2,604	46,332	2021 / 22	46,659	502	2,498	43,659	2021	239,553	55.2%
2022	49,984	556	2,634	46,794	2022 / 23	47,096	502	2,528	44,066	2022	241,812	55.2%
2023	50,600	550	2,666	47,384	2023 / 24	47,535	490	2,556	44,489	2023	243,938	55.0%
2024	51,264	537	2,696	48,031	2024 / 25	47,933	466	2,586	44,881	2024	246,540	54.9%
2025	51,893	511	2,724	48,658	2025 / 26	48,356	466	2,615	45,275	2025	248,440	54.7%
2026	52,525	511	2,754	49,260	2026 / 27	48,801	467	2,645	45,689	2026	250,948	54.5%

NOTE: FORECASTED SUMMER AND WINTER DEMANDS ARE NON-COINCIDENT.

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 4.0
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL										
YEAR	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	STREET & HIGHWAY LIGHTING GWH	OTHER SALES GWH	TOTAL SALES GWH	WHOLESALE PURCHASES FOR RESALE GWH	WHOLESALE SALES FOR RESALE GWH	UTILITY USE & LOSSES GWH	AGGREGATION ADJUSTMENT GWH	NET ENERGY FOR LOAD GWH
2007	111,029	7,972,577	13,926	78,798	980,139	80,395	21,215	35,830	592,102	813	5,410	217,265	0	9,335	13,972	-7,709	232,863
2008	107,076	7,976,527	13,424	78,243	982,682	79,622	20,408	29,845	683,800	806	5,385	211,918	0	9,596	13,171	-7,833	226,852
2009	108,089	7,963,401	13,573	76,978	979,643	78,578	19,084	27,347	697,846	814	5,382	210,347	0	6,325	13,722	-4,430	225,964
2010	113,220	7,949,627	14,242	76,174	977,541	77,924	19,030	26,772	710,817	832	5,365	214,621	0	7,497	15,959	-4,919	233,158
2011	108,105	7,986,541	13,536	76,410	984,046	77,649	18,744	26,911	696,518	825	5,340	209,424	0	6,736	11,716	-4,001	223,875
2012	104,109	8,040,087	12,949	77,046	994,125	77,501	17,891	25,712	695,823	820	5,351	205,217	0	6,229	12,878	-3,449	220,875
2013	105,038	8,133,269	12,915	79,473	1,006,868	78,931	15,347	20,451	750,428	814	5,297	205,969	0	5,755	12,755	-2,915	221,564
2014	106,463	8,145,799	13,070	79,488	1,013,907	78,398	15,374	21,399	718,445	802	5,444	207,571	0	9,201	11,762	-3,810	224,724
2015	112,373	8,274,599	13,580	82,098	1,022,399	80,299	15,557	22,457	692,746	832	5,736	216,596	0	10,576	12,407	-5,145	234,434
2016	113,095	8,390,275	13,479	82,289	1,035,629	79,458	15,418	22,788	676,584	823	5,700	217,325	0	11,033	11,134	-5,449	234,043
2007-2016 % AAGR	0.21%			0.48%			-3.48%										0.06%
2017	111,196	8,533,238	13,031	81,960	1,052,032	77,906	15,431	23,753	649,644	824	5,686	215,097	0	9,588	10,787	-4,604	230,868
2018	112,515	8,667,796	12,981	82,815	1,065,809	77,702	15,666	24,232	646,500	817	5,718	217,531	0	9,122	11,166	-4,412	233,407
2019	113,380	8,802,002	12,881	83,463	1,079,383	77,325	15,918	24,595	647,205	813	5,780	219,354	0	9,027	11,474	-4,338	235,517
2020	114,662	8,933,820	12,835	84,279	1,092,607	77,136	16,201	24,861	651,663	812	5,839	221,793	0	8,981	11,567	-4,320	238,021
2021	115,339	9,063,083	12,726	84,936	1,105,281	76,846	16,305	25,053	650,820	811	5,882	223,273	0	8,508	11,482	-3,710	239,553
2022	116,579	9,191,170	12,684	85,727	1,118,072	76,674	16,264	25,209	645,166	814	5,939	225,323	0	8,109	11,693	-3,313	241,812
2023	117,583	9,318,408	12,618	86,522	1,130,599	76,528	16,353	25,363	644,758	815	5,995	227,268	0	8,225	11,805	-3,360	243,938
2024	118,853	9,444,523	12,584	87,366	1,142,586	76,463	16,372	25,507	641,863	814	6,055	229,460	0	7,888	12,124	-2,932	246,540
2025	120,095	9,568,904	12,551	88,187	1,154,293	76,399	16,320	25,650	636,257	812	6,113	231,527	0	7,994	11,906	-2,987	248,440
2026	121,257	9,691,533	12,512	88,934	1,165,774	76,288	16,388	25,788	635,489	811	6,174	233,564	0	8,105	12,303	-3,024	250,948
2017-2026 % AAGR	0.97%			0.91%			0.67%										0.93%

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 5.0

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	SUMMER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		SUMMER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2015	45,716	0	71	0	240	2,198	1,338	49,563
2016	47,671	0	75	0	238	2,265	1,372	51,621
2017	44,586	474	1,397	1,051	457	2,319	1,405	51,689
2018	45,041	503	1,428	1,070	419	2,373	1,432	52,266
2019	45,533	520	1,447	1,087	420	2,420	1,459	52,886
2020	45,838	540	1,464	1,105	419	2,463	1,487	53,316
2021	46,332	562	1,480	1,124	419	2,503	1,513	53,933
2022	46,794	556	1,495	1,139	419	2,543	1,538	54,484
2023	47,384	550	1,511	1,155	419	2,580	1,564	55,163
2024	48,031	537	1,525	1,171	419	2,618	1,589	55,890
2025	48,658	511	1,538	1,186	419	2,657	1,614	56,583
2026	49,260	511	1,552	1,202	419	2,695	1,637	57,276
CAAGR (%):	1.11%							

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 6.0

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	WINTER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		WINTER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2015/16	37,881	0	96	0	221	2,363	688	41,249
2016/17	36,682	0	88	0	251	2,409	703	40,133
2017/18	41,994	459	1,602	781	419	2,461	728	48,444
2018/19	42,462	475	1,622	791	420	2,500	743	49,013
2019/20	42,835	493	1,640	801	419	2,538	757	49,483
2020/21	43,285	515	1,658	812	419	2,574	775	50,038
2021/22	43,659	502	1,676	822	419	2,607	788	50,473
2022/23	44,066	502	1,696	832	419	2,639	806	50,960
2023/24	44,489	490	1,714	842	419	2,673	822	51,449
2024/25	44,881	466	1,733	853	419	2,704	839	51,895
2025/26	45,275	466	1,752	863	419	2,738	856	52,369
2026/27	45,689	467	1,771	874	419	2,768	873	52,861
CAAGR (%):	**0.94%**							

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 7.0

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWH)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
		ENERGY REDUCTION						
YEAR	NET ENERGY FOR LOAD	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	CUMULATIVE CONSERVATION RESIDENTIAL	CUMULATIVE CONSERVATION COMM./IND.	TOTAL ENERGY FOR LOAD
2015	234,434	0	0	0	1,424	5,169	4,062	245,090
2016	234,043	0	0	0	1,517	5,275	4,162	244,998
2017	230,868	0	0	9	2,470	5,362	4,246	242,956
2018	233,407	0	0	9	2,469	5,444	4,311	245,641
2019	235,517	0	0	9	2,469	5,530	4,374	247,900
2020	238,021	0	0	10	2,470	5,614	4,440	250,556
2021	239,553	0	0	10	2,459	5,697	4,504	252,224
2022	241,812	0	0	10	2,459	5,780	4,570	254,632
2023	243,938	0	0	10	2,459	5,863	4,636	256,907
2024	246,540	0	0	10	2,460	5,945	4,703	259,659
2025	248,440	0	0	10	2,459	6,029	4,773	261,712
2026	250,948	0	0	10	2,459	6,109	4,841	264,368
CAAGR (%):	0.93%							

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF INTERRUPTIBLE LOAD AND LOAD MANAGEMENT (MW)
2017 THROUGH 2026

SUMMER

YEAR	DEF			FPL		JEA	SEC		TAL		TEC		FRCC TOTALS			FRCC TOTAL INT + LM
	INT	RES LM	COM LM	RES LM	COM LM	INT	INT	RES LM	RES LM	COM LM	INT	COM LM	INT	RES LM	COM LM	
2017	225	372	78	952	869	106	33	73	0	3	110	101	474	1,397	1,051	2,922
2018	255	378	82	970	881	106	34	75	5	5	108	102	503	1,428	1,070	3,001
2019	272	384	87	977	892	106	34	76	10	6	108	102	520	1,447	1,087	3,054
2020	292	390	91	984	903	106	34	77	13	8	108	103	540	1,464	1,105	3,109
2021	314	396	95	990	915	106	34	78	16	10	108	104	562	1,480	1,124	3,166
2022	316	402	99	996	926	106	39	79	18	10	95	104	556	1,495	1,139	3,190
2023	316	408	103	1,003	937	106	33	80	20	10	95	105	550	1,511	1,155	3,216
2024	303	414	108	1,010	947	106	34	81	20	10	94	106	537	1,525	1,171	3,233
2025	276	420	112	1,016	958	106	34	82	20	10	95	106	511	1,538	1,186	3,235
2026	276	426	116	1,023	969	106	34	83	20	10	95	107	511	1,552	1,202	3,265

WINTER

YEAR	DEF			FPL		JEA	SEC		TAL		TEC		FRCC TOTALS			FRCC TOTAL INT + LM
	INT	RES LM	COM LM	RES LM	COM LM	INT	INT	RES LM	RES LM	COM LM	INT	COM LM	INT	RES LM	COM LM	
2017/18	230	694	78	806	605	106	31	102	0	0	92	98	459	1,602	781	2,842
2018/19	246	706	82	812	610	106	31	104	0	0	92	99	475	1,622	791	2,888
2019/20	264	718	86	817	615	106	31	105	0	0	92	100	493	1,640	801	2,934
2020/21	284	730	91	822	621	106	32	106	0	0	93	100	515	1,658	812	2,985
2021/22	285	742	95	827	626	106	32	107	0	0	79	101	502	1,676	822	3,000
2022/23	285	754	99	833	632	106	31	109	0	0	80	101	502	1,696	832	3,030
2023/24	274	766	103	838	637	106	31	110	0	0	79	102	490	1,714	842	3,046
2024/25	250	778	107	844	643	106	31	111	0	0	79	103	466	1,733	853	3,052
2025/26	250	790	112	849	648	106	31	113	0	0	79	103	466	1,752	863	3,081
2026/27	250	802	116	855	654	106	32	114	0	0	79	104	467	1,771	874	3,112

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF EXISTING CAPACITY
AS OF DECEMBER 31, 2016

UTILITY	NET CAPABILITY (MW) SUMMER	WINTER
DUKE ENERGY FLORIDA	8,323	9,447
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION INC	0	0
FLORIDA MUNICIPAL POWER AGENCY	1,283	1,323
FLORIDA POWER & LIGHT COMPANY	26,139	27,828
FORT PIERCE UTILITIES AUTHORITIES	0	0
GAINESVILLE REGIONAL UTILITIES	521	550
HOMESTEAD ENERGY SERVICES	32	32
JEA	3,769	4,110
KEY WEST UTILITY BOARD	37	37
KISSIMMEE UTILITY AUTHORITY	242	253
LAKE WORTH UTILITIES CITY OF	77	80
LAKELAND CITY OF	844	890
NEW SMYRNA BEACH UTILITIES COMMISSION OF	44	48
OCALA UTILITY SERVICES	0	0
ORLANDO UTILITIES COMMISSION	1,482	1,528
REEDY CREEK IMPROVEMENT DISTRICT	55	55
SEMINOLE ELECTRIC COOPERATIVE INC	2,012	2,178
ST CLOUD CITY OF	0	0
TALLAHASSEE CITY OF	746	822
TAMPA ELECTRIC COMPANY	4,337	4,728
US CORPS OF ENGINEERS - MOBILE	44	44
VERO BEACH CITY OF	0	0
FRCC EXISTING CAPACITY (DECEMBER 31)	49,986	53,952
FRCC EXISTING CAPACITY (SUMMER 17, WINTER 17/18)	50,814	53,580
FIRM NON-UTILITY PURCHASES (DECEMBER 31)	4,156	4,446
FIRM NON-UTILITY PURCHASES (SUMMER 17, WINTER 17/18)	3,881	4,154
TOTAL FRCC EXISTING (DECEMBER 31)	**54,142**	**58,398**
TOTAL FRCC EXISTING (SUMMER 17, WINTER 17/18)	**54,695**	**57,734**

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD				SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
DUKE ENERGY FLORIDA															
ANCLOTE	1	PASCO	ST	NG	PL	---	---	0	10 / 1974	--- / ----	522.0	538.0	508.0	524.0	OP
ANCLOTE	2	PASCO	ST	NG	PL	---	---	0	10 / 1978	--- / ----	520.0	538.0	505.0	524.0	OP
AVON PARK	P1	HIGHLANDS	GT	NG	PL	DFO	TK	3	12 / 1968	6 / 2020	24.0	25.0	24.0	25.0	OP
AVON PARK	P2	HIGHLANDS	GT	DFO	TK	---	---	0	12 / 1968	6 / 2020	24.0	25.0	24.0	25.0	OP
BAYBORO	P1	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	--- / ----	44.0	56.0	44.0	56.0	OP
BAYBORO	P2	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	--- / ----	41.0	52.0	41.0	52.0	OP
BAYBORO	P3	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	--- / ----	43.0	55.0	43.0	55.0	OP
BAYBORO	P4	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	--- / ----	43.0	54.0	43.0	54.0	OP
CRYSTAL RIVER	1	CITRUS	ST	BIT	RR	BIT	WA	0	10 / 1966	4 / 2018	348.0	358.0	324.0	332.0	OP
CRYSTAL RIVER	2	CITRUS	ST	BIT	RR	BIT	WA	0	11 / 1969	4 / 2018	462.0	469.0	442.0	448.0	OP
CRYSTAL RIVER	4	CITRUS	ST	BIT	WA	BIT	RR	0	12 / 1982	--- / ----	769.0	767.0	712.0	721.0	OP
CRYSTAL RIVER	5	CITRUS	ST	BIT	WA	BIT	RR	0	10 / 1984	--- / ----	767.0	778.0	710.0	721.0	OP
DEBARY	P2	VOLUSIA	GT	DFO	TK	---	---	0	3 / 1976	--- / ----	48.0	64.0	48.0	64.0	OP
DEBARY	P3	VOLUSIA	GT	DFO	TK	---	---	0	12 / 1975	--- / ----	50.0	63.0	50.0	63.0	OP
DEBARY	P4	VOLUSIA	GT	DFO	TK	---	---	0	4 / 1976	--- / ----	50.0	63.0	50.0	63.0	OP
DEBARY	P5	VOLUSIA	GT	DFO	TK	---	---	0	12 / 1975	--- / ----	50.0	63.0	50.0	63.0	OP
DEBARY	P6	VOLUSIA	GT	DFO	TK	---	---	0	4 / 1976	--- / ----	51.0	67.0	51.0	63.0	OP
DEBARY	P7	VOLUSIA	GT	NG	PL	DFO	TK	8	10 / 1992	--- / ----	79.0	97.0	79.0	97.0	OP
DEBARY	P8	VOLUSIA	GT	NG	PL	DFO	TK	0	10 / 1992	--- / ----	78.0	96.0	78.0	96.0	OP
DEBARY	P9	VOLUSIA	GT	NG	PL	DFO	TK	0	10 / 1992	--- / ----	80.0	97.0	80.0	97.0	OP
DEBARY	P10	VOLUSIA	GT	DFO	TK	---	---	0	10 / 1992	--- / ----	75.0	95.0	75.0	95.0	OP
HIGGINS	P1	PINELLAS	GT	NG	PL	---	---	0	3 / 1969	6 / 2020	20.0	25.0	20.0	25.0	EO
HIGGINS	P2	PINELLAS	GT	NG	PL	---	---	0	4 / 1969	6 / 2020	25.0	25.0	25.0	25.0	EO
HIGGINS	P3	PINELLAS	GT	NG	PL	---	---	0	12 / 1970	6 / 2020	31.0	36.0	31.0	36.0	EO
HIGGINS	P4	PINELLAS	GT	NG	PL	DFO	TK	0	1 / 1971	6 / 2020	31.0	35.0	31.0	35.0	EO
HINES ENERGY COMPLEX	1GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 1999	--- / ----	143.0	174.0	142.0	174.0	OP
HINES ENERGY COMPLEX	1GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 1999	--- / ----	146.0	174.0	145.0	174.0	OP
HINES ENERGY COMPLEX	1ST	POLK	CA	WH	NA	DFO	TK	0	4 / 1999	--- / ----	162.0	186.0	158.0	180.0	OP
HINES ENERGY COMPLEX	2GT1	POLK	CT	NG	PL	DFO	TK	0	12 / 2003	--- / ----	151.0	186.0	151.0	186.0	OP
HINES ENERGY COMPLEX	2GT2	POLK	CT	NG	PL	DFO	TK	0	12 / 2003	--- / ----	151.0	186.0	151.0	186.0	OP
HINES ENERGY COMPLEX	2ST	POLK	CA	WH	NA	DFO	TK	0	12 / 2003	--- / ----	180.0	197.0	175.0	191.0	OP
HINES ENERGY COMPLEX	3GT1	POLK	CT	NG	PL	DFO	TK	0	11 / 2005	--- / ----	150.0	186.0	150.0	186.0	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
DUKE ENERGY FLORIDA (cont.)															
HINES ENERGY COMPLEX	3GT2	POLK	CT	NG	PL	DFO	TK	0	11 / 2005	--- / -----	151.0	186.0	151.0	186.0	OP
HINES ENERGY COMPLEX	3ST	POLK	CA	WH	NA	DFO	TK	0	11 / 2005	--- / -----	177.0	198.0	170.0	192.0	OP
HINES ENERGY COMPLEX	4GT1	POLK	CT	NG	PL	DFO	TK	0	12 / 2007	--- / -----	146.0	182.0	146.0	182.0	OP
HINES ENERGY COMPLEX	4GT2	POLK	CT	NG	PL	DFO	TK	0	12 / 2007	--- / -----	148.0	182.0	148.0	182.0	OP
HINES ENERGY COMPLEX	4ST	POLK	CA	WH	NA	DFO	TK	0	12 / 2007	--- / -----	168.0	188.0	160.0	180.0	OP
INTERCESSION CITY	P1	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	47.0	63.0	47.0	63.0	OP
INTERCESSION CITY	P2	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	46.0	61.0	46.0	61.0	OP
INTERCESSION CITY	P3	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	46.0	63.0	46.0	63.0	OP
INTERCESSION CITY	P4	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	46.0	62.0	46.0	62.0	OP
INTERCESSION CITY	P5	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	45.0	61.0	45.0	61.0	OP
INTERCESSION CITY	P6	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	--- / -----	47.0	62.0	47.0	62.0	OP
INTERCESSION CITY	P7	OSCEOLA	GT	NG	PL	DFO	PL	5	10 / 1993	--- / -----	78.0	94.0	78.0	94.0	OP
INTERCESSION CITY	P8	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / -----	79.0	95.0	79.0	95.0	OP
INTERCESSION CITY	P9	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / -----	79.0	95.0	79.0	95.0	OP
INTERCESSION CITY	P10	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / -----	78.0	95.0	78.0	95.0	OP
INTERCESSION CITY	P11	OSCEOLA	GT	DFO	PL	---	---	0	1 / 1997	--- / -----	141.0	161.0	0.0	161.0	OP
INTERCESSION CITY	P12	OSCEOLA	GT	NG	PL	DFO	PL	5	12 / 2000	--- / -----	73.0	92.0	73.0	92.0	OP
INTERCESSION CITY	P13	OSCEOLA	GT	NG	PL	DFO	PL	0	12 / 2000	--- / -----	75.0	92.0	75.0	92.0	OP
INTERCESSION CITY	P14	OSCEOLA	GT	NG	PL	DFO	PL	0	12 / 2000	--- / -----	72.0	95.0	72.0	92.0	OP
P. L. BARTOW	4AGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / -----	184.0	184.0	183.0	183.0	OP
P. L. BARTOW	4BGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / -----	181.0	181.0	180.0	180.0	OP
P. L. BARTOW	4CGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / -----	188.0	188.0	187.0	187.0	OP
P. L. BARTOW	4DGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / -----	185.0	185.0	184.0	184.0	OP
P. L. BARTOW	4ST	PINELLAS	CA	WH	NA	DFO	TK	0	6 / 2009	--- / -----	402.0	402.0	386.0	386.0	OP
P. L. BARTOW	P1	PINELLAS	GT	DFO	WA	---	---	0	5 / 1972	--- / -----	41.0	52.0	41.0	52.0	OP
P. L. BARTOW	P2	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 1972	--- / -----	41.0	57.0	41.0	57.0	OP
P. L. BARTOW	P3	PINELLAS	GT	DFO	WA	---	---	0	6 / 1972	--- / -----	41.0	53.0	41.0	53.0	OP
P. L. BARTOW	P4	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 1972	--- / -----	45.0	61.0	45.0	61.0	OP
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	PL	DFO	TK	9	10 / 1980	--- / -----	49.0	67.0	49.0	67.0	OP
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO	TK	---	---	0	10 / 1980	--- / -----	50.0	66.0	50.0	66.0	OP
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	PL	DFO	TK	0	11 / 1980	--- / -----	50.0	67.0	50.0	67.0	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
DUKE ENERGY FLORIDA (cont.)															
TIGER BAY	1GT	POLK	CT	NG	PL	---	---	0	8 / 1997	--- / -----	130.0	160.0	130.0	160.0	OP
TIGER BAY	1ST	POLK	CA	WH	NA	---	---	0	8 / 1997	--- / -----	73.0	74.0	70.0	71.0	OP
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	NG	PL	---	---	0	1 / 1994	--- / -----	48.0	49.0	47.0	48.0	OP
										DEF TOTAL (Excluding Solar):			8,323.0	9,447.0	
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION INC															
MARATHON	1	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1988	--- / -----	2.0	2.0	2.0	2.0	SB
MARATHON	2	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1988	--- / -----	2.0	2.0	2.0	2.0	SB
MARATHON	3	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1955	--- / -----	2.5	2.5	2.5	2.5	SB
MARATHON	6	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1973	--- / -----	2.5	2.5	2.5	2.5	SB
MARATHON	7	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1973	--- / -----	2.5	2.5	2.5	2.5	SB
MARATHON	8	MONROE	IC	DFO	TK	RFO	TK	0	1 / 1998	--- / -----	3.5	3.5	3.5	3.5	SB
MARATHON	9	MONROE	IC	DFO	TK	RFO	TK	0	1 / 2001	--- / -----	3.5	3.5	3.5	3.5	SB
										FKE TOTAL:			0.0	0.0	
FLORIDA MUNICIPAL POWER AGENCY															
CANE ISLAND *	1GT	OSCEOLA	GT	NG	PL	DFO	TK	0	11 / 1994	--- / -----	17.5	19.0	17.5	19.0	OP
CANE ISLAND *	2CT	OSCEOLA	CT	NG	PL	DFO	TK	0	6 / 1995	--- / -----	35.5	37.5	34.5	36.5	OP
CANE ISLAND *	2CW	OSCEOLA	CA	WH	NA	DFO	---	0	6 / 1995	--- / -----	22.0	22.0	20.0	20.0	OP
CANE ISLAND *	3CT	OSCEOLA	CT	NG	PL	DFO	TK	0	1 / 2002	--- / -----	77.0	81.0	75.0	79.0	OP
CANE ISLAND *	3CW	OSCEOLA	CA	WH	NA	DFO	---	0	1 / 2002	--- / -----	47.5	48.5	45.0	46.0	OP
CANE ISLAND	4CT	OSCEOLA	CT	NG	PL	---	---	0	7 / 2011	--- / -----	154.0	159.0	150.0	155.0	OP
CANE ISLAND	4CW	OSCEOLA	CA	WH	NA	---	---	0	7 / 2011	--- / -----	153.0	158.0	150.0	155.0	OP
INDIAN RIVER *	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / -----	14.2	18.0	12.2	14.1	OP
INDIAN RIVER *	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / -----	14.2	18.0	12.2	14.1	OP
INDIAN RIVER *	C	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / -----	22.3	26.2	21.6	23.0	OP
INDIAN RIVER *	D	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / -----	22.3	26.2	21.6	23.0	OP
ST. LUCIE *	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / -----	86.2	89.6	86.2	89.6	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
FLORIDA MUNICIPAL POWER AGENCY (cont.)															
STANTON *	1	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	--- / -----	114.8	114.8	114.8	114.8	OP
STANTON *	2	ORANGE	ST	BIT	RR	---	---	0	6 / 1996	--- / -----	125.9	125.9	125.1	125.1	OP
STANTON A *	CT	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / -----	11.3	12.6	11.3	12.6	OP
STANTON A *	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / -----	10.0	10.0	10.0	10.0	OP
STOCK ISLAND	CT2	MONROE	GT	DFO	WA	---	---	0	9 / 1999	--- / -----	15.9	15.9	15.9	15.9	OP
STOCK ISLAND	CT3	MONROE	GT	DFO	WA	---	---	0	9 / 1999	--- / -----	14.1	14.1	14.1	14.1	OP
STOCK ISLAND	CT4	MONROE	GT	DFO	WA	---	---	0	6 / 2006	--- / -----	46.0	46.0	46.0	46.0	OP
TREASURE COAST ENERGY CTR	1	ST. LUCIE	CT	NG	PL	DFO	TK	0	6 / 2008	--- / -----	154.0	159.0	150.0	155.0	OP
TREASURE COAST ENERGY CTR	1	ST. LUCIE	CA	WH	NA	DFO	RR	0	6 / 2008	--- / -----	153.0	158.0	150.0	155.0	OP
											FMPA TOTAL:		1,283.0	1,322.8	
FLORIDA POWER & LIGHT COMPANY															
CAPE CANAVERAL	3A	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / -----	246.3	288.6	246.3	288.6	OP
CAPE CANAVERAL	3B	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / -----	246.3	288.6	246.3	288.6	OP
CAPE CANAVERAL	3C	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / -----	246.3	288.6	246.3	288.6	OP
CAPE CANAVERAL	3ST	BREVARD	ST	NG	PL	DFO	TK	4	4 / 2013	--- / -----	488.1	521.2	471.1	504.2	OP
CEDAR BAY	1	DUVAL	ST	BIT	RR	---	---	0	1 / 1994	1 / 2017	250.0	250.0	250.0	250.0	OP
FT. MYERS	1	LEE	GT	DFO	WA	---	---	0	5 / 1974	--- / -----	54.2	61.7	54.0	61.5	OP
FT. MYERS	9	LEE	GT	DFO	WA	---	---	0	5 / 1974	--- / -----	54.2	61.7	54.0	61.5	OP
FT. MYERS	2CTA	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2CTB	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2CTC	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2CTD	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2CTE	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2CTF	LEE	CT	NG	PL	---	---	0	6 / 2002	--- / -----	179.4	200.0	179.4	200.0	OP
FT. MYERS	2ST1	LEE	CA	WH	NA	---	---	0	6 / 2002	--- / -----	60.0	68.0	60.0	68.0	OP
FT. MYERS	2ST2	LEE	CA	WH	NA	---	---	0	6 / 2002	--- / -----	409.6	456.0	387.6	434.0	OP
FT. MYERS	3CTA	LEE	CT	NG	PL	DFO	TK	7	6 / 2001	--- / -----	182.6	200.6	182.0	200.0	OP
FT. MYERS	3CTB	LEE	CT	NG	PL	DFO	TK	7	6 / 2001	--- / -----	182.6	200.6	182.0	200.0	OP
FT. MYERS	3CTC	LEE	CT	NG	PL	DFO	TK	7	12 / 2016	--- / -----	211.6	222.6	211.0	222.0	OP
FT. MYERS	3CTD	LEE	CT	NG	PL	DFO	TK	7	12 / 2016	--- / -----	211.6	222.6	211.0	222.0	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
FLORIDA POWER & LIGHT COMPANY (cont.)															
LAUDERDALE	3	BROWARD	GT	NG	PL	DFO	TK	3	8 / 1970	--- / ----	34.4	37.3	34.3	37.2	OP
LAUDERDALE	5	BROWARD	GT	NG	PL	DFO	TK	3	8 / 1970	--- / ----	34.4	37.3	34.3	37.2	OP
LAUDERDALE	4GT1	BROWARD	CT	NG	PL	DFO	TK	2	5 / 1993	12 / 2018	156.0	172.1	156.0	172.1	OP
LAUDERDALE	4GT2	BROWARD	CT	NG	PL	DFO	TK	2	5 / 1993	12 / 2018	156.0	172.1	156.0	172.1	OP
LAUDERDALE	4ST	BROWARD	CA	NG	PL	DFO	TK	2	10 / 1957	12 / 2018	135.0	148.8	130.0	143.8	OP
LAUDERDALE	5GT1	BROWARD	CT	NG	PL	DFO	TK	2	6 / 1993	12 / 2018	156.0	172.1	156.0	172.1	OP
LAUDERDALE	5GT2	BROWARD	CT	NG	PL	DFO	TK	2	6 / 1993	12 / 2018	156.0	172.1	156.0	172.1	OP
LAUDERDALE	5ST	BROWARD	CA	NG	PL	DFO	TK	2	4 / 1958	12 / 2018	135.0	148.8	130.0	143.8	OP
LAUDERDALE	6CTA	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ----	211.6	222.6	211.0	222.0	OP
LAUDERDALE	6CTB	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ----	211.6	222.6	211.0	222.0	OP
LAUDERDALE	6CTC	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ----	211.6	222.6	211.0	222.0	OP
LAUDERDALE	6CTD	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ----	211.6	222.6	211.0	222.0	OP
LAUDERDALE	6CTE	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ----	211.6	222.6	211.0	222.0	OP
MANATEE	1	MANATEE	ST	NG	PL	RFO	WA	21	10 / 1976	--- / ----	841.0	851.6	809.0	819.0	OP
MANATEE	2	MANATEE	ST	NG	PL	RFO	WA	21	12 / 1977	--- / ----	841.0	851.6	809.0	819.0	OP
MANATEE	3CTA	MANATEE	CT	NG	PL	---	---	0	6 / 2005	--- / ----	164.0	190.1	164.0	190.1	OP
MANATEE	3CTB	MANATEE	CT	NG	PL	---	---	0	6 / 2005	--- / ----	164.0	190.1	164.0	190.1	OP
MANATEE	3CTC	MANATEE	CT	NG	PL	---	---	0	6 / 2005	--- / ----	164.0	190.1	164.0	190.1	OP
MANATEE	3CTD	MANATEE	CT	NG	PL	---	---	0	6 / 2005	--- / ----	164.0	190.1	164.0	190.1	OP
MANATEE	3ST	MANATEE	CA	NG	PL	---	---	0	6 / 2005	--- / ----	503.0	504.6	485.0	486.6	OP
MARTIN	1	MARTIN	ST	NG	PL	RFO	WA	21	12 / 1980	--- / ----	855.8	862.2	823.0	829.0	OP
MARTIN	2	MARTIN	ST	NG	PL	RFO	WA	21	6 / 1981	--- / ----	834.6	841.0	803.0	809.0	OP
MARTIN	3GT1	MARTIN	CT	NG	PL	---	---	0	2 / 1994	--- / ----	151.8	185.0	151.8	185.0	OP
MARTIN	3GT2	MARTIN	CT	NG	PL	---	---	0	2 / 1994	--- / ----	151.8	185.0	151.8	185.0	OP
MARTIN	3ST	MARTIN	CA	NG	PL	---	---	0	2 / 1994	--- / ----	189.4	169.0	183.4	163.0	OP
MARTIN	4GT1	MARTIN	CT	NG	PL	---	---	0	4 / 1994	--- / ----	148.6	173.0	148.6	173.0	OP
MARTIN	4GT2	MARTIN	CT	NG	PL	---	---	0	4 / 1994	--- / ----	151.8	185.0	151.8	185.0	OP
MARTIN	4ST	MARTIN	CA	NG	PL	---	---	0	4 / 1994	--- / ----	183.6	162.0	177.6	156.0	OP
MARTIN	8CTA	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ----	164.0	173.2	164.0	173.2	OP
MARTIN	8CTB	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ----	164.0	173.2	164.0	173.2	OP
MARTIN	8CTC	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ----	176.8	203.0	176.8	203.0	OP
MARTIN	8CTD	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ----	176.8	203.0	176.8	203.0	OP
MARTIN	8ST	MARTIN	CA	NG	PL	DFO	TK	0	6 / 2005	--- / ----	470.4	507.6	447.4	484.6	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
FLORIDA POWER & LIGHT COMPANY (cont.)															
PORT EVERGLADES	5A	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / -----	271.9	297.1	271.9	297.1	OP
PORT EVERGLADES	5B	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / -----	271.9	297.1	271.9	297.1	OP
PORT EVERGLADES	5C	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / -----	271.9	297.1	271.9	297.1	OP
PORT EVERGLADES	5ST	BROWARD	CA	NG	PL	DFO	TK	5	4 / 2016	--- / -----	438.3	463.7	421.3	446.7	OP
RIVIERA	5A	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / -----	246.3	287.0	246.3	287.0	OP
RIVIERA	5B	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / -----	246.3	287.0	246.3	287.0	OP
RIVIERA	5C	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / -----	246.3	287.0	246.3	287.0	OP
RIVIERA	5ST	PALM BEACH	CA	NG	PL	DFO	TK	4	6 / 2014	--- / -----	490.1	506.0	473.1	489.0	OP
SANFORD	4CTA	VOLUSIA	CT	NG	PL	---	---	0	10 / 2003	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	4CTB	VOLUSIA	CT	NG	PL	---	---	0	10 / 2003	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	4CTC	VOLUSIA	CT	NG	PL	---	---	0	10 / 2003	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	4CTD	VOLUSIA	CT	NG	PL	---	---	0	10 / 2003	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	4ST	VOLUSIA	CA	NG	PL	---	---	0	10 / 2003	--- / -----	362.0	349.1	349.0	336.6	OP
SANFORD	5CTA	VOLUSIA	CT	NG	PL	---	---	0	6 / 2002	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	5CTB	VOLUSIA	CT	NG	PL	---	---	0	6 / 2002	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	5CTC	VOLUSIA	CT	NG	PL	---	---	0	6 / 2002	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	5CTD	VOLUSIA	CT	NG	PL	---	---	0	6 / 2002	--- / -----	164.0	190.1	164.0	190.1	OP
SANFORD	5ST	VOLUSIA	CA	NG	PL	---	---	0	6 / 2002	--- / -----	362.0	349.1	349.0	336.6	OP
SCHERER *	4	MONROE, GA	ST	BIT	RR	---	---	0	7 / 1988	--- / -----	639.0	638.0	634.0	635.0	OP
ST. JOHNS RIVER *	1	DUVAL	ST	BIT	RR	PC	WA	0	4 / 1987	--- / -----	132.0	134.0	127.0	130.0	OP
ST. JOHNS RIVER *	2	DUVAL	ST	BIT	RR	PC	WA	0	7 / 1988	--- / -----	133.0	132.0	127.0	130.0	OP
ST. LUCIE	1	ST. LUCIE	ST	NUC	TK	---	---	0	5 / 1976	--- / -----	1,032.0	1,072.0	981.0	1,003.0	OP
ST. LUCIE *	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / -----	843.0	862.0	840.0	860.0	OP
TURKEY POINT	2	DADE	ST	RFO	WA	NG	PL	0	4 / 1968	--- / -----	---	---	---	---	SC
TURKEY POINT	3	DADE	ST	NUC	TK	---	---	0	12 / 1972	--- / -----	846.2	874.2	811.0	839.0	OP
TURKEY POINT	4	DADE	ST	NUC	TK	---	---	0	9 / 1973	--- / -----	856.2	883.2	821.0	848.0	OP
TURKEY POINT	5CTA	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / -----	164.0	190.1	164.0	190.1	OP
TURKEY POINT	5CTB	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / -----	164.0	190.1	164.0	190.1	OP
TURKEY POINT	5CTC	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / -----	164.0	190.1	164.0	190.1	OP
TURKEY POINT	5CTD	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / -----	164.0	190.1	164.0	190.1	OP
TURKEY POINT	5ST	DADE	CA	NG	PL	DFO	TK	3	5 / 2007	--- / -----	556.0	501.6	531.0	476.6	OP

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
FLORIDA POWER & LIGHT COMPANY (cont.)															
WEST COUNTY	3GT1	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	3GT2	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	3GT3	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	3ST	PALM BEACH	CA	NG	PL	DFO	TK	2	6 / 2011	--- / -----	512.0	546.8	490.0	524.8	OP
WEST COUNTY	CT1A	PALM BEACH	CT	NG	PL	DFO	TK	2	8 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	CT1B	PALM BEACH	CT	NG	PL	DFO	TK	0	8 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	CT1C	PALM BEACH	CT	NG	PL	DFO	TK	2	8 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	ST1	PALM BEACH	CA	NG	PL	DFO	TK	2	8 / 2009	--- / -----	512.0	546.8	490.0	524.8	OP
WEST COUNTY	CT2A	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	CT2B	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	CT2C	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / -----	243.0	270.4	243.0	270.4	OP
WEST COUNTY	ST2	PALM BEACH	CA	NG	PL	DFO	TK	2	11 / 2009	--- / -----	512.0	546.8	490.0	524.8	OP
										FPL TOTAL (Excluding Solar):			26,008.6	27,828.4	
GAINESVILLE REGIONAL UTILITIES															
DEERHAVEN	FS01	ALACHUA	ST	NG	PL	RFO	TK	0	8 / 1972	8 / 2022	80.0	80.0	75.0	75.0	OP
DEERHAVEN	FS02	ALACHUA	ST	BIT	RR	---	---	0	10 / 1981	--- / -----	251.0	251.0	228.0	228.0	OP
DEERHAVEN	GT01	ALACHUA	GT	NG	PL	DFO	TK	0	7 / 1976	--- / -----	18.0	23.0	17.5	22.0	OP
DEERHAVEN	GT02	ALACHUA	GT	NG	PL	DFO	TK	0	8 / 1976	--- / -----	18.0	23.0	17.5	22.0	OP
DEERHAVEN	GT03	ALACHUA	GT	NG	PL	DFO	TK	0	1 / 1996	--- / -----	71.5	82.0	71.0	81.0	OP
J. R. KELLY	FS08	ALACHUA	CA	WH	NA	---	---	0	5 / 2001	--- / -----	37.5	38.0	36.0	37.0	OP
J. R. KELLY	GT04	ALACHUA	CT	NG	PL	DFO	TK	0	5 / 2001	--- / -----	72.5	82.0	72.0	81.0	OP
SOUTH ENERGY CENTER	1	ALACHUA	GT	NG	PL	---	---	0	5 / 2009	--- / -----	4.5	4.5	3.5	3.5	OP
										GRU TOTAL:			520.5	549.5	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
HOMESTEAD ENERGY SERVICES															
G. W. IVEY	2	DADE	IC	NG	PL	DFO	TK	100	3 / 1970	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	3	DADE	IC	NG	PL	DFO	TK	100	3 / 1970	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	13	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	14	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	15	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	16	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	17	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / -----	2.0	2.0	1.8	1.8	OP
G. W. IVEY	19	DADE	IC	NG	PL	DFO	TK	100	2 / 1975	--- / -----	9.0	9.0	7.5	7.5	OP
G. W. IVEY	20	DADE	IC	NG	PL	DFO	TK	100	5 / 1981	--- / -----	6.5	6.5	6.0	6.0	OP
G. W. IVEY	21	DADE	IC	NG	PL	DFO	TK	100	5 / 1981	--- / -----	6.5	6.5	6.0	6.0	OP
										HST TOTAL:			32.1	32.1	
JEA															
BRANDY BRANCH	CT2	DUVAL	CT	NG	PL	---	---	0	5 / 2001	--- / -----	150.5	186.5	150.0	186.0	OP
BRANDY BRANCH	CT3	DUVAL	CT	NG	PL	DFO	TK	0	10 / 2001	--- / -----	150.5	186.5	150.0	186.0	OP
BRANDY BRANCH	GT1	DUVAL	GT	NG	PL	DFO	TK	0	5 / 2001	--- / -----	150.5	192.7	150.0	191.0	OP
BRANDY BRANCH	STM4	DUVAL	CA	WH	NA	---	---	0	1 / 2005	--- / -----	211.0	232.7	201.0	223.0	OP
GREENLAND ENERGY CTR	GT1	DUVAL	GT	NG	PL	---	---	0	6 / 2011	--- / -----	150.5	186.5	150.0	186.0	OP
GREENLAND ENERGY CTR	GT2	DUVAL	GT	NG	PL	---	---	0	6 / 2011	--- / -----	150.5	186.5	150.0	186.0	OP
J. D. KENNEDY	GT7	DUVAL	GT	NG	PL	DFO	WA	0	6 / 2000	--- / -----	150.5	192.7	150.0	191.0	OP
J. D. KENNEDY	GT8	DUVAL	GT	NG	PL	DFO	WA	0	6 / 2009	--- / -----	150.5	192.7	150.0	191.0	OP
NORTHSIDE	1	DUVAL	ST	PC	WA	BIT	WA	0	5 / 2003	--- / -----	310.0	310.0	293.0	293.0	OP
NORTHSIDE	2	DUVAL	ST	PC	WA	BIT	WA	0	4 / 2003	--- / -----	310.0	310.0	293.0	293.0	OP
NORTHSIDE	3	DUVAL	ST	NG	PL	RFO	WA	0	6 / 1977	--- / -----	540.0	540.0	524.0	524.0	OP
NORTHSIDE	GT3	DUVAL	GT	DFO	WA	---	---	0	1 / 1975	--- / -----	53.4	62.0	53.0	61.6	OP
NORTHSIDE	GT4	DUVAL	GT	DFO	WA	---	---	0	1 / 1975	--- / -----	53.4	62.0	53.0	61.6	OP
NORTHSIDE	GT5	DUVAL	GT	DFO	WA	---	---	0	12 / 1974	--- / -----	53.4	62.0	53.0	61.6	OP
NORTHSIDE	GT6	DUVAL	GT	DFO	WA	---	---	0	12 / 1974	--- / -----	53.4	62.0	53.0	61.6	OP
SCHERER *	4	MONROE, GA	ST	BIT	RR	---	---	0	2 / 1989	--- / -----	208.0	208.0	194.0	194.0	OP
ST. JOHNS RIVER *	1	DUVAL	ST	BIT	RR	PC	WA	0	3 / 1987	--- / -----	528.0	537.6	501.0	510.0	OP
ST. JOHNS RIVER *	2	DUVAL	ST	BIT	RR	PC	WA	0	5 / 1988	--- / -----	528.0	537.6	501.0	510.0	OP
										JEA TOTAL:			3,769.0	4,110.4	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
KEY WEST UTILITY BOARD															
STOCK ISLAND	EP2	MONROE	IC	DFO	TK	---	---	0	7 / 2014	--- / ----	2.0	2.0	2.0	2.0	OP
STOCK ISLAND	GT1	MONROE	GT	DFO	WA	---	---	0	11 / 1978	--- / ----	19.8	19.8	18.5	18.5	OP
STOCK ISLAND MSD	MSD1	MONROE	IC	DFO	WA	---	---	0	6 / 1991	--- / ----	8.8	8.8	8.0	8.0	OP
STOCK ISLAND MSD	MSD2	MONROE	IC	DFO	WA	---	---	0	6 / 1991	--- / ----	8.8	8.8	8.0	8.0	OP
										KEY TOTAL:			36.5	36.5	
KISSIMMEE UTILITY AUTHORITY															
CANE ISLAND *	1GT	OSCEOLA	GT	NG	PL	DFO	TK	0	1 / 1995	--- / ----	17.5	19.0	17.5	19.0	OP
CANE ISLAND *	2CT	OSCEOLA	CT	NG	PL	DFO	TK	0	6 / 1995	--- / ----	35.5	37.5	34.5	36.5	OP
CANE ISLAND *	2CW	OSCEOLA	CA	WH	NA	DFO	---	0	6 / 1995	--- / ----	22.0	22.0	20.0	20.0	OP
CANE ISLAND *	3CT	OSCEOLA	CT	NG	PL	DFO	TK	0	1 / 2002	--- / ----	77.0	81.0	75.0	79.0	OP
CANE ISLAND *	3CW	OSCEOLA	CA	WH	NA	DFO	---	0	1 / 2002	--- / ----	47.5	48.5	45.0	46.0	OP
INDIAN RIVER *	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ----	4.4	5.6	3.8	4.4	OP
INDIAN RIVER *	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ----	4.4	5.6	3.8	4.4	OP
STANTON *	1	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	--- / ----	20.8	20.8	20.8	20.8	OP
STANTON A *	CT	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ----	11.3	12.6	11.3	12.6	OP
STANTON A *	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / ----	10.0	10.0	10.0	10.0	OP
										KUA TOTAL:			241.7	252.7	
LAKELAND CITY OF															
LARSEN	2	POLK	GT	NG	PL	DFO	TK	16	11 / 1962	--- / ----	10.0	14.0	10.0	14.0	OP
LARSEN	3	POLK	GT	NG	PL	DFO	TK	16	12 / 1962	--- / ----	9.0	13.0	9.0	13.0	OP
LARSEN	8CT	POLK	CT	NG	PL	DFO	TK	3	7 / 1992	--- / ----	78.0	95.0	76.0	93.0	OP
LARSEN	8ST	POLK	CA	WH	PL	DFO	TK	3	4 / 1956	--- / ----	29.0	31.0	29.0	31.0	OP
MCINTOSH	2	POLK	ST	NG	PL	RFO	TK	14	6 / 1976	--- / ----	114.0	114.0	106.0	106.0	OP
MCINTOSH *	3	POLK	ST	BIT	RR	---	TK	0	9 / 1982	--- / ----	219.0	219.0	205.0	205.0	OP
MCINTOSH	5CT	POLK	CT	NG	PL	---	---	0	5 / 2001	--- / ----	219.0	239.0	212.0	233.0	OP
MCINTOSH	5ST	POLK	CA	WH	NA	---	---	0	5 / 2002	--- / ----	126.0	121.0	126.0	121.0	OP
MCINTOSH	D1	POLK	IC	DFO	TK	---	---	0	1 / 1970	--- / ----	2.5	2.5	2.5	2.5	OP
MCINTOSH	D2	POLK	IC	DFO	TK	---	---	0	1 / 1970	--- / ----	2.5	2.5	2.5	2.5	OP
MCINTOSH	GT1	POLK	GT	NG	PL	DFO	TK	0	5 / 1973	--- / ----	17.0	19.0	16.0	19.0	OP

*Jointly Owned Unit

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL TRANSP. METHOD	ALTERNATE FUEL FUEL TYPE	ALTERNATE FUEL TRANSP. METHOD	ALT. FUEL STORAGE (DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	STATUS
LAKELAND CITY OF (cont.)															
WINSTON	1-5	POLK	IC	DFO	TK	---	---	0	12 / 2001	--- / -----	12.5	12.5	12.5	12.5	OP
WINSTON	6-10	POLK	IC	DFO	TK	---	---	0	12 / 2001	--- / -----	12.5	12.5	12.5	12.5	OP
WINSTON	11-15	POLK	IC	DFO	TK	---	---	0	12 / 2001	--- / -----	12.5	12.5	12.5	12.5	OP
WINSTON	16-20	POLK	IC	DFO	TK	---	---	0	12 / 2001	--- / -----	12.5	12.5	12.5	12.5	OP
										LAK TOTAL:			844.0	890.0	
LAKE WORTH UTILITIES CITY OF															
TOM G. SMITH	GT-1	PALM BEACH	GT	DFO	TK	---	---	0	12 / 1976	--- / -----	26.0	29.0	26.0	27.0	OP
TOM G. SMITH	GT-2	PALM BEACH	CT	NG	PL	DFO	TK	2	3 / 1978	--- / -----	21.0	23.0	20.0	20.0	OP
TOM G. SMITH	MU1	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / -----	2.0	2.0	1.8	2.0	IR
TOM G. SMITH	MU2	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / -----	2.0	2.0	1.8	2.0	IR
TOM G. SMITH	MU3	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / -----	2.0	2.0	1.8	2.0	IR
TOM G. SMITH	MU4	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / -----	2.0	2.0	1.8	2.0	IR
TOM G. SMITH	MU5	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / -----	2.0	2.0	1.8	2.0	IR
TOM G. SMITH	S-3	PALM BEACH	ST	NG	PL	RFO	TK	6	11 / 1967	--- / -----	27.0	27.0	22.0	24.0	OP
TOM G. SMITH	S-5	PALM BEACH	CA	WH	NA	---	---	0	3 / 1978	--- / -----	10.0	10.0	9.0	9.0	OP
										LWU TOTAL:			77.0	80.0	
NEW SMYRNA BEACH UTILITIES COMMISSION OF															
FIELD STREET	1	VOLUSIA	GT	DFO	TK	---	---	0	5 / 2001	--- / -----	22.0	24.0	22.0	24.0	OP
FIELD STREET	2	VOLUSIA	GT	DFO	TK	---	---	0	5 / 2001	--- / -----	22.0	24.0	22.0	24.0	OP
										NSB TOTAL:			44.0	48.0	
ORLANDO UTILITIES COMMISSION															
INDIAN RIVER *	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / -----	15.6	18.1	15.6	18.1	OP
INDIAN RIVER *	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / -----	15.6	18.1	15.6	18.1	OP
INDIAN RIVER *	C	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / -----	83.0	88.5	83.0	88.5	OP
INDIAN RIVER *	D	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / -----	83.0	88.5	83.0	88.5	OP

*Jointly Owned Unit

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
ORLANDO UTILITIES COMMISSION (cont.)															
MCINTOSH *	3	POLK	ST	BIT	RR	---	---	0	9 / 1982	--- / -----	146.0	146.0	133.0	136.0	OP
ST. LUCIE *	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / -----	63.0	63.0	60.0	60.0	OP
STANTON *	1	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	--- / -----	321.0	321.0	302.3	302.3	OP
STANTON *	2	ORANGE	ST	BIT	RR	---	---	0	6 / 1996	--- / -----	344.0	344.0	324.3	324.3	OP
STANTON A *	CTA	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / -----	55.2	58.7	51.3	54.6	OP
STANTON A *	CTB	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / -----	55.2	58.7	51.3	54.6	OP
STANTON A *	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / -----	76.7	81.6	71.0	75.6	OP
STANTON B	CT	ORANGE	CT	NG	PL	DFO	TK	3	2 / 2010	--- / -----	173.0	185.0	170.0	182.0	OP
STANTON B	ST	ORANGE	CA	WH	NA	DFO	TK	3	2 / 2010	--- / -----	122.0	125.0	122.0	125.0	OP
											OUC TOTAL:		**1,482.4**	**1,527.6**	
REEDY CREEK IMPROVEMENT DISTRICT															
CENTRAL ENERGY PLANT	1	ORANGE	CC	NG	PL	DFO	TK	0	1 / 1989	--- / -----	56.0	56.0	55.0	55.0	OP
CEP DIESEL	1	ORANGE	IC	DFO	TK	---	---	0	5 / 2014	--- / -----	1.2	1.2	1.2	1.2	IR
REEDY CREEK DIESEL	D1-D	ORANGE	IC	DFO	TK	---	---	0	1 / 1983	--- / -----	5.0	5.0	4.6	4.6	IR
											RCI TOTAL:		**55.0**	**55.0**	
SEMINOLE ELECTRIC COOPERATIVE INC															
MIDULLA GENERATING STATION	4	HARDEE	GT	NG	PL	DFO	TK	0	12 / 2006	--- / -----	54.0	62.0	54.0	62.0	OP
MIDULLA GENERATING STATION	5	HARDEE	GT	NG	PL	DFO	TK	0	12 / 2006	--- / -----	54.0	62.0	54.0	62.0	OP
MIDULLA GENERATING STATION	6	HARDEE	GT	NG	PL	DFO	TK	0	12 / 2006	--- / -----	54.0	62.0	54.0	62.0	OP
MIDULLA GENERATING STATION	7	HARDEE	GT	NG	PL	DFO	TK	0	12 / 2006	--- / -----	54.0	62.0	54.0	62.0	OP
MIDULLA GENERATING STATION	8	HARDEE	GT	NG	PL	DFO	TK	0	12 / 2006	--- / -----	54.0	62.0	54.0	62.0	OP
MIDULLA GENERATING STATION	CT1	HARDEE	CT	NG	PL	DFO	TK	0	1 / 2002	--- / -----	153.0	182.0	151.5	180.0	OP
MIDULLA GENERATING STATION	CT2	HARDEE	CT	NG	PL	DFO	TK	0	1 / 2002	--- / -----	153.0	182.0	151.5	180.0	OP
MIDULLA GENERATING STATION	ST	HARDEE	CA	WH	NA	DFO	TK	0	1 / 2002	--- / -----	181.0	181.0	179.0	179.0	OP
SEMINOLE GENERATING STATION	1	PUTNAM	ST	BIT	RR	---	---	0	2 / 1984	--- / -----	673.0	713.0	626.0	664.0	OP
SEMINOLE GENERATING STATION	2	PUTNAM	ST	BIT	RR	---	---	0	12 / 1984	--- / -----	680.0	713.0	634.0	665.0	OP
											SEC TOTAL:		**2,012.0**	**2,178.0**	

*Jointly Owned Unit

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
TALLAHASSEE CITY OF															
C. H. CORN HYDRO	1	LEON	HY	WAT	WA	—	---	0	9 / 1985	--- / ------	---	---	---	---	EO
C. H. CORN HYDRO	2	LEON	HY	WAT	WA	—	---	0	8 / 1985	--- / ------	---	---	---	---	EO
C. H. CORN HYDRO	3	LEON	HY	WAT	WA	—	---	0	1 / 1986	--- / ------	---	---	---	---	EO
HOPKINS	1	LEON	ST	NG	PL	—	---	0	5 / 1971	10 / 2018	81.0	85.0	76.0	78.0	OP
HOPKINS	2	LEON	CA	WH	NA	NG	PL	0	10 / 1977	--- / ------	146.0	150.0	141.0	145.0	OP
HOPKINS	2A	LEON	CT	NG	PL	DFO	TK	3	6 / 2008	--- / ------	160.0	186.0	159.0	185.0	OP
HOPKINS	GT1	LEON	GT	NG	PL	DFO	TK	3	2 / 1970	4 / 2017	12.0	14.0	12.0	14.0	OP
HOPKINS	GT2	LEON	GT	NG	PL	DFO	TK	3	9 / 1972	4 / 2017	24.0	26.0	24.0	26.0	OP
HOPKINS	GT3	LEON	GT	NG	PL	DFO	TK	3	9 / 2005	--- / ------	49.0	49.0	46.0	48.0	OP
HOPKINS	GT4	LEON	GT	NG	PL	DFO	TK	3	11 / 2005	--- / ------	49.0	49.0	46.0	48.0	OP
PURDOM	8CT	WAKULLA	CT	NG	PL	DFO	TK	9	7 / 2000	--- / ------	160.7	185.2	150.0	182.0	OP
PURDOM	8ST	WAKULLA	CA	WH	NA	—	---	0	7 / 2000	--- / ------	76.3	80.8	72.0	76.0	OP
PURDOM	GT1	WAKULLA	GT	NG	PL	DFO	TK	9	12 / 1963	10 / 2018	10.0	10.0	10.0	10.0	OP
PURDOM	GT2	WAKULLA	GT	NG	PL	DFO	TK	9	5 / 1964	10 / 2018	10.0	10.0	10.0	10.0	OP
											TAL TOTAL:		746.0	822.0	
TAMPA ELECTRIC COMPANY (cont.)															
BAYSIDE	3	HILLSBOROUGH	GT	NG	PL	---	---	0	7 / 2009	--- / ------	57.0	62.0	56.0	61.0	OP
BAYSIDE	4	HILLSBOROUGH	GT	NG	PL	---	---	0	7 / 2009	--- / ------	57.0	62.0	56.0	61.0	OP
BAYSIDE	5	HILLSBOROUGH	GT	NG	PL	---	---	0	4 / 2009	--- / ------	57.0	62.0	56.0	61.0	OP
BAYSIDE	6	HILLSBOROUGH	GT	NG	PL	---	---	0	4 / 2009	--- / ------	57.0	62.0	56.0	61.0	OP
BAYSIDE	1A	HILLSBOROUGH	CT	NG	PL	---	---	0	4 / 2003	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	1B	HILLSBOROUGH	CT	NG	PL	---	---	0	4 / 2003	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	1C	HILLSBOROUGH	CT	NG	PL	---	---	0	4 / 2003	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	1ST	HILLSBOROUGH	CA	WH	NA	---	---	0	4 / 2003	--- / ------	236.0	246.0	233.0	243.0	OP
BAYSIDE	2A	HILLSBOROUGH	CT	NG	PL	---	---	0	1 / 2004	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	2B	HILLSBOROUGH	CT	NG	PL	---	---	0	1 / 2004	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	2C	HILLSBOROUGH	CT	NG	PL	---	---	0	1 / 2004	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	2D	HILLSBOROUGH	CT	NG	PL	---	---	0	1 / 2004	--- / ------	158.0	185.0	156.0	183.0	OP
BAYSIDE	2ST	HILLSBOROUGH	CA	WH	NA	—	---	0	1 / 2004	--- / ------	308.0	318.0	305.0	315.0	OP

*Jointly Owned Unit

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LOAD AND RESOURCE PLAN
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EXISTING GENERATING FACILITIES AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
TAMPA ELECTRIC COMPANY															
BIG BEND	1	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	10 / 1970	--- / -----	410.0	420.0	385.0	395.0	OP
BIG BEND	2	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	4 / 1973	--- / -----	410.0	420.0	385.0	395.0	OP
BIG BEND	3	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	5 / 1976	--- / -----	420.0	425.0	395.0	400.0	OP
BIG BEND	4	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	2 / 1985	--- / -----	470.0	475.0	437.0	442.0	OP
BIG BEND	CT4	HILLSBOROUGH	GT	NG	PL	---	---	0	8 / 2009	--- / -----	57.0	62.0	56.0	61.0	OP
POLK	2	POLK	GT	NG	PL	DFO	TK	3	7 / 2000	--- / -----	152.0	184.0	151.0	183.0	OP
POLK	3	POLK	GT	NG	PL	DFO	TK	3	5 / 2002	--- / -----	152.0	184.0	151.0	183.0	OP
POLK	4	POLK	GT	NG	PL	---	---	0	3 / 2007	--- / -----	152.0	184.0	151.0	183.0	OP
POLK	5	POLK	GT	NG	PL	---	---	0	4 / 2007	--- / -----	152.0	184.0	151.0	183.0	OP
POLK	1CT	POLK	CT	PC	TK	NG	PL	0	9 / 1996	--- / -----	170.0	170.0	169.0	169.0	OP
POLK	1CA	POLK	CA	WH	NA	---	---	0	9 / 1996	--- / -----	120.0	120.0	51.0	51.0	OP
										TEC TOTAL (Excluding Solar):			4,336.0	4,728.0	
US CORPS OF ENGINEERS - MOBILE															
JIM WOODRUFF	1	GADSDEN	HY	WAT	NA	---	---	0	2 / 1957	--- / -----	14.5	14.5	14.5	14.5	OP
JIM WOODRUFF	2	GADSDEN	HY	WAT	NA	---	---	0	3 / 1957	--- / -----	14.5	14.5	14.5	14.5	OP
JIM WOODRUFF	3	GADSDEN	HY	WAT	NA	---	---	0	4 / 1957	--- / -----	14.5	14.5	14.5	14.5	OP
										UCEM TOTAL:			43.5	43.5	
										FRCC EXISTING (Excluding Firm Solar):			49,854	53,952	
										FRCC EXISTING FIRM SOLAR:			132	0	
										TOTAL FRCC EXISTING:			49,986	53,952	

*Jointly Owned Unit

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LOAD AND RESOURCE PLAN
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FRCC Form 1.0 (Solar)
EXISTING SOLAR GENERATING FACILITIES AS OF DECEMBER 31, 2016[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		NON-FIRM		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	STATUS
DUKE ENERGY FLORIDA												
OSCEOLA SOLAR	PV1	OSCEOLA	PV	SUN	5 / 2016	--- / ----	3.8	---	---	---	---	OP
PERRY SOLAR	PV1	TAYLOR	PV	SUN	8 / 2016	--- / ----	5.1	---	---	---	---	OP
						DEF SOLAR TOTAL:	**8.9**	**0.0**	**0.0**	**0.0**	**0.0**	
FLORIDA POWER & LIGHT COMPANY												
BABCOCK RANCH SOLAR	1	CHARLOTTE	PV	SUN	12 / 2016	--- / ----	74.5	38.7	---	---	---	OP
CITRUS SOLAR	1	DESOTO	PV	SUN	12 / 2016	--- / ----	74.5	38.7	---	---	---	OP
DESOTO NEXT GENERATION SOLAR ENERGY CENTER	1	DESOTO	PV	SUN	10 / 2009	--- / ----	25.0	11.5	---	---	---	OP
MANATEE SOLAR	1	MANATEE	PV	SUN	12 / 2016	--- / ----	74.5	38.7	---	---	---	OP
SPACE COAST	1	BREVARD	PV	SUN	4 / 2010	--- / ----	10.0	3.2	---	---	---	OP
						FPL SOLAR TOTAL:	**258.5**	**130.8**	**0.0**	**0.0**	**0.0**	
TAMPA ELECTRIC COMPANY												
LEGOLAND	1	HILLSBOROUGH	PV	SUN	12 / 2016	--- / ----	1.5	0.5	---	---	---	OP
TIA	1	HILLSBOROUGH	PV	SUN	12 / 2015	--- / ----	1.6	0.5	---	---	---	OP
						TEC SOLAR TOTAL:	**3.1**	**1.0**	**0.0**	**0.0**	**0.0**	

FRCC EXISTING (Excluding Firm Solar):	**49,854**	**53,952**
FRCC EXISTING FIRM SOLAR:	**132**	**0**
TOTAL FRCC EXISTING:	**49,986**	**53,952**

[1]**Notes:**

DEF: Firm Summer potential export to grid at the time of peak was set at zero for current TYSP, but may vary after further demonstration study.

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SUMMARY OF JOINTLY OWNED GENERATING FACILITIES
As of December 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	NET CAPABILITY		
PLANT NAME	UTILS	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	STATUS
CANE ISLAND 1	FMPA	OSCEOLA	GT	NG	PL	DFO	TK	0	11 / 1994	— / ----	17.5	19.0	OP
	KUA										17.5	19.0	OP
											35.0	38.0	
CANE ISLAND 2	FMPA	OSCEOLA	CT	NG	PL	DFO	TK	0	6 / 1995	— / ----	54.5	56.5	OP
	KUA										54.5	56.5	OP
											109.0	113.0	
CANE ISLAND 3	FMPA	OSCEOLA	CT	NG	PL	DFO	TK	0	1 / 2002	— / ----	120.0	125.0	OP
	KUA										120.0	125.0	OP
											240.0	250.0	
INDIAN RIVER A	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	— / ----	12.2	14.1	OP
	KUA										3.8	4.4	OP
	OUC										15.6	18.1	OP
											31.6	36.6	
INDIAN RIVER B	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	— / ----	12.2	14.1	OP
	KUA										3.8	4.4	OP
	OUC										15.6	18.1	OP
											31.6	36.6	
INDIAN RIVER C	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	— / ----	21.6	23.0	OP
	OUC										83.0	88.5	OP
											104.6	111.5	
INDIAN RIVER D	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	— / ----	21.6	23.0	OP
	OUC										83.0	88.5	OP
											104.6	111.5	
MCINTOSH 3	LAK	POLK	ST	BIT	RR	NA	TK	0	9 / 1982	— / ----	205.0	205.0	OP
	OUC										133.0	136.0	OP
											338.0	341.0	

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SUMMARY OF JOINTLY OWNED GENERATING FACILITIES
As of December 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	NET CAPABILITY		
PLANT NAME	UTILS	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	STATUS
SCHERER 4	FPL	MONROE, GA	ST	BIT	RR	---	---	0	7 / 1988	--- / -----	634.0	635.0	OP
	JEA										194.0	194.0	OP
											828.0	**829.0**	
ST. JOHNS RIVER 1	FPL	DUVAL	ST	BIT	RR	PC	WA	0	4 / 1987	--- / ----	127.0	130.0	OP
	JEA										501.0	510.0	OP
											628.0	**640.0**	
ST. JOHNS RIVER 2	FPL	DUVAL	ST	BIT	RR	PC	WA	0	7 / 1988	--- / ----	127.0	130.0	OP
	JEA										501.0	510.0	OP
											628.0	**640.0**	
ST. LUCIE 2	FMPA	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / -----	86.2	89.6	OP
	FPL										840.0	860.0	OP
	OUC										60.0	60.0	OP
											986.2	**1,009.6**	
STANTON 1	FMPA	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	--- / -----	114.8	114.8	OP
	KUA										20.8	20.8	OP
	OUC										302.3	302.3	OP
											437.9	**437.9**	
STANTON 2	FMPA	ORANGE	ST	BIT	RR	---	---	0	6 / 1996	--- / -----	125.1	125.1	OP
	OUC										324.3	324.3	OP
											449.4	**449.4**	
STANTON A	FMPA	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ----	100.3	106.6	OP
(includes SOU capacity purchase)	KUA										21.3	22.6	OP
	OUC										515.6	527.8	OP
											637.2	**657.0**	

2017
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FLORIDA RELIABILITY COORDINATING COUNCIL
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PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2017														
DEF	OSPREY	CT1	POLK	CT	NG	PL	—	—	0	1 / 2017	81.6	81.6	81.6	81.6	CO
DEF	OSPREY	CT2	POLK	CT	NG	PL	—	—	0	1 / 2017	81.6	81.6	81.6	81.6	CO
DEF	OSPREY	ST	POLK	CA	WH	PL	—	—	0	1 / 2017	81.7	81.7	81.7	81.7	CO
FPL	CEDAR BAY	1	DUVAL	ST	BIT	RR	—	—	0	1 / 2017	-250.0	-250.0	-250.0	-250.0	RT
TEC	POLK	2	POLK	GT	NG	PL	DFO	TK	3	1 / 2017	-152.0	-184.0	-151.0	-183.0	FC
TEC	POLK	3	POLK	GT	NG	PL	DFO	TK	3	1 / 2017	-152.0	-184.0	-151.0	-183.0	FC
TEC	POLK	4	POLK	GT	NG	PL	—	—	0	1 / 2017	-152.0	-184.0	-151.0	-183.0	FC
TEC	POLK	5	POLK	GT	NG	PL	—	—	0	1 / 2017	-152.0	-184.0	-151.0	-183.0	FC
TEC	POLK	2A	POLK	CT	NG	PL	DFO	TK	3	1 / 2017	152.0	184.0	151.0	183.0	FC
TEC	POLK	2B	POLK	CT	NG	PL	DFO	TK	3	1 / 2017	152.0	184.0	151.0	183.0	FC
TEC	POLK	2C	POLK	CT	NG	PL	—	—	0	1 / 2017	152.0	184.0	151.0	183.0	FC
TEC	POLK	2D	POLK	CT	NG	PL	—	—	0	1 / 2017	152.0	184.0	151.0	183.0	FC
TEC	POLK	2ST	POLK	CA	WH	NA	—	—	0	1 / 2017	462.0	466.0	459.0	463.0	TS
FPL	MARTIN	8CTA	MARTIN	CT	NG	PL	DFO	—	0	2 / 2017	3.5	28.8	3.5	28.8	OT
FPL	MARTIN	4GT1	MARTIN	CT	NG	PL	DFO	TK	0	3 / 2017	9.0	19.0	9.0	19.0	OT
FPL	MARTIN	8CTB	MARTIN	CT	NG	PL	DFO	—	0	3 / 2017	3.5	28.8	3.5	28.8	OT
DEF	HINES ENERGY COMPLEX	1GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	16.8	0.0	16.8	0.0	A
DEF	HINES ENERGY COMPLEX	1GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	16.8	0.0	16.8	0.0	A
DEF	HINES ENERGY COMPLEX	1ST	POLK	CA	WH	NA	—	—	2	4 / 2017	17.4	4.0	17.4	0.0	A
DEF	HINES ENERGY COMPLEX	2GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	18.8	0.0	18.8	0.0	A
DEF	HINES ENERGY COMPLEX	2GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	18.8	0.0	18.8	0.0	A
DEF	HINES ENERGY COMPLEX	2ST	POLK	CA	WH	NA	—	—	0	4 / 2017	19.4	0.0	19.4	0.0	A
DEF	HINES ENERGY COMPLEX	3GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	19.8	0.0	19.8	0.0	A
DEF	HINES ENERGY COMPLEX	3GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	19.8	0.0	19.8	0.0	A
DEF	HINES ENERGY COMPLEX	3ST	POLK	CA	WH	NA	—	—	0	4 / 2017	20.4	0.0	20.4	0.0	A
DEF	HINES ENERGY COMPLEX	4GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	21.8	0.0	21.8	0.0	A
DEF	HINES ENERGY COMPLEX	4GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 2017	21.8	0.0	21.8	0.0	A
DEF	HINES ENERGY COMPLEX	4ST	POLK	CA	WH	NA	DFO	TK	0	4 / 2017	21.4	0.0	21.4	0.0	A
FPL	MANATEE	3CTA	MANATEE	CT	NG	PL	—	—	0	4 / 2017	3.3	10.6	3.3	10.6	OT
TAL	HOPKINS	GT1	LEON	GT	NG	PL	DFO	TK	3	4 / 2017	-12.0	-14.0	-12.0	-14.0	RT
TAL	HOPKINS	GT2	LEON	GT	NG	PL	DFO	TK	3	4 / 2017	-24.0	-26.0	-24.0	-26.0	RT
FPL	FT. MYERS	3CTC	LEE	CT	NG	TK	DFO	—	7	5 / 2017	20.0	0.0	20.0	0.0	OT
FPL	FT. MYERS	3CTD	LEE	CT	NG	TK	DFO	—	7	5 / 2017	20.0	0.0	20.0	0.0	OT
FPL	LAUDERDALE	6CTA	BROWARD	CT	NG	PL	DFO	TK	2	5 / 2017	20.0	0.0	20.0	0.0	A
FPL	LAUDERDALE	6CTB	BROWARD	CT	NG	PL	DFO	TK	2	5 / 2017	20.0	0.0	20.0	0.0	A
FPL	LAUDERDALE	6CTC	BROWARD	CT	NG	PL	DFO	TK	2	5 / 2017	20.0	0.0	20.0	0.0	A

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(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2017 (cont.)														
FPL	LAUDERDALE	6CTD	BROWARD	CT	NG	PL	DFO	TK	2	5 / 2017	20.0	0.0	20.0	0.0	A
FPL	LAUDERDALE	6CTE	BROWARD	CT	NG	PL	DFO	TK	2	5 / 2017	20.0	0.0	20.0	0.0	A
FPL	MANATEE	3CTB	MANATEE	CT	NG	PL	---	---	0	5 / 2017	3.3	10.6	3.3	10.6	OT
FPL	MANATEE	3CTC	MANATEE	CT	NG	PL	---	---	0	5 / 2017	3.3	10.6	3.3	10.6	OT
FPL	MANATEE	3CTD	MANATEE	CT	NG	PL	---	---	0	6 / 2017	3.3	10.6	3.3	10.6	OT
FPL	SANFORD	4CTC	VOLUSIA	CT	NG	PL	---	---	0	8 / 2017	2.0	18.9	2.0	18.9	OT
FPL	SANFORD	4CTD	VOLUSIA	CT	NG	PL	---	---	0	8 / 2017	2.0	18.9	2.0	18.9	OT
DEF	INTERCESSION CITY	P11	OSCEOLA	GT	DFO	PL	---	---	0	9 / 2017	0.0	0.0	140.0	0.0	OT
FPL	SANFORD	5CTD	VOLUSIA	CT	NG	PL	---	---	0	10 / 2017	2.0	18.9	2.0	18.9	OT
FPL	SANFORD	5CTA	VOLUSIA	CT	NG	PL	---	---	0	11 / 2017	2.0	18.9	2.0	18.9	OT
FPL	TURKEY POINT	5CTA	DADE	CT	NG	PL	---	---	0	12 / 2017	-9.9	14.4	-9.9	14.4	OT
FPL	TURKEY POINT	5CTB	DADE	CT	NG	PL	---	---	0	12 / 2017	-9.9	14.4	-9.9	14.4	OT
GRU	SOUTH ENERGY CENTER	2	ALACHUA	IC	NG	PL	---	---	0	12 / 2017	7.8	7.8	7.4	7.4	L
											2017 TOTAL:		955.7	648.7	
	2018														
JEA	ST. JOHNS RIVER	1	DUVAL	ST	BIT	RR	PC	WA	0	1 / 2018	-528.0	-537.6	-501.0	-510.0	OT
JEA	ST. JOHNS RIVER	2	DUVAL	ST	BIT	RR	PC	WA	0	1 / 2018	-528.0	-537.6	-501.0	-510.0	OT
FPL	TURKEY POINT	5CTC	DADE	CT	NG	PL	---	---	0	3 / 2018	-9.9	14.4	-9.9	14.4	OT
FPL	TURKEY POINT	5CTD	DADE	CT	NG	PL	---	---	0	3 / 2018	-9.9	14.4	-9.9	14.4	OT
DEF	CRYSTAL RIVER	1	CITRUS	ST	BIT	RR	BIT	WA	0	4 / 2018	-348.0	-358.0	-324.0	-332.0	RT
DEF	CRYSTAL RIVER	2	CITRUS	ST	BIT	RR	BIT	WA	0	4 / 2018	-462.0	-469.0	-442.0	-448.0	RT
DEF	CITRUS	1	CITRUS	CC	NG	PL	NG	PL	0	5 / 2018	830.0	920.0	820.0	910.0	P
FPL	SANFORD	4CTA	VOLUSIA	CT	NG	PL	---	---	0	5 / 2018	2.0	18.9	2.0	18.9	OT
FPL	SANFORD	4CTB	VOLUSIA	CT	NG	PL	---	---	0	5 / 2018	2.0	18.9	2.0	18.9	OT
FPL	SANFORD	5CTB	VOLUSIA	CT	NG	PL	---	---	0	6 / 2018	2.0	18.9	2.0	18.9	OT
FPL	SANFORD	5CTC	VOLUSIA	CT	NG	PL	---	---	0	6 / 2018	2.0	18.9	2.0	18.9	OT
TAL	SUB 12 DISTRIBUTED GEN.	IC 1	LEON	IC	NG	PL	---	---	0	7 / 2018	9.3	9.3	9.2	9.2	P
TAL	SUB 12 DISTRIBUTED GEN.	IC 2	LEON	IC	NG	PL	---	---	0	7 / 2018	9.3	9.3	9.2	9.2	P
FPL	TURKEY POINT	3	DADE	ST	NUC	TK	---	---	0	10 / 2018	20.0	20.0	20.0	20.0	A
TAL	HOPKINS	1	LEON	ST	NG	PL	---	---	0	10 / 2018	-81.0	-85.0	-76.0	-78.0	RT
TAL	HOPKINS	IC 1	LEON	IC	NG	PL	---	---	0	10 / 2018	18.7	18.7	18.4	18.4	P
TAL	HOPKINS	IC 2	LEON	IC	NG	PL	---	---	0	10 / 2018	18.7	18.7	18.4	18.4	P
TAL	HOPKINS	IC 3	LEON	IC	NG	PL	---	---	0	10 / 2018	18.7	18.7	18.4	18.4	P

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(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2018 (cont.)														
TAL	HOPKINS	IC 4	LEON	IC	NG	PL	—	—	0	10 / 2018	18.7	18.7	18.4	18.4	P
TAL	PURDOM	GT1	WAKULLA	GT	NG	PL	DFO	TK	9	10 / 2018	-10.0	-10.0	-10.0	-10.0	RT
TAL	PURDOM	GT2	WAKULLA	GT	NG	PL	DFO	TK	9	10 / 2018	-10.0	-10.0	-10.0	-10.0	RT
DEF	CITRUS	1	CITRUS	CC	NG	PL	NG	PL	0	11 / 2018	820.0	910.0	820.0	910.0	P
FPL	MARTIN	8CTC	MARTIN	CT	NG	PL	DFO	TK	3	11 / 2018	2.0	5.2	2.0	5.2	OT
FPL	LAUDERDALE	4GT1	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2018	-156.0	-172.1	-156.0	-172.1	RT
FPL	LAUDERDALE	4GT2	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2018	-156.0	-172.1	-156.0	-172.1	RT
FPL	LAUDERDALE	4ST	BROWARD	CA	NG	PL	DFO	TK	2	12 / 2018	-135.0	-148.8	-130.0	-143.8	RT
FPL	LAUDERDALE	5GT1	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2018	-156.0	-172.1	-156.0	-172.1	RT
FPL	LAUDERDALE	5GT2	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2018	-156.0	-172.1	-156.0	-172.1	RT
FPL	LAUDERDALE	5ST	BROWARD	CA	NG	PL	DFO	TK	2	12 / 2018	-135.0	-148.8	-130.0	-143.8	RT
											2018 TOTAL:		-1,005.8	-832.4	
	2019														
FPL	MARTIN	8CTD	MARTIN	CT	NG	PL	DFO	TK	3	1 / 2019	2.0	5.2	2.0	5.2	OT
FPL	ST. JOHNS RIVER	1	DUVAL	ST	BIT	RR	PC	WA	0	3 / 2019	-127.0	-130.0	-127.0	-130.0	OT
FPL	ST. JOHNS RIVER	2	DUVAL	ST	BIT	RR	PC	WA	0	3 / 2019	-127.0	-130.0	-127.0	-130.0	OT
FPL	FT. MYERS	2CTE	LEE	CT	NG	PL	—	—	0	4 / 2019	1.0	0.0	1.0	0.0	OT
FPL	FT. MYERS	2CTF	LEE	CT	NG	PL	—	—	0	5 / 2019	1.0	0.0	1.0	0.0	OT
FPL	TURKEY POINT	4	DADE	ST	NUC	TK	—	—	0	5 / 2019	20.0	20.0	20.0	20.0	A
FPL	OKEECHOBEE ENERGY CENTER	1	UNKNOWN	CC	NG	PL	DFO	PL	0	6 / 2019	1,748.0	1,754.0	1,748.0	1,754.0	P
FPL	SANFORD	4ST	VOLUSIA	CA	NG	PL	—	—	0	11 / 2019	36.9	24.0	36.9	24.0	OT
											2019 TOTAL:		1,554.9	1,543.2	
	2020														
FMPA	ST. LUCIE	2	ST LUCIE	ST	NUC	—	TK	—	—	1 / 2020	-1.6	-1.5	-1.6	-1.5	OT
FPL	SANFORD	5ST	VOLUSIA	CA	NG	PL	—	—	0	1 / 2020	36.9	24.0	36.9	24.0	OT
FPL	FT. MYERS	2CTA	LEE	CT	NG	PL	—	—	0	3 / 2020	1.0	0.0	1.0	0.0	OT
FPL	FT. MYERS	2CTB	LEE	CT	NG	PL	—	—	0	3 / 2020	1.0	0.0	1.0	0.0	OT
FPL	FT. MYERS	2CTC	LEE	CT	NG	PL	—	—	0	5 / 2020	1.0	0.0	1.0	0.0	OT
FPL	FT. MYERS	2CTD	LEE	CT	NG	PL	—	—	0	5 / 2020	1.0	0.0	1.0	0.0	OT
FPL	FT. MYERS	2ST1	LEE	CA	WH	NA	—	—	0	5 / 2020	71.0	37.0	71.0	37.0	OT

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2020 (cont.)														
DEF	AVON PARK	P1	HIGHLANDS	GT	NG	PL	DFO	TK	3	6 / 2020	-24.0	-25.0	-24.0	-25.0	RT
DEF	AVON PARK	P2	HIGHLANDS	GT	DFO	TK	—	—	0	6 / 2020	-24.0	-25.0	-24.0	-25.0	RT
DEF	HIGGINS	P1	PINELLAS	GT	NG	PL	DFO	TK	0	6 / 2020	0.0	0.0	0.0	0.0	RT
DEF	HIGGINS	P2	PINELLAS	GT	NG	PL	DFO	TK	0	6 / 2020	0.0	0.0	0.0	0.0	RT
DEF	HIGGINS	P3	PINELLAS	GT	NG	PL	DFO	TK	0	6 / 2020	0.0	0.0	0.0	0.0	RT
DEF	HIGGINS	P4	PINELLAS	GT	NG	PL	DFO	TK	1	6 / 2020	0.0	0.0	0.0	0.0	RT
											2020 TOTAL:		**62.3**	**9.5**	
	2021														
SEC	UNNAMED CC	1	PUTNAM	CC	NG	PL	—	—	0	5 / 2021	593.0	592.0	593.0	592.0	P
TEC	FUTURE	CT1	UNKNOWN	GT	NG	PL	—	—	0	5 / 2021	206.0	222.0	204.0	220.0	P
											2021 TOTAL:		**797.0**	**812.0**	
	2022														
FPL	CAPE CANAVERAL	3A	BREVARD	CT	NG	PL	DFO	PL	0	6 / 2022	29.3	20.0	29.3	20.0	OT
FPL	CAPE CANAVERAL	3B	BREVARD	CT	NG	PL	DFO	PL	0	6 / 2022	29.3	20.0	29.3	20.0	OT
FPL	CAPE CANAVERAL	3C	BREVARD	CT	NG	PL	DFO	PL	0	6 / 2022	29.3	20.0	29.3	20.0	OT
FPL	DANIA BEACH ENERGY CENTER	1	BROWARD	CC	NG	PL	DFO	WA	0	6 / 2022	1,163.0	1,176.0	1,163.0	1,176.0	P
OUC	UNKNOWN	1	ORANGE	CC	NG	PL	DFO	TK	3	6 / 2022	380.0	400.0	360.0	380.0	OT
GRU	DEERHAVEN	FS01*	ALACHUA	ST	NG	PL	RFO	TK	0	8 / 2022	-80.0	-80.0	-75.0	-75.0	RT
SEC	UNNAMED CC	2	UNKNOWN	CC	NG	PL	—	—	0	12 / 2022	593.0	592.0	593.0	592.0	P
											2022 TOTAL:		**2,128.9**	**2,133.0**	
	2023														
DEF	OSPREY	CT1	POLK	CT	NG	PL	—	—	0	5 / 2023	83.8	98.3	83.8	98.3	OT
DEF	OSPREY	CT2	POLK	CT	NG	PL	—	—	0	5 / 2023	83.8	98.3	83.8	98.3	OT
DEF	OSPREY	ST	POLK	CA	WH	PL	—	—	0	5 / 2023	145.3	158.3	145.3	158.3	OT
FPL	RIVIERA	1A	PALM BEACH	CT	NG	PL	RFO	WA	0	6 / 2023	28.7	26.7	28.7	26.7	OT
FPL	RIVIERA	1A	PALM BEACH	CC	NG	PL	RFO	WA	0	6 / 2023	28.7	26.7	28.7	26.7	OT
FPL	RIVIERA	1A	PALM BEACH	CC	NG	PL	RFO	WA	0	6 / 2023	28.7	26.7	28.7	26.7	OT
											2023 TOTAL:		**399.0**	**435.0**	

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(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2024														
TEC	FUTURE	CT2	UNKNOWN	GT	NG	PL	—	—	0	5 / 2024	206.0	222.0	204.0	220.0	P
DEF	UNKNOWN	P1	UNKNOWN	CT	NG	PL	DFO	TK	4	6 / 2024	229.4	240.2	228.4	239.2	P
TAL	HOPKINS	IC 5	LEON	IC	NG	PL	—	—	0	6 / 2024	18.7	18.7	18.4	18.4	P
SEC	UNNAMED CT	1	UNKNOWN	GT	NG	PL	—	—	0	12 / 2024	215.0	244.0	215.0	244.0	P
											2024 TOTAL:		**665.8**	**721.6**	
	2025														
DEF	UNKOWN	P2	UNKNOWN	CT	NG	PL	DFO	TK	4	6 / 2025	229.4	240.2	228.4	239.2	P
											2025 TOTAL:		**228.4**	**239.2**	
	2026														
DEF	UNKNOWN	P3	UNKNOWN	CT	NG	PL	DFO	TK	4	6 / 2026	229.4	240.2	228.4	239.2	P
											2026 TOTAL:		**228.4**	**239.2**	

FRCC FUTURE (Excluding Firm Solar):	**6,015**	**5,949**
FRCC FUTURE FIRM SOLAR:	**1,111**	**0**
FRCC FUTURE TOTAL:	**7,126**	**5,949**

*Jointly Owned Unit

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 (Solar)
PLANNED AND PROSPECTIVE SOLAR GENERATING FACILITY ADDITIONS AND CHANGES[1,2]
(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		NON-FIRM		
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	EFFECTIVE CHANGE DATE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	CHANGE/ STATUS
	2017											
TEC	BIG BEND SOLAR	1	HILLSBOROUGH	PV	SUN	2 / 2017	18.0	8.0	---	---	---	P
SEC	MGS SOLAR	1	HARDEE	PV	SUN	4 / 2017	2.2	---	---	---	1.1	P
DEF	SUWANNEE SOLAR FACILITY	3	SUWANNEE	PV	SUN	12 / 2017	9.0	---	---	---	---	P
FPL	CORAL FARMS SOLAR ENERGY CENTER	1	PUTNAM	PV	SUN	12 / 2017	74.5	40.2	---	---	---	P
FPL	HORIZON SOLAR ENERGY CENTER	1	PUTNAM	PV	SUN	12 / 2017	74.5	40.2	---	---	---	P
FPL	INDIAN RIVER SOLAR ENERGY CENTER	1	INDIAN RIVER	PV	SUN	12 / 2017	74.5	40.2	---	---	---	P
FPL	WILDFLOWER SOLAR ENERGY CENTER	1	DESOTO	PV	SUN	12 / 2017	74.5	40.2	---	---	---	P
	2018											
FPL	BAREFOOT BAY SOLAR ENERGY CENTER	1	BREVARD	PV	SUN	2 / 2018	74.5	40.2	---	---	---	P
FPL	BLUE CYPRESS SOLAR ENERGY CENTER	1	INDIAN RIVER	PV	SUN	2 / 2018	74.5	40.2	---	---	---	P
FPL	HAMMOCK SOLAR ENERGY CENTER	1	HENDRY	PV	SUN	2 / 2018	74.5	40.2	---	---	---	P
FPL	LOGGERHEAD SOLAR ENERGY CENTER	1	ST LUCIE	PV	SUN	2 / 2018	74.5	40.2	---	---	---	P
DEF	SOLAR	4	UNKNOWN	PV	SUN	6 / 2018	20.0	---	---	---	---	P
	2019											
DEF	SOLAR	5	UNKNOWN	PV	SUN	6 / 2019	50.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2019	0.0	-0.7	---	---	---	D(S)
FPL	UNSITED SOLAR	1	UNKNOWN	PV	SUN	12 / 2019	298.0	160.0	---	---	---	P
	2020											
DEF	SOLAR	6	UNKNOWN	PV	SUN	6 / 2020	75.0	---	---	---	---	P
DEF	SOLAR	7	UNKNOWN	PV	SUN	6 / 2020	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2020	0.0	-1.0	---	---	---	D(S)
FPL	UNSITED SOLAR	1	UNKNOWN	PV	SUN	12 / 2020	298.0	160.0	---	---	---	P
	2021											
DEF	SOLAR	8	UNKNOWN	PV	SUN	6 / 2021	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2021	0.0	-1.8	---	---	---	D(S)
FPL	UNSITED SOLAR	1	UNKNOWN	PV	SUN	12 / 2021	298.0	160.0	---	---	---	P

Notes:

[1]DEF: Firm Summer potential export to grid at the time of peak was set at zero for current TYSP, but may vary after further demonstration study.

[2]Big Bend Solar began commerical operation on 02/10/2017. The as-built nameplate capacity is 19.8 MW_{AC} with a maximum daily capability of 19.36 MW_{AC}

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 (Solar)
PLANNED AND PROSPECTIVE SOLAR GENERATING FACILITY ADDITIONS AND CHANGES[1,2]
(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		NON-FIRM		
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	EFFECTIVE CHANGE DATE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	CHANGE/ STATUS
	2022											
DEF	SOLAR	9	UNKNOWN	PV	SUN	6 / 2022	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2022	0.0	-2.1	---	---	---	D(S)
FPL	UNSITED SOLAR	1	UNKNOWN	PV	SUN	12 / 2022	298.0	160.0	---	---	---	P
	2023											
DEF	SOLAR	10	UNKNOWN	PV	SUN	6 / 2023	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2023	0.0	-2.7	---	---	---	D(S)
FPL	UNSITED SOLAR	1	UNKNOWN	PV	SUN	12 / 2023	298.0	160.0	---	---	---	P
	2024											
DEF	SOLAR	11	UNKNOWN	PV	SUN	6 / 2024	75.0	---	---	---	---	P
DEF	SOLAR	12	UNKNOWN	PV	SUN	6 / 2024	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2024	0.0	-3.0	---	---	---	D(S)
	2025											
DEF	SOLAR	13	UNKNOWN	PV	SUN	6 / 2025	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2025	0.0	-3.6	---	---	---	D(S)
	2026											
DEF	SOLAR	14	UNKNOWN	PV	SUN	6 / 2026	75.0	---	---	---	---	P
FPL	SOLAR DEGRADATION	-	N/A	PV	SUN	8 / 2026	0.0	-3.8	---	---	---	D(S)

FRCC FUTURE (Excluding Firm Solar):	**6,015**	**5,949**
FRCC FUTURE FIRM SOLAR:	**1,111**	**0**
FRCC FUTURE TOTAL:	**7,126**	**5,949**

Notes:

[1]DEF: Firm Summer potential export to grid at the time of peak was set at zero for current TYSP, but may vary after further demonstration study.

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 10

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE	OUTSIDE	REGIONAL	REGIONAL	NON-UTILITY	AVAILABLE	TOTAL PEAK	LOAD MANAGEMENT & INT.		PEAK	LOAD MANAGEMENT & INT.	
YEAR	REGION (MW)	REGION (MW)	IMPORTS (MW)	EXPORTS (MW)	PURCHASES (MW)	CAPACITY (MW)	DEMAND (MW)	(MW)	% OF PEAK	DEMAND (MW)	(MW)	% OF PEAK
2017	49,986	828	424	0	3,881	55,120	47,508	7,612	16%	44,586	10,534	24%
2018	49,484	828	424	0	3,928	54,664	48,042	6,622	14%	45,041	9,623	21%
2019	50,955	828	524	0	3,469	55,776	48,587	7,189	15%	45,533	10,243	22%
2020	51,213	828	624	0	3,484	56,149	48,947	7,202	15%	45,838	10,311	22%
2021	52,168	828	200	0	3,026	56,222	49,498	6,724	14%	46,332	9,890	21%
2022	53,862	828	200	0	3,031	57,921	49,984	7,937	16%	46,794	11,127	24%
2023	55,011	828	200	0	3,033	59,072	50,600	8,472	17%	47,384	11,688	25%
2024	55,619	828	200	0	2,007	58,654	51,264	7,390	14%	48,031	10,623	22%
2025	56,059	828	200	0	1,854	58,941	51,893	7,048	14%	48,658	10,283	21%
2026	56,284	828	200	0	1,717	59,028	52,525	6,503	12%	49,260	9,768	20%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE	OUTSIDE	REGIONAL	REGIONAL	NON-UTILITY	AVAILABLE	TOTAL PEAK	LOAD MANAGEMENT & INT.		PEAK	LOAD MANAGEMENT & INT.	
YEAR	REGION (MW)	REGION (MW)	IMPORTS (MW)	EXPORTS (MW)	PURCHASES (MW)	CAPACITY (MW)	DEMAND (MW)	(MW)	% OF PEAK	DEMAND (MW)	(MW)	% OF PEAK
2017 / 18	52,751	829	424	0	4,154	58,158	44,836	13,322	30%	41,994	16,164	38%
2018 / 19	52,684	829	424	0	3,740	57,677	45,350	12,327	27%	42,462	15,215	36%
2019 / 20	54,505	829	524	0	3,756	59,614	45,769	13,845	30%	42,835	16,779	39%
2020 / 21	54,492	829	624	0	3,755	59,700	46,270	13,430	29%	43,285	16,415	38%
2021 / 22	55,304	829	200	0	3,214	59,547	46,659	12,888	28%	43,659	15,888	36%
2022 / 23	57,437	829	200	0	3,216	61,682	47,096	14,586	31%	44,066	17,616	40%
2023 / 24	57,872	829	200	0	2,661	61,561	47,535	14,026	30%	44,489	17,072	38%
2024 / 25	58,593	829	200	0	1,991	61,613	47,933	13,680	29%	44,881	16,732	37%
2025 / 26	58,832	829	200	0	1,874	61,735	48,356	13,379	28%	45,275	16,460	36%
2026 / 27	59,072	829	200	0	1,854	61,954	48,801	13,153	27%	45,689	16,265	36%

NOTE - COLUMN 11: NET FIRM PEAK DEMAND = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

2017
FRCC Form 11
CONTRACTED FIRM IMPORTS AND FIRM EXPORTS
FROM/TO OUTSIDE THE FRCC REGION AT TIME OF PEAK (MW)
AS OF JANUARY 1, 2017

SUMMER

	IMPORTS			EXPORTS		NET INTER-
YEAR	DEF	JEA	TOTAL		TOTAL	CHANGE
2017	424	0	424		0	424
2018	424	0	424		0	424
2019	424	100	524		0	524
2020	424	200	624		0	624
2021	0	200	200		0	200
2022	0	200	200		0	200
2023	0	200	200		0	200
2024	0	200	200		0	200
2025	0	200	200		0	200
2026	0	200	200		0	200

WINTER

	IMPORTS			EXPORTS		NET INTER-
YEAR	DEF	JEA	TOTAL		TOTAL	CHANGE
2017 / 18	424	0	424		0	424
2018 / 19	424	0	424		0	424
2019 / 20	424	100	524		0	524
2020 / 21	424	200	624		0	624
2021 / 22	0	200	200		0	200
2022 / 23	0	200	200		0	200
2023 / 24	0	200	200		0	200
2024 / 25	0	200	200		0	200
2025 / 26	0	200	200		0	200
2026 / 27	0	200	200		0	200

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
DUKE ENERGY FLORIDA																
	BEN HILL GRIFFIN	1	POLK	ST	NG	DFO	11 / 1981	0.5	0.5	0.5	0.5	---	---	---	---	NC
	CITRUS WORLD	1	POLK	ST	NG	DFO	11 / 1979	0.4	0.4	0.4	0.4	---	---	---	---	NC
	CITRUS WORLD	4	POLK	ST	NG	DFO	12 / 1987	4.0	4.0	4.0	4.0	---	---	---	---	NC
	FL POWER DEVELOPMENT	1	UNKNOWN	ST	AB	---	6 / 2014	60.0	60.0	60.0	60.0	60.0	60.0	---	---	C
	MULBERRY	1	POLK	CA	NG	DFO	7 / 1994	115.0	120.0	115.0	115.0	115.0	115.0	---	---	C
	ORANGE COGEN (CFR-BIOGEN)	1	POLK	CS	NG	---	6 / 1995	104.0	104.0	104.0	104.0	104.0	104.0	---	---	C
	ORLANDO COGEN	1	ORANGE	CA	NG	---	10 / 1993	125.2	135.0	123.2	133.0	115.0	115.0	9.0	18.8	C
	PASCO COUNTY RES. RECOV.	1	PASCO	ST	MSW	---	3 / 1991	26.0	26.0	23.0	23.0	23.0	23.0	---	---	C
	PINELLAS COUNTY RES. RECOV.	1	PINELLAS	ST	MSW	---	4 / 1983	44.6	44.6	40.0	40.0	40.0	40.0	---	---	C
	PINELLAS COUNTY RES. RECOV.	2	PINELLAS	ST	MSW	---	6 / 1986	17.1	17.1	14.8	14.8	14.8	14.8	---	---	C
	POTASH of SASKATCHEWAN	1	HAMILTON	ST	WH	---	1 / 1980	16.2	16.2	15.0	15.0	---	---	1.0	1.0	NC
	POTASH of SASKATCHEWAN	2	HAMILTON	ST	WH	---	5 / 1986	28.0	28.0	27.0	27.0	---	---	0.2	0.2	NC
	PROCTOR & GAMBLE (BUCKEYE)	1-4	TAYLOR	ST	WDS	---	1 / 1954	38.0	38.0	38.0	38.0	---	---	---	---	NC
	RIDGE GENERATING STATION	1	POLK	ST	WDS	---	5 / 1994	39.6	39.6	39.6	39.6	39.6	39.6	---	---	C
											DEF TOTAL:	511.4	511.4	10.2	20.0	
FLORIDA MUNICIPAL POWER AGENCY																
	CUTRALE		LAKE	CC	NG	---	12 / 1987	4.6	4.6	4.6	4.6	---	---	---	---	NC
	US SUGAR CORPORATION		HENDRY	OT	OBS	---	2 / 1984	26.5	26.5	26.5	26.5	---	---	---	---	NC
											FMPA TOTAL:	0.0	0.0	0.0	0.0	
FLORIDA POWER & LIGHT COMPANY																
	BROWARD-SOUTH	1	BROWARD	OT	MSW	---	4 / 1991	68.0	68.0	54.0	54.0	3.5	3.5	---	---	C
	GEORGIA PACIFIC	1	PUTNAM	OT	WDS	---	2 / 1983	52.0	52.0	52.0	52.0	---	---	---	---	NC
	INDIANTOWN	1	MARTIN	OT	BIT	---	12 / 1995	330.0	330.0	330.0	330.0	330.0	330.0	---	---	C
	INEOS BIO	1	INDIAN RIVER	OT	WDS	OTH	1 / 2014	6.4	6.4	6.4	6.4	---	---	---	---	NC
	MIAMI DADE (RR)	1	DADE	OT	MSW	OTH	9 / 1991	77.0	77.0	77.0	77.0	---	---	---	---	NC
	NEW HOPE / OKEELANTA	1	PALM BEACH	OT	OBS	NG	11 / 1985	140.0	140.0	155.0	180.0	---	---	---	---	NC
	TROPICANA	1	MANATEE	OT	NG	OTH	3 / 1990	46.7	46.7	46.7	46.7	---	---	---	---	NC
	WASTE MANAGEMENT (CCL)	1	BROWARD	OT	LFG	OTH	5 / 2011	7.2	7.2	7.2	7.2	---	---	---	---	NC
	WASTE MANAGEMENT (RE)	1	BROWARD	OT	LFG	OTH	4 / 1989	11.5	11.5	11.5	11.5	---	---	---	---	NC
											FPL TOTAL (Excluding Solar):	333.5	333.5	0.0	0.0	

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
GAINESVILLE REGIONAL UTILITIES																
	G2 ENERGY	1	MARION	IC	LFG	---	12 / 2008	4.0	4.0	3.7	3.4	3.7	3.4	---	---	C
	GVL RENEWABLE ENERGY	1	ALACHUA	ST	WDS	---	12 / 2013	116.0	116.0	102.5	102.5	102.5	102.5	---	---	C
											GRU TOTAL:	106.2	105.9	0.0	0.0	
JEA																
	ANHEUSER BUSCH		DUVAL	ST	NG	---	4 / 1988	0.0	0.0	8.0	9.0	---	---	---	---	NC
	TRAILRIDGE	1	DUVAL	IC	LFG	---	12 / 2008	9.0	9.0	9.0	9.0	9.0	9.0	---	---	C
	TRAILRIDGE	2	SARASOTA	IC	LFG	---	2 / 2015	6.0	6.0	6.0	6.0	6.0	6.0	---	---	C
											JEA TOTAL (Excluding Solar):	15.0	15.0	0.0	0.0	
SEMINOLE ELECTRIC COOPERATIVE INC																
	BREVARD LANDFILL	1	BREVARD	ST	LFG	---	4 / 2008	9.0	9.0	9.0	9.0	9.0	9.0	---	---	C
	CITY OF TAMPA REF-TO-ENERGY	1	HILLSBOROUGH	ST	MSW	---	8 / 2011	20.0	20.0	20.0	20.0	20.0	20.0	---	---	C
	HARDEE POWER STATION	CT1A	HARDEE	CT	NG	DFO	1 / 2013	74.0	91.0	74.0	91.0	74.0	91.0	---	---	C
	HARDEE POWER STATION	CT1B	HARDEE	CT	NG	DFO	1 / 2013	74.0	91.0	74.0	91.0	74.0	91.0	---	---	C
	HARDEE POWER STATION	CT2A	HARDEE	GT	NG	DFO	1 / 2013	70.0	89.0	70.0	89.0	70.0	89.0	---	---	C
	HARDEE POWER STATION	CT2B	HARDEE	GT	NG	DFO	1 / 2013	70.0	89.0	70.0	89.0	70.0	89.0	---	---	C
	HARDEE POWER STATION	ST1	HARDEE	CA	WH	DFO	1 / 2013	72.0	85.0	72.0	85.0	72.0	85.0	---	---	C
	HILLSB. WASTE TO ENERGY	1	HILLSBOROUGH	ST	MSW	---	3 / 2010	9.5	9.5	9.5	9.5	9.5	9.5	---	---	C
	HILLSB. WASTE TO ENERGY	2	HILLSBOROUGH	ST	MSW	---	3 / 2010	9.5	9.5	9.5	9.5	9.5	9.5	---	---	C
	HILLSB. WASTE TO ENERGY	3	HILLSBOROUGH	ST	MSW	---	3 / 2010	9.5	9.5	9.5	9.5	9.5	9.5	---	---	C
	HILLSB. WASTE TO ENERGY	4	HILLSBOROUGH	ST	MSW	---	3 / 2010	9.5	9.5	9.5	9.5	9.5	9.5	---	---	C
	LEE COUNTY RES. RECOV.	1	LEE	ST	MSW	---	1 / 2009	30.0	36.0	30.0	36.0	30.0	36.0	---	---	C
	LEE COUNTY RES. RECOV.	2	LEE	ST	MSW	---	1 / 2009	15.0	19.0	15.0	19.0	15.0	19.0	---	---	C
	SEMINOLE LANDFILL	1	SEMINOLE	ST	LFG	---	10 / 2007	6.2	6.2	6.2	6.2	6.2	6.2	---	---	C
	TELOGIA POWER	1	LIBERTY	ST	WDS	---	7 / 2009	13.0	13.0	13.0	13.0	13.0	13.0	---	---	C
	TIMBERLINE ENERGY	1	HERNANDO	ST	LFG	---	2 / 2008	1.6	1.6	1.6	1.6	1.6	1.6	---	---	C
											SEC TOTAL:	492.8	587.8	0.0	0.0	

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
TAMPA ELECTRIC COMPANY																
	CF INDUSTRIES	1	HILLSBOROUGH	ST	WH	---	12 / 1988	34.1	34.1	34.1	34.1	---	---	1.2	1.2	NC
	CITY OF TAMPA SEWAGE	1-5	HILLSBOROUGH	IC	OBG	---	7 / 1989	0.5	0.5	0.5	0.5	---	---	---	---	NC
	CUTRALE CITRUS JUICES	1-3	POLK	CC	NG	---	12 / 1987	6.5	6.5	6.5	6.5	---	---	---	---	NC
	MILLPOINT	1-3	HILLSBOROUGH	OT	WH	NG	12 / 1995	43.4	43.4	43.4	43.4	---	---	4.9	4.9	NC
	NEW WALES	1-2	POLK	ST	WH	---	12 / 1984	88.0	88.0	88.0	88.0	---	---	---	---	NC
	RIDGEWOOD	1-2	HILLSBOROUGH	ST	WH	---	10 / 1992	63.0	63.0	63.0	63.0	---	---	---	---	NC
	SOUTH PIERCE	1-2	POLK	ST	WH	---	9 / 1969	35.0	35.0	35.0	35.0	---	---	1.0	1.0	NC
	ST. JOSEPHS HOSPITAL	1	HILLSBOROUGH	IC	NG	---	4 / 1993	1.6	1.6	1.6	1.6	---	---	---	---	NC
											TEC TOTAL:	0.0	0.0	7.1	7.1	
											FRCC NON-UTILITY (Excluding Solar):	1459	1554	17	27	
											FRCC NON-UTILITY SOLAR:	0	0	14	0	
											FRCC NON-UTILITY TOTAL:	1,459	1,554	32	27	

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0 (Solar)
EXISTING SOLAR NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		UNCOMMITTED		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERCIAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
FLORIDA POWER & LIGHT COMPANY												
	FIRST SOLAR	1	DADE	PV	SUN	3 / 2010	0.1	---	---	---	---	NC
	ROTHENBACK PARK	1	SARASOTA	PV	SUN	10 / 2007	0.2	---	---	---	---	NC
								0.0	0.0	0.0	0.0	
JEA												
	JACKSONVILLE SOLAR	1	DUVAL	PV	SUN	9 / 2010	15.0	---	---	---	---	C
								0.0	0.0	0.0	0.0	
LAKELAND CITY OF												
	AIRPORT PHASE 1		POLK	PV	SUN	1 / 2012	2.2	---	---	2.2	---	NC
	AIRPORT PHASE 2		POLK	PV	SUN	9 / 2012	2.7	---	---	2.7	---	NC
	AIRPORT PHASE 3		POLK	PV	SUN	12 / 2016	3.1	---	---	3.1	---	NC
	BELLA VISTA		POLK	PV	SUN	7 / 2015	6.0	---	---	6.0	---	NC
	LAKELAND CENTER		POLK	PV	SUN	3 / 2010	0.2	---	---	0.2	---	NC
								0.0	0.0	14.2	0.0	

FRCC NON-UTILITY (Excluding Solar):	1459	1554	17	27
FRCC NON-UTILITY SOLAR:	0	0	14	0
FRCC NON-UTILITY TOTAL:	1,459	1,554	32	27

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.1
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
							COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT	GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
	2017															
SEC	LEE COUNTY RES. RECOV.	1	LEE	ST	MSW	---	1 / 2017	-30.0	-36.0	-30.0	-36.0	-30.0	-36.0	---	---	CE
SEC	LEE COUNTY RES. RECOV.	2	LEE	ST	MSW	---	1 / 2017	-15.0	-19.0	-15.0	-19.0	-15.0	-19.0	---	---	CE
	2018															
SEC	BREVARD LANDFILL	1	BREVARD	ST	LFG	---	4 / 2018	-9.0	-9.0	-9.0	-9.0	-9.0	-9.0	---	---	CE
SEC	SEMINOLE LANDFILL	1	SEMINOLE	ST	LFG	---	4 / 2018	-6.2	-6.2	-6.2	-6.2	-6.2	-6.2	---	---	CE
DEF	US ECOGEN POLK	1	POLK	OT	AB	---	6 / 2018	60.0	60.0	60.0	60.0	60.0	60.0	---	---	C
JEA	TRAILRIDGE	1	DUVAL	IC	LFG	---	12 / 2018	9.0	9.0	9.0	9.0	-9.0	-9.0	---	---	CE
	2019															
FPL	INDIANTOWN	2	MARTIN	ST	BIT	---	3 / 2019	-330.0	-330.0	-330.0	-330.0	-330.0	-330.0	---	---	CE
	2020															
SEC	TIMBERLINE ENERGY	1	HERNANDO	ST	LFG	---	4 / 2020	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	---	---	CE
	2021															
	NO ENTRIES															
	2022															
	NO ENTRIES															

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

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PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
	2023															
DEF	ORLANDO COGEN	1	ORANGE	CA	NG	---	12 / 2023	-125.2	-135.0	-123.2	-133.0	-115.0	-115.0	-9.0	-18.8	NC
GRU	G2 ENERGY	1	MARION	IC	LFG	---	12 / 2023	-4.0	-4.0	-3.7	-3.4	-3.7	-3.7	---	---	CE
SEC	TELOGIA POWER	1	LIBERTY	ST	WDS	---	12 / 2023	-13.0	-13.0	-13.0	-13.0	-13.0	-13.0	---	---	CE
	2024															
DEF	MULBERRY	1	POLK	CA	NG	---	9 / 2024	-115.0	-120.0	-115.0	-115.0	-115.0	-115.0	---	---	NC
	2025															
SEC	HILLSB. WASTE TO ENERGY	1	HILLSBOROUGH	ST	MSW	---	3 / 2025	-9.5	-9.5	-9.5	-9.5	-9.5	-9.5	---	---	CE
SEC	HILLSB. WASTE TO ENERGY	2	HILLSBOROUGH	ST	MSW	---	3 / 2025	-9.5	-9.5	-9.5	-9.5	-9.5	-9.5	---	---	CE
SEC	HILLSB. WASTE TO ENERGY	3	HILLSBOROUGH	ST	MSW	---	3 / 2025	-9.5	-9.5	-9.5	-9.5	-9.5	-9.5	---	---	CE
SEC	HILLSB. WASTE TO ENERGY	4	HILLSBOROUGH	ST	MSW	---	3 / 2025	-9.5	-9.5	-9.5	-9.5	-9.5	-9.5	---	---	CE
DEF	ORANGE COGEN (CFR-BIOGEN)	1	POLK	CS	NG	---	12 / 2025	-104.0	-104.0	-104.0	-104.0	-104.0	-104.0	---	---	CE
	2026															
SEC	CITY OF TAMPA REFUSE-TO-ENERGY	1	HILLSBOROUGH	ST	MSW	---	8 / 2026	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	---	---	CE

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LOAD AND RESOURCE PLAN
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INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
	2017											
JEA	MONTGOMERY SOLAR FARM	1	DUVAL	PV	SUN	5 / 2017	7.0	---	---	---	---	C
JEA	OLD PLANK ROAD SOLAR FARM	1	DUVAL	PV	SUN	8 / 2017	3.0	---	---	---	---	C
JEA	BLAIR SITE SOLAR	1	DUVAL	PV	SUN	12 / 2017	4.0	---	---	---	---	C
JEA	IMESON SOLAR	1	DUVAL	PV	SUN	12 / 2017	5.0	---	---	---	---	C
JEA	OLD KINGS ROAD SOLAR	1	DUVAL	PV	SUN	12 / 2017	1.0	---	---	---	---	C
JEA	SIMMONS ROAD SOLAR	1	DUVAL	PV	SUN	12 / 2017	2.0	---	---	---	---	C
JEA	STARRATT SOLAR	1	DUVAL	PV	SUN	12 / 2017	5.0	---	---	---	---	C
	2018											
TAL	FL SOLAR 1	1	LEON	PV	SUN	1 / 2018	26.0	---	---	20.0	20.0	C
DEF	SOLAR QF	1 & 2	UNKNOWN	PV	SUN	6 / 2018	150.0	---	---	---	---	NC
	2019											
DEF	SOLAR QF	3	UNKNOWN	PV	SUN	6 / 2019	75.0	---	---	---	---	NC
	2020											
DEF	SOLAR QF	4	UNKNOWN	PV	SUN	6 / 2020	75.0	---	---	---	---	NC
	2021											
DEF	SOLAR QF	5	UNKNOWN	PV	SUN	6 / 2021	75.0	---	---	---	---	NC
	2022											
DEF	SOLAR QF	6	UNKNOWN	PV	SUN	6 / 2022	75.0	---	---	---	---	NC
	2023											
DEF	SOLAR QF	7	UNKNOWN	PV	SUN	6 / 2023	75.0	---	---	---	---	NC

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.1 (Solar)
PLANNED AND PROSPECTIVE SOLAR NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
								FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
	2024											
DEF	SOLAR QF	8	UNKNOWN	PV	SUN	6 / 2024	75.0	---	---	---	---	NC
	2025											
DEF	SOLAR QF	9	UNKNOWN	PV	SUN	6 / 2025	75.0	---	---	---	---	NC
	2026											
DEF	SOLAR QF	10	UNKNOWN	PV	SUN	6 / 2026	75.0	---	---	---	---	NC

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
NON-UTILITY GENERATING FACILITIES SUMMARY

	SUMMER	
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED NUG GENERATION (MW)
2017	1,413.9	31.5
2018	1,458.7	51.5
2019	1,119.7	51.5
2020	1,118.1	51.5
2021	1,118.1	51.5
2022	1,118.1	51.5
2023	1,118.1	51.5
2024	986.4	42.5
2025	833.4	33.5
2026	709.4	24.5

	WINTER	
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED NUG GENERATION (MW)
2017/18	1,498.6	47.1
2018/19	1,204.4	47.1
2019/20	1,204.4	47.1
2020/21	1,202.8	47.1
2021/22	1,202.8	47.1
2022/23	1,202.8	47.1
2023/24	1,071.1	28.3
2024/25	918.1	28.3
2025/26	814.1	28.3
2026/27	794.1	28.3

2017

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

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SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
ALACHUA	FMPA	08/14/83	---	0.4	0.4	NUC	Entitlement Share of St. Lucie Project (St. Lucie #2)
DEF	CAL	01/01/15	01/02/17	245	245	NG	Osprey Tolling Agreement
DEF	GE	04/01/07	04/30/24	158.7	172.4	NG	Shady Hills PPA
DEF	GE	04/01/07	04/30/24	158.7	172.4	NG	Shady Hills PPA
DEF	GE	04/01/07	04/30/24	158.7	172.4	NG	Shady Hills PPA
DEF	NSG	06/01/12	05/31/27	158.6	169.4	NG	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	158.6	169.4	NG	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	158.6	169.4	NG	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	158.6	169.4	NG	Vandolah with present owner (Northern Star Generation)
DEF	SOU	06/01/16	05/31/21	424	424	NG	Southern purchase extension
FKE	FPL	02/17/11	12/31/31	156	122	NG	FKE has entered into a long term full reqirements contract with FPL to purchase power
FMPA	KEY	04/01/98	12/31/32	36.5	36.5	DFO	All KEYS owned capacity is used by FMPA to serve the ARP
FMPA	KUA	01/01/14	---	241.7	252.7	NG	All KUA owned capacity is used by FMPA to serve the ARP
FMPA	SOU	10/01/03	09/30/23	79	84	NG	PPA with SOU (Stanton A)
FMPA	SOU	12/16/07	12/16/27	162	180	NG	PPA with SOU (Oleander 5)
FMPA	TBD	06/01/24	09/30/24	22	0	OTH	Placeholder for meeting Summer loads plus reserve margin
FMPA	TBD	06/01/25	09/30/25	40	0	OTH	Placeholder for meeting Summer loads plus reserve margin
FMPA	TBD	06/01/26	09/30/26	58	0	OTH	Placeholder for meeting Summer loads plus reserve margin
FPL	JEA	03/01/87	03/31/19	382	389	BIT	Unit Power Sales - Firm Contract
FPL	OTH	01/01/12	04/01/34	40	40	MSW	Palm Beach SWA
FPL	OTH	01/01/15	04/01/34	70	70	MSW	Palm Beach SWA- additional
GRU	A.R.	12/17/13	12/31/43	102.5	102.5	WDS	This is a woody waste fueled biomass unit
GRU	FIT	01/01/09	12/31/28	0.2	0.1	SUN	Load-reducing 2009 Feed-In Tariff installations
GRU	FIT	01/01/10	12/31/29	1.0	0.3	SUN	Load-reducing 2010 Feed-In Tariff installations
GRU	FIT	01/01/11	12/31/30	2.1	0.6	SUN	Load-reducing 2011 Feed-In Tariff installations
GRU	FIT	01/01/12	12/31/31	1.7	0.5	SUN	Load-reducing 2012 Feed-In Tariff installations
GRU	FIT	01/01/13	12/31/32	1.6	0.4	SUN	Load-reducing 2013 Feed-In Tariff installations
GRU	G2 U1&2	01/01/09	12/31/23	2.9	2.9	LFG	This Renewable Energy power producer,G2 Energy,is located in Ocala, FL at the Baseline Landfill
GRU	G2 U3	09/01/10	12/31/23	0.8	0.8	LFG	This is an amendment to the original 3 MW contract
HST	DEF	01/01/13	12/31/19	40	40	BIT	System sales contract. Historically, the majority of the generation has been coal, with NG as the secondary fuel
HST	FMPA	08/14/83	—	7	7.3	NUC	Entitlement Share in St. Lucie Project (St. Lucie #2)

2017

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

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SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
HST	FMPA	07/01/87	---	7.7	7.7	BIT	Entitlement Share in Stanton Project (Stanton 1)
HST	FMPA	07/01/87	---	5.1	5.1	BIT	Entitlement Share in Tri-City Project (Stanton 1)
HST	FMPA	06/01/96	---	8.3	8.3	BIT	Entitlement Share in Stanton II Project (Stanton 2)
HST	FPL	01/01/16	12/31/24	27	27	OTH	System sale from FPL
HST	MDA	01/01/20	12/31/25	15	15	OTH	TBD
HST	SEC	01/01/16	12/31/21	15	15	OTH	Contract from SEC
JEA	MEAG	06/01/19	06/01/39	100	100	NUC	Nuclear PPA from the Municipal Electric Authority of Georgia (MEAG) for Vogtle Unit 3
JEA	MEAG	06/01/20	06/01/40	100	100	NUC	Nuclear PPA from the Municipal Electric Authority of Georgia (MEAG) for Vogtle Unit 4
JEA	TBD	01/01/18	01/01/20	225	225	OTH	Annual Capacity & Energy
JEA	TBD	06/01/20	09/30/26	200	0	OTH	Summer Capacity & Energy Purchase
LWU	FMPA	08/14/83	01/01/46	21.6	22.4	NUC	Entitlement Share in St. Lucie Project (St. Lucie #2)
LWU	FMPA	07/01/87	01/01/46	10.4	10.4	BIT	Entitlement Share in Stanton Project (Stanton 1)
LWU	OUC	01/01/17	12/31/17	36	36	OTH	Represents PR purchase from OUC
LWU	OUC	01/01/18	12/31/18	38	38	OTH	Represents PR purchase from OUC
NSB	DEF	01/01/09	12/31/18	30	30	NA	Partial Requirements
NSB	FMPA	08/14/83	---	8.6	8.9	NUC	Entitlement Share in St. Lucie Project (St. Lucie #2)
NSB	FPL	02/01/14	12/31/18	45	45	NA	Native Load Firm
NSB	FPL	01/01/17	01/01/19	20	20	NG	Native Load Firm Peaking
NSB	TBD	01/01/18	12/31/24	60	60	NA	Future supply
OUC	OTH	10/01/13	09/30/33	2.6	2.6	LFG	LFG PPA (Port Charlotte)
OUC	OTH	07/01/15	12/31/17	9	9	LFG	LFG PPA (CBI)
OUC	OTH	01/01/17	12/31/36	6	6	LFG	LFG PPA (Orange County)
OUC	OTH	01/01/17	12/31/35	9.0	0	SUN	Stanton Solar Farm PPA
OUC	OTH	01/01/18	12/31/18	11	11	LFG	LFG PPA (CBI)
OUC	OTH	01/01/19	12/31/19	12	12	LFG	LFG PPA (CBI)
OUC	OTH	01/01/20	12/31/20	13	13	LFG	LFG PPA (CBI)
OUC	OTH	01/01/21	12/31/21	14	14	LFG	LFG PPA (CBI)
OUC	OTH	01/01/22	12/31/22	19	19	LFG	LFG PPA (CBI)
OUC	OTH	01/01/23	12/31/23	21	21	LFG	LFG PPA (CBI)
OUC	OTH	01/01/24	12/31/25	24	24	LFG	LFG PPA (CBI)

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LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

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SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
OUC	OTH	01/01/26	04/01/27	26	26	LFG	LFG PPA (CBI)
OUC	SOU	01/01/03	09/30/23	342	343	NG	OUC PPA with SOU for Stanton A capacity. No decision made whether to extend or terminate PPA at this time
RCI	DEF	03/01/16	03/01/31	2.1	2.2	SUN	PV PPA
RCI	DEF	01/01/17	12/31/17	138	89	NA	Firm Base Load Purchase, this is a reserved product
RCI	DEF	01/01/18	12/31/18	139	89	NA	Firm Base Load Purchase, this is a reserved product
RCI	DEF	01/01/19	12/31/19	140	90	NA	Firm Base Load Purchase, this is a reserved product
RCI	DEF	01/01/20	12/31/20	141	90	NA	Firm Base Load Purchase, this is a reserved product
RCI	HARVEST	03/01/14	12/31/34	1.2	1.2	OBG	Harvest Power anaerobic digester
RCI	TBD	01/01/19	12/31/20	9	9	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/21	12/31/21	150	115	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/22	12/31/22	151	116	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/23	12/31/23	152	117	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/24	12/31/24	153	118	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/25	12/31/25	154	119	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/26	12/31/26	155	119	NA	Undetermined Purchase, this is a reserved product
RCI	TBD	01/01/27	12/31/27	158	120	NA	Undetermined Purchase, this is a reserved product
RCI	TEC	01/01/16	12/31/18	15	15	NA	Firm Peaking Purchase, this is a reserved product
SEC	BREVARD	04/01/08	03/31/18	9	9	LFG	Brevard Energy: Landfill gas-to-energy facility
SEC	DEF	01/01/14	12/31/20	0	600	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/14	12/31/20	150	150	NA	System firm intermediate capacity purchase
SEC	DEF	06/01/16	12/31/18	50	50	NA	System Firm Base Capacity Purchase
SEC	DEF	06/01/16	12/31/18	200	200	NA	System firm intermediate capacity purchase
SEC	DEF	06/01/17	09/30/20	100	0	NA	System firm Summer Seasonal Peaking Capacity purchase
SEC	DEF	01/01/19	05/31/19	0	250	NA	System firm intermediate capacity purchase
SEC	DEF	06/01/19	12/31/22	500	500	NA	System firm intermediate capacity purchase
SEC	DEF	01/01/21	12/31/21	0	275	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/22	12/31/22	0	450	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/23	12/31/23	0	250	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/23	12/31/24	200	200	NA	System firm intermediate capacity purchase
SEC	DEF	01/01/24	12/31/24	0	300	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/25	12/31/25	0	350	NA	System firm Winter Seasonal Peaking Capacity purchase

2017

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12

SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
SEC	DEF	01/01/26	12/31/26	0	225	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/27	03/31/27	0	300	NA	System firm Winter Seasonal Peaking Capacity purchase
SEC	FPL	06/01/14	05/31/21	200	200	NA	System firm intermediate capacity purchase
SEC	HILLS	03/01/10	02/28/25	38	38	MSW	Municipal solid waste facility (Hillsborough Waste to Energy)
SEC	HPP	01/01/13	12/31/32	74	91	NG	Intermediate firm capacity purchase - Hardee CT1A
SEC	HPP	01/01/13	12/31/32	70	89	NG	CT firm capacity purchase - Hardee CT2A
SEC	HPP	01/01/13	12/31/32	70	89	NG	CT firm capacity purchase - Hardee CT 2B
SEC	HPP	01/01/13	12/31/32	74	91	NG	Intermediate firm capacity purchase - Hardee CT1B
SEC	HPP	01/01/13	12/31/32	72	85	WH	Intermediate firm capacity purchase - Hardee ST1
SEC	OTH	01/01/14	12/31/54	54	54	DFO	Firm purchase from SECI Members for Diesel Generation (CBGs)
SEC	SEMINOLE	10/01/07	03/31/18	6.2	6.2	LFG	Seminole Energy: Landfill gas-to-energy facility
SEC	SOU	01/01/10	05/31/21	153	182	NG	CT firm capacity purchase - Oleander 2(2nd PPA)
SEC	SOU	01/01/10	05/31/21	153	182	NG	CT firm capacity purchase - Oleander 3(2nd PPA)
SEC	SOU	01/01/10	05/31/21	153	182	NG	CT firm capacity purchase - Oleander 4(2nd PPA)
SEC	Tampa	08/01/11	07/31/26	20	20	MSW	McKay Bay Waste to Energy facility (City of Tampa Waste to Energy)
SEC	TBD	12/01/20	03/31/21	0	1	NG	System firm seasonal purchase
SEC	TBD	06/01/21	09/30/21	152	0	NG	System firm seasonal purchase
SEC	TBD	12/01/21	03/31/22	0	37	NG	System firm seasonal purchase
SEC	TBD	06/01/22	09/30/22	208	0	NG	System firm seasonal purchase
SEC	TBD	12/01/22	03/31/23	0	6	NG	System firm seasonal purchase
SEC	TBD	12/01/23	03/31/24	0	31	NG	System firm seasonal purchase
SEC	TBD	06/01/24	09/30/24	44	0	NG	System firm seasonal purchase
SEC	TBD	06/01/25	09/30/25	125	0	NG	System firm seasonal purchase
SEC	TBD	12/01/25	03/31/26	0	200	NG	System firm seasonal purchase
SEC	TBD	06/01/26	09/30/26	197	0	NG	System firm seasonal purchase
SEC	TBD	12/01/26	03/31/27	0	224	NG	System firm seasonal purchase
SEC	TELOGIA	07/01/09	11/30/23	13	13	WDS	Telogia Power LLC: Wood waste fueled biomass facility
SEC	TIMBERLINE	02/01/08	03/31/20	1.6	1.6	LFG	Timberline Energy: Landfill gas-to-energy facility - Hernando
STC	FMPA	06/01/96	01/01/46	15.1	15.1	BIT	Entitlement Share in Stanton II Project (Stanton 2)
STC	OUC	10/01/16	09/30/17	161	144	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/17	09/30/18	166	149	OTH	Interchange between OUC and STC per Interlocal Agreement

2017

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

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SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
STC	OUC	10/01/18	09/30/19	170	153	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/19	09/30/20	174	157	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/20	09/30/21	178	160	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/21	09/30/22	183	163	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/22	09/30/23	187	167	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/23	09/30/24	191	171	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/24	09/30/25	195	175	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/25	09/30/26	200	179	OTH	Interchange between OUC and STC per Interlocal Agreement
STC	OUC	10/01/26	09/30/27	204	183	OTH	Interchange between OUC and STC per Interlocal Agreement
TEC	DEF	02/01/16	02/28/17	250	250	NG	Firm purchase contract with Duke Energy of Florida through 2/28/2017
TEC	PAC	01/01/09	12/31/18	121	121	NG	Firm purchase contract with Quantum Pasco Power through 12/31/2018
VER	FMPA	08/14/83	01/01/46	13.2	13.7	NUC	Entitlement Share in St. Lucie Project (St. Lucie #2)
VER	FMPA	07/01/87	01/01/46	20.8	20.8	BIT	Entitlement Share in Stanton Project (Stanton 1)
VER	FMPA	07/01/87	01/01/46	17	17	BIT	Entitlement Share in Stanton II Project (Stanton 2)
VER	OUC	10/01/16	09/30/17	139	139	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/17	09/30/18	140	140	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/18	09/30/19	142	142	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/19	09/30/20	145	145	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/20	09/30/21	147	147	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/21	09/30/22	150	150	OTH	Represents MW projected to be provided to VER by OUC
VER	OUC	10/01/22	09/30/23	153	153	OTH	Represents MW projected to be provided to VER by OUC
VER	TBD	10/01/23	09/30/24	157	148	OTH	Unspecified PPA
VER	TBD	10/01/24	09/30/25	159	153	OTH	Unspecified PPA
VER	TBD	10/01/25	09/30/26	162	155	OTH	Unspecified PPA
VER	TBD	10/01/26	09/30/27	162	180	OTH	Unspecified PPA

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.0
FUEL REQUIREMENTS
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FUEL REQUIREMENTS		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	NUCLEAR		TRILLION BTU	321	310	308	317	316	315	321	316	316	321	316
(2)	COAL		1000 TON	17,543	19,165	15,427	14,060	14,471	14,946	15,099	15,217	15,405	13,769	13,991
	RESIDUAL													
(3)		STEAM	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
	DISTILLATE													
(7)		STEAM	1000 BBL	214	81	73	67	66	49	48	43	45	65	64
(8)		CC	1000 BBL	83	296	41	63	12	14	14	18	17	14	13
(9)		CT	1000 BBL	328	173	71	75	54	50	70	75	79	92	74
(10)		TOTAL:	1000 BBL	625	550	185	205	132	113	132	136	141	171	151
	NATURAL GAS													
(11)		STEAM	1000 MCF	99,950	74,422	67,632	63,471	61,232	54,770	56,556	51,838	55,261	54,828	54,388
(12)		CC	1000 MCF	944,748	930,358	982,550	1,005,642	1,002,622	1,006,737	1,009,172	1,026,073	1,031,561	1,067,817	1,082,158
(13)		CT	1000 MCF	30,940	21,589	21,883	20,865	19,952	22,629	24,094	21,625	27,238	28,919	30,650
(14)		TOTAL:	1000 MCF	1,075,638	1,026,369	1,072,065	1,089,978	1,083,806	1,084,136	1,089,822	1,099,536	1,114,060	1,151,564	1,167,196
(15)	OTHER	PET COKE	1000 TON	1,195	786	748	848	865	808	809	831	840	867	868
		LFG & BIOFUELS	1000 MMBTU	344	366	344	365	387	396	422	432	435	435	444

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.1
ENERGY SOURCES (GWH)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5) ACTUAL	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		GWH	7,816	2,320	3,933	3,127	2,264	2,774	2,854	2,828	2,711	2,703	2,870
(2)	NUCLEAR		GWH	29,052	29,017	28,842	29,686	29,581	29,419	30,038	29,569	29,491	30,046	29,577
(3)	COAL		GWH	38,606	43,019	34,820	31,369	32,771	33,710	33,844	33,948	34,653	30,843	31,423
	RESIDUAL													
(4)		STEAM	GWH	446	154	34	92	10	3	1	1	1	6	8
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL:	GWH	446	154	34	92	10	3	1	1	1	6	8
	DISTILLATE													
(8)		STEAM	GWH	55	22	20	20	19	18	17	15	15	16	16
(9)		CC	GWH	154	271	54	72	32	30	25	25	34	33	30
(10)		CT	GWH	138	80	36	43	24	27	29	32	25	31	22
(11)		TOTAL:	GWH	347	373	110	135	75	75	71	72	74	80	68
	NATURAL GAS													
(12)		STEAM	GWH	9,482	7,508	6,909	6,552	6,286	5,672	5,830	5,391	5,688	5,654	5,600
(13)		CC	GWH	134,967	135,630	144,360	149,693	150,625	150,054	150,188	152,191	153,201	158,493	160,560
(14)		CT	GWH	2,834	1,977	2,072	1,995	1,881	2,107	2,208	1,978	2,520	2,694	2,858
(15)		TOTAL:	GWH	147,283	145,115	153,341	158,240	158,792	157,833	158,226	159,560	161,409	166,841	169,018
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES													
(17)		BIOFUELS	GWH	20	24	24	24	24	24	24	24	24	24	24
(18)		BIOMASS	GWH	885	708	954	1,111	1,121	1,118	1,114	1,148	1,078	1,052	1,095
(19)		HYDRO	GWH	21	14	14	14	14	14	14	14	14	14	14
(20)		LANDFILL GAS	GWH	344	512	475	398	424	432	450	439	453	475	487
(21)		MSW	GWH	1,451	1,432	1,420	1,421	1,428	1,422	1,422	1,422	1,426	1,181	1,085
(22)		SOLAR	GWH	310	888	2,455	2,973	4,093	5,109	6,069	7,026	7,922	8,212	8,458
(23)		WIND	GWH	0	0	0	0	0	0	0	0	0	0	0
(24)		OTHER RENEW.	GWH	14	16	16	16	16	16	16	16	16	16	16
(25)		TOTAL:	GWH	3,045	3,594	5,358	5,957	7,120	8,135	9,109	10,089	10,933	10,974	11,179
(26)	OTHER		GWH	7,448	7,276	6,969	6,911	7,408	7,604	7,669	7,871	7,268	6,947	6,805
(27)	NET ENERGY FOR LOAD		GWH	234,043	230,868	233,407	235,517	238,021	239,553	241,812	243,938	246,540	248,440	250,948

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.2
ENERGY SOURCES (%)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		%	3.34%	1.00%	1.69%	1.33%	0.95%	1.16%	1.18%	1.16%	1.10%	1.09%	1.14%
(2)	NUCLEAR		%	12.41%	12.57%	12.36%	12.60%	12.43%	12.28%	12.42%	12.12%	11.96%	12.09%	11.79%
(3)	COAL		%	16.50%	18.63%	14.92%	13.32%	13.77%	14.07%	14.00%	13.92%	14.06%	12.41%	12.52%
	RESIDUAL													
(4)		STEAM	%	0.19%	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	0.19%	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(9)		CC	%	0.07%	0.12%	0.02%	0.03%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(10)		CT	%	0.06%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(11)		TOTAL:	%	0.15%	0.16%	0.05%	0.06%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
	NATURAL GAS													
(12)		STEAM	%	4.05%	3.25%	2.96%	2.78%	2.64%	2.37%	2.41%	2.21%	2.31%	2.28%	2.23%
(13)		CC	%	57.67%	58.75%	61.85%	63.56%	63.28%	62.64%	62.11%	62.39%	62.14%	63.80%	63.98%
(14)		CT	%	1.21%	0.86%	0.89%	0.85%	0.79%	0.88%	0.91%	0.81%	1.02%	1.08%	1.14%
(15)		TOTAL:	%	62.93%	62.86%	65.70%	67.19%	66.71%	65.89%	65.43%	65.41%	65.47%	67.16%	67.35%
(16)	NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	RENEWABLES													
(17)		BIOFUELS	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(18)		BIOMASS	%	0.38%	0.31%	0.41%	0.47%	0.47%	0.47%	0.46%	0.47%	0.44%	0.42%	0.44%
(19)		HYDRO	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(20)		LANDFILL GAS	%	0.15%	0.22%	0.20%	0.17%	0.18%	0.18%	0.19%	0.18%	0.18%	0.19%	0.19%
(21)		MSW	%	0.62%	0.62%	0.61%	0.60%	0.60%	0.59%	0.59%	0.58%	0.58%	0.48%	0.43%
(22)		SOLAR	%	0.13%	0.38%	1.05%	1.26%	1.72%	2.13%	2.51%	2.88%	3.21%	3.31%	3.37%
(23)		WIND	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(24)		OTHER RENEW.	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(25)		TOTAL:	%	1.30%	1.56%	2.30%	2.53%	2.99%	3.40%	3.77%	4.14%	4.43%	4.42%	4.45%
(26)	OTHER		%	3.18%	3.15%	2.99%	2.93%	3.11%	3.17%	3.17%	3.23%	2.95%	2.80%	2.71%
(27)	NET ENERGY FOR LOAD		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 13
SUMMARY AND SPECIFICATIONS OF PROPOSED TRANSMISSION LINES
AS OF JANUARY 1, 2017

(1)	(2)		(3)	(4)	(5)	(6)	(7)
LINE OWNERSHIP	TERMINALS		LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE (MO./YR)	NOMINAL VOLTAGE (kV)	CAPACITY (MVA)	SITED UNDER *
FPL	RAVEN	DUVAL	45	12 / 2018	230	759	TLSA
FPL	ST. JOHNS	PRINGLE	25	12 / 2018	230	759	TLSA
TAL	SUB 14 115	SUB 7 115	6	12 / 2018	115	230	NA
FPL	LEVEE	MIDWAY	150	6 / 2019	500	2598	TLSA
DEF	WILLISTON NORTH	BRONSON	14	11 / 2020	230	1370	NA
JEA	GREENLAND ENERGY CTR	NOCATEE	4.4	12 / 2020	230	668	NA
TEC	UNSITED	UNSITED (FUTURE CT1)	0	5 / 2021	0	0	NA
DEF	KATHLEEN	HAINES CITY EAST	50	6 / 2023	230	1260	NA
TEC	UNSITED	UNSITED (FUTURE CC1)	0	5 / 2024	0	0	NA

* TLSA: Transmission Line Siting Act

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

ABBREVIATIONS

ELECTRIC MARKET PARTICIPANTS

CAL	-	Calpine
DEF	-	Duke Energy Florida
FKE	-	Florida Keys Electric Cooperative Association, Inc.
FMD	-	Ft. Meade, City of
FMPA	-	Florida Municipal Power Agency
FPL	-	Florida Power & Light
FPU	-	Florida Public Utitlities
FTP	-	Ft. Pierce Utilities Authority
GE	-	General Electric
GaPC	-	Georgia Power Company
GPC	-	Gulf Power Company
GRU	-	Gainesville Regional Utilities
HPP	-	Hardee Power Partners
HST	-	Homestead Energy Services
JEA	-	JEA
KEY	-	Key West, City of
KUA	-	Kissimmee Utility Authority
LAK	-	Lakeland, City of
LCEC	-	Lee County Electric Cooperative
LWU	-	Lake Worth Utilities, City of
NSB	-	New Smyrna Beach, Utilities Commission of
NSG	-	Northern Star Generation
NRG	-	NRG Energy
OUC	-	Orlando Utilities Commission
OUS	-	Ocala Utility Services
PEC	-	PowerSouth Energy Cooperative
RCI	-	Reedy Creek Improvement District
SEC	-	Seminole Electric Cooperative, Inc.
SEPA	-	Southeastern Power Administration
SREC	-	Santa Rosa Energy Center
SOU	-	Southern Power Company
STC	-	St. Cloud, City of
TAL	-	Tallahassee, City of
TEC	-	Tampa Electric Company
VER	-	Vero Beach, City of
WAU	-	Wauchula, City of

OTHER

FRCC	-	Florida Reliability Coordinating Council

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

GENERATION TERMS

Status of Generation Facilities

A	–	Generating unit capability increased
CO	–	Change of ownership (including change of shares of jointly owned units)
D	–	Generating unit capability decreased
D (S)	–	Solar Degradation
EO	–	Non-Firm Generating Capacity (Energy Only). This generation is not included in calculation of Total Available Capacity.
FC	–	Existing generator planned for conversion to another fuel or energy source
IP	–	Planned generator indefinitely postponed or canceled
IR	–	Inactive Reserves. This generation is not included in calculation of Total Available Capacity.
L	–	Regulatory approval pending. Not under construction
M	–	Generating unit put in deactivated shutdown status
NS	–	Merchant Plant - No system impact study, not under construction
OP	–	Operating, available to operate, or on short-term scheduled or forced outage
OP (IR)	–	Generating unit placed into OP status from Inactive Reserves
OP (M)	–	Generating unit placed into OP status following scheduled maintenance
OP (U)	–	Generating unit placed into OP status following scheduled uprate
OS	–	On long-term scheduled or forced outage; not available to operate. This generation is not included in calculation of Total Available Capacity.
OS (IR)	–	Generating unit placed into OS status for Inactive Reserves
OS (M)		Generating unit placed into OS status for scheduled maintenance
OS (RS)	–	Generating unit placed into OS status for reserve shutdown
OS (U)	–	Generating unit placed into OS status for scheduled unit uprate
OT	–	Other
P	–	Planned for installation but not utility-authorized. Not under construction
RA	–	Previously deactivated or retired generator planned for reactivation
RE	–	Retired
RP	–	Proposed for repowering or life extension
RT	–	Existing generator scheduled for retirement
SB	–	Cold Standby: deactivated, in long-term storage and cannot be made available for service in a short period of time. This generation is not included in calculation of Total Available Capacity.
SC	–	Synchronous Condenser
SD	–	Sold to independent power producer
SI	–	Merchant Plant - System impact study completed, not under construction
T	–	Regulatory approval received but not under construction
TS	–	Construction complete, but not yet in commercial operation
U	–	Under construction, less than or equal to 50% complete
V	–	Under construction, more than 50% complete

Ownership

COG	–	Cogenerator
IPP	–	Independent Power Producer
J	–	Utility, joint ownership with one or more other utilities
MER	–	Merchant Generator
SPP	–	Small Power Producing qualifying facility
U	–	Utility, single ownership by respondent

Contracts

C	–	Contract in place
CE	–	Contract Ends
D	–	Decrease in Contract Amount
I	–	Increase in Contract Amount
NC	–	No Contract

Types of Generation Units

CA	–	Combined Cycle Steam Part
CC	–	Combined Cycle Total Unit
CE	–	Compressed Air Energy Storage
CS	–	Combined Cycle Single Shaft
CT	–	Combined Cycle Combustion Turbine Part
FC	–	Fuel Cell
GT	–	Gas Turbine (includes Jet Engine Design)
HY	–	Hydraulic Turbine
IC	–	Internal Combustion Engine
NA	–	Not Available
OT	–	Other
PV	–	Photovoltaic
ST	–	Steam Turbine, including nuclear, and solar steam
WT	–	Wind Turbine

Fuel Transportation Method

CV	–	Conveyor
NA	–	Not Applicable
PL	–	Pipeline
RR	–	Railroad
TK	–	Truck
UN	–	Unknown at this time
WA	–	Water Transportation

Types of Fuel

AB	–	Agriculture Byproducts, Bagasse, Straw, Energy Crops
BIT	–	Bituminous Coal
DFO	–	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No 2 Fuel Oil, No 4 Fuel Oil)
LFG	–	Landfill Gas
LIG	–	Lignite
MSW	–	Municipal Solid Waste
NA	–	Not Available or Not Applicable
NG	–	Natural Gas
NUC	–	Nuclear
OBG	–	Other BioMass Gases
OBL	–	Other BioMass Liquids
OBS	–	Other BioMass Solids
OG	–	Other Gas
OTH	–	Other
PC	–	Petroleum Coke
RFO	–	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)
SUB	–	Subbituminous Coal
SUN	–	Solar (Photovoltaic, Thermal)
WAT	–	Water
WDS	–	Wood/Wood Waste Solids
WDL	–	Wood/Wood Waste Liquids
WH	–	Waste Heat / Combined Cycle Steam Part
WND	–	Wind

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

CONTRACT TERMS

FR	--	Full Requirement service agreement
PR	--	Partial Requirement service agreement
Schd D	--	Long term firm capacity and energy interchange agreement
Schd E	--	Non-Firm capacity and energy interchange agreement
Schd F	--	Long term non-firm capacity and energy interchange agreement
Schd G	--	Back-up reserve service
Schd J	--	Contract which the terms and conditions are negotiated yearly
UPS	--	Unit Power Sale

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

DEFINITIONS

CAAGR
- Compound Average Annual Growth Rate, usually expressed as a percent.

INTERRUPTIBLE LOAD
- Load which may be disconnected at the supplier's discretion.

LOAD FACTOR
- A percent which is the calculation of NEL / (annual peak demand * the number of hours in the year).

NET CAPABILITY OR NET CAPACITY
- The continous gross capacity, less the power required by all auxillaries associated with the unit.

NET ENERGY FOR LOAD (NEL)
- The net system generation PLUS interchange received MINUS interchange delivered.

PEAK DEMAND OR PEAK LOAD
- The net 60-minute integrated demand, actual or adjusted. Forecasted loads assume normal weather conditions.

PENINSULAR FLORIDA
- Geographically, those Florida utilities located east of the Apalachicola River.

QUALIFYING FACILITY (QF)
- The cogenerator or small power producer which meets FERC criteria for a qualifying facility.

SALES FOR RESALE
- Energy sales to other electric utilities.

STATE OF FLORIDA
- Utilities in Peninsular Florida plus Gulf Power Company, West Florida Electric Cooperative, Choctawhatchee Electric Cooperative, Escambia River Electric Cooperative, Gulf Coast Electric Cooperative, and PowerSouth Energy Cooperative.

SUMMER
- June 1 through August 31 of each year being studied.

WINTER
- December 1 through March 1.

YEAR
- The calendar year, January 1, through December 31. Unless otherwise indicated, this is the year used for historical and forecast data.

STATE OF FLORIDA SUPPLEMENT

TO THE

FLORIDA RELIABILITY COORDINATING COUNCIL

2017

REGIONAL LOAD & RESOURCE PLAN

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)
	SUMMER PEAK DEMAND (MW)			
YEAR	ACTUAL PEAK DEMAND (MW)			
2007	49,485			
2008	47,562			
2009	49,142			
2010	48,427			
2011	47,724			
2012	46,709			
2013	47,301			
2014	48,659			
2015	48,649			
2016	50,621			

(6)	(7)	(8)	(9)	(10)
	WINTER PEAK DEMAND (MW)			
YEAR	ACTUAL PEAK DEMAND (MW)			
2007 / 08	44,254			
2008 / 09	48,304			
2009 / 10	54,780			
2010 / 11	48,789			
2011 / 12	40,920			
2012 / 13	38,893			
2013 / 14	42,071			
2014 / 15	45,653			
2015 / 16	40,448			
2016 / 17	39,418			

(11)	(12)	(13)
	ENERGY	
YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2007	246,952	57.0%
2008	240,891	57.8%
2009	239,415	55.6%
2010	247,276	51.5%
2011	237,860	55.7%
2012	234,312	57.3%
2013	235,057	56.7%
2014	238,689	56.0%
2015	248,351	58.3%
2016	248,019	55.9%

YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)
2017	50,379	474	2,448	47,457
2018	50,941	503	2,498	47,940
2019	51,509	520	2,534	48,455
2020	51,891	540	2,569	48,782
2021	52,459	562	2,604	49,293
2022	52,952	556	2,634	49,762
2023	53,578	550	2,666	50,362
2024	54,252	537	2,696	51,019
2025	54,898	511	2,724	51,663
2026	55,545	511	2,754	52,280

YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)
2017 / 18	47,544	459	2,383	44,702
2018 / 19	48,083	475	2,413	45,195
2019 / 20	48,525	493	2,441	45,591
2020 / 21	49,040	515	2,470	46,055
2021 / 22	49,436	502	2,498	46,436
2022 / 23	49,879	502	2,528	46,849
2023 / 24	50,325	490	2,556	47,279
2024 / 25	50,737	466	2,586	47,685
2025 / 26	51,174	466	2,615	48,093
2026 / 27	51,542	467	2,645	48,430

YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2017	244,736	58.9%
2018	247,397	58.9%
2019	249,620	58.8%
2020	252,265	59.0%
2021	253,881	58.8%
2022	256,195	58.8%
2023	258,383	58.6%
2024	261,054	58.4%
2025	263,029	58.1%
2026	265,609	58.0%

NOTE: FORECASTED SUMMER AND WINTER DEMANDS ARE NON-COINCIDENT.

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 4.0
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL										
YEAR	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	STREET & HIGHWAY LIGHTING GWH	OTHER SALES GWH	TOTAL SALES GWH	WHOLESALE PURCHASES FOR RESALE GWH	WHOLESALE SALES FOR RESALE GWH	UTILITY USE & LOSSES GWH	AGGREGATION ADJUSTMENT GWH	NET ENERGY FOR LOAD GWH
2007	116,506	8,343,790	13,963	82,769	1,033,930	80,053	23,263	36,133	643,816	837	5,410	228,785	0	11,526	14,773	-8,132	246,952
2008	112,425	8,351,236	13,462	82,204	1,036,492	79,310	22,619	30,136	750,564	829	5,385	223,462	0	11,774	13,891	-8,236	240,891
2009	113,343	8,338,111	13,593	80,874	1,033,057	78,286	20,811	27,627	753,285	839	5,382	221,249	0	8,515	14,472	-4,821	239,415
2010	118,871	8,325,474	14,278	80,171	1,030,890	77,769	20,716	27,047	765,926	858	5,365	225,981	0	9,840	16,782	-5,327	247,276
2011	113,410	8,364,698	13,558	80,321	1,037,455	77,421	20,543	27,184	755,702	850	5,340	220,464	0	8,948	12,448	-4,000	237,860
2012	109,163	8,419,984	12,965	80,905	1,047,831	77,212	19,616	25,979	755,071	845	5,351	215,880	0	8,341	13,541	-3,450	234,312
2013	110,127	8,515,868	12,932	83,283	1,061,129	78,485	17,047	20,709	823,169	835	5,297	216,589	0	7,954	13,429	-2,915	235,057
2014	111,825	8,532,564	13,106	83,326	1,068,656	77,973	17,223	21,657	795,263	827	5,444	218,645	0	11,374	12,479	-3,809	238,689
2015	117,738	8,666,064	13,586	85,996	1,077,633	79,801	17,355	22,706	764,335	857	5,736	227,682	0	12,827	12,987	-5,145	248,351
2016	118,453	8,786,683	13,481	86,158	1,091,505	78,935	17,248	23,035	748,774	848	5,700	228,407	0	13,237	11,825	-5,450	248,019
2007-2016 % AAGR	0.18%			0.45%			-3.27%										0.05%
2017	116,586	8,934,153	13,049	85,713	1,108,378	77,332	17,095	24,003	712,203	848	5,686	225,928	0	11,953	11,460	-4,605	244,736
2018	117,941	9,074,051	12,998	86,610	1,122,661	77,147	17,329	24,484	707,768	840	5,718	228,438	0	11,528	11,843	-4,412	247,397
2019	118,849	9,212,957	12,900	87,287	1,136,674	76,792	17,581	24,847	707,570	834	5,780	230,331	0	11,469	12,157	-4,337	249,620
2020	120,194	9,349,141	12,856	88,142	1,150,303	76,625	17,865	25,113	711,385	832	5,839	232,872	0	11,456	12,256	-4,319	252,265
2021	120,905	9,482,252	12,751	88,830	1,163,341	76,358	17,968	25,305	710,057	831	5,882	234,416	0	10,998	12,176	-3,709	253,881
2022	122,152	9,613,647	12,706	89,644	1,176,449	76,199	17,927	25,461	704,096	834	5,939	236,496	0	10,623	12,389	-3,313	256,195
2023	123,159	9,744,009	12,639	90,471	1,189,273	76,073	18,016	25,615	703,338	835	5,995	238,476	0	10,763	12,504	-3,360	258,383
2024	124,440	9,873,208	12,604	91,347	1,201,553	76,024	18,036	25,759	700,182	834	6,055	240,712	0	10,448	12,826	-2,932	261,054
2025	125,698	10,000,603	12,569	92,197	1,213,548	75,973	17,983	25,902	694,271	832	6,113	242,823	0	10,581	12,611	-2,986	263,029
2026	126,880	10,126,151	12,530	92,974	1,225,306	75,878	18,051	26,040	693,203	831	6,174	244,910	0	10,711	13,011	-3,023	265,609
2017-2026 % AAGR	0.94%			0.91%			0.61%										0.91%

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 5.0

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	SUMMER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		SUMMER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2015	48,649	0	71	0	452	2,457	1,566	53,195
2016	50,621	0	75	0	450	2,529	1,600	55,275
2017	47,457	474	1,397	1,051	669	2,588	1,634	55,270
2018	47,940	503	1,428	1,070	631	2,648	1,662	55,882
2019	48,455	520	1,447	1,087	632	2,701	1,690	56,532
2020	48,782	540	1,464	1,105	631	2,751	1,719	56,992
2021	49,293	562	1,480	1,124	631	2,799	1,746	57,635
2022	49,762	556	1,495	1,139	631	2,847	1,772	58,202
2023	50,362	550	1,511	1,155	631	2,893	1,800	58,902
2024	51,019	537	1,525	1,171	631	2,940	1,827	59,650
2025	51,663	511	1,538	1,186	631	2,988	1,854	60,371
2026	52,280	511	1,552	1,202	631	3,035	1,879	61,090
CAAGR (%):	1.08%							

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 6.0
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	WINTER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		WINTER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2015/16	40,448	0	96	0	433	2,740	866	44,595
2016/17	39,418	0	88	0	463	2,789	880.99	43,651
2017/18	44,702	459	1,602	781	631	2,845	906	51,926
2018/19	45,195	475	1,622	791	632	2,890	921	52,526
2019/20	45,591	493	1,640	801	631	2,934	935	53,025
2020/21	46,055	515	1,658	812	631	2,977	953	53,601
2021/22	46,436	502	1,676	822	631	3,019	966	54,052
2022/23	46,849	502	1,696	832	631	3,060	984	54,554
2023/24	47,279	490	1,714	842	631	3,104	1,000	55,060
2024/25	47,685	466	1,733	853	631	3,146	1,017	55,531
2025/26	48,093	466	1,752	863	631	3,190	1,034	56,029
2026/27	48,430	467	1,771	874	631	3,230	1,051	56,454
CAAGR (%):	0.89%							

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 7.0
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWH)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
		ENERGY REDUCTION						
YEAR	NET ENERGY FOR LOAD	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	CUMULATIVE CONSERVATION RESIDENTIAL	CUMULATIVE CONSERVATION COMM./IND.	TOTAL ENERGY FOR LOAD
2015	248,351	0	0	0	1,425	5,811	4,490	260,078
2016	248,019	0	0	0	1,518	5,924	4,591	260,053
2017	244,736	0	0	9	2,471	6,017	4,677	257,911
2018	247,397	0	0	9	2,470	6,106	4,745	260,728
2019	249,620	0	0	9	2,470	6,201	4,810	263,111
2020	252,265	0	0	10	2,471	6,294	4,878	265,919
2021	253,881	0	0	10	2,460	6,387	4,945	267,684
2022	256,195	0	0	10	2,460	6,481	5,014	270,161
2023	258,383	0	0	10	2,460	6,575	5,083	272,512
2024	261,054	0	0	10	2,461	6,669	5,154	275,349
2025	263,029	0	0	10	2,460	6,765	5,227	277,492
2026	265,609	0	0	10	2,460	6,857	5,299	280,236
CAAGR (%):	0.91%							

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

SUMMARY OF INTERRUPTIBLE LOAD AND LOAD MANAGEMENT (MW)
2017 THROUGH 2026

SUMMER

YEAR	FRCC TOTALS			STATE TOTALS			STATE TOTAL INT + LM
	INT	RES LM	COM LM	INT	RES LM	COM LM	
2017	474	1,397	1,051	474	1,397	1,051	2,922
2018	503	1,428	1,070	503	1,428	1,070	3,001
2019	520	1,447	1,087	520	1,447	1,087	3,054
2020	540	1,464	1,105	540	1,464	1,105	3,109
2021	562	1,480	1,124	562	1,480	1,124	3,166
2022	556	1,495	1,139	556	1,495	1,139	3,190
2023	550	1,511	1,155	550	1,511	1,155	3,216
2024	537	1,525	1,171	537	1,525	1,171	3,233
2025	511	1,538	1,186	511	1,538	1,186	3,235
2026	511	1,552	1,202	511	1,552	1,202	3,265

WINTER

YEAR	FRCC TOTALS			STATE TOTALS			STATE TOTAL INT + LM
	INT	RES LM	COM LM	INT	RES LM	COM LM	
2017/18	459	1,602	781	459	1,602	781	2,842
2018/19	475	1,622	791	475	1,622	791	2,888
2019/20	493	1,640	801	493	1,640	801	2,934
2020/21	515	1,658	812	515	1,658	812	2,985
2021/22	502	1,676	822	502	1,676	822	3,000
2022/23	502	1,696	832	502	1,696	832	3,030
2023/24	490	1,714	842	490	1,714	842	3,046
2024/25	466	1,733	853	466	1,733	853	3,052
2025/26	466	1,752	863	466	1,752	863	3,081
2026/27	467	1,771	874	467	1,771	874	3,112

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
SUMMARY OF EXISTING CAPACITY
AS OF DECEMBER 31, 2016

UTILITY	NET CAPABILITY (MW) SUMMER	WINTER
GULF POWER COMPANY	2,251	2,290
POWERSOUTH ENERGY COOPERATIVE	1,902	2,098
TOTALS		
FRCC REGION	49,986	53,952
STATE OF FLORIDA	54,139	58,340
FRCC FIRM NON-UTILITY PURCHASES	4,156	4,446
STATE FIRM NON-UTILITY PURCHASES	4,156	4,446
TOTAL FRCC REGION	**54,142**	**58,398**
TOTAL STATE OF FLORIDA	**58,295**	**62,786**

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE			GROSS CAPABILITY		NET CAPABILITY		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
GULF POWER COMPANY															
CRIST	4	ESCAMBIA	ST	BIT	WA	NG	PL	0	7 / 1959	--- / ----	79.0	79.0	75.0	75.0	OP
CRIST	5	ESCAMBIA	ST	BIT	WA	NG	PL	0	6 / 1961	--- / ----	77.0	77.0	75.0	75.0	OP
CRIST	6	ESCAMBIA	ST	BIT	WA	NG	PL	0	5 / 1970	--- / ----	317.0	317.0	299.0	299.0	OP
CRIST	7	ESCAMBIA	ST	BIT	WA	NG	PL	0	8 / 1973	--- / ----	498.0	498.0	475.0	475.0	OP
DANIEL *	1	JACKSON, MS	ST	BIT	RR	RFO	TK	0	9 / 1977	--- / ----	259.0	259.0	255.0	255.0	OP
DANIEL *	2	JACKSON, MS	ST	BIT	RR	RFO	TK	0	6 / 1981	--- / ----	259.0	259.0	255.0	255.0	OP
LANSING SMITH	3	BAY	CC	NG	PL	---	---	0	4 / 2002	--- / ----	567.0	595.0	556.0	584.0	OP
LANSING SMITH	A	BAY	GT	DFO	TK	---	---	0	5 / 1971	--- / ----	32.0	40.0	32.0	40.0	OP
PEA RIDGE	1	SANTA ROSA	GT	NG	PL	---	---	0	5 / 1998	12 / 2018	4.0	5.0	4.0	5.0	OP
PEA RIDGE	2	SANTA ROSA	GT	NG	PL	---	---	0	5 / 1998	12 / 2018	4.0	5.0	4.0	5.0	OP
PEA RIDGE	3	SANTA ROSA	GT	NG	PL	---	---	0	5 / 1998	12 / 2018	4.0	5.0	4.0	5.0	OP
PERDIDO	1	ESCAMBIA	IC	LFG	PL	---	---	0	10 / 2010	--- / ----	1.8	1.8	1.5	1.5	OP
PERDIDO	2	ESCAMBIA	IC	LFG	PL	---	---	0	10 / 2010	--- / ----	1.8	1.8	1.5	1.5	OP
SCHERER *	3	MONROE, GA	ST	BIT	RR	---	---	0	1 / 1987	--- / ----	224.0	224.0	214.0	214.0	OP
											GPC TOTAL:		2,251	2,290	

*Jointly Owned Unit

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL TRANSP. METHOD	ALTERNATE FUEL FUEL TYPE	ALTERNATE FUEL TRANSP. METHOD	ALT. FUEL STORAGE (DAYS BURN)	COMMERCIAL IN-SERVICE MO. / YEAR	EXPECTED RETIREMENT MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	STATUS
POWERSOUTH ENERGY COOPERATIVE															
CHARLES R. LOWMAN	1	WASHINGTON, AL	ST	BIT	WA	---	---	0	6 / 1969	--- / -----	78.0	78.0	78.0	78.0	OP
CHARLES R. LOWMAN	2	WASHINGTON, AL	ST	BIT	WA	---	---	0	6 / 1978	--- / -----	235.0	235.0	235.0	235.0	OP
CHARLES R. LOWMAN	3	WASHINGTON, AL	ST	BIT	WA	---	---	0	6 / 1980	--- / -----	238.0	238.0	238.0	238.0	OP
GANTT	3	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1926	--- / -----	1.0	1.0	1.0	1.0	OP
GANTT	4	COVINGTON, AL	HY	WAT	WA	---	---	0	2 / 1945	--- / -----	1.8	1.8	1.8	1.8	OP
JAMES H. MILLER JR. *	1	JEFFERSON, AL	ST	BIT	WA	---	---	0	6 / 1978	--- / -----	57.0	57.0	57.0	57.0	OP
JAMES H. MILLER JR. *	2	JEFFERSON, AL	ST	BIT	WA	---	---	0	6 / 1985	--- / -----	57.0	57.0	57.0	57.0	OP
MCINTOSH	1	WASHINGTON, AL	CE	NG	PL	---	---	0	6 / 1991	--- / -----	110.0	110.0	110.0	110.0	OS
MCINTOSH	2	WASHINGTON, AL	GT	NG	PL	DFO	TK	0	6 / 1998	--- / -----	114.0	120.0	114.0	120.0	OP
MCINTOSH	3	WASHINGTON, AL	GT	NG	PL	DFO	TK	0	6 / 1998	--- / -----	114.0	120.0	114.0	120.0	OP
MCINTOSH	4	WASHINGTON, AL	CT	NG	PL	---	---	0	12 / 2010	--- / -----	175.0	224.0	175.0	224.0	OP
MCINTOSH	5	WASHINGTON, AL	CT	NG	PL	---	---	0	12 / 2010	--- / -----	175.0	224.0	175.0	224.0	OP
MCWILLIAMS	1	COVINGTON, AL	CA	WH	NA	---	---	0	12 / 1954	--- / -----	9.0	9.0	9.0	9.0	OP
MCWILLIAMS	2	COVINGTON, AL	CA	WH	NA	---	---	0	12 / 1954	--- / -----	9.0	9.0	9.0	9.0	OP
MCWILLIAMS	3	COVINGTON, AL	CA	WH	NA	---	---	0	8 / 1959	--- / -----	21.0	21.0	21.0	21.0	OP
MCWILLIAMS	4	COVINGTON, AL	GT	NG	PL	DFO	TK	0	12 / 1996	--- / -----	103.0	110.0	103.0	110.0	OP
MCWILLIAMS	VAN1	COVINGTON, AL	CT	NG	PL	---	---	0	1 / 2002	--- / -----	168.0	203.0	168.0	203.0	OP
MCWILLIAMS	VAN2	COVINGTON, AL	CT	NG	PL	---	---	0	1 / 2002	--- / -----	168.0	203.0	168.0	203.0	OP
MCWILLIAMS	VAN3	COVINGTON, AL	CA	WH	NA	---	---	0	1 / 2002	--- / -----	174.0	183.0	174.0	183.0	OP
POINT A	1	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1945	--- / -----	1.4	1.4	1.4	1.4	OP
POINT A	2	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1925	--- / -----	1.4	1.4	1.4	1.4	OP
POINT A	3	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1949	--- / -----	1.6	1.6	1.6	1.6	OP
										PEC TOTAL:			1,902	2,098	
										FRCC TOTAL:			49,986	53,952	
										STATE TOTAL:			54,139	58,340	

*Jointly Owned Unit

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2017														
GPC	LANSING SMITH	3	BAY	CC	NG	PL	---	---	0	6 / 2017	21.0	21.0	21.0	21.0	OP
											2017 TOTAL:		**21**	**21**	
	2018														
GPC	PEA RIDGE	1	SANTA ROSA	GT	NG	PL	---	---	---	12 / 2018	-4.0	-5.0	-4.0	-5.0	RT
GPC	PEA RIDGE	2	SANTA ROSA	GT	NG	PL	---	---	---	12 / 2018	-4.0	-5.0	-4.0	-5.0	RT
GPC	PEA RIDGE	3	SANTA ROSA	GT	NG	PL	---	---	---	12 / 2018	-4.0	-5.0	-4.0	-5.0	RT
											2018 TOTAL:		**-12**	**-15**	
	2019														
	NO ENTRIES														
	2020														
	NO ENTRIES														
	2021														
	NO ENTRIES														

*Jointly Owned Unit

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2017 THROUGH DECEMBER 31, 2026)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	EFFECTIVE CHANGE DATE MO. / YEAR	GROSS CAPABILITY SUMMER (MW)	GROSS CAPABILITY WINTER (MW)	NET CAPABILITY SUMMER (MW)	NET CAPABILITY WINTER (MW)	CHANGE/ STATUS
	2022														
	NO ENTRIES														
	2023														
GPC	UNNAMED CT	N/A	ESCAMBIA	CT	NG	PL	DFO	TK	0	6 / 2023	662.0	685.0	654.0	677.0	P
											2023 TOTAL:		654	677	
	2024														
	NO ENTRIES														
	2025														
	NO ENTRIES														
	2026														
	NO ENTRIES														

FRCC FUTURE TOTAL:	7,126	5,949
STATE FUTURE TOTAL:	7,789	6,632

*Jointly Owned Unit

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 10

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE STATE	OUTSIDE STATE	STATE IMPORTS	STATE EXPORTS	NON-UTILITY PURCHASES	AVAILABLE CAPACITY	TOTAL PEAK DEMAND	LOAD MANAGEMENT & INT.		PEAK DEMAND	LOAD MANAGEMENT & INT.	
YEAR	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% OF PEAK	(MW)	(MW)	% OF PEAK
2017	51,534	3,454	1,398	50	3,881	60,218	50,379	9,839	20%	47,457	12,761	27%
2018	51,032	3,454	1,398	50	3,928	59,762	50,941	8,821	17%	47,940	11,822	25%
2019	52,491	3,454	1,498	50	3,469	60,862	51,509	9,353	18%	48,455	12,407	26%
2020	52,749	3,454	1,598	0	3,484	61,285	51,891	9,394	18%	48,782	12,503	26%
2021	53,704	3,454	1,174	0	3,026	61,358	52,459	8,899	17%	49,293	12,065	24%
2022	55,398	3,454	1,174	0	3,031	63,057	52,952	10,105	19%	49,762	13,295	27%
2023	57,201	3,454	289	0	3,033	63,977	53,578	10,399	19%	50,362	13,615	27%
2024	57,809	3,454	289	0	2,007	63,559	54,252	9,307	17%	51,019	12,540	25%
2025	58,249	3,454	289	0	1,854	63,846	54,898	8,948	16%	51,663	12,183	24%
2026	58,474	3,454	289	0	1,717	63,934	55,545	8,389	15%	52,280	11,654	22%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE STATE	OUTSIDE STATE	STATE IMPORTS	STATE EXPORTS	NON-UTILITY PURCHASES	AVAILABLE CAPACITY	TOTAL PEAK DEMAND	LOAD MANAGEMENT & INT.		PEAK DEMAND	LOAD MANAGEMENT & INT.	
YEAR	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% OF PEAK	(MW)	(MW)	% OF PEAK
2017 / 18	54,338	3,651	1,418	50	4,154	63,512	47,544	15,968	34%	44,702	18,810	42%
2018 / 19	54,256	3,651	1,418	50	3,740	63,015	48,083	14,932	31%	45,195	17,820	39%
2019 / 20	56,077	3,651	1,518	50	3,756	64,952	48,525	16,427	34%	45,591	19,361	42%
2020 / 21	56,064	3,651	1,618	0	3,755	65,088	49,040	16,048	33%	46,055	19,033	41%
2021 / 22	56,876	3,651	1,194	0	3,214	64,935	49,436	15,499	31%	46,436	18,499	40%
2022 / 23	59,009	3,651	1,194	0	3,216	67,070	49,879	17,191	34%	46,849	20,221	43%
2023 / 24	60,121	3,651	309	0	2,661	66,741	50,325	16,416	33%	47,279	19,462	41%
2024 / 25	60,842	3,651	309	0	1,991	66,793	50,737	16,056	32%	47,685	19,108	40%
2025 / 26	61,081	3,651	309	0	1,874	66,915	51,174	15,741	31%	48,093	18,822	39%
2026 / 27	61,321	3,651	309	0	1,854	67,134	51,542	15,592	30%	48,430	18,704	39%

NOTE - COLUMN 11: NET FIRM PEAK DEMAND = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
GULF POWER COMPANY																
	BAY COUNTY RESOURCE RECOV.	1	BAY	ST	MSW	---	2 / 1987	12.5	12.5	11.0	11.0	---	---	11.0	11.0	NC
	INTERNATIONAL PAPER COMPANY	1	ESCAMBIA	ST	WDS	NG	5 / 1983	28.1	28.1	21.4	21.4	---	---	---	---	NC
	INTERNATIONAL PAPER COMPANY	2	ESCAMBIA	ST	WDS	NG	5 / 1983	28.1	28.1	21.4	21.4	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	1	ESCAMBIA	ST	NG	---	4 / 1988	1.1	1.1	1.1	1.1	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	2	ESCAMBIA	ST	NG	---	4 / 1988	1.1	1.1	1.1	1.1	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	3	ESCAMBIA	ST	NG	---	4 / 1988	1.1	1.1	1.1	1.1	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	4	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	5	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	6	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	7	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	8	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	9	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	10	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	PENSACOLA CHRISTIAN COLLEGE	11	ESCAMBIA	IC	NG	---	6 / 2006	1.8	1.8	1.8	1.8	---	---	---	---	NC
	SOLUTIA	1	ESCAMBIA	ST	NG	DFO	1 / 1954	5.0	5.0	5.0	5.0	---	---	---	---	NC
	SOLUTIA	2	ESCAMBIA	ST	NG	DFO	1 / 1954	5.0	5.0	5.0	5.0	---	---	---	---	NC
	SOLUTIA	3	ESCAMBIA	ST	NG	DFO	1 / 1954	6.0	6.0	6.0	6.0	---	---	---	---	NC
	SOLUTIA	4	ESCAMBIA	ST	NG	---	5 / 2005	86.0	86.0	86.0	86.0	---	---	---	---	NC
	STONE CONTAINER	1	BAY	ST	DFO	NG	1 / 1960	4.0	4.0	4.0	4.0	---	---	---	---	NC
	STONE CONTAINER	2	BAY	ST	BIT	---	1 / 1960	5.0	5.0	5.0	5.0	---	---	---	---	NC
	STONE CONTAINER	3	BAY	ST	WDS	NG	1 / 1960	8.6	8.6	8.6	8.6	---	---	---	---	NC
	STONE CONTAINER	4	BAY	ST	WDS	NG	1 / 1960	17.1	17.1	17.1	17.1	---	---	---	---	NC
			GPC TOTAL:									0.0	0.0	11.0	11.0	
											FRCC NON-UTILITY TOTAL:	1,459	1,554	32	41	
											STATE NON-UTILITY TOTAL:	1,459	1,554	43	52	

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 3.1
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
							COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT	GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
												FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
	2017															
	NO ENTRIES															
	2018															
	NO ENTRIES															
	2019															
	NO ENTRIES															
	2020															
	NO ENTRIES															
	2021															
	NO ENTRIES															
	2022															
	NO ENTRIES															
	2023															
	NO ENTRIES															
	2024															
	NO ENTRIES															
	2025															
	NO ENTRIES															
	2026															

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 3.1
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
							COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT	GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK				
					FUEL TYPE							FIRM		UNCOMMITTED		
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	PRI	ALT	MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	CONTRACT STATUS
NO ENTRIES																

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

NON-UTILITY GENERATING FACILITIES SUMMARY

	SUMMER			WINTER	
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED NUG GENERATION (MW)	YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED NUG GENERATION (MW)
2017	1,413.9	42.5	2017/18	1,498.6	58.1
2018	1,458.7	62.5	2018/19	1,204.4	58.1
2019	1,119.7	62.5	2019/20	1,204.4	58.1
2020	1,118.1	62.5	2020/21	1,202.8	58.1
2021	1,118.1	62.5	2021/22	1,202.8	58.1
2022	1,118.1	62.5	2022/23	1,202.8	58.1
2023	1,118.1	62.5	2023/24	1,071.1	39.3
2024	986.4	53.5	2024/25	918.1	39.3
2025	833.4	44.5	2025/26	814.1	39.3
2026	709.4	35.5	2026/27	794.1	39.3

2017

LOAD AND RESOURCE PLAN

STATE OF FLORIDA

FRCC Form 12

SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)		
DEF	SOU	06/01/16	05/31/21	424	424	NG	Southern purchase extension
FLINT	GPC	06/01/10	12/31/19	50	50	BIT	GPC Scherer 3 allocation of Southern Unit Power Sale
GPC	MSCG	01/01/17	12/31/35	89	109	WND	Purchase from Morgan Stanley Capital Group MSCG
GPC	SENA	06/01/14	05/24/23	885	885	NG	PPA with power marketer (Shell Energy)
JEA	MEAG	06/01/19	06/01/39	100	100	NUC	Nuclear PPA from the Municipal Electric Authority of Georgia (MEAG) for Vogtle Unit 3
JEA	MEAG	06/01/20	06/01/40	100	100	NUC	Nuclear PPA from the Municipal Electric Authority of Georgia (MEAG) for Vogtle Unit 4

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.0
FUEL REQUIREMENTS
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FUEL REQUIREMENTS		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	NUCLEAR		TRILLION BTU	321	310	308	317	316	315	321	316	316	321	316
(2)	COAL		1000 TON	20,260	21,424	16,658	15,917	16,533	17,390	17,350	18,027	18,420	17,085	17,230
	RESIDUAL													
(3)		STEAM	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	792	235	53	141	15	5	1	2	2	9	13
	DISTILLATE													
(7)		STEAM	1000 BBL	238	95	82	79	78	62	61	58	60	79	80
(8)		CC	1000 BBL	83	296	41	63	12	14	14	18	17	14	13
(9)		CT	1000 BBL	329	173	71	75	54	50	70	77	81	93	77
(10)		TOTAL:	1000 BBL	650	564	194	217	144	126	145	153	158	186	170
	NATURAL GAS													
(11)		STEAM	1000 MCF	100,470	74,422	67,632	63,471	61,232	54,770	56,556	51,838	55,261	54,828	54,388
(12)		CC	1000 MCF	1,007,920	996,761	1,053,206	1,081,066	1,069,685	1,068,439	1,071,185	1,062,434	1,059,447	1,097,496	1,110,887
(13)		CT	1000 MCF	32,764	22,924	23,350	21,737	20,711	23,520	24,803	27,182	33,997	36,426	38,444
(14)		TOTAL:	1000 MCF	1,141,154	1,094,107	1,144,188	1,166,274	1,151,628	1,146,729	1,152,544	1,141,454	1,148,705	1,188,750	1,203,719
(15)	OTHER	PET COKE	1000 TON	1,195	786	748	848	865	808	809	831	840	867	868
		LFG & BIOFUELS	1000 MMBTU	601	605	583	604	627	635	661	671	675	674	683

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.1
ENERGY SOURCES (GWH)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5) ACTUAL	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		GWH	6,043	237	3,600	795	702	1,148	1,671	436	4,008	3,012	3,542
(2)	NUCLEAR		GWH	29,052	29,017	28,842	29,686	29,581	29,419	30,038	29,569	29,491	30,046	29,577
(3)	COAL		GWH	43,638	48,051	37,566	35,556	37,502	39,332	39,049	40,443	41,573	38,475	38,872
	RESIDUAL													
(4)		STEAM	GWH	446	154	34	92	10	3	1	1	1	6	8
(5)		CC	GWH	864	790	924	1,038	995	968	978	961	952	902	896
(6)		CT	GWH	75	14	26	82	71	83	66	33	16	16	16
(7)		TOTAL:	GWH	1,385	958	984	1,212	1,076	1,054	1,045	995	969	924	920
	DISTILLATE													
(8)		STEAM	GWH	55	22	20	20	19	18	17	15	15	16	16
(9)		CC	GWH	154	271	54	72	32	30	25	25	34	33	30
(10)		CT	GWH	139	80	36	43	24	27	29	33	26	32	23
(11)		TOTAL:	GWH	348	373	110	135	75	75	71	73	75	81	69
	NATURAL GAS													
(12)		STEAM	GWH	9,501	7,508	6,909	6,552	6,286	5,672	5,830	5,391	5,688	5,654	5,600
(13)		CC	GWH	143,604	144,096	153,265	159,166	158,977	157,688	157,848	159,355	156,197	161,812	163,747
(14)		CT	GWH	2,902	2,058	2,153	1,995	1,881	2,107	2,208	2,494	3,172	3,422	3,614
(15)		TOTAL:	GWH	156,007	153,662	162,327	167,713	167,144	165,467	165,886	167,240	165,057	170,888	172,961
(16)	NUG		GWH	171	172	174	176	177	179	181	183	185	186	188
	RENEWABLES													
(17)		BIOFUELS	GWH	20	24	24	24	24	24	24	24	24	24	24
(18)		BIOMASS	GWH	885	708	954	1,111	1,121	1,118	1,114	1,148	1,078	1,052	1,095
(19)		HYDRO	GWH	25	19	19	19	19	19	19	19	19	19	19
(20)		LANDFILL GAS	GWH	368	537	500	423	449	457	475	464	478	500	512
(21)		MSW	GWH	1,508	1,465	1,420	1,421	1,428	1,422	1,422	1,422	1,426	1,181	1,085
(22)		SOLAR	GWH	310	992	2,695	3,212	4,331	5,345	6,304	7,260	8,155	8,444	8,688
(23)		WIND	GWH	675	1,031	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031	1,031
(24)		OTHER RENEW.	GWH	14	16	16	16	16	16	16	16	16	16	16
(25)		TOTAL:	GWH	3,805	4,792	6,659	7,257	8,421	9,432	10,405	11,384	12,229	12,267	12,470
(26)	OTHER			7,570	7,474	7,135	7,090	7,587	7,775	7,849	8,060	7,467	7,150	7,010
(27)	NET ENERGY FOR LOAD			248,019	244,736	247,397	249,620	252,265	253,881	256,195	258,383	261,054	263,029	265,609

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.2
ENERGY SOURCES (%)
AS OF JANUARY 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	FIRM INTER-REGION INTERCHANGE		%	2.44%	0.10%	1.46%	0.32%	0.28%	0.45%	0.65%	0.17%	1.54%	1.15%	1.33%
(2)	NUCLEAR		%	11.71%	11.86%	11.66%	11.89%	11.73%	11.59%	11.72%	11.44%	11.30%	11.42%	11.14%
(3)	COAL		%	17.59%	19.63%	15.18%	14.24%	14.87%	15.49%	15.24%	15.65%	15.93%	14.63%	14.64%
	RESIDUAL													
(4)		STEAM	%	0.18%	0.06%	0.01%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.35%	0.32%	0.37%	0.42%	0.39%	0.38%	0.38%	0.37%	0.36%	0.34%	0.34%
(6)		CT	%	0.03%	0.01%	0.01%	0.03%	0.03%	0.03%	0.03%	0.01%	0.01%	0.01%	0.01%
(7)		TOTAL:	%	0.56%	0.39%	0.40%	0.49%	0.43%	0.42%	0.41%	0.39%	0.37%	0.35%	0.35%
	DISTILLATE													
(8)		STEAM	%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(9)		CC	%	0.06%	0.11%	0.02%	0.03%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(10)		CT	%	0.06%	0.03%	0.01%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(11)		TOTAL:	%	0.14%	0.15%	0.04%	0.05%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
	NATURAL GAS													
(12)		STEAM	%	3.83%	3.07%	2.79%	2.62%	2.49%	2.23%	2.28%	2.09%	2.18%	2.15%	2.11%
(13)		CC	%	57.90%	58.88%	61.95%	63.76%	63.02%	62.11%	61.61%	61.67%	59.83%	61.52%	61.65%
(14)		CT	%	1.17%	0.84%	0.87%	0.80%	0.75%	0.83%	0.86%	0.97%	1.22%	1.30%	1.36%
(15)		TOTAL:	%	62.90%	62.79%	65.61%	67.19%	66.26%	65.18%	64.75%	64.73%	63.23%	64.97%	65.12%
(16)	NUG		%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
	RENEWABLES													
(17)		BIOFUELS	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(18)		BIOMASS	%	0.36%	0.29%	0.39%	0.45%	0.44%	0.44%	0.43%	0.44%	0.41%	0.40%	0.41%
(19)		HYDRO	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(20)		LANDFILL GAS	%	0.15%	0.22%	0.20%	0.17%	0.18%	0.18%	0.19%	0.18%	0.18%	0.19%	0.19%
(21)		MSW	%	0.61%	0.60%	0.57%	0.57%	0.57%	0.56%	0.56%	0.55%	0.55%	0.45%	0.41%
(22)		SOLAR	%	0.12%	0.41%	1.09%	1.29%	1.72%	2.11%	2.46%	2.81%	3.12%	3.21%	3.27%
(23)		WIND	%	0.27%	0.42%	0.42%	0.41%	0.41%	0.41%	0.40%	0.40%	0.40%	0.39%	0.39%
(24)		OTHER RENEW.	%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(25)		TOTAL:	%	1.53%	1.96%	2.69%	2.91%	3.34%	3.72%	4.06%	4.41%	4.68%	4.66%	4.69%
(26)	OTHER		%	3.05%	3.05%	2.88%	2.84%	3.01%	3.06%	3.06%	3.12%	2.86%	2.72%	2.64%
(27)	NET ENERGY FOR LOAD		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

2017
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 13
SUMMARY AND SPECIFICATIONS OF PROPOSED TRANSMISSION LINES
AS OF JANUARY 1, 2017

(1)	(2)		(3)	(4)	(5)	(6)	(7)
LINE OWNERSHIP	TERMINALS		LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE (MO./YR)	NOMINAL VOLTAGE (kV)	CAPACITY (MVA)	SITED UNDER
PEC	GASKIN	BAYOU GEORGE	---	12 / 2018	115	217	NA
PEC	SOUTHPORT	BAYOU GEORGE	8	12 / 2018	115	217	NA

MERCHANT GENERATION IN FLORIDA

MERCHANT GENERATION IN FLORIDA

FRCC has included information on merchant generation facilities for the following companies:

1. Calpine Eastern (CAL)
2. General Electric (GE)
3. Santa Rosa Energy Center, LLC (SREC)
4. Northern Star Generating Services (NSG)
5. NRG Energy, Inc. (NRG)
6. Southern Power Company (SOU)

CODES USED IN FORMS FOR MERCHANT GENERATING FACILITIES

Status of Generation Facilities

A	--	Generating unit capability increased (rerated or relicensed)
D	--	Generating unit capability decreased (rerated or relicensed)
IR	--	The state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time
M	--	Generating unit put in deactivated shutdown status
NS	--	Merchant plant – No system impact study, not under construction
OP	--	In commercial operation
OT	--	Other
RA	--	Previously deactivated or retired generator planned for reactivation
RP	--	Proposed for repowering or life extension
SB	--	Cold Standby; deactivated, in long-term storage and cannot be made available for service in a short period of time
SI	--	Merchant plant – System impact study completed, not under construction
TS	--	Construction complete, but not yet in commercial operation
U	--	Under construction, less than or equal to 50% complete
V	--	Under construction, more than 50% complete

Ownership

IPP	--	Independent Power Producer
MER	--	Merchant Generator

Contracts

C	--	Contract in Place
CC	--	Contract Change
D	--	Decrease in Contract Amount
I	--	Increase in Contract Amount
NC	--	No Contract
R	--	Retirement

Types of Generation Units

CA	--	Combined Cycle Steam Part
CC	--	Combined Cycle Total Unit
CE	--	Compressed Air Energy Storage
CS	--	Combined Cycle Single Shaft
CT	--	Combined Cycle Combustion Turbine Part
FC	--	Fuel Cell
GT	--	Gas Turbine (includes Jet Engine Design)
HY	--	Hydraulic Turbine
IC	--	Internal Combustion Engine
NA	--	Not Available
OT	--	Other
PV	--	Photovoltaic
ST	--	Steam Turbine, including nuclear, and solar steam
WT	--	Wind Turbine

Types of Fuel

AB	--	Agriculture Byproducts, Bagasse, Straw, Energy Crops
BIT	--	Bituminous Coal
DFO	--	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No 2 Fuel Oil, No 4 Fuel Oil)
LFG	--	Landfill Gas
LIG	--	Lignite
MSW	--	Municipal Solid Waste
NA	--	Not Available or Not Applicable
NG	--	Natural Gas
NUC	--	Nuclear
OBG	--	Other Biomass Gases
OBL	--	Other Biomass Liquids
OBS	--	Other Biomass Solids
OG	--	Other Gas
OTH	--	Other
PC	--	Petroleum Coke
RFO	--	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)
SUB	--	Subbituminous Coal
SUN	--	Solar (Photovoltaic, Thermal)
WAT	--	Water
WDS	--	Wood/Wood Waste Solids
WDL	--	Wood/Wood Waste Liquids
WH	--	Waste Heat / Combined Cycle Steam Part
WND	--	Wind

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING MERCHANT GENERATION FACILITIES
IN FLORIDA
AS OF DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7) (8)	(9)	(10)			(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	
								GROSS CAPABILITY			NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK							
													FIRM		UNCOMMITTED					
FACILITY NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	COMMERCIAL IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUM (MW)		WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	OWNERSHIP	UNIT STATUS	CONTRACT STATUS	
CALPINE EASTERN (CAL)																				
AUBURNDALE PEAKER ENERGY CTR	CTP	POLK	GT	NG	DFO	5 / 2002	--- / -----	130.1	(1)	---	117.0	126.0	117.0	117.0	---	9.0	MER	OP	C	
GENERAL ELECTRIC (GE)																				
SHADY HILLS POWER CO.	1 GT	PASCO	GT	NG	DFO	2 / 2002	--- / -----	180.2	(1)	---	156.0	172.0	156.0	172.0	---	---	MER	OP	C	(2)
SHADY HILLS POWER CO.	2 GT	PASCO	GT	NG	DFO	2 / 2002	--- / -----	180.2	(1)	---	156.0	172.0	156.0	172.0	---	---	MER	OP	C	(2)
SHADY HILLS POWER CO.	3 GT	PASCO	GT	NG	DFO	2 / 2002	--- / -----	180.2	(1)	---	156.0	172.0	156.0	172.0	---	---	MER	OP	C	(2)
SANTA ROSA ENERGY CENTER, LLC (SREC)																				
SANTA ROSA ENERGY CENTER	CT01	SANTA ROSA	CT	NG	---	6 / 2003	--- / ----	165.7	(1)	177.7	161.4	173.4	---	---	161.0	173.0	MER	OP	NC	
SANTA ROSA ENERGY CENTER	ST01	SANTA ROSA	CA	WH	---	6 / 2003	--- / ----	74.5	(1)	74.5	74.5	74.5	---	---	75.0	75.0	MER	OP	NC	
NORTHERN STAR GENERATING SERVICES (NSG)																				
VANDOLAH POWER CO.	1	HARDEE	GT	NG	DFO	6 / 2002	6 / 2042	162.7		172.6	160.7	170.6	160.7	170.6	---	---	MER	OP	C	
VANDOLAH POWER CO.	2	HARDEE	GT	NG	DFO	6 / 2002	6 / 2042	162.7		172.6	160.7	170.6	160.7	170.6	---	---	MER	OP	C	
VANDOLAH POWER CO.	3	HARDEE	GT	NG	DFO	6 / 2002	6 / 2042	162.7		172.6	160.7	170.6	160.7	170.6	---	---	MER	OP	C	
VANDOLAH POWER CO.	4	HARDEE	GT	NG	DFO	6 / 2002	6 / 2042	162.7		172.6	160.7	170.6	160.7	170.6	---	---	MER	OP	C	
NRG ENERGY, INC (NRG)																				
OSCEOLA	1	OSCEOLA	GT	NG	DFO	12 / 2001	--- / -----	155.0		167.0	150.0	163.0	---	---	150.0	163.0	IPP/MER	SB	NC	(3)
OSCEOLA	2	OSCEOLA	GT	NG	DFO	12 / 2001	--- / -----	155.0		167.0	150.0	163.0	---	---	150.0	163.0	IPP/MER	SB	NC	(3)
OSCEOLA	3	OSCEOLA	GT	NG	DFO	3 / 2002	--- / -----	155.0		167.0	150.0	163.0	---	---	150.0	163.0	IPP/MER	SB	NC	(3)
SOUTHERN POWER COMPANY (SOU)																				
OLEANDER POWER PROJECT	1	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	156.4		167.8	155.4	166.8	0.0	0.0	155.4	166.8	MER	OP	NC	
OLEANDER POWER PROJECT	2	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	157.0		168.4	156.00	167.4	156.0	167.4	0.0	0.0	MER	OP	C	
OLEANDER POWER PROJECT	3	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	154.9		166.2	153.9	165.2	153.9	165.2	0.0	0.0	MER	OP	C	
OLEANDER POWER PROJECT	4	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	156.8		168.4	155.8	167.4	155.8	167.4	0.0	0.0	MER	OP	C	
OLEANDER POWER PROJECT	5	BREVARD	GT	NG	DFO	12 / 2007	--- / -----	160.7		173.4	159.7	172.4	159.7	172.4	0.0	0.0	MER	OP	C	
STANTON ENERGY CENTER	A	ORANGE	CT	NG	DFO	10 / 2003	--- / -----	415.4		433.4	406.4	424.5	406.4	424.5	0.0	0.0	MER	OP	C	(4)
									TOTALS:		3,101	3,325	2,260	2,412	841	913				

(1) This is the generator nameplate rating.
(2) All capacities based on Duke Toll contract ambient conditions.
(3) Currently in mothballed status, but no mothball status code exists, the closest status is "SB": Cold Standby, deactivated, in long-term storage and cannot be made available for service in a short period of time.
(4) This is a jointly owned unit. Only the amount owned by SOU is shown.

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

PLANNED AND PROSPECTIVE MERCHANT GENERATION FACILITIES
IN FLORIDA
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK						
												FIRM		UNCOMMITTED				
UTIL	FACILITY NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	EFFECTIVE CHANGE DATE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	OWNERSHIP	UNIT STATUS	CONTRACT STATUS
CALPINE EASTERN (CAL)																		
	No Activity Reported																	
GENERAL ELECTRIC (GE)																		
	SHADY HILLS POWER CO.	4CC	PASCO	CC	NG	DFO	6 / 2021	---	---	500.0	520.0	---	---	500.0	520.0	MER	NS	NC
SANTA ROSA ENERGY CENTER, LLC (SREC)																		
	No Activity Reported																	
NORTHERN STAR GENERATING SERVICES (NSG)																		
	No Activity Reported																	
NRG ENERGY, INC (NRG)																		
	No Activity Reported																	
SOUTHERN POWER COMPANY (SOU)																		
	No Activity Reported																	

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

PLANNED AND PROSPECTIVE MERCHANT GENERATION FACILITIES
IN FLORIDA
JANUARY 1, 2017 THROUGH DECEMBER 31, 2026

ORDERED BY IN-SERVICE DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK						
												FIRM		UNCOMMITTED				
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE PRI	FUEL TYPE ALT	EFFECTIVE CHANGE DATE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	OWNERSHIP	UNIT STATUS	CONTRACT STATUS
	2017																	
	No Activity Reported																	
	2018																	
	No Activity Reported																	
	2019																	
	No Activity Reported																	
	2020																	
	No Activity Reported																	
	2021																	
GE	SHADY HILLS POWER CO.	4CC	PASCO	CC	NG	DFO	6 / 2021	---	---	500.0	520.0	---	---	500.0	520.0	MER	NS	NC
	2022																	
	No Activity Reported																	
	2023																	
	No Activity Reported																	
	2024																	
	No Activity Reported																	
	2025																	
	No Activity Reported																	
	2026																	
	No Activity Reported																	
							2017 - 2026 TOTALS:			500.0	520.0	0.0	0.0	500.0	520.0			

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF MERCHANT FIRM CAPACITY AND ENERGY CONTRACTS
As of January 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		NET CAPABILITY		DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)	
DEF	GE	04/01/07	04/30/24	468	516	Toll to DEF for 100% of output (Capability based on contract ambient conditions)
DEF	VANDOLAH	06/01/12	05/31/27	643	683	Contract does not call for Vandolah to provide a specific MW output, but instead calls for the performance of an annual capacity test to determine the MW output for that year. Data provided is based on the contract results for June 2016 (Summer) and Dec 2016 (Winter).
FMPA	SOU	10/01/03	09/30/23	81	85	SOU Ownership contracted to FMPA (Stanton A)
FMPA	SOU	12/16/07	12/15/22	160	172	Oleander Unit 5
OUC	SOU	10/01/03	09/30/23	325	340	SOU Ownership contracted to OUC (Stanton A)
SEC	SOU	01/01/10	05/31/21	156	167	Oleander Unit 2
SEC	SOU	01/01/10	05/31/21	154	165	Oleander Unit 3
SEC	SOU	01/01/10	05/31/21	156	167	Oleander Unit 4

2017
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF MERCHANT GENERATING FACILITIES
IN THE FRCC REGION

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	SUMMER				WINTER		
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED (MW)	NET CAPABILITY (MW)	YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED (MW)	NET CAPABILITY (MW)
2017	2,259.6	841.4	3,101.0	2017/18	2,412.3	912.8	3,325.1
2018	2,259.6	841.4	3,101.0	2018/19	2,412.3	912.8	3,325.1
2019	2,259.6	841.4	3,101.0	2019/20	2,412.3	912.8	3,325.1
2020	2,259.6	841.4	3,101.0	2020/21	2,412.3	912.8	3,325.1
2021	1,793.6	1,807.4	3,601.0	2021/22	1,914.0	1,931.1	3,845.1
2022	1,793.6	1,807.4	3,601.0	2022/23	1,742.0	2,103.1	3,845.1
2023	1,633.6	1,967.4	3,601.0	2023/24	1,317.0	2,528.1	3,845.1
2024	759.6	2,841.4	3,601.0	2024/25	801.0	3,044.1	3,845.1
2025	759.6	2,841.4	3,601.0	2025/26	801.0	3,044.1	3,845.1
2026	759.6	2,841.4	3,601.0	2026/27	801.0	3,044.1	3,845.1

NOTES: Only columns (4) and (8) are cumulative on a seasonal basis.
Columns (2), (3), (6), and (7) represent the seasonal capabilities available as they have been modified by contract terms.

EXHIBIT NO. 110

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: WOOD / HINES

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: TAMPA ELECTRIC COMPANY 2017 TEN YEAR SITE PLAN – EXCERPTS - NUMBER OF CUSTOMERS AND WINTER PEAK DEMAND SCHEDULES 2.1, 2.2, 2.3, AND 3.2

DOCUMENTS: TAMPA ELECTRIC COMPANY TEN-YEAR SITE PLAN, SUBMITTED TO THE FLORIDA PUBLIC SERVICE COMMISSION APRIL 3, 2017

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 110
PARTY: Quantum, Daly, Tulk
DESCRIPTION: Tampa Electric 2017 10-Year Site Plan

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2017 to December 2026

Submitted to: Florida Public Service Commission
April 3, 2017

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,381,555	2.5	8,951	658,429	13,595	6,334	75,259	84,165
2018	1,409,550	2.5	9,093	670,752	13,556	6,388	76,050	84,000
2019	1,437,372	2.5	9,256	683,068	13,551	6,457	76,763	84,119
2020	1,464,810	2.5	9,377	695,253	13,487	6,506	77,440	84,015
2021	1,491,254	2.5	9,496	707,020	13,431	6,551	78,097	83,886
2022	1,517,131	2.5	9,652	718,565	13,433	6,610	78,744	83,948
2023	1,542,488	2.5	9,784	729,906	13,404	6,676	79,373	84,106
2024	1,567,349	2.5	9,927	741,053	13,396	6,747	79,979	84,362
2025	1,591,735	2.5	10,077	752,012	13,400	6,819	80,563	84,638
2026	1,615,661	2.5	10,230	762,788	13,412	6,892	81,130	84,954

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	1,945	1,651	1,178,491	0	80	1,803	19,114
2018	1,940	1,668	1,162,826	0	81	1,823	19,325
2019	1,959	1,682	1,164,809	0	81	1,850	19,603
2020	1,974	1,691	1,167,309	0	82	1,869	19,808
2021	1,993	1,701	1,171,695	0	82	1,887	20,010
2022	1,887	1,712	1,101,842	0	82	1,913	20,144
2023	1,910	1,724	1,107,858	0	81	1,941	20,391
2024	1,925	1,735	1,109,344	0	80	1,973	20,651
2025	1,947	1,746	1,115,255	0	78	2,004	20,926
2026	1,970	1,757	1,121,347	0	76	2,038	21,206

Notes:

December 31, 2016 Status

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	104	942	20,160	8,371	743,710
2018	104	952	20,381	8,449	756,919
2019	0	966	20,570	8,526	770,039
2020	0	977	20,784	8,604	782,988
2021	0	987	20,996	8,682	795,500
2022	0	994	21,137	8,759	807,780
2023	0	1,006	21,397	8,837	819,840
2024	0	1,019	21,670	8,914	831,681
2025	0	1,033	21,959	8,992	843,314
2026	0	1,047	22,253	9,070	854,744

Notes:

December 31, 2016 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL). Contract ended with FTM on 12/31/08, DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. RCID began again in 2016. Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	4,818	15	4,803	94	0	540	98	69	4,002
2017/18	4,882	15	4,867	92	0	547	98	70	4,060
2018/19	4,938	0	4,938	92	0	554	99	71	4,122
2019/20	5,010	0	5,010	92	0	562	100	73	4,183
2020/21	5,073	0	5,073	93	0	570	100	74	4,236
2021/22	5,128	0	5,128	79	0	578	101	76	4,294
2022/23	5,197	0	5,197	80	0	586	101	78	4,352
2023/24	5,265	0	5,265	79	0	594	102	80	4,411
2024/25	5,337	0	5,337	79	0	602	103	81	4,472
2025/26	5,408	0	5,408	79	0	610	103	83	4,532

Notes:

December 31, 2016 Status

2011/2012 Net Firm Demand is not coincident with system peak

*Includes residential and commercial/industrial conservation.

**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.

***Includes energy planner program

Values shown may be affected due to rounding.

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Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2017 to December 2026

Submitted to: Florida Public Service Commission
April 3, 2017

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Figure VI-II: Site Location of Polk Power Station 69

Figure VI-III: Site Location of Big Bend Power Station 70

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	CC	=	Combined Cycle
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	PV	=	Photovoltaic
	ST	=	Steam Turbine
Unit Status:	LTRS	=	Long-Term Reserve Stand-By
	OP	=	Operating (In commercial operation)
	OT	=	Other
	P	=	Planned
	T	=	Regulatory Approval Received
	U	=	Under Construction, less than or equal to 50 percent complete
	V	=	Under Construction, more than 50 percent complete
Fuel Type:	BIT	=	Bituminous Coal
	RFO	=	Residual Fuel Oil (Heavy - #6 Oil)
	DFO	=	Distillate Fuel Oil (Light - #2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
	BIO	=	Biomass
	SOLAR	=	Solar Energy
Environmental:	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SCR	=	Selective Catalytic Reduction
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

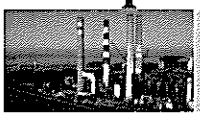
Tampa Electric Company's (TEC) 2017 Ten Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for the 2017 – 2026 time period. The 2017 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost effective alternatives to ensure the delivery of adequate, safe and reliable power to TEC's customers.

The resource plan presented here is similar to the plan presented by TEC in 2016. The Polk 2 Combined Cycle conversion project is complete, increasing incremental capacity by 463 MW winter and 459 MW summer. In 2015 TEC constructed a 1.6 MW_{AC} photovoltaic (PV) solar array located at Tampa International Airport (TIA) as well as a 1.5 MW_{AC} PV solar array at LEGOLAND®. TEC also completed an 18 MW_{AC} solar PV located at Big Bend Power Station with commercial operation in February 2017. In addition, TEC plans are to add peaking combustion turbines in 2021 and 2024 to continue to adequately meet reserve margin in future years.

TEC is committed to reliably serve the system's demand and energy requirements of its customers. TEC will continue to meet resource requirements with the most economical combination of Demand Side Management (DSM), conservation, renewable energy, purchased power, and generation capacity additions. The resource additions in TEC's 2017 TYSP are projected to be needed based on our current Integrated Resource Planning (IRP) process. The IRP process incorporates an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The IRP process is discussed further in Chapter III.

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Chapter I



DESCRIPTION OF EXISTING FACILITIES

Tampa Electric has three (3) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and multiple solar facilities.

Big Bend Power Station



Big Bend units 1-4 are four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction (SCR) air pollution control systems. Big Bend CT 4 is one (1) aero-derivative combustion turbine that entered into service in 2009 and can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station



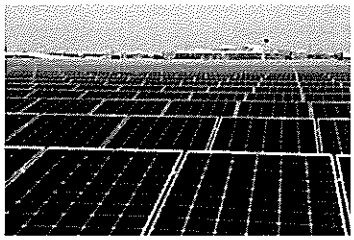
The station operates two (2) natural gas-fired combined cycle units and (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3,4,5,6 are four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station



The station operates one (1) integrated coal gasification combined cycle unit and one (1) natural gas-fired combined cycle unit. Polk Unit 1 is an integrated gasification combined cycle (IGCC) unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Unit 1 can also be fired with natural gas. On January 16, 2017 Polk 2 Combined Cycle entered commercial operation. Polk 2 CC utilizes four (4) combustion turbines (formally Polk 2-5 simple cycle CT's), four (4) HRSGs and one (1) steam turbine.

Solar



At Tampa International Airport there are 6,175 fixed solar PV panels located atop the south economy parking garage that was placed into service in 2015. The PV solar array located at LEGOLAND® Florida consists of 5,000 solar panels and began operation on December 8, 2016. In addition, the Big Bend Solar Station consisting of 200,000 PV modules located near Big Bend Power Station on nearly 106 acres began operation on February 10, 2017.

Schedule 1

Existing Generating Facilities
As of December 31, 2016

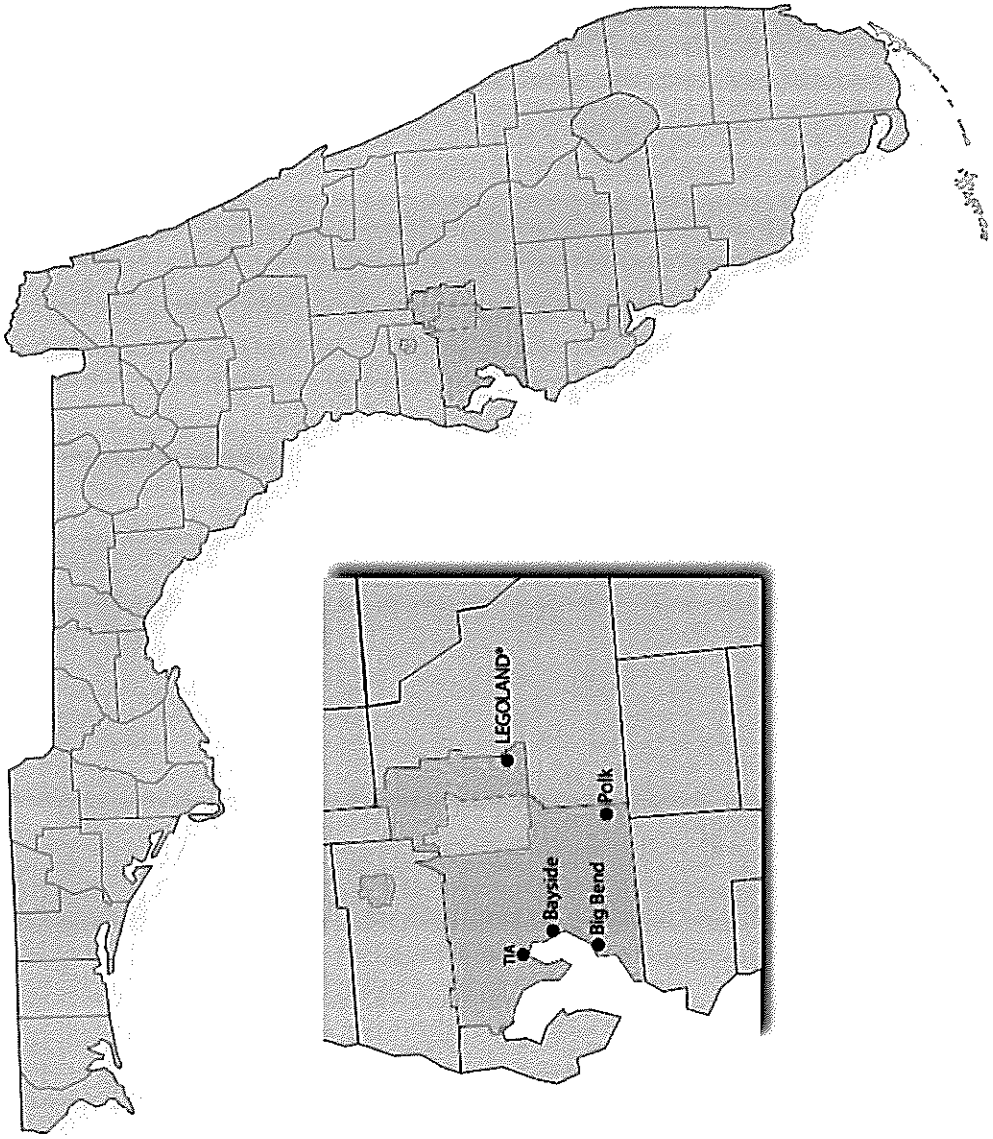
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt Fuel Days	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,892,400	1,658	1,693
	1		ST	BIT	NG	WA/RR	PL	NA	10/70	**	445,500	385	395
	2		ST	BIT	NG	WA/RR	PL	NA	04/73	**	445,500	385	395
	3		ST	BIT	NG	WA/RR	PL	NA	05/76	**	445,500	395	400
	4		ST	BIT	NG	WA/RR	PL	NA	02/85	**	486,000	437	442
	CT 4		GT	NG	DFO	PL	TK	*	08/09	**	69,900	56	61
Bayside		Hillsborough Co. 4/30S/19E									2,293,759	1,854	2,083
	1		CC	NG	NA	PL	NA	NA	04/03	**	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	**	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
Polk		Polk Co. 2,3/32S/23E									1,029,379	824	952
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		GT	NG	DFO	PL	TK	*	07/00	**	175,770	151	183
	3		GT	NG	DFO	PL	TK	*	05/02	**	175,770	151	183
	4		GT	NG	NA	PL	NA	NA	03/07	**	175,770	151	183
	5		GT	NG	NA	PL	NA	NA	04/07	**	175,770	151	183
TIA		Hillsborough Co. 31/28S/18E											
	1		PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®		Polk Co. 02/29S/26E											
	1		PV	SOLAR	NA	NA	NA	NA	12/16	**	1,500	1.5	1.5
											TOTAL	4,339	4,731

Notes:

* Limited by environmental permit

** Undetermined

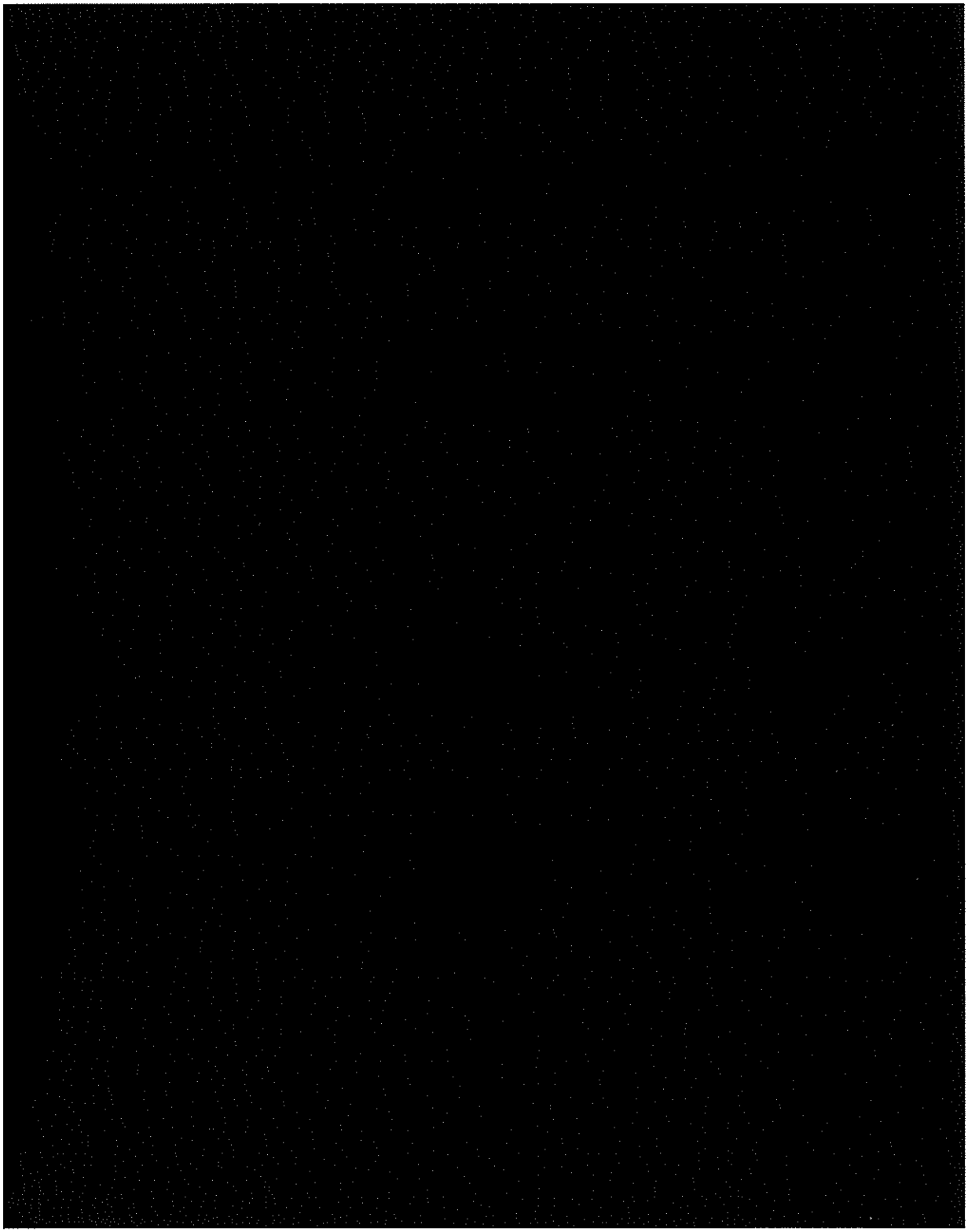
Figure I-I: Tampa Electric Service Area Map



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Figure I-II: Tampa Electric Service Area Transmission System



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Chapter II



TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the IRP is developed. Recognizing its importance, TEC employs the necessary methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection that represents the highest probability of occurrence.

This chapter is devoted to describing TEC's forecasting methods and the major assumptions utilized in developing the 2017-2026 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2017-2026 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2017-2026 customer, demand and energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, TEC uses MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast that is consistent with short-term statistical forecasts.

TEC's retail customer, demand and energy forecasts are the result of six separate forecasting analyses:

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Interruptible Demand and Energy Analysis
6. Conservation, Load Management and Cogeneration Programs



The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy is forecasted separately and then combined in the final forecast, as well as the effects of photovoltaic (PV) and electric vehicle (EV) related energy. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is a seven-equation model. The primary economic drivers in the customer forecast models are population estimates, service area households and employment growth. Below is a description of the models used for the five-customer classes.

1. *Residential Customer Model:* Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates were used to forecast the future growth patterns in residential customers.

2. *Commercial Customer Model:* Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers:

    a. The Commercial Customer Model is a function of population. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

    b. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service Model projects the number of customers as a function of construction employment.

3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
    a. The General Service Customer Model is a function of Hillsborough County

commercial employment.

b. The General Service Demand Customer Model is based on Hillsborough County manufacturing employment and the recent growth trend in the sector.

4. *Public Authority Customer Model:* Customer projections are based on the recent growth trend in the sector.

5. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trend in the sector.

3. Energy Multiregression Model

There are a total of seven energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering (SAE). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term time frame, as do econometric regression models.

1. *Residential Energy Model:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

   $$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

   Where:

   $$\begin{aligned} \text{XHeat}_{y,m} &= \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m} \\ \text{XCool}_{y,m} &= \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m} \\ \text{XOtherUse}_{y,m} &= \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m} \end{aligned}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined

by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{\,y} / \text{Efficiency}_{\,y}}{\text{Saturation}_{\,basey} / \text{Efficiency}_{\,basey}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{\,y} / \text{Efficiency}_{\,y}}{\text{Saturation}_{\,basey} / \text{Efficiency}_{\,basey}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{\,y} / \text{Efficiency}_{\,y}}{\text{Saturation}_{\,basey} / \text{Efficiency}_{\,basey}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{\,y,m}}{\text{Price}_{\,basey,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{\,y,m}}{\text{HH Income}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{HH Size}_{\,y,m}}{\text{HH Size}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{HDD}_{\,y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{\,y,m}}{\text{Price}_{\,basey,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{\,y,m}}{\text{HH Income}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{HH Size}_{\,y,m}}{\text{HH Size}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{CDD}_{\,y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{\,y,m}}{\text{Price}_{\,basey,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{\,y,m}}{\text{HH Income}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{HH Size}_{\,y,m}}{\text{HH Size}_{\,basey,m}} \right)^{.15} \times \left(\frac{\text{Billing Days}_{\,y,m}}{\text{Billing Days}_{\,basey,m}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time as well as estimate trend adjustments.

2. *Commercial Energy Models:* total commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.

    a. Commercial Energy Model: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and

in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

b. Temporary Service Energy Model: This model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Non-phosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.

    a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

    b. The General Service Demand Energy Model is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

4. *Public Authority Sector Model:* Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

5. *Street & Highway Lighting Sector Model:* The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street and highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The seven energy models described above, plus the effects of PV and EV related energy, and an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. Peak Demand Multiregression Model

After the retail net energy for load forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the temperature at the time of the peak and the 24-hour average on the day of the peak and day prior to the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate-coincident peak forecast to arrive at the final projected peak demand.

5. Interruptible Demand and Energy Analysis

TEC interruptible customers are relatively few in number, which has allowed the company's Sales and Marketing Department to obtain detailed knowledge of industry developments including:

- Knowledge of expansion and close-out plans;
- Familiarity with historical and projected trends;
- Personal contact with industry personnel;
- Governmental legislation;
- Familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the interruptible customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast and the commercial/industrial interruptible rate class forecasts are based. Further inputs are provided by individual customer trend analysis and discussions with industry experts.

6. Conservation, Load Management and Cogeneration Programs

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings are based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of DSM savings throughout the forecast horizon.

TEC retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

TEC has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.

2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.

3. Provide customers with some ability to control energy usage and decrease energy costs.

4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy goals for the residential and commercial/industrial sectors.

5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2016, TEC continued operating within the 2015-2024 DSM Plan which supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The company also successfully completed the phased closure of the company's residential load management program (Prime Time) pursuant to Consummating Order No. PSC-15-0434-CO-EG. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to TEC customers; four types are for residential customers and two types are for commercial/industrial customers.

2. Residential Ceiling Insulation – a rebate program that encourages existing residential customers to install additional ceiling insulation in existing homes.

3. Residential Duct Repair – a rebate program that encourages residential customers to repair leaky duct work of central air conditioning systems in existing homes.

4. Residential Electronically Commutated Motor (ECM) – a rebate program that encourages residential customers to replace their existing HVAC air handler motor with an ECM.

5. Energy Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers and students on energy-efficiency and conservation in an organized setting. Participants are provided with an energy savings kit which includes energy saving devices and supporting information appropriate for the audience.

6. Energy Star for New Homes - a rebate program that encourages residential customers to construct residential dwellings that qualify for the Energy Star Award by achieving efficiency levels greater than current Florida building code baseline practices.

7. Residential Heating and Cooling – a rebate program that encourages residential customers to install high-efficiency residential heating and cooling equipment in existing homes.

8. Neighborhood Weatherization – a program that provides for the installation of energy efficient measures for qualified low-income customers.

9. Residential Price Responsive Load Management (Energy Planner) – a program that reduces weather-sensitive loads through an innovative price responsive rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

10. Residential Wall Insulation – a rebate program that encourages existing residential customers to install additional wall insulation in existing homes.

11. Residential Window Replacement – a rebate program that encourages existing residential customers to install window upgrades in existing homes.

12. Commercial Ceiling Insulation – a rebate program that encourages commercial and industrial customers to install additional ceiling insulation in existing commercial structures.

13. Commercial Chiller – a rebate program that encourages commercial and industrial customers to install high efficiency chiller equipment.

14. Cogeneration – an incentive program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

15. Conservation Value – a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures that are not sanctioned by other commercial programs.

16. Cool Roof – a rebate program that encourages commercial and industrial customers to install a cool roof system above conditioned spaces.

17. Commercial Cooling – a rebate program that encourages commercial and industrial customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

18. Demand Response – a turn-key incentive program for commercial and industrial customers to reduce their demand for electricity in response to market signals.

19. Commercial Duct Repair – a rebate program that encourage existing commercial and industrial customers to repair leaky ductwork of central air-conditioning systems in existing commercial and industrial facilities.

20. Commercial Electronically Commutated Motors (ECM) - a rebate program that encourages commercial and industrial customers to replace their existing air handler motors or refrigeration fan motors with an ECM.

21. Industrial Load Management – an incentive program whereby large industrial customers allow for the interruption of their facility or portions of their facility electrical load.

22. Lighting Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing conditioned areas of commercial and industrial facilities.

23. Lighting Non-Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing non-conditioned areas of commercial and industrial facilities.

24. Lighting Occupancy Sensors – a rebate program that encourages commercial and industrial customers to install occupancy sensors to control commercial lighting systems.

25. Commercial Load Management – an incentive program that encourages commercial and industrial customers to allow for the control of weather-sensitive heating, cooling and water heating systems to reduce the associated weather sensitive peak.

26. Refrigeration Anti-Condensate Control – a rebate program that encourages commercial and industrial customers to install anti-condensate equipment sensors and control within refrigerated door systems.

27. Standby Generator – an incentive program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

28. Thermal Energy Storage - a rebate program that encourages commercial and industrial customers to install an off-peak air conditioning system.

29. Commercial Wall Insulation – a rebate program that encourages commercial and industrial customers to install wall insulation in existing commercial and industrial structures.

30. Commercial Water Heating – a rebate program that encourages commercial and industrial customers to install high efficiency water heating systems.

31. Conservation Research and Development (R&D) – a program that allows for the exploration of DSM measures that have insufficient data on the cost-effectiveness of the measure and the potential impact to TEC and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 130201-EI, Order No. PSC-14-0696-FOF-EU, Issued December 16, 2014. The 2016 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

TEC developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give TEC insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

TABLE III-1

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Savings at the Generator

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017		5.2			2.2			4.8	
2018		6.5			2.7			6.1	
2019		7.6			3.1			6.9	
2020		7.6			3.3			7.4	
2021		8.0			3.3			7.7	
2022		7.4			3.0			6.9	
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017		1.6			2.7			8.0	
2018		1.7			3.3			9.2	
2019		1.6			3.3			9.9	
2020		1.7			3.5			10.3	
2021		1.9			3.6			10.4	
2022		1.9			3.3			10.2	
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017		6.8			4.9			12.8	
2018		8.2			6.0			15.3	
2019		9.2			6.4			16.8	
2020		9.3			6.8			17.7	
2021		9.9			6.9			18.1	
2022		9.3			6.3			17.1	
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers for the period of 2017-2026. The average annual population growth rate is expected to be 1.8%.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years (2017-2026), employment is assumed to rise at a 1.4% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.4% average annual rate from 2017-2026. Moody's Analytics supplies output projections.

4. Real Household Income

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2017-2026, real household income for Hillsborough County is expected to increase at a 2.1% average annual rate.

5. *Price of Electricity*

Forecasts for the price of electricity by customer class are supplied by TEC's Regulatory Affairs Department.

6. *Appliance Efficiency Standards*

Another factor influencing energy consumption is the movement toward more efficient appliances such as heat pumps, refrigerators, lighting and other household appliances. The forces behind this development include market pressures for greater energy-saving devices, legislation, rules, and the appliance efficiency standards enacted by the state and federal governments. Also influencing energy consumption is the customer saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather related appliances also help to lower electricity consumption. Although there is an increasing saturation trend of electronic equipment and appliances in households throughout the forecast period, it does not offset the efficiency gains from lighting and appliances.

7. *Weather*

The weather assumptions are the most difficult to project. Therefore, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on twenty years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3 in Chapter IV.

1. Retail Energy

For 2017-2026, retail energy sales are projected to rise at a 1.2% annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.5% and 0.9%, respectively.

2. Wholesale Energy

For 2017-2018, TEC will sell Reedy Creek Improvement District (RCID) 15 MW of firm wholesale power.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the period of 2017-2026, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.4% in the summer and 1.4% in the winter.

Chapter III



INTEGRATED RESOURCE PLANNING PROCESSES

TEC's IRP process was designed to evaluate demand-side and supply-side resources on a comparable and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental energy efficiency and conservation programs, is developed. Then, without any incremental energy efficiency and conservation, an interim supply plan based on the system requirements is developed based upon this new demand and energy forecast. This interim supply plan is used to identify the basis for the next potential avoided unit(s). The data from this interim supply plan provides the baseline data that is used to perform a comprehensive cost effectiveness analysis of the energy efficiency and conservation programs.

Once this comprehensive analysis is complete, and the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply-side resources.

The cost-effectiveness of energy efficiency and demand-response programs is based on the following standard Commission tests: the Rate Impact Measure test (RIM), the Total Resource Cost test (TRC) and the Participants Cost test (PCT). Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

Each adopted measure is quantified into its coincident summer and winter peak kW reduction contribution and its annual kWh savings and is reflected in the demand and energy forecast. TEC evaluates and reports energy efficiency and demand response measures that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the TEC service area.

The technologies that pass the screening are included in a supply-side analysis that examines various supply-side alternatives for meeting future capacity requirements.

TEC uses a computer model developed by ABB, System Optimizer (SO), to evaluate supply-side

resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for capacity additions that would most economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total present worth revenue requirements.

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by ABB. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources in our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

The result of the IRP process provides TEC with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.1. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, TEC has converted Polk Units 2-5 to Polk 2 CC, a natural gas combined cycle unit with the addition of a steam turbine that has gone in-service in 2017. The company is also planning the addition of a simple cycle combustion turbine in 2021 and another simple cycle combustion turbine in 2024.

TEC will continue to assess competitive purchase power agreements that may replace or delay the scheduled new units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

FINANCIAL ASSUMPTIONS

TEC makes numerous financial assumptions as part of the preparation for its TYSP process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the TYSP.

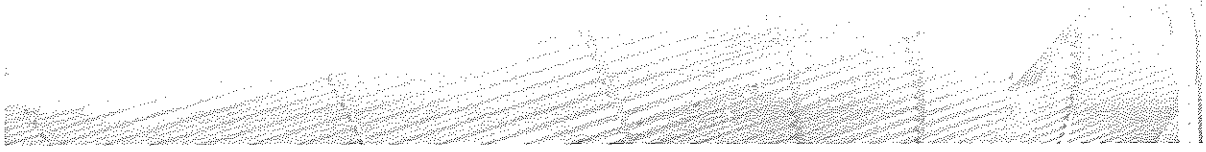
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using TEC's IRP process. As part of this process, TEC evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in more detailed economic analyses.

TEC forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Wood Mackenzie Energy Group, Coal Daily, Inside FERC, and Platt's Oilgram. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.



TAMPA ELECTRIC'S RENEWABLE ENERGY INITIATIVES

Since being approved as a permanent Renewable Energy Program by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006. TEC has offered the Renewable Energy Program which offers residential, commercial and industrial customers the opportunity to purchase 200 kWh renewable energy blocks for their home or business. In 2009, TEC added a new portion to the program which allows residential, commercial and industrial customers the opportunity to purchase renewable energy to power a specific event.

Through December 2016, TEC's Renewable Energy Program has over 1,749 customers purchasing over 2,600 blocks of renewable energy each month and there have been over 4,000 one-time blocks purchased.

The company's renewable-generation portfolio is a mix of various technologies and renewable fuel sources, including seven smaller, company-owned photovoltaic (PV) arrays. The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, TEC's Manatee Viewing Center, Tampa's Lowry Park Zoo, the Florida Aquarium and LEGOLAND® Florida's Imagination Zone. To further educate the public on the benefits of renewable energy, the installations at these facilities include interactive displays that were built to provide a hands-on experience to engage visitors' interest in solar technology.

TEC continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. The company completed the installation of its first large-scale solar facility at Tampa International Airport in December 2015. The solar PV array, sized at 1.6 MW_{AC}, can produce enough electricity to power up to 250 homes. In December 2016, TEC completed its second large-scale PV system – a 1.5 MW_{AC} array at LEGOLAND® Florida in Winter Haven. This array was constructed on a shade canopy in the park's preferred parking lot and generates enough energy to power more than 200 homes. TEC owns both large-scale solar PV facilities and the electricity they produce goes to the grid to benefit TEC customers. In February 2017, TEC placed in operation the 18 MW_{AC} array which is located at the company's Big Bend Station.

Renewable program participation has reached a level where it is necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2016, participating customers have utilized over 83 GWh of renewable energy since the program inception.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers. Through December 2016, more than 1,100 customers installed PV systems on their homes or businesses, accounting for more than 12 MW of net metered, distributed solar generation interconnected on TEC's grid.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

TEC's generating unit performance assumptions are used to evaluate long-range system operating costs associated with integrated resource plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on a repetitive pattern.

The forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rates are projected based on an average of three years of historical data, future expectations, and any necessary adjustments to account for current unit conditions.

GENERATION RELIABILITY CRITERIA

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100. Capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from TEC's available capacity.

TEC's supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the firm peak demand and interruptible and load management loads.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply-side resources, as well as suppliers of equipment and services, will be identified using various database resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply-side resources to be supplied from self-build, purchased power, or asset purchases. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings

and process-improvement recommendations.

TRANSMISSION CONSTRAINTS AND IMPACTS

Based on a variety of assessments and sensitivity studies of the TEC transmission system, using year 2016 Florida Reliability Coordinating Council (FRCC) database models, no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document were identified in these studies.

TRANSMISSION PLANNING RELIABILITY CRITERIA

1. Transmission

TEC developed the transmission planning reliability criteria, as described in the FERC Form 715 filing, to assess and test the strength and limits of the transmission system, while meeting the load responsibility and being able to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the FRCC's *FRCC Regional Transmission Planning Process*. The FRCC's transmission planning criteria are consistent with the North American Electric Reliability Corporation (NERC) Reliability Standards.

In general, the NERC Reliability Standards state the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and select multiple contingency conditions. In addition to the FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at https://www.oasis.oati.com/TEC/index.html.

The transmission planning reliability criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute rules for system expansion. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

2. Available Transmission Transfer Capability (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the *Attachment C of TEC Open Access Transmission Tariff FERC Electric Tariff, Fourth Revised Volume No. 4* document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/TransmissionTariff.pdf, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

TEC's transmission system planning assessment practices are developed according to the TEC and NERC Reliability Standards to ensure a reliable system is planned that demonstrates adequacy within TEC's footprint to meet present and future system needs. The Reliability Standards require that the TEC transmission system be planned such that it will remain stable within the applicable facility ratings and voltage rating limits and without cascading outages under normal system conditions, as well as single and multiple contingency events.

TEC performs transmission studies independently, collaboratively with other utilities, and as part of the FRCC to determine if the system meets the criteria. The studies involve the use of steady-state power flows, transient stability analyses, short circuit assessments and various other assessments to ensure adequate system performance.

1. Base Case Operating Conditions

The System Planning department ensures the TEC transmission system can support peak and off-peak system load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

2. Single Contingency Planning Criteria

The TEC transmission system is designed to support any single event outage of a transmission circuit, autotransformer, generator or shunt device (including FRCC studies of Category P1 and P2-1 events) at a variety of load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

3. Multiple Contingency Planning Criteria

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more BES transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document

4. Transmission Construction and Upgrade Plans

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are directly monitorable and yield measurable results. The achievements and durability of energy savings from the company's conservation and load management programs is validated by several methods. First, TEC has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

1. Periodic system load reduction analysis for price responsive load management (Energy Planner), Commercial industrial load management and Commercial demand response to confirm and verify the accuracy of TEC's load reduction estimation formulas.

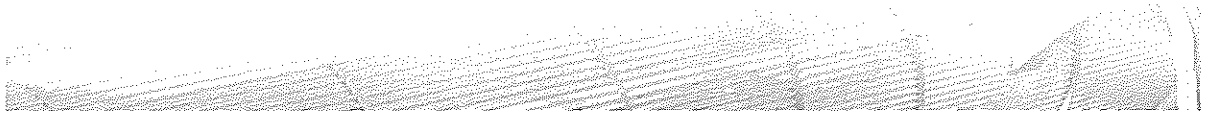
2. Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.

3. Analysis of DOE2 modeling of various program participants.

4. End-use monitoring and evaluation of projects and programs.

5. Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy-efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements, and ECM motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.



Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to TEC's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

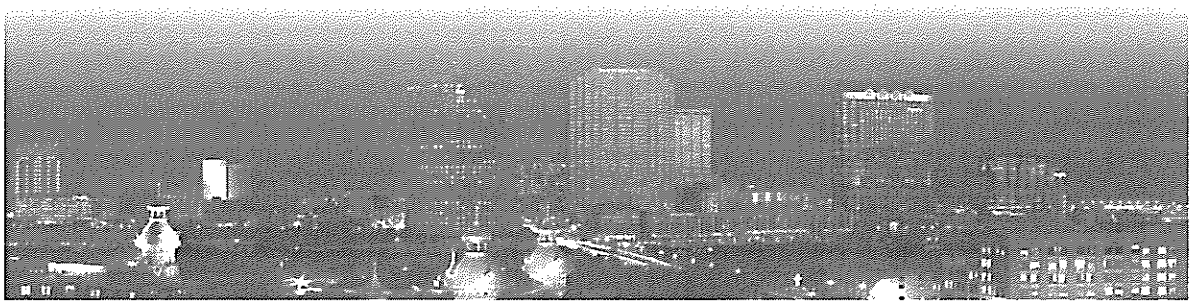
Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWh

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent



Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,381,555	2.5	8,951	658,429	13,595	6,334	75,259	84,165
2018	1,409,550	2.5	9,093	670,752	13,556	6,388	76,050	84,000
2019	1,437,372	2.5	9,256	683,068	13,551	6,457	76,763	84,119
2020	1,464,810	2.5	9,377	695,253	13,487	6,506	77,440	84,015
2021	1,491,254	2.5	9,496	707,020	13,431	6,551	78,097	83,886
2022	1,517,131	2.5	9,652	718,565	13,433	6,610	78,744	83,948
2023	1,542,488	2.5	9,784	729,906	13,404	6,676	79,373	84,106
2024	1,567,349	2.5	9,927	741,053	13,396	6,747	79,979	84,362
2025	1,591,735	2.5	10,077	752,012	13,400	6,819	80,563	84,638
2026	1,615,661	2.5	10,230	762,788	13,412	6,892	81,130	84,954

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2017	1,388,319	2.5	9,009	661,597	13,617	6,348	75,426	84,158
2018	1,423,392	2.5	9,210	677,234	13,599	6,416	76,391	83,986
2019	1,458,605	2.5	9,436	693,010	13,616	6,500	77,288	84,098
2020	1,493,741	2.5	9,621	708,799	13,574	6,564	78,155	83,987
2021	1,528,176	2.5	9,808	724,307	13,541	6,625	79,010	83,852
2022	1,562,334	2.6	10,034	739,729	13,565	6,701	79,862	83,910
2023	1,597,256	2.6	10,238	755,081	13,558	6,784	80,704	84,062
2024	1,631,939	2.6	10,457	770,370	13,574	6,874	81,528	84,315
2025	1,666,401	2.6	10,685	785,601	13,601	6,965	82,337	84,589
2026	1,700,661	2.6	10,919	800,775	13,635	7,058	83,135	84,903

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2017	1,374,791	2.5	8,894	655,261	13,574	6,321	75,093	84,172
2018	1,395,775	2.5	8,976	664,302	13,513	6,361	75,710	84,015
2019	1,416,346	2.5	9,079	673,223	13,485	6,415	76,244	84,141
2020	1,436,301	2.4	9,137	681,905	13,400	6,449	76,735	84,043
2021	1,455,049	2.4	9,193	690,069	13,322	6,479	77,202	83,920
2022	1,473,022	2.4	9,283	697,914	13,301	6,522	77,653	83,987
2023	1,490,277	2.4	9,347	705,462	13,250	6,571	78,082	84,149
2024	1,506,845	2.4	9,422	712,726	13,220	6,625	78,483	84,408
2025	1,522,756	2.4	9,501	719,718	13,201	6,678	78,858	84,688
2026	1,538,031	2.4	9,581	726,444	13,190	6,733	79,211	85,006

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	1,945	1,651	1,178,491	0	80	1,803	19,114
2018	1,940	1,668	1,162,826	0	81	1,823	19,325
2019	1,959	1,682	1,164,809	0	81	1,850	19,603
2020	1,974	1,691	1,167,309	0	82	1,869	19,808
2021	1,993	1,701	1,171,695	0	82	1,887	20,010
2022	1,887	1,712	1,101,842	0	82	1,913	20,144
2023	1,910	1,724	1,107,858	0	81	1,941	20,391
2024	1,925	1,735	1,109,344	0	80	1,973	20,651
2025	1,947	1,746	1,115,255	0	78	2,004	20,926
2026	1,970	1,757	1,121,347	0	76	2,038	21,206

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2017	1,948	1,653	1,178,343	0	80	1,804	19,188
2018	1,945	1,672	1,163,021	0	81	1,825	19,476
2019	1,967	1,687	1,165,696	0	81	1,852	19,836
2020	1,985	1,699	1,168,202	0	82	1,872	20,123
2021	2,006	1,711	1,172,683	0	82	1,891	20,412
2022	1,903	1,724	1,103,911	0	82	1,917	20,638
2023	1,929	1,738	1,110,147	0	81	1,946	20,979
2024	1,948	1,751	1,112,247	0	80	1,979	21,337
2025	1,974	1,764	1,118,774	0	78	2,011	21,713
2026	2,000	1,777	1,125,567	0	76	2,046	22,099

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2017	1,943	1,649	1,178,229	0	80	1,802	19,040
2018	1,935	1,664	1,162,572	0	81	1,822	19,174
2019	1,951	1,676	1,164,166	0	81	1,848	19,374
2020	1,964	1,684	1,166,226	0	82	1,866	19,498
2021	1,980	1,692	1,170,154	0	82	1,883	19,617
2022	1,871	1,701	1,099,700	0	82	1,908	19,665
2023	1,891	1,710	1,105,644	0	81	1,936	19,826
2024	1,902	1,719	1,106,649	0	80	1,966	19,995
2025	1,922	1,728	1,112,070	0	78	1,997	20,177
2026	1,941	1,737	1,117,656	0	76	2,030	20,362

Notes:

*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	104	942	20,160	8,371	743,710
2018	104	952	20,381	8,449	756,919
2019	0	966	20,570	8,526	770,039
2020	0	977	20,784	8,604	782,988
2021	0	987	20,996	8,682	795,500
2022	0	994	21,137	8,759	807,780
2023	0	1,006	21,397	8,837	819,840
2024	0	1,019	21,670	8,914	831,681
2025	0	1,033	21,959	8,992	843,314
2026	0	1,047	22,253	9,070	854,744

Notes:

December 31, 2016 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
Contract ended with FTM on 12/31/08, DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. RCID began again in 2016.
Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,381,555	2.5	8,951	658,429	13,595	6,334	75,259	84,165
2018	1,409,550	2.5	9,093	670,752	13,556	6,388	76,050	84,000
2019	1,437,372	2.5	9,256	683,068	13,551	6,457	76,763	84,119
2020	1,464,810	2.5	9,377	695,253	13,487	6,506	77,440	84,015
2021	1,491,254	2.5	9,496	707,020	13,431	6,551	78,097	83,886
2022	1,517,131	2.5	9,652	718,565	13,433	6,610	78,744	83,948
2023	1,542,488	2.5	9,784	729,906	13,404	6,676	79,373	84,106
2024	1,567,349	2.5	9,927	741,053	13,396	6,747	79,979	84,362
2025	1,591,735	2.5	10,077	752,012	13,400	6,819	80,563	84,638
2026	1,615,661	2.5	10,230	762,788	13,412	6,892	81,130	84,954

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2017	1,388,319	2.5	9,009	661,597	13,617	6,348	75,426	84,158
2018	1,423,392	2.5	9,210	677,234	13,599	6,416	76,391	83,986
2019	1,458,605	2.5	9,436	693,010	13,616	6,500	77,288	84,098
2020	1,493,741	2.5	9,621	708,799	13,574	6,564	78,155	83,987
2021	1,528,176	2.5	9,808	724,307	13,541	6,625	79,010	83,852
2022	1,562,334	2.6	10,034	739,729	13,565	6,701	79,862	83,910
2023	1,597,256	2.6	10,238	755,081	13,558	6,784	80,704	84,062
2024	1,631,939	2.6	10,457	770,370	13,574	6,874	81,528	84,315
2025	1,666,401	2.6	10,685	785,601	13,601	6,965	82,337	84,589
2026	1,700,661	2.6	10,919	800,775	13,635	7,058	83,135	84,903

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2017	1,374,791	2.5	8,894	655,261	13,574	6,321	75,093	84,172
2018	1,395,775	2.5	8,976	664,302	13,513	6,361	75,710	84,015
2019	1,416,346	2.5	9,079	673,223	13,485	6,415	76,244	84,141
2020	1,436,301	2.4	9,137	681,905	13,400	6,449	76,735	84,043
2021	1,455,049	2.4	9,193	690,069	13,322	6,479	77,202	83,920
2022	1,473,022	2.4	9,283	697,914	13,301	6,522	77,653	83,987
2023	1,490,277	2.4	9,347	705,462	13,250	6,571	78,082	84,149
2024	1,506,845	2.4	9,422	712,726	13,220	6,625	78,483	84,408
2025	1,522,756	2.4	9,501	719,718	13,201	6,678	78,858	84,688
2026	1,538,031	2.4	9,581	726,444	13,190	6,733	79,211	85,006

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	1,945	1,651	1,178,491	0	80	1,803	19,114
2018	1,940	1,668	1,162,826	0	81	1,823	19,325
2019	1,959	1,682	1,164,809	0	81	1,850	19,603
2020	1,974	1,691	1,167,309	0	82	1,869	19,808
2021	1,993	1,701	1,171,695	0	82	1,887	20,010
2022	1,887	1,712	1,101,842	0	82	1,913	20,144
2023	1,910	1,724	1,107,858	0	81	1,941	20,391
2024	1,925	1,735	1,109,344	0	80	1,973	20,651
2025	1,947	1,746	1,115,255	0	78	2,004	20,926
2026	1,970	1,757	1,121,347	0	76	2,038	21,206

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2017	1,948	1,653	1,178,343	0	80	1,804	19,188
2018	1,945	1,672	1,163,021	0	81	1,825	19,476
2019	1,967	1,687	1,165,696	0	81	1,852	19,836
2020	1,985	1,699	1,168,202	0	82	1,872	20,123
2021	2,006	1,711	1,172,683	0	82	1,891	20,412
2022	1,903	1,724	1,103,911	0	82	1,917	20,638
2023	1,929	1,738	1,110,147	0	81	1,946	20,979
2024	1,948	1,751	1,112,247	0	80	1,979	21,337
2025	1,974	1,764	1,118,774	0	78	2,011	21,713
2026	2,000	1,777	1,125,567	0	76	2,046	22,099

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
2017	1,943	1,649	1,178,229	0	80	1,802	19,040
2018	1,935	1,664	1,162,572	0	81	1,822	19,174
2019	1,951	1,676	1,164,166	0	81	1,848	19,374
2020	1,964	1,684	1,166,226	0	82	1,866	19,498
2021	1,980	1,692	1,170,154	0	82	1,883	19,617
2022	1,871	1,701	1,099,700	0	82	1,908	19,665
2023	1,891	1,710	1,105,644	0	81	1,936	19,826
2024	1,902	1,719	1,106,649	0	80	1,966	19,995
2025	1,922	1,728	1,112,070	0	78	1,997	20,177
2026	1,941	1,737	1,117,656	0	76	2,030	20,362

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	104	942	20,160	8,371	743,710
2018	104	952	20,381	8,449	756,919
2019	0	966	20,570	8,526	770,039
2020	0	977	20,784	8,604	782,988
2021	0	987	20,996	8,682	795,500
2022	0	994	21,137	8,759	807,780
2023	0	1,006	21,397	8,837	819,840
2024	0	1,019	21,670	8,914	831,681
2025	0	1,033	21,959	8,992	843,314
2026	0	1,047	22,253	9,070	854,744

Notes:

December 31, 2016 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
Contract ended with FTM on 12/31/08, DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. RCID began again in 2016.
Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2017	104	946	20,238	8,371	747,047
2018	104	960	20,540	8,449	763,746
2019	0	978	20,813	8,526	780,511
2020	0	992	21,116	8,604	797,257
2021	0	1,007	21,419	8,681	813,709
2022	0	1,018	21,655	8,760	830,075
2023	0	1,035	22,014	8,837	846,360
2024	0	1,053	22,390	8,914	862,563
2025	0	1,071	22,784	8,992	878,694
2026	0	1,091	23,190	9,069	894,756

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2017	104	946	20,238	8,371	747,047
2018	104	960	20,540	8,449	763,746
2019	0	978	20,813	8,526	780,511
2020	0	992	21,116	8,604	797,257
2021	0	1,007	21,419	8,681	813,709
2022	0	1,018	21,655	8,760	830,075
2023	0	1,035	22,014	8,837	846,360
2024	0	1,053	22,390	8,914	862,563
2025	0	1,071	22,784	8,992	878,694
2026	0	1,091	23,190	9,069	894,756

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

Forecast of Energy Consumption and Number of Customers by Customer Class Low Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2017	104	939	20,083	8,371	740,374
2018	104	945	20,224	8,449	750,125
2019	0	955	20,329	8,526	759,669
2020	0	961	20,459	8,604	768,928
2021	0	968	20,585	8,681	777,644
2022	0	970	20,635	8,760	786,028
2023	0	978	20,804	8,837	794,091
2024	0	987	20,982	8,914	801,842
2025	0	996	21,173	8,992	809,296
2026	0	1,005	21,367	9,069	816,461

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,276	148	4,128	143	69	84	53	55	3,723
2009	4,316	136	4,180	120	54	90	58	59	3,799
2010	4,171	118	4,053	73	33	97	75	65	3,710
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,310	15	4,294	110	0	154	101	96	3,833
2018	4,372	15	4,357	108	0	159	102	99	3,888
2019	4,426	0	4,426	108	0	164	102	103	3,948
2020	4,486	0	4,486	108	0	170	103	107	3,998
2021	4,546	0	4,546	108	0	175	104	112	4,047
2022	4,598	0	4,598	95	0	181	104	116	4,101
2023	4,662	0	4,662	95	0	186	105	120	4,156
2024	4,728	0	4,728	94	0	191	106	125	4,212
2025	4,796	0	4,796	95	0	197	106	129	4,269
2026	4,862	0	4,862	95	0	202	107	133	4,325

Notes:

December 31, 2016 Status

2010 and 2016 Net Firm Demand is not coincident with system peak

*Includes residential and commercial/industrial conservation.

**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.

***Includes Energy Planner program

Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2017	4,327	15	4,311	110	0	154	101	96	3,850
2018	4,406	15	4,391	108	0	159	102	99	3,922
2019	4,479	0	4,479	108	0	164	102	103	4,001
2020	4,557	0	4,557	108	0	170	103	107	4,069
2021	4,637	0	4,637	108	0	175	104	112	4,138
2022	4,710	0	4,710	95	0	181	104	116	4,213
2023	4,795	0	4,795	95	0	186	105	120	4,289
2024	4,882	0	4,882	94	0	191	106	125	4,366
2025	4,973	0	4,973	95	0	197	106	129	4,446
2026	5,063	0	5,063	95	0	202	107	133	4,526

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2017	4,293	15	4,277	110	0	154	101	96	3,816
2018	4,338	15	4,323	108	0	159	102	99	3,854
2019	4,374	0	4,374	108	0	164	102	103	3,896
2020	4,416	0	4,416	108	0	170	103	107	3,928
2021	4,457	0	4,457	108	0	175	104	112	3,958
2022	4,490	0	4,490	95	0	181	104	116	3,993
2023	4,534	0	4,534	95	0	186	105	120	4,028
2024	4,579	0	4,579	94	0	191	106	125	4,063
2025	4,626	0	4,626	95	0	197	106	129	4,099
2026	4,671	0	4,671	95	0	202	107	133	4,134

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	4,818	15	4,803	94	0	540	98	69	4,002
2017/18	4,882	15	4,867	92	0	547	98	70	4,060
2018/19	4,938	0	4,938	92	0	554	99	71	4,122
2019/20	5,010	0	5,010	92	0	562	100	73	4,183
2020/21	5,073	0	5,073	93	0	570	100	74	4,236
2021/22	5,128	0	5,128	79	0	578	101	76	4,294
2022/23	5,197	0	5,197	80	0	586	101	78	4,352
2023/24	5,265	0	5,265	79	0	594	102	80	4,411
2024/25	5,337	0	5,337	79	0	602	103	81	4,472
2025/26	5,408	0	5,408	79	0	610	103	83	4,532

Notes:

December 31, 2016 Status

2011/2012 Net Firm Demand is not coincident with system peak

*Includes residential and commercial/industrial conservation.

**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.

***Includes energy planner program

Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2016/17	4,836	15	4,821	94	0	540	98	69	4,020
2017/18	4,918	15	4,903	92	0	547	98	70	4,096
2018/19	4,993	0	4,993	92	0	554	99	71	4,177
2019/20	5,085	0	5,085	92	0	562	100	73	4,258
2020/21	5,168	0	5,168	93	0	570	100	74	4,331
2021/22	5,244	0	5,244	79	0	578	101	76	4,410
2022/23	5,336	0	5,336	80	0	586	101	78	4,491
2023/24	5,427	0	5,427	79	0	594	102	80	4,573
2024/25	5,522	0	5,522	79	0	602	103	81	4,657
2025/26	5,618	0	5,618	79	0	610	103	83	4,742

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2016/17	4,800	15	4,785	94	0	540	98	69	3,984
2017/18	4,846	15	4,831	92	0	547	98	70	4,024
2018/19	4,884	0	4,884	92	0	554	99	71	4,068
2019/20	4,936	0	4,936	92	0	562	100	73	4,109
2020/21	4,980	0	4,980	93	0	570	100	74	4,143
2021/22	5,014	0	5,014	79	0	578	101	76	4,180
2022/23	5,063	0	5,063	80	0	586	101	78	4,218
2023/24	5,110	0	5,110	79	0	594	102	80	4,256
2024/25	5,159	0	5,159	79	0	602	103	81	4,294
2025/26	5,208	0	5,208	79	0	610	103	83	4,332

Notes:

*Includes residential and commercial/industrial conservation.

**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

***Includes Energy Planner program

Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale ***	Utility Use & Losses	Net Energy for Load	Load **** Factor %
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	431	212	18,990	752	909	20,650	56.8
2009	19,449	444	231	18,774	191	978	19,943	54.4
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,296	474	259	18,564	93	642	19,298	53.0
2012	19,178	493	273	18,412	69	839	19,320	56.3
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,377	546	305	18,526	0	789	19,315	54.4
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,053	597	342	19,114	104	942	20,160	54.7
2018	20,285	609	352	19,325	104	952	20,381	54.6
2019	20,586	621	362	19,603	0	966	20,570	54.4
2020	20,815	634	374	19,808	0	977	20,784	54.1
2021	21,043	646	387	20,010	0	987	20,996	54.1
2022	21,203	659	400	20,144	0	994	21,137	53.9
2023	21,476	672	413	20,391	0	1,006	21,397	53.9
2024	21,761	684	425	20,651	0	1,019	21,670	53.7
2025	22,061	697	438	20,926	0	1,033	21,959	53.9
2026	22,367	709	451	21,206	0	1,047	22,253	53.9

Notes:

December 31, 2016 Status

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner program

***Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.

****Load Factor is the ratio of total system average load to peak demand.

Values shown may be affected due to rounding.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale***	Utility Use & Losses	Net Energy for Load	Load **** Factor %
2017	20,127	597	342	19,188	104	946	20,238	54.7
2018	20,436	609	352	19,476	104	960	20,540	54.5
2019	20,819	621	362	19,836	0	978	20,813	54.4
2020	21,131	634	374	20,123	0	992	21,116	54.0
2021	21,445	646	387	20,412	0	1,007	21,419	54.0
2022	21,696	659	400	20,638	0	1,018	21,655	53.9
2023	22,063	672	413	20,979	0	1,035	22,014	53.8
2024	22,446	684	425	21,337	0	1,053	22,390	53.6
2025	22,848	697	438	21,713	0	1,071	22,784	53.7
2026	23,259	709	451	22,099	0	1,091	23,190	53.8

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale ***	Utility Use & Losses	Net Energy for Load	Load **** Factor %
2017	19,959	597	342	19,040	104	939	20,083	54.7
2018	20,114	609	352	19,174	104	945	20,224	54.6
2019	20,334	621	362	19,374	0	955	20,329	54.5
2020	20,481	634	374	19,498	0	961	20,459	54.2
2021	20,625	646	387	19,617	0	968	20,585	54.2
2022	20,699	659	400	19,665	0	970	20,635	54.0
2023	20,884	672	413	19,826	0	978	20,804	54.0
2024	21,079	684	425	19,995	0	987	20,982	53.8
2025	21,286	697	438	20,177	0	996	21,173	54.0
2026	21,497	709	451	20,362	0	1,005	21,367	54.0

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 4
Base Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,209	1,488	4,265	1,500
February	3,105	1,370	3,479	1,322	3,522	1,333
March	3,169	1,476	3,323	1,460	3,363	1,473
April	3,619	1,534	3,483	1,556	3,526	1,571
May	3,633	1,780	3,695	1,800	3,742	1,820
June	3,971	1,950	3,978	1,957	4,028	1,980
July	4,146	2,089	4,002	2,011	4,054	2,036
August	4,116	2,035	4,059	2,057	4,113	2,083
September	3,822	1,925	3,781	1,903	3,830	1,927
October	3,557	1,686	3,581	1,704	3,629	1,725
November	2,891	1,382	3,001	1,406	3,040	1,423
December	2,996	1,474	3,762	1,495	3,814	1,512
TOTAL		20,173		20,160		20,381

December 31, 2016 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 4
High Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,227	1,494	4,301	1,511
February	3,105	1,370	3,494	1,327	3,551	1,343
March	3,169	1,476	3,336	1,466	3,391	1,484
April	3,619	1,534	3,497	1,561	3,555	1,583
May	3,633	1,780	3,710	1,807	3,773	1,834
June	3,971	1,950	3,994	1,965	4,062	1,995
July	4,146	2,089	4,018	2,019	4,087	2,053
August	4,116	2,035	4,076	2,065	4,147	2,099
September	3,822	1,925	3,796	1,910	3,862	1,942
October	3,557	1,686	3,596	1,711	3,658	1,739
November	2,891	1,382	3,013	1,412	3,064	1,434
December	2,996	1,474	3,777	1,500	3,845	1,522
TOTAL		20,173		20,238		20,540

December 31, 2016 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 4
Low Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,191	1,483	4,229	1,488
February	3,105	1,370	3,465	1,318	3,493	1,323
March	3,169	1,476	3,309	1,455	3,336	1,462
April	3,619	1,534	3,468	1,550	3,497	1,559
May	3,633	1,780	3,680	1,793	3,711	1,806
June	3,971	1,950	3,962	1,950	3,995	1,964
July	4,146	2,089	3,985	2,002	4,021	2,020
August	4,116	2,035	4,042	2,049	4,079	2,066
September	3,822	1,925	3,765	1,895	3,799	1,911
October	3,557	1,686	3,567	1,697	3,599	1,712
November	2,891	1,382	2,990	1,401	3,017	1,412
December	2,996	1,474	3,747	1,489	3,783	1,500
TOTAL		20,173		20,084		20,224

December 31, 2016 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Unit	Actual 2015	Actual 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	3,682	3,005	3,761	3,635	3,781	3,604	3,222	3,101	3,138	3,244	3,283	3,283
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	1	1	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	1	1	0	0	0	0	0	0	0	0	0	0
(12)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	1000 MCF	74,847	77,896	71,973	77,042	75,535	79,583	88,875	91,917	92,301	94,204	94,997	98,270
(14)	ST	1000 MCF	0	8,736	4,650	4,519	4,597	4,458	4,037	3,899	3,921	4,086	4,110	4,131
(15)	CC	1000 MCF	66,304	59,525	64,508	67,413	67,422	70,868	78,381	79,565	82,281	81,176	82,087	83,458
(16)	GT	1000 MCF	8,543	9,635	2,815	5,110	3,516	4,257	6,457	8,453	6,099	8,942	8,800	10,681
(17)	Other (Specify)													
(18)	PC	1000 Ton	325	393	422	350	435	433	395	432	432	407	432	432

Notes:
Values shown may be affected due to rounding.
All values exclude ignition.

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2015	Actual 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Annual Firm Interchange	GWh	438	193	143	166	0	0	0	0	0	0	0	0
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	8,208	7,667	8,389	8,105	8,431	8,042	7,180	6,871	6,968	7,209	7,305	7,299
(4)	Residual	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(10)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	GWh	9,919	10,129	10,066	10,660	10,536	11,086	12,335	12,649	12,857	12,987	13,092	13,425
(15)	ST	GWh	0	899	425	413	427	408	363	345	351	364	367	368
(16)	CC	GWh	9,161	8,381	9,392	9,792	9,800	10,303	11,395	11,546	11,961	11,818	11,932	12,093
(17)	GT	GWh	758	849	249	455	309	375	577	758	545	805	793	964
(18)	Renewable	GWh	0	3	34	47	47	46	46	46	45	45	45	44
(19)	Solar	GWh	0	3	34	47	47	46	46	46	45	45	45	44
(20)	Other (Specify)													
(21)	PC	GWh	911	1,100	1,193	988	1,231	1,224	1,116	1,220	1,220	1,148	1,220	1,220
(22)	Net Interchange	GWh	289	842	195	275	235	296	229	261	217	191	206	175
(23)	Purchased Energy from Non-Utility Generators	GWh	341	237	140	140	90	90	90	90	90	90	90	90
(24)	Net Energy for Load	GWh	20,105	20,173	20,160	20,381	20,570	20,784	20,996	21,137	21,397	21,670	21,959	22,253

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.

Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2015	Actual 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Annual Firm Interchange	%	2.2	1.0	0.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(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	%	40.8	38.0	41.6	39.8	41.0	38.7	34.2	32.5	32.6	33.3	33.3	32.8
(4)	Residual	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	GT	%	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)	D	%	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	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	D	%	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	%	49.3	50.2	49.9	52.3	51.2	53.3	58.7	59.8	60.1	59.9	59.6	60.3
(15)	ST	%	0.0	4.5	2.1	2.0	2.1	2.0	1.7	1.6	1.6	1.7	1.7	1.7
(16)	CC	%	45.6	41.5	46.6	48.0	47.6	49.6	54.3	54.6	55.9	54.5	54.3	54.3
(17)	GT	%	3.8	4.2	1.2	2.2	1.5	1.8	2.7	3.6	2.5	3.7	3.6	4.3
(18)	Renewable	%	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(19)	Solar	%	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(20)	Other (Specify)													
(21)	PC	%	4.5	5.5	5.9	4.8	6.0	5.9	5.3	5.8	5.7	5.3	5.6	5.5
(22)	Net Interchange	%	1.4	4.2	1.0	1.3	1.1	1.4	1.1	1.2	1.0	0.9	0.9	0.8
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	1.7	1.2	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(25)	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

Notes:
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.

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Chapter V



FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to TEC's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing resources and analyzed to determine the resource options which best meets TEC's future system demand and energy requirements. A detailed discussion of TEC's integrated resource planning process is included in Chapter III.

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology availability, dispatch ability, and lead times for construction. To meet the expected system demand and energy requirements over the next ten years, both peaking and intermediate resources are needed. In 2017, TEC will be utilizing the newly converted Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to Polk 2 CC, a natural gas combined cycle (NGCC) unit for its intermediate load needs. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. TEC also completed an 18 MW_{AC} PV solar array located at Big Bend Station in early 2017. Beyond 2017, the company foresees the future needs being additional peaking capacity from two combustion turbines, one in 2021 and additional combustion turbine in 2024, which it proposes to meet by additions and/or future purchase power agreements.

TEC will compare viable purchased power options as an alternative and/or enhancements to planned unit additions, conservation, and load management. At a minimum, the purchased power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter III.

COGENERATION

In 2017, TEC plans for 369 MW of cogeneration capacity operating in its service area.

Table IV-I 2017 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	306
Firm to Tampa Electric	0
As-available to Tampa Electric	7
Export to other systems	56
Total	369

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has long-term firm sale and purchase power agreements. Below are the contracts for capacity and energy:

- 15 MW sale to Reedy Creek Improvement District (RCID) through December 31, 2018.
- 121 MW purchase from Quantum Pasco Power through December 2018
- 250 MW purchase from Duke Energy through February 28, 2017

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of solid fuels and natural gas for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2017 coal and petcoke will fuel 47.4% of the net energy for load and natural gas will fuel 50.1%. The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's generating units also have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability. However, TEC's capacity is roughly evenly split between solid fuels and natural gas.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities. Since 1998, TEC has reduced annual sulfur dioxides (SO_2) by 94 percent, nitrogen oxides (NO_x) by 91 percent, particulate matter (PM) by 87 percent and mercury emissions by 90 percent. These reductions were the result of a December 1999 agreement between the Florida Department of Environmental Protection and TEC. In February 2000, TEC reached a similar agreement with the U.S. Environmental Protection Agency in a Consent Decree. TEC fulfilled all commitments of the agreement and the motion to terminate the Consent Decree was granted on November 22, 2013. The order granting the motion to terminate the Consent Final Judgment was granted on May 6, 2015. TEC's major activities to increase pollution control and decrease emissions include:

- Improvement of the Big Bend electrostatic precipitators

- The installation of natural gas-fired igniters at Big Bend Station and ongoing engineering testing through 2017 will continue to provide opportunities to augment coal-fired operation and further reduce emissions during startup and normal operation.

- Polk Power Station combined-cycle project will improve system reliability and further reduce emissions system-wide.

TEC will continue to reduce emissions through project enhancements and best operation & maintenance work practices. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

Water Quality

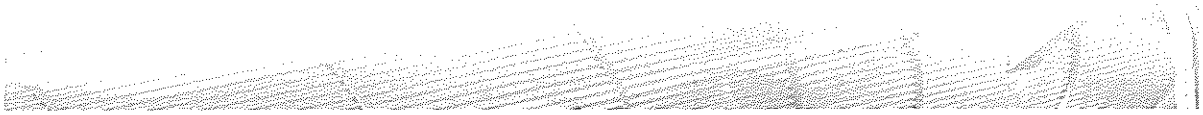
The final 316(b) rule became effective in October 2014 and seeks to reduce impingement and entrainment at cooling water intakes. This rule affects both Big Bend and Bayside Power Stations, since both withdraw cooling water from waters of the U.S. The full impact of the new regulations will be determined by the results of the study elements performed to comply with the rule as well as the actual requirements of the state regulatory agencies.

FDEP's numeric nutrient regulations are effective and may potentially impact the discharge from the Polk Power Station cooling water reservoir in the future. The established nitrogen allocations by Tampa Bay Nitrogen Management Consortium for both Bayside and Big Bend Power Stations are expected to meet the numeric nutrient criteria in Tampa Bay.

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. New limits will require new treatment technology at Big Bend Station and potentially require new treatment at Polk Power Station.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds and the converted Units 1-3 slag fines pond are covered by this rule. The slag pond will be cleaned out and lined in 2017 to allow for continued storm water storage. Planning is underway to cap and close the Economizer Ponds in-place by 2019 and to perform post-closure care and monitoring for 30 years thereafter. There are no regulated CCR units at Polk or Bayside Power Stations.



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)
Year	Firm Installed Capacity MW	Firm * Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2017	4,804	121	15	0	4,910	3,833	1,077	28%	0	1,077	28%
2018	4,804	121	15	0	4,910	3,888	1,022	26%	0	1,022	26%
2019	4,804	0	0	0	4,804	3,948	857	22%	0	857	22%
2020	4,804	0	0	0	4,804	3,998	806	20%	0	806	20%
2021	5,008	0	0	0	5,008	4,047	961	24%	0	961	24%
2022	5,008	0	0	0	5,008	4,101	907	22%	0	907	22%
2023	5,008	0	0	0	5,008	4,156	852	21%	0	852	21%
2024	5,212	0	0	0	5,212	4,212	1,000	24%	0	1,000	24%
2025	5,212	0	0	0	5,212	4,269	943	22%	0	943	22%
2026	5,212	0	0	0	5,212	4,325	887	21%	0	887	21%

Notes:

* Includes purchase power agreement (PPA) Quantum Pasco Power of 121 MW through 2018.

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)
Year	Firm Installed Capacity MW	Firm * Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2016-17	5,191	371	15	0	5,547	4,002	1,545	39%	0	1,545	39%
2017-18	5,191	121	15	0	5,297	4,060	1,237	30%	0	1,237	30%
2018-19	5,191	0	0	0	5,191	4,122	1,069	26%	0	1,069	26%
2019-20	5,191	0	0	0	5,191	4,183	1,008	24%	0	1,008	24%
2020-21	5,191	0	0	0	5,191	4,236	955	23%	0	955	23%
2021-22	5,411	0	0	0	5,411	4,294	1,117	26%	0	1,117	26%
2022-23	5,411	0	0	0	5,411	4,352	1,059	24%	0	1,059	24%
2023-24	5,411	0	0	0	5,411	4,411	1,000	23%	0	1,000	23%
2024-25	5,631	0	0	0	5,631	4,472	1,159	26%	0	1,159	26%
2025-26	5,631	0	0	0	5,631	4,532	1,099	24%	0	1,099	24%

Notes:

* Includes purchase power agreements (PPA) with Duke Energy Florida LLC of 250 MW through Feb 2017, and Quantum Pasco Power of 121 MW through 2018.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Fuel Alternate	Fuel Trans. Primary	Fuel Trans. Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Polk 2 CC	2	Polk	CC	NG	DFO	PL	TK	01/14	01/17	*	*	1,063	1,195	OP**
Big Bend Solar	1	Big Bend	PV	SOLAR	NA	NA	NA	5/16	02/17	*	*	18	18	OP**
Future CT 1	1	*	GT	NG	NA	PL	NA	05/19	05/21	*	*	204	220	P
Future CT 2	2	*	GT	NG	NA	PL	NA	05/22	05/24	*	*	204	220	P

Notes:

* Undetermined

** Polk 2 Combined Cycle began commercial operation 01/16/17 and Big Bend Solar began commercial operation 02/10/17.

Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.

Schedule 9
(Page 1 of 2)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 1
(2)	Net Capability	
	A. Summer	204 MW
	B. Winter	220 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Mar 2019
	B. Commercial In-Service Date	May 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2021)	11.2 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,944 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	854.71
	Direct Construction Cost ($/kW) [1]	629.39
	AFUDC* Amount ($/kW) [1]	87.71
	Escalation ($/kW) [1]	137.62
	Fixed O&M ($/kW – Yr) [1]	13.49
	Variable O&M ($/MWh) [1]	2.17
	K-Factor	1.4181

[1] Based on In-Service Year.
* Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 2 of 2)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 2
(2)	Net Capability	
	A. Summer	204 MW
	B. Winter	220 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Mar 2022
	B. Commercial In-Service Date	May 2024
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2023)	9.6 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,920 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	920.43
	Direct Construction Cost ($/kW) [1]	622.65
	AFUDC* Amount ($/kW) [1]	94.45
	Escalation ($/kW) [1]	203.34
	Fixed O&M ($/kW – Yr) [1]	14.48
	Variable O&M ($/MWh) [1]	2.33
	K-Factor	1.4181

[1] Based on In-Service Year.
* Based on the current AFUDC rate of 6.46%

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length **	Voltage	Anticipated In-Service Date	Anticipated Capital Investment ***	Substations	Participation with Other Utilities
Future CT 1	Unsited *	-	-	-	-	May 2021	-	-	-
Future CT 2	Unsited *	-	-	-	-	May 2024	-	-	-

Note:

* Specific information related to "Unsited" units unknown at this time.

** Approximate mileage listed is based on construction activity, not overall circuit length.

*** Cumulative capital investment at the in-service date.

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Figure VI-I: Site Location of H.L. Culbreath Bayside Power Station

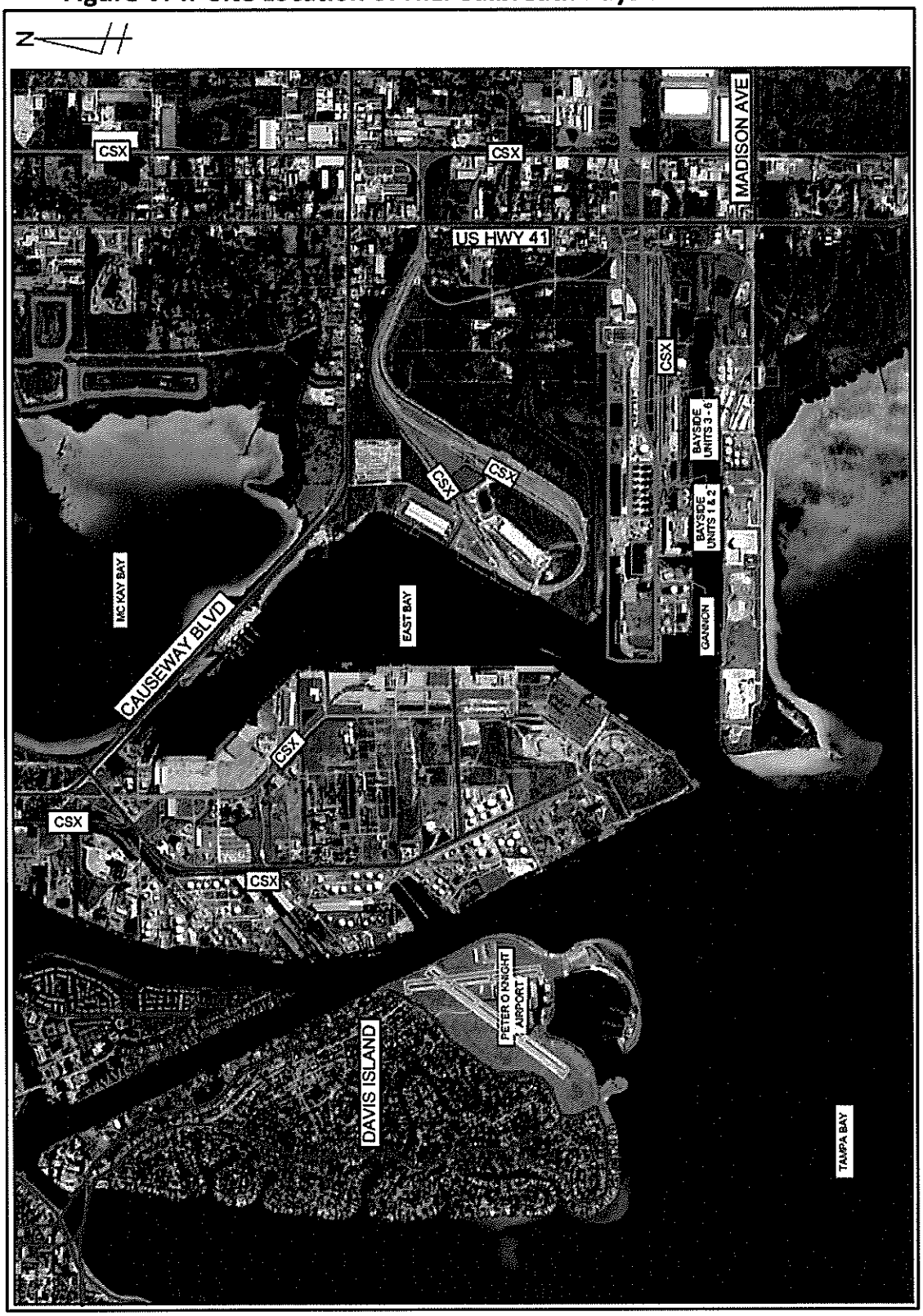


Figure VI-II: Site Location of Polk Power Station

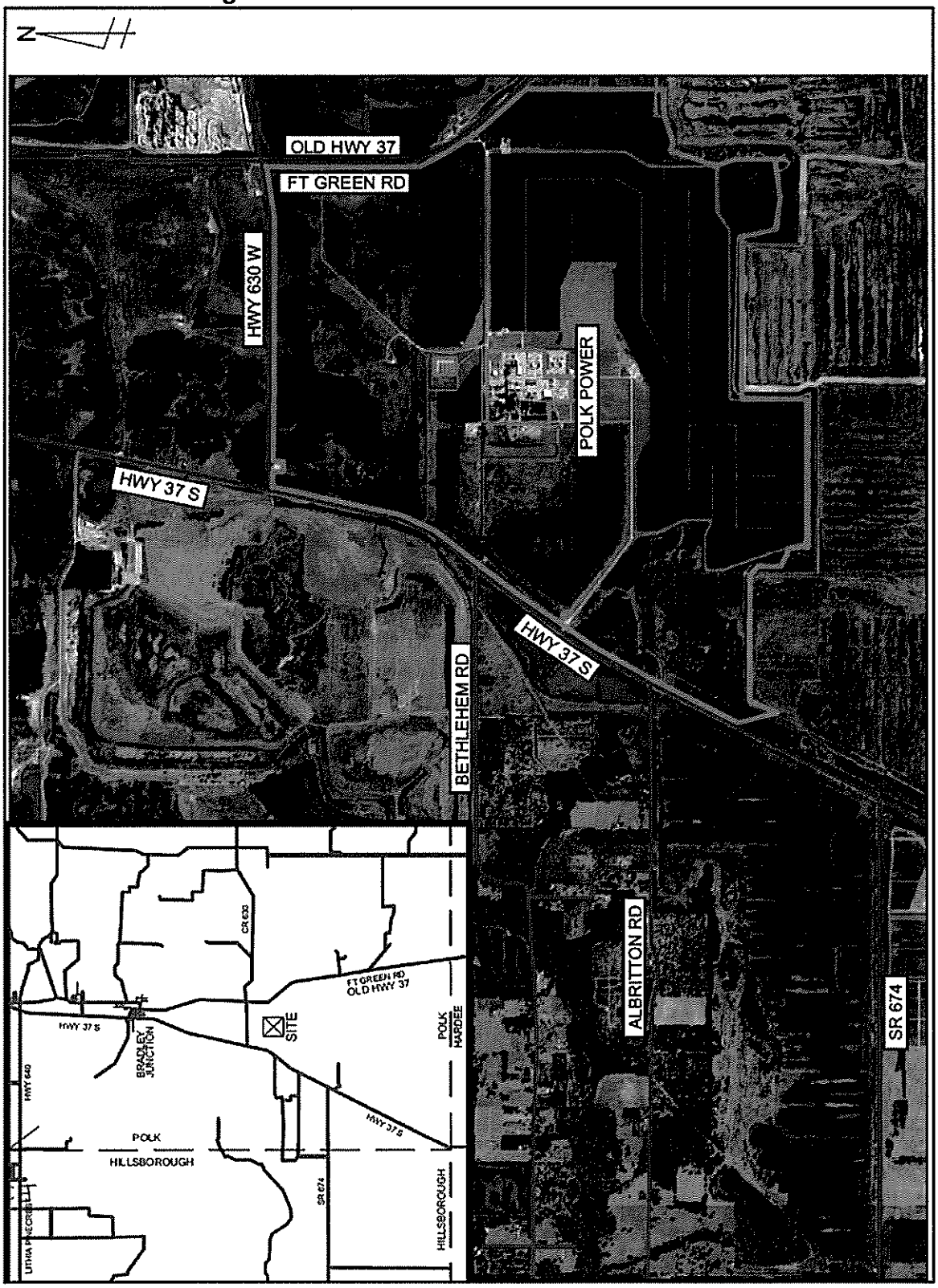


Figure VI-III: Site Location of Big Bend Power Station

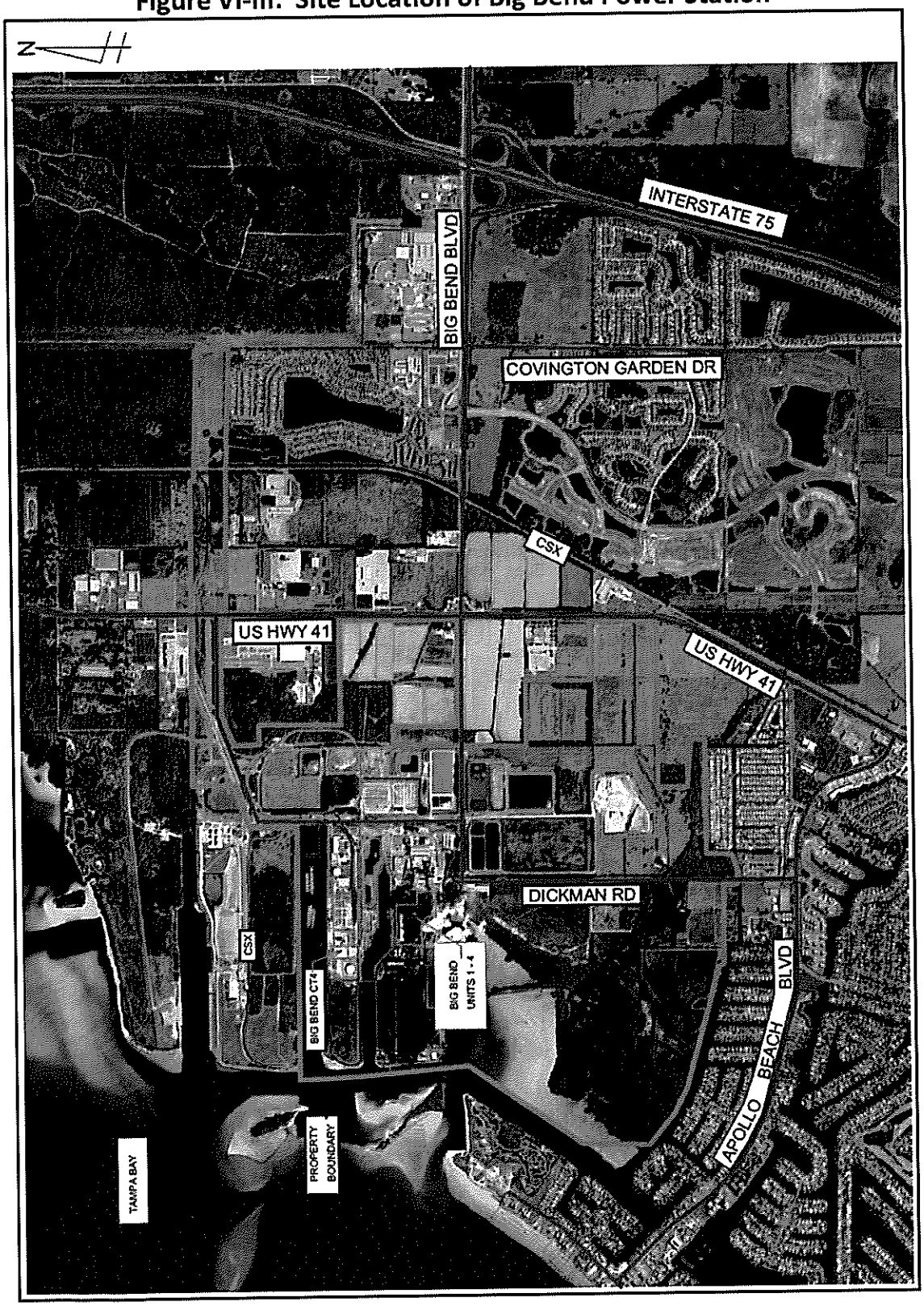


EXHIBIT NO. 111

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: WARD / DIAZGRANADOS / WAGNER / WOOD / _____

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: FRCC PRESENTATION – 2017 TEN YEAR SITE PLAN WORKSHOP EXCERPTS

DOCUMENTS: COVER PAGE AND PAGES 14, 18, 22, 23, 25, 26, 32

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

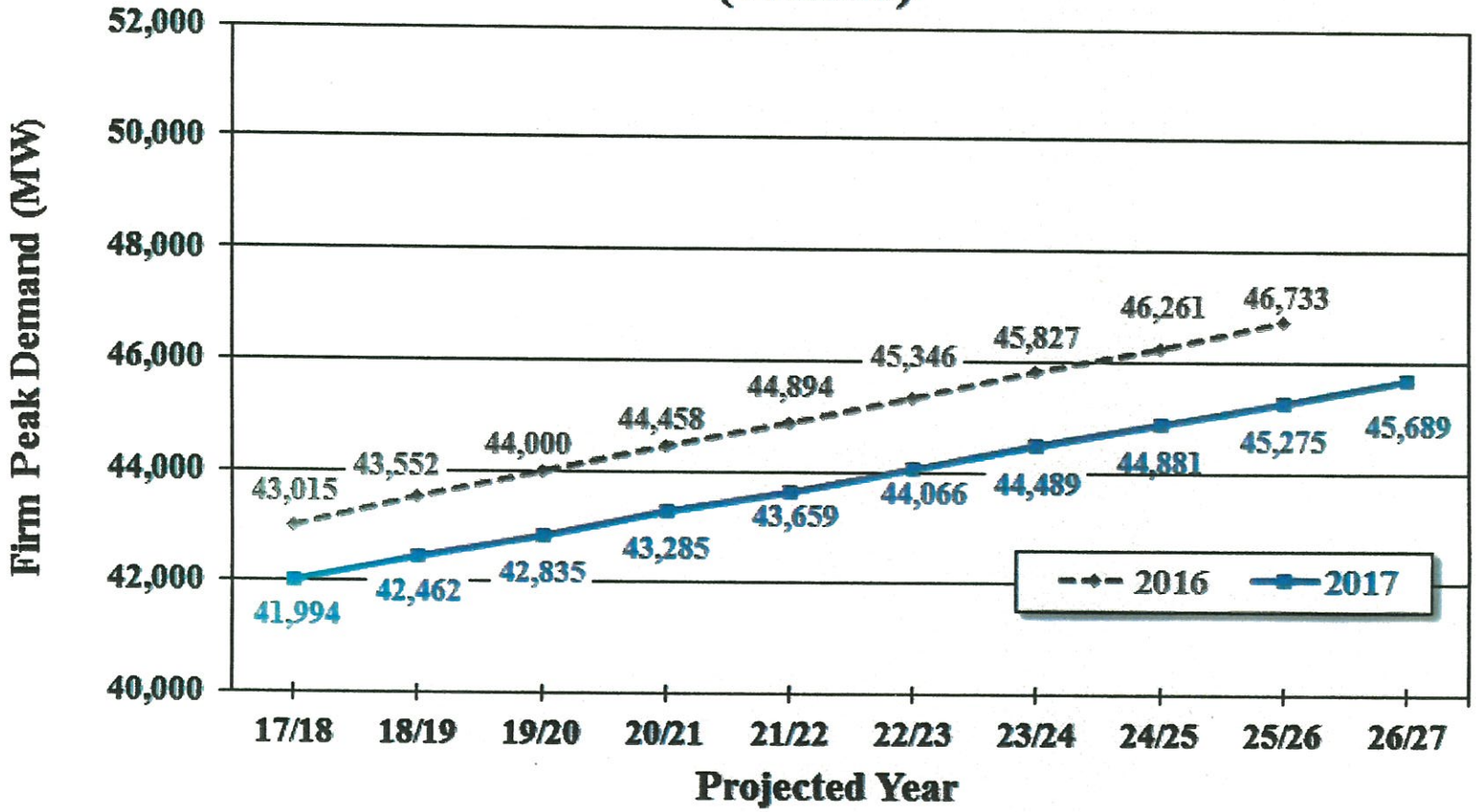
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 111
PARTY: Quantum, Daly, Tulk
DESCRIPTION: FRCC Presentation 2017 Ten-Year Site Plan Workshop

Florida Public Service Commission
2017 Ten-Year Site Plan Workshop
FRCC Presentation

Stacy Dochoda
President and CEO

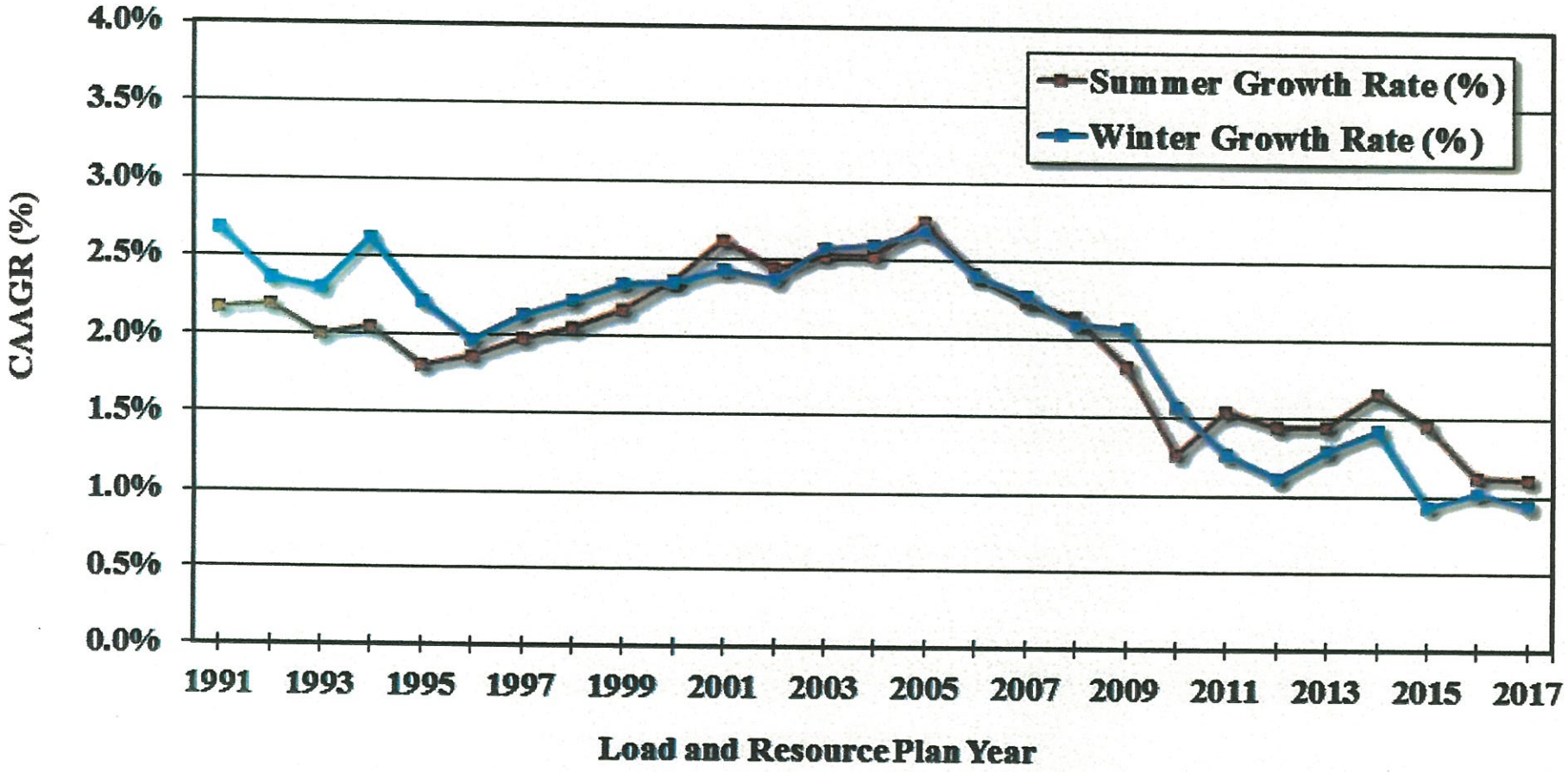
September 12, 2017

Comparison of 2016 vs. 2017 Firm Peak Demand Forecast[1/] (Winter)



[1/] Firm Peak Demand includes impacts of DSM (cumulative Demand Response and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation) as well as Energy Efficiency Codes and Standards

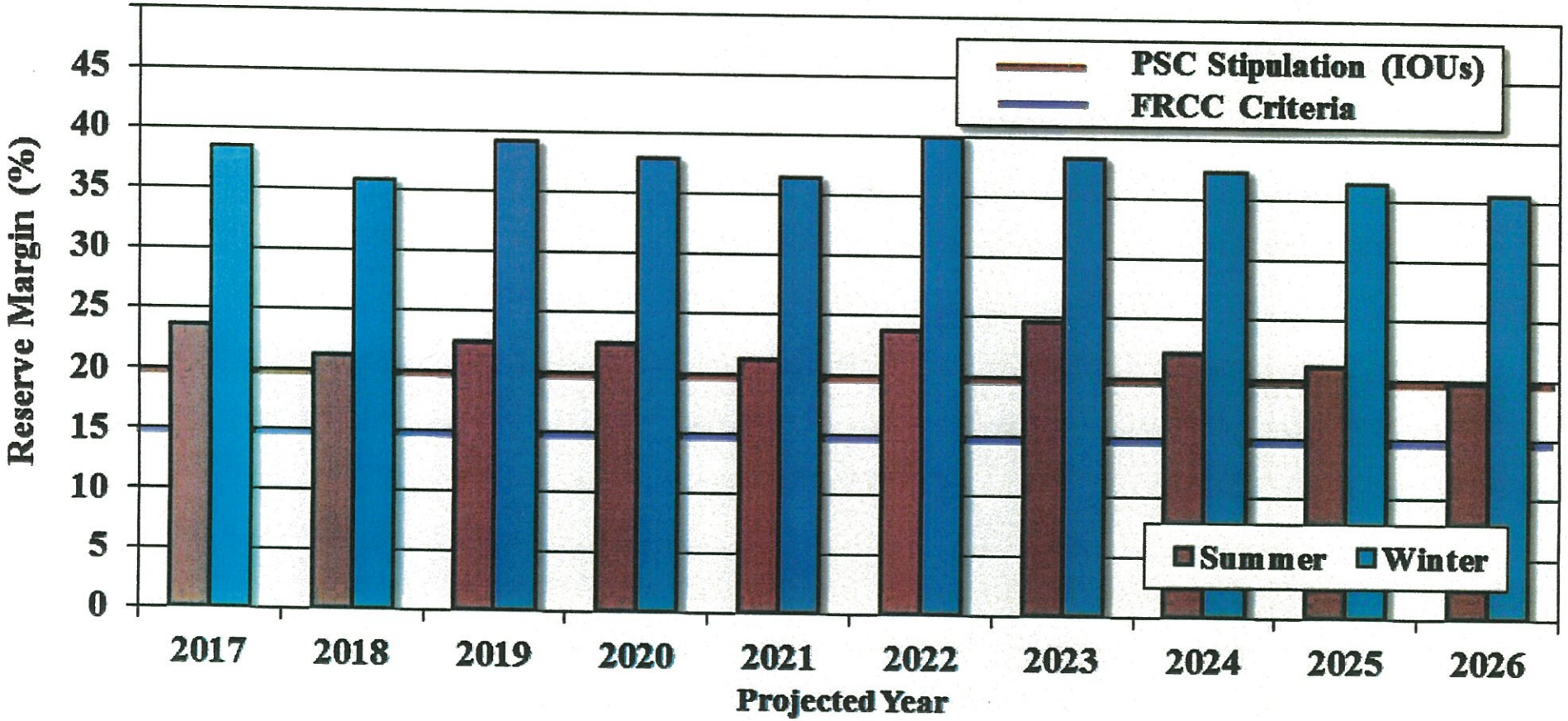
Historical Compound Average Annual Growth Rate[1/] for Firm Peak Demand (MW)



[1/]Projected growth rate from prior forecasts

Planned Reserve Margin[1/ 2/]

(Based on Firm Load)

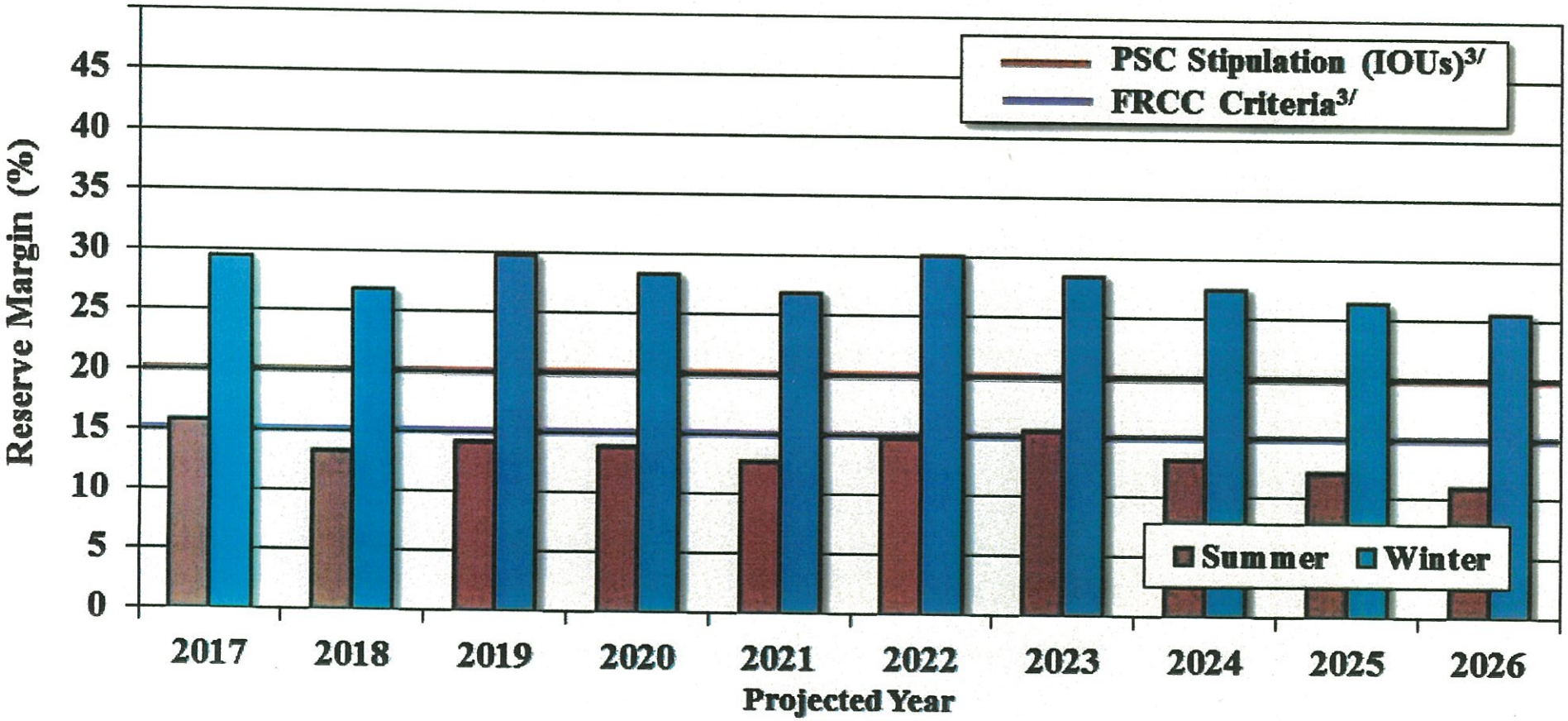


[1/] Projected impacts of Energy Efficiency codes and standards are included in all projections.

[2/] Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are included.

Planned Reserve Margin[1/]

(Excluding projected DR and Utility EE/EC Impacts) [2/]



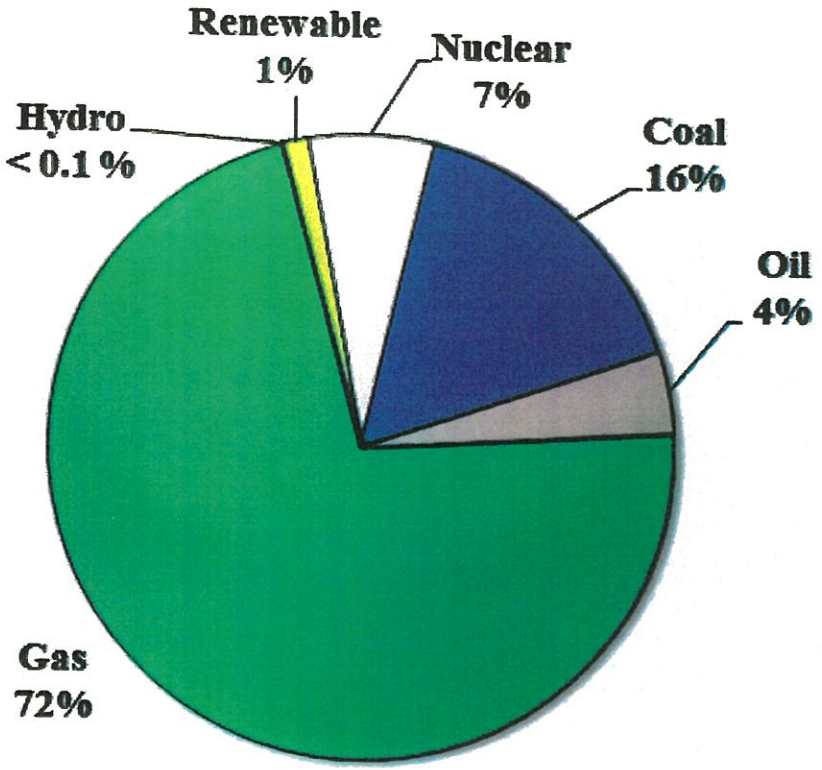
[1/] Projected impacts of Energy Efficiency codes and standards are included in all projections.

[2/] Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are excluded.

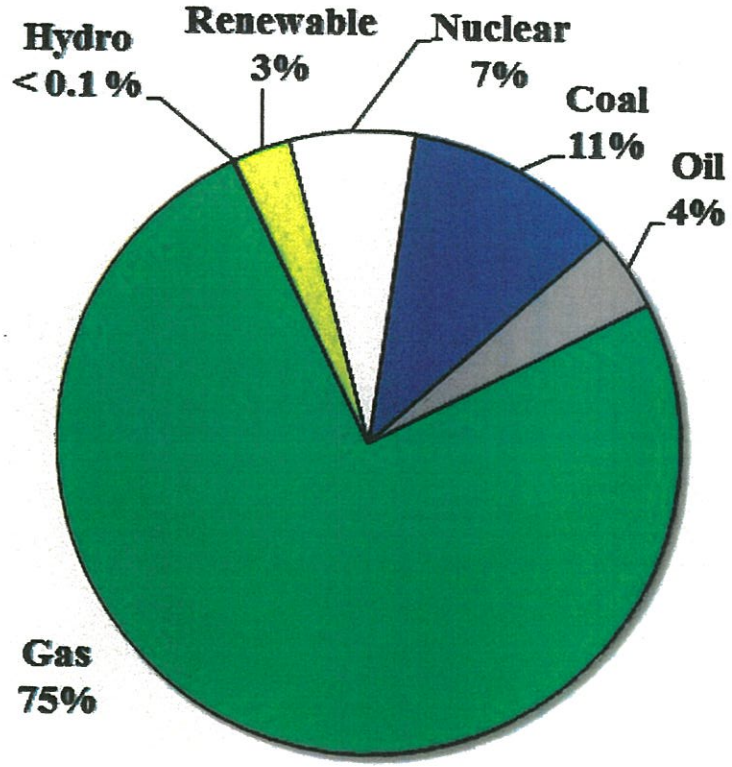
[3/] PSC stipulation and FRCC criteria are based on firm load as per slide 22. The values shown on this slide are solely for illustrative purposes.

Forecasted Fuel Mix

Summer Capacity[1/] (MW)



2017
55,120 MW

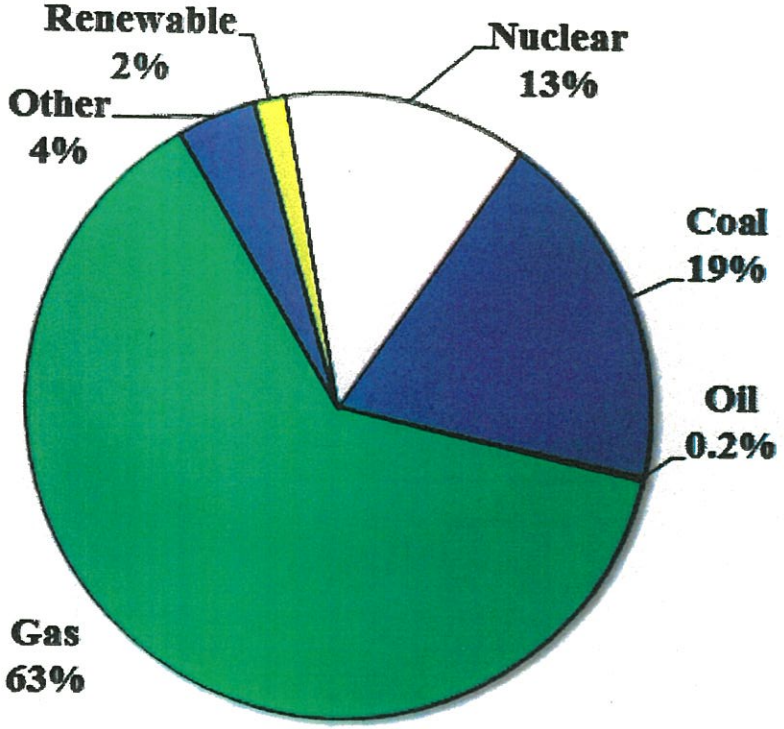


2026
59,028 MW

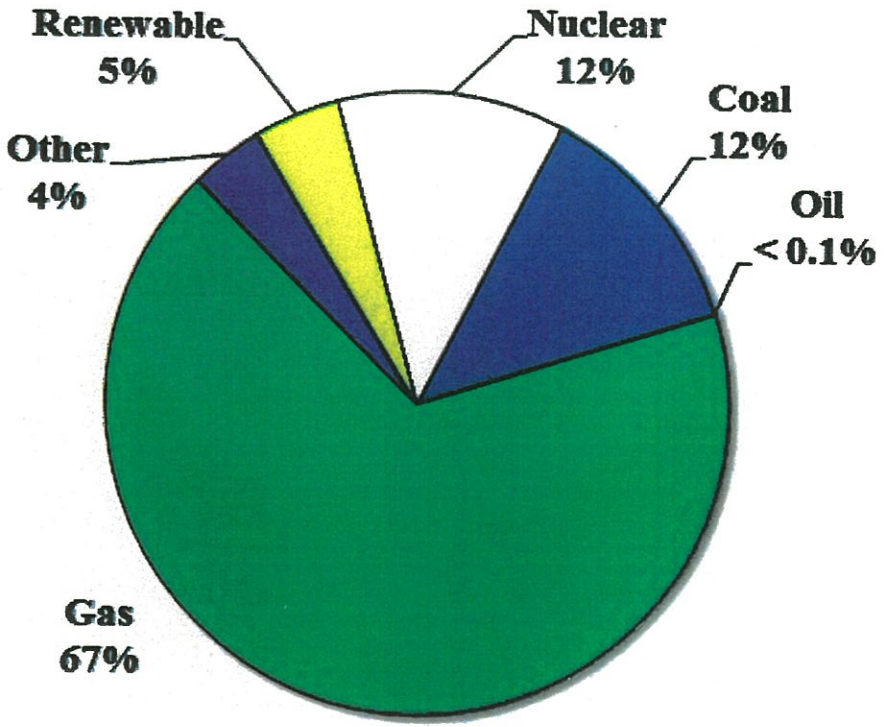
[1/] Only accounts for firm capacity

Forecasted Fuel Mix

Net Energy for Load (GWh)



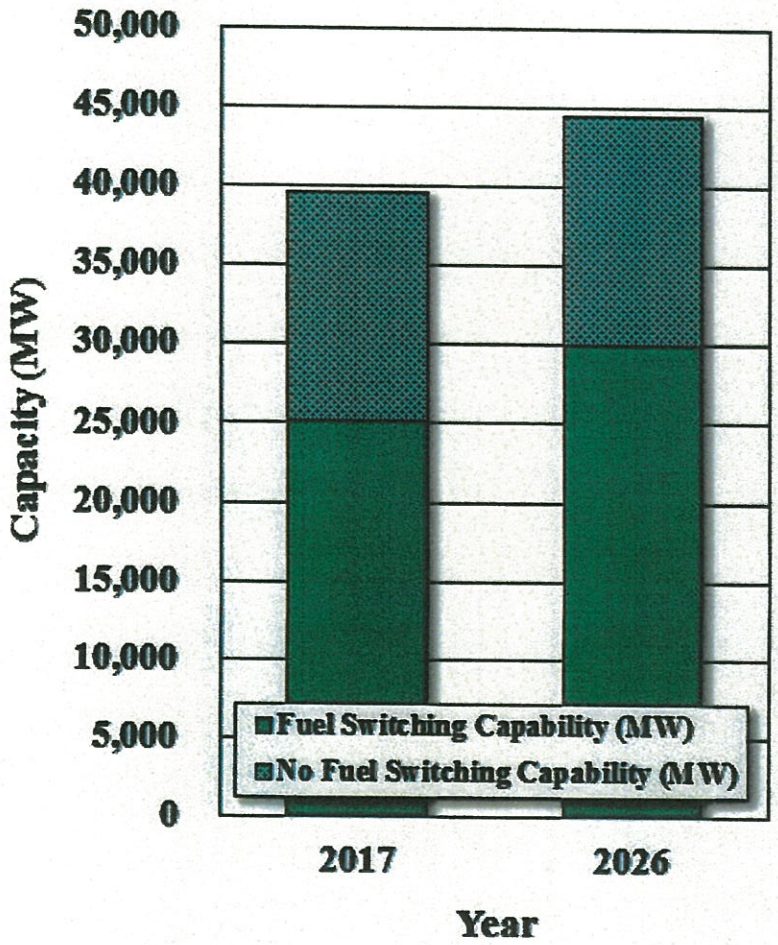
2017
230,868 GWh



2026
250,948 GWh

Natural Gas Alternate Fuel Capability

Summer Capacity (MW)



Florida Public Service Commission
2017 Ten-Year Site Plan Workshop
FRCC Presentation

Stacy Dochoda
President and CEO

20170266|0267
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. _____ EXHIBIT 111
COMPANY _____
WITNESS _____
DATE 3|21|2018

September 12, 2017

Agenda

FRCC Load & Resource Plan

- Integrated Resource Planning Process
- Load Forecast and Demand-Side Management (DSM)
- Generation Additions and Reserve Margins
- Fuel Mix
- Renewable Resources
- Natural Gas Infrastructure in Florida

Reliability Assurance Process – FRCC

- April 2017 Energy Alert

Florida Reliability Coordinating Council

Vision: To maintain a highly reliable and secure bulk power system for peninsular Florida

2017 Load & Resource Plan
Executive Summary

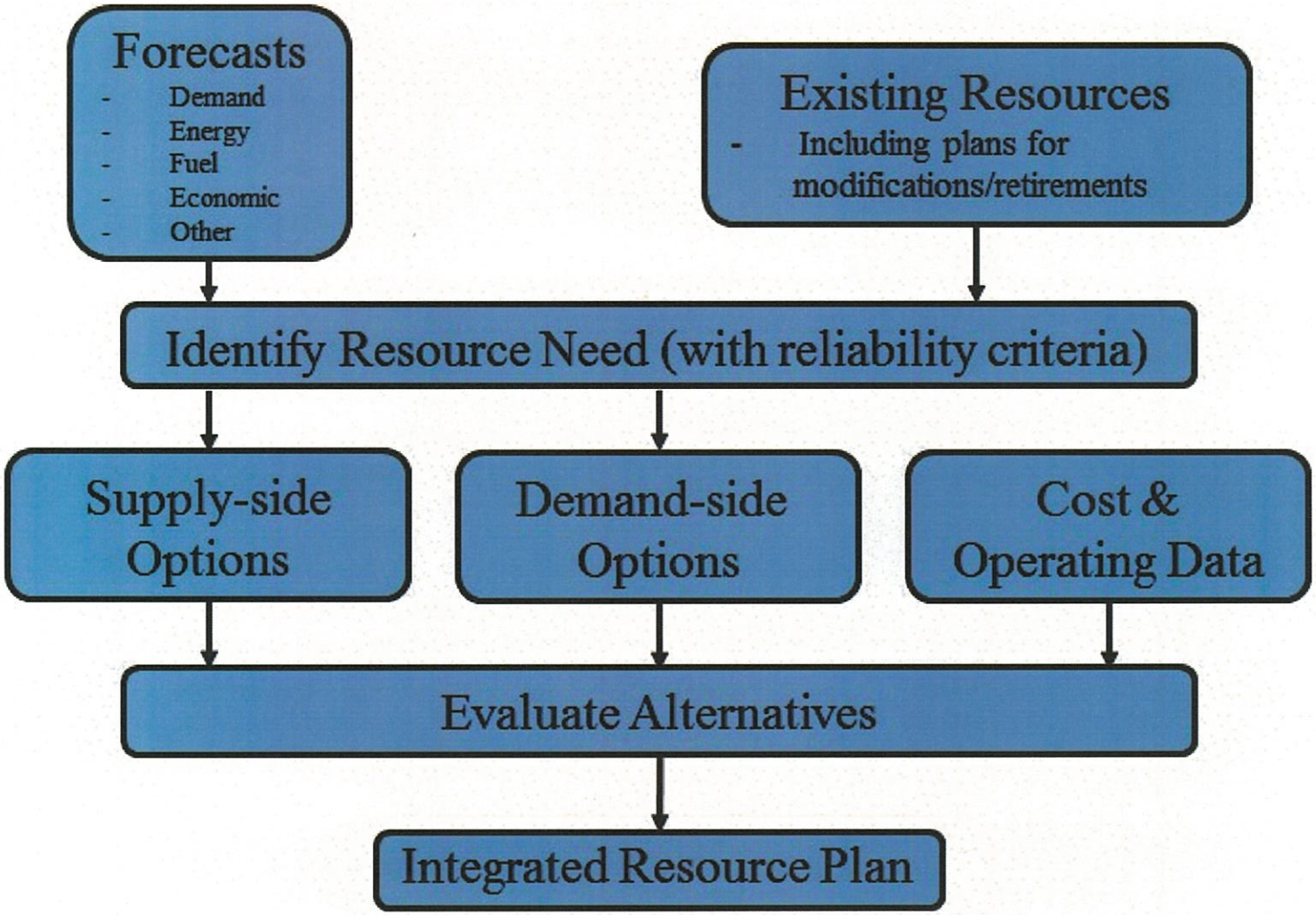
- Firm peak demand forecasts slightly lower than 2016 TYSP
- Forecasted energy sales comparable to 2016 TYSP
- 9,200 MW of new firm generation planned over the forecast horizon
- Planned Reserve Margins at or above 20%
- Demand Side Management (DSM) projected to be a significant component of projected reserves

2017 Load & Resource Plan
Executive Summary (cont.)

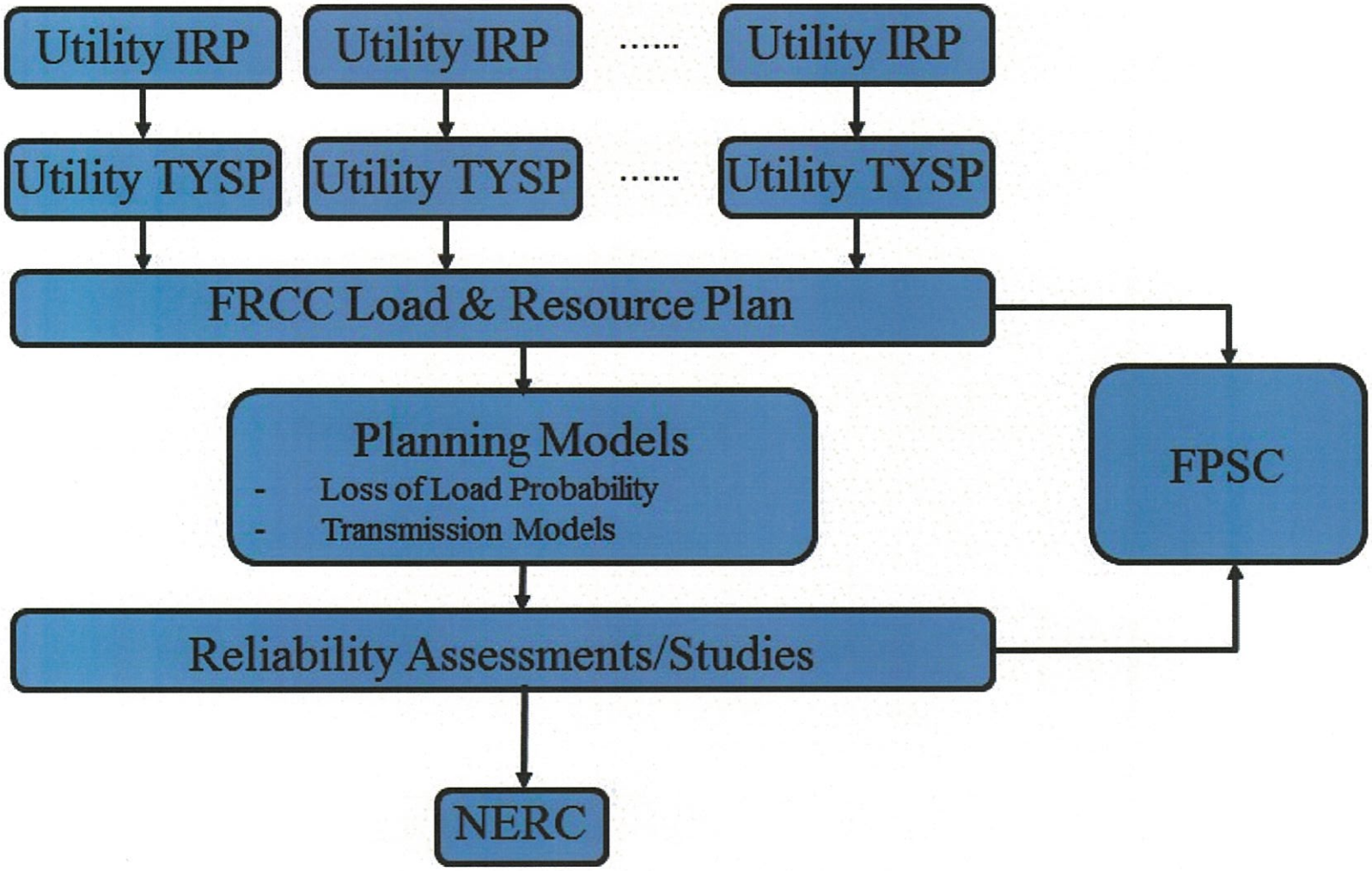
- Changes to FRCC Region's fuel mix over the next ten years (as a % of total energy served):
  - Natural Gas increases from 63% to 67%
  - Renewable increases from 2% to 5%
  - Coal decreases from 19% to 12%
- Solar energy increases 7,600 GWh
- Third major natural gas pipeline in-service July 2017

FRCC
Load & Resource
Plan

Utility Integrated Resource Planning (IRP) Process Overview



FRCC Planning Process Overview



Load Forecast and Demand-Side Management (DSM)

- Firm peak demand forecasts slightly lower than 2016 TYSPs
  - Firm summer and winter peak demands grow 1.1% and 0.9% per year; respectively
- Forecasted energy sales comparable to 2016 TYSPs
  - Net Energy for Load grows 0.9% per year

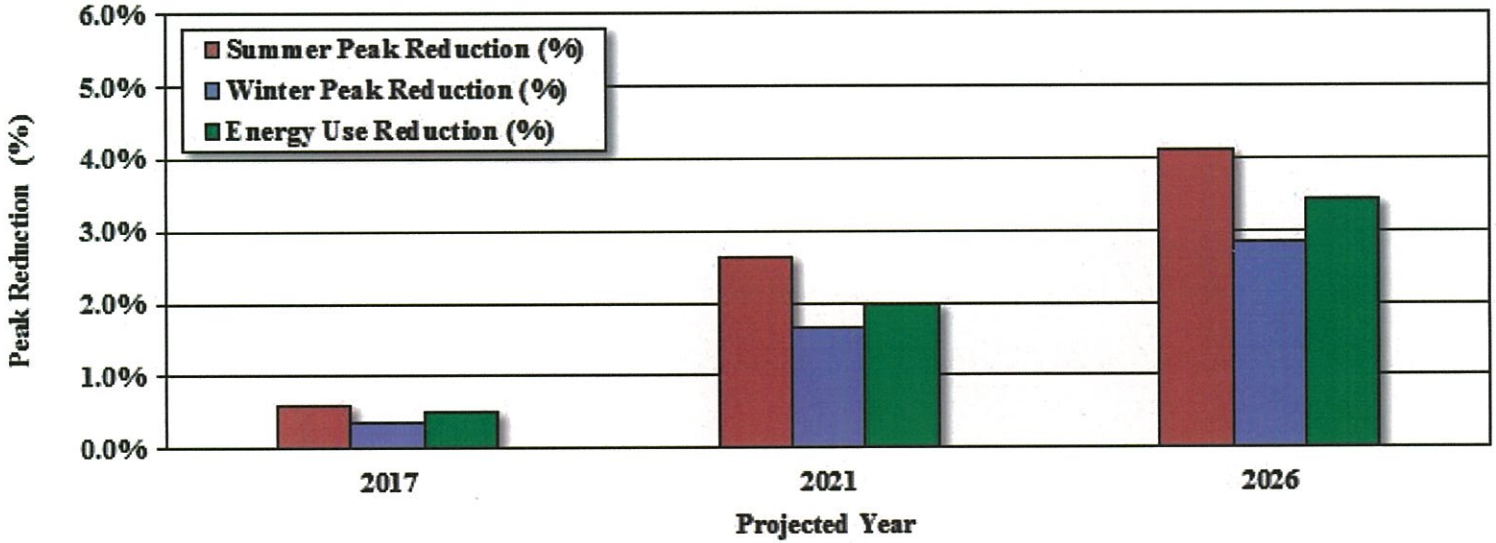
Load Forecast and DSM (cont.)

- Demand Response (DR) reduces firm summer peak (MW) by 6.3% on average
- Utility-sponsored Energy Efficiency/Energy Conservation (EE/EC) programs reduce summer peak (MW) by 1.4% by 2026
- Energy Efficiency delivered through mandated codes and standards reduces summer peak (MW) by at least 4.1% by 2026
- DSM is made up of DR and Utility-sponsored EE/EC
- Projected impacts of Energy Efficiency codes and standards included in all utilities' forecasts

Load Forecast Factors

- Florida unemployment (actual) continues to decrease
- Population growth is projected to remain strong
- Actual employment growth remains healthy, but wage and income growth have not kept pace
- Increasing impacts from codes and standards and also (to a lesser extent) from customer-owned distributed generation (solar)
- Commercial customer base is being monitored due to challenges presented by online commerce

Estimated Cumulative Impacts of Energy Efficiency Codes and Standards[1/ 2/]

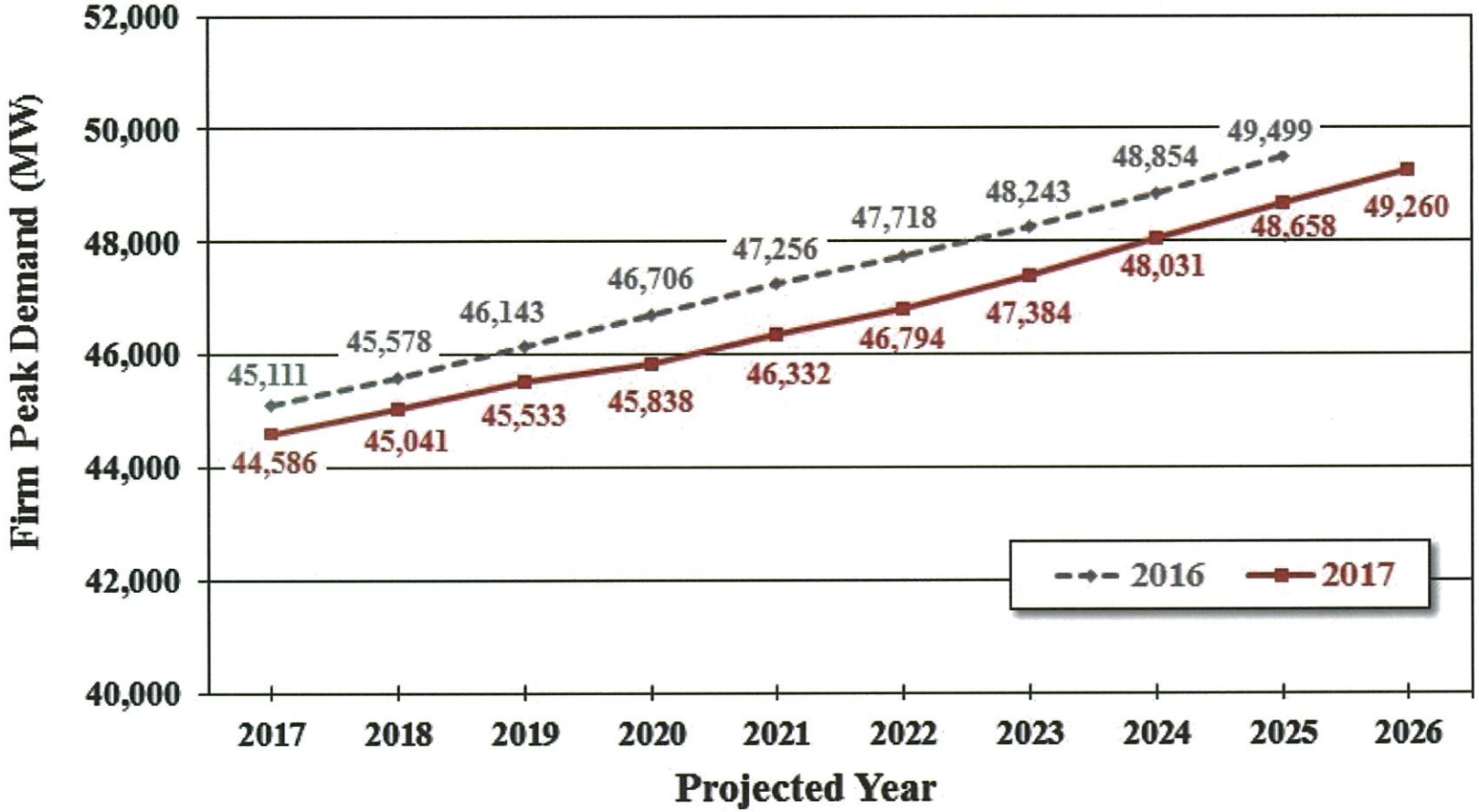


	2017	2021	2026
Summer Peak Reduction (MW)	300	1,300	2,100
Winter Peak Reduction (MW)	100	700	1,300
Energy Use Reduction (GWh)	1,200	4,800	9,000

[1/] Two utilities provide estimates on the incremental (2017-on) impacts of Energy Efficiency codes and standards. These impacts were compared against peak and NEL for all utilities. The amounts above likely understate the full impact of code and standards – since not all utilities were able to estimate impacts.

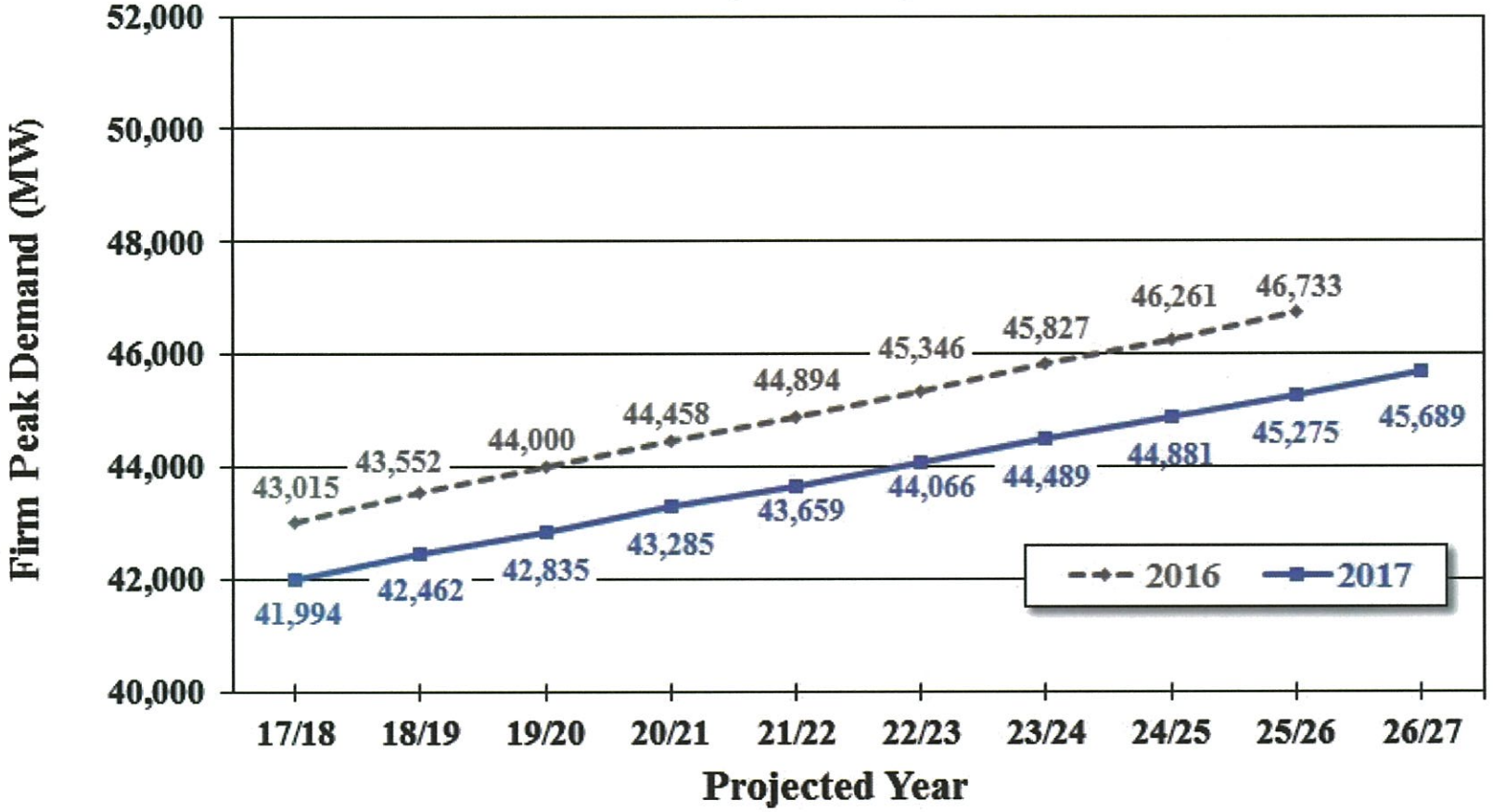
[2/] For data and charts shown after this slide, Energy Efficiency codes and standards are embedded within utility load forecasts

Comparison of 2016 vs. 2017 Firm Peak Demand Forecast[1/] (Summer)



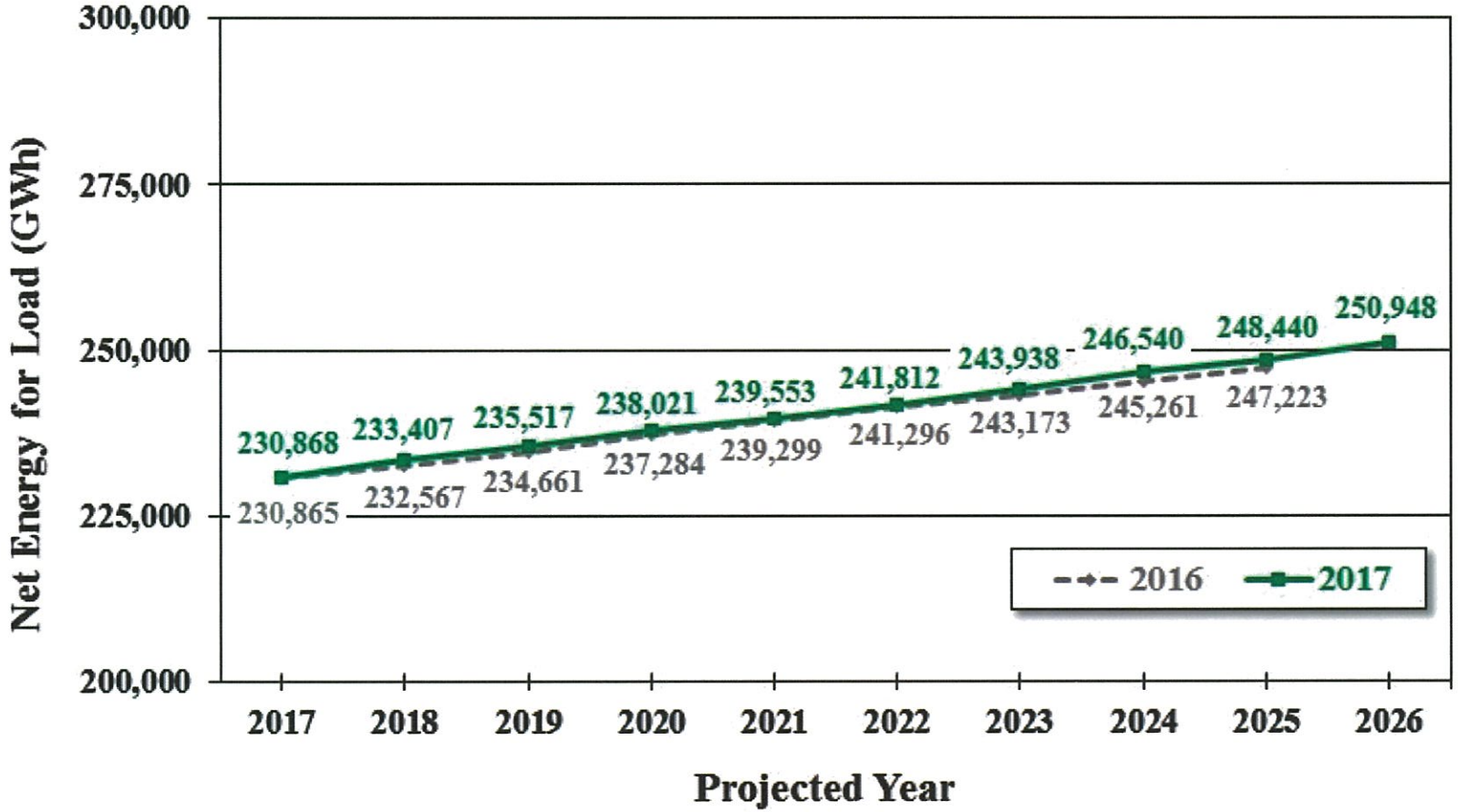
[1/] Firm Peak Demand includes impacts of DSM (cumulative Demand Response and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation) as well as Energy Efficiency Codes and Standards

Comparison of 2016 vs. 2017 Firm Peak Demand Forecast[1/] (Winter)



[1/] Firm Peak Demand includes impacts of DSM (cumulative Demand Response and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation) as well as Energy Efficiency Codes and Standards

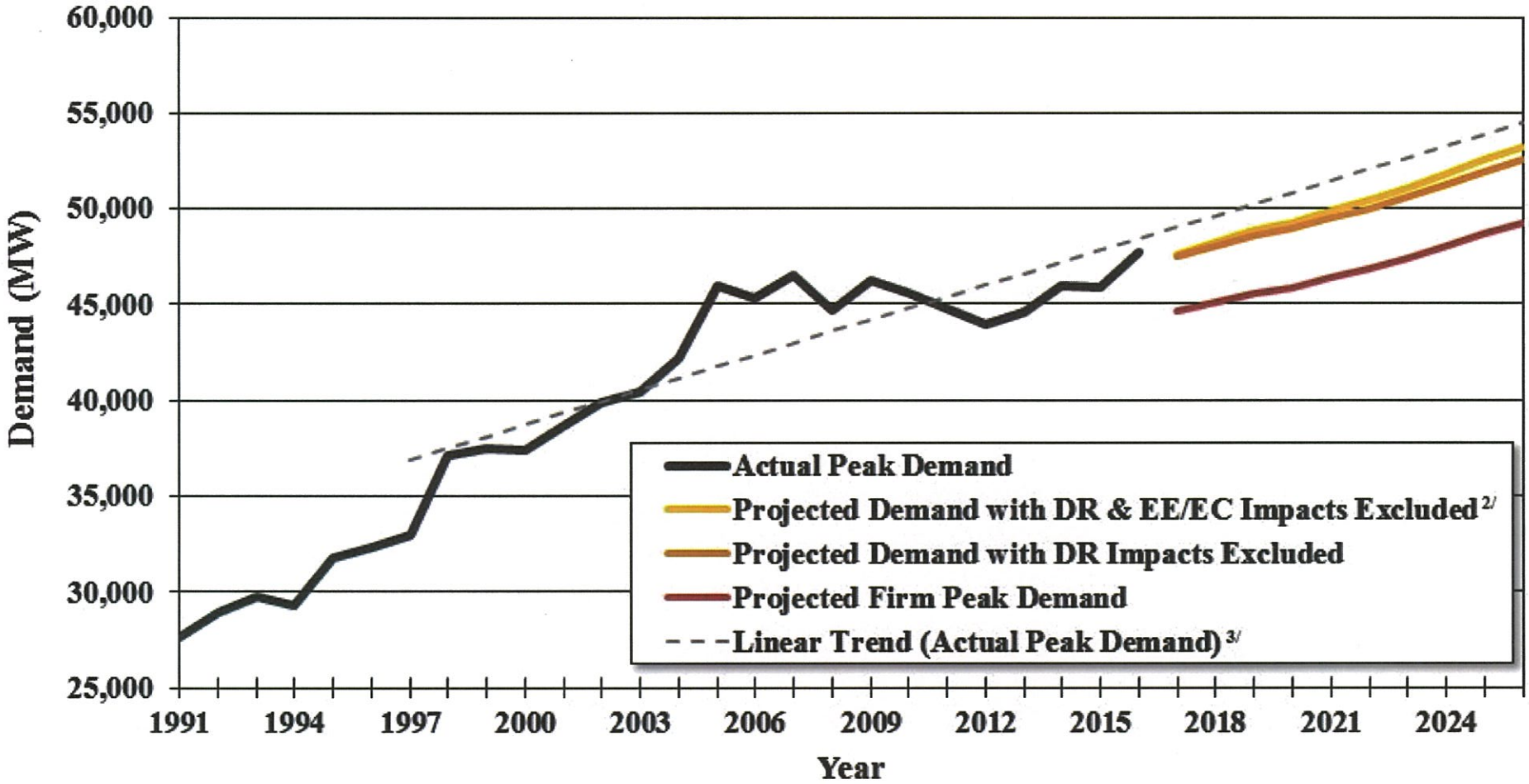
Comparison of 2016 vs. 2017
Net Energy for Load (NEL) Forecast



[1/] Firm Peak Demand includes impacts of DSM (cumulative Demand Response and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation) as well as Energy Efficiency Codes and Standards

Summer Peak Demands

Actual and Forecasted[1/]

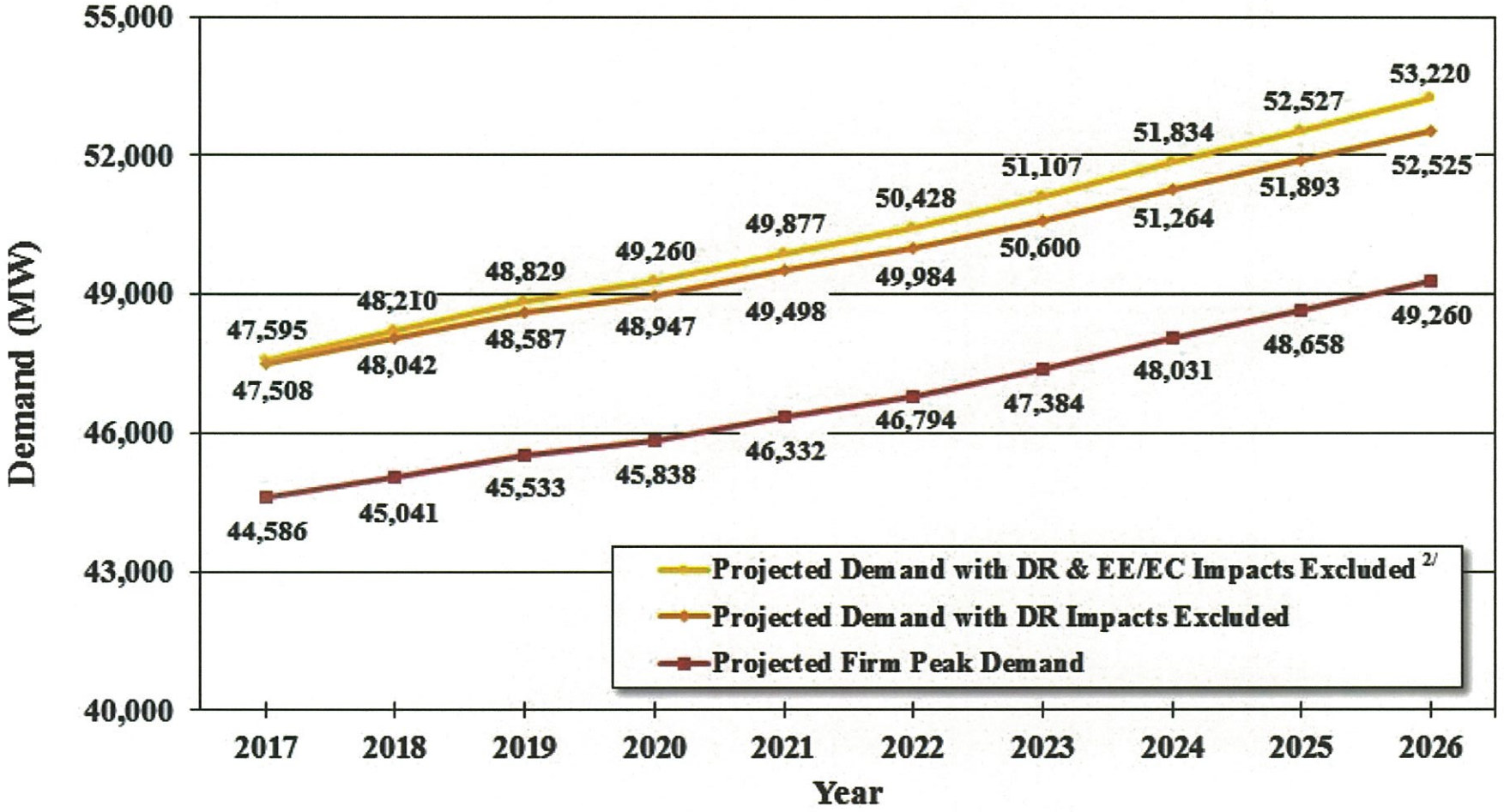


1/ Projected impacts of Energy Efficiency codes and standards are included in all projections.

2/ Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility-sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are excluded.

3/ Linear trend based on actual peak demand from 1997 to 2016.

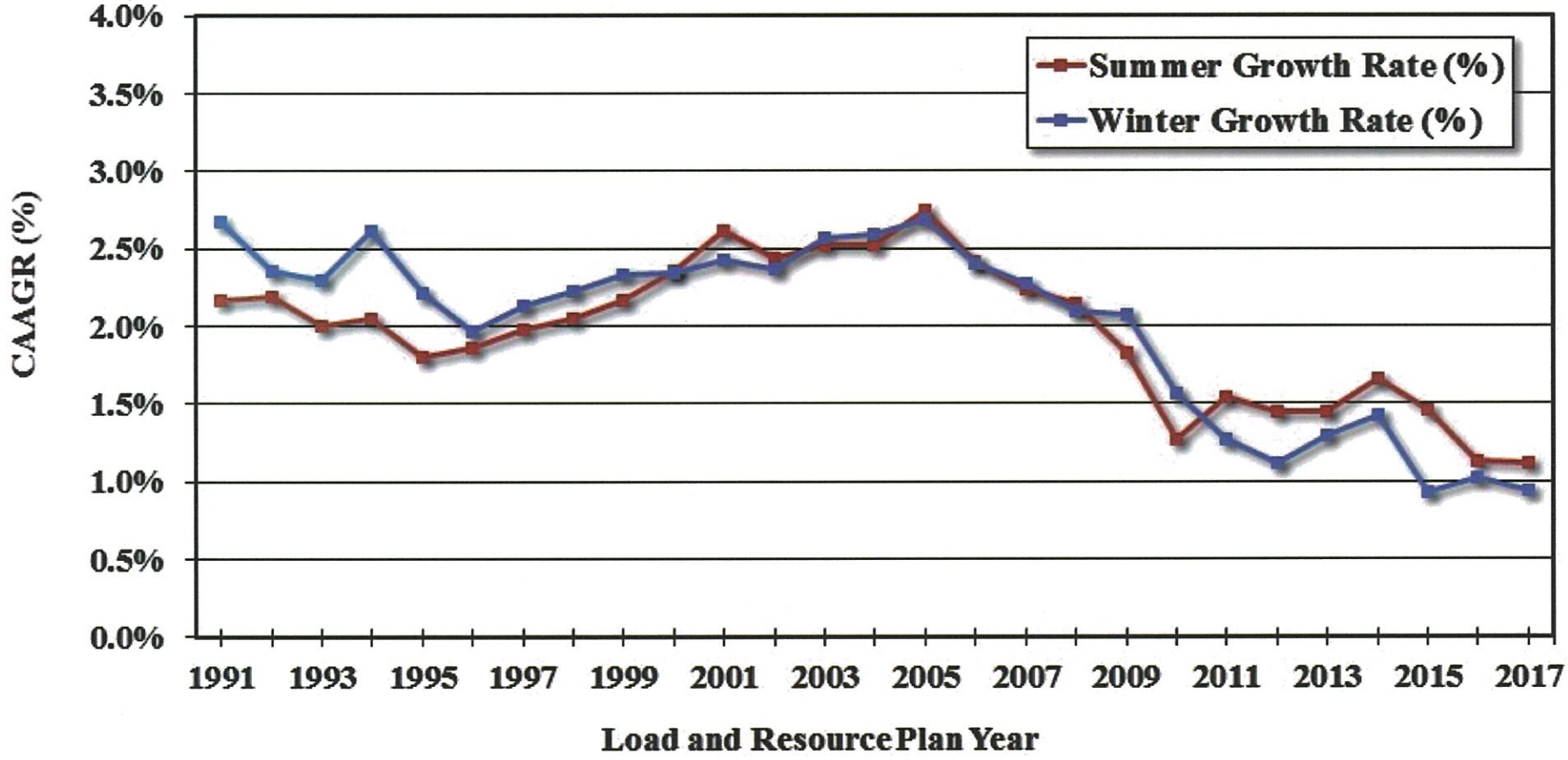
Forecasted Summer Peak Demand[1/]



1/ Projected impacts of Energy Efficiency codes and standards are included in all projections.

2/ Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility-sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are excluded.

Historical Compound Average Annual Growth Rate[1/] for Firm Peak Demand (MW)

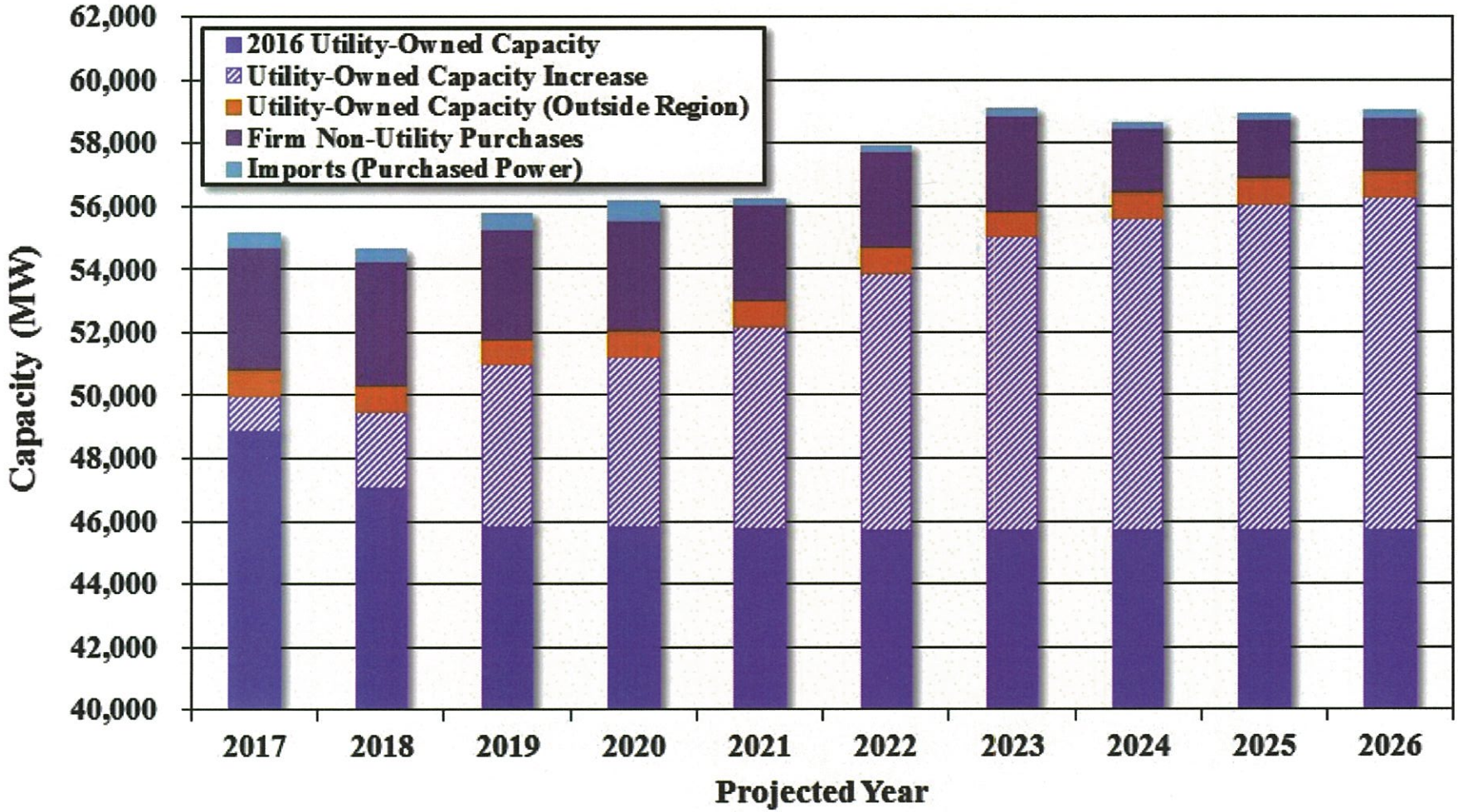


[1/]Projected growth rate from prior forecasts

Generation Additions and Reserve Margins

- 9,200 MW of new generation planned over the forecast horizon
- Planned Reserve Margins at or above 20%
- DSM projected to be a significant component of projected reserves

Projected Total Available Capacity
(Summer)



Nuclear Outlook is Stable in 10-yr Horizon

Existing[1/] Nuclear Capacity (Summer)

St. Lucie 1	981 MW
St. Lucie 2	986 MW
Turkey Point 3	811 MW
Turkey Point 4	821 MW
	3,599 MW

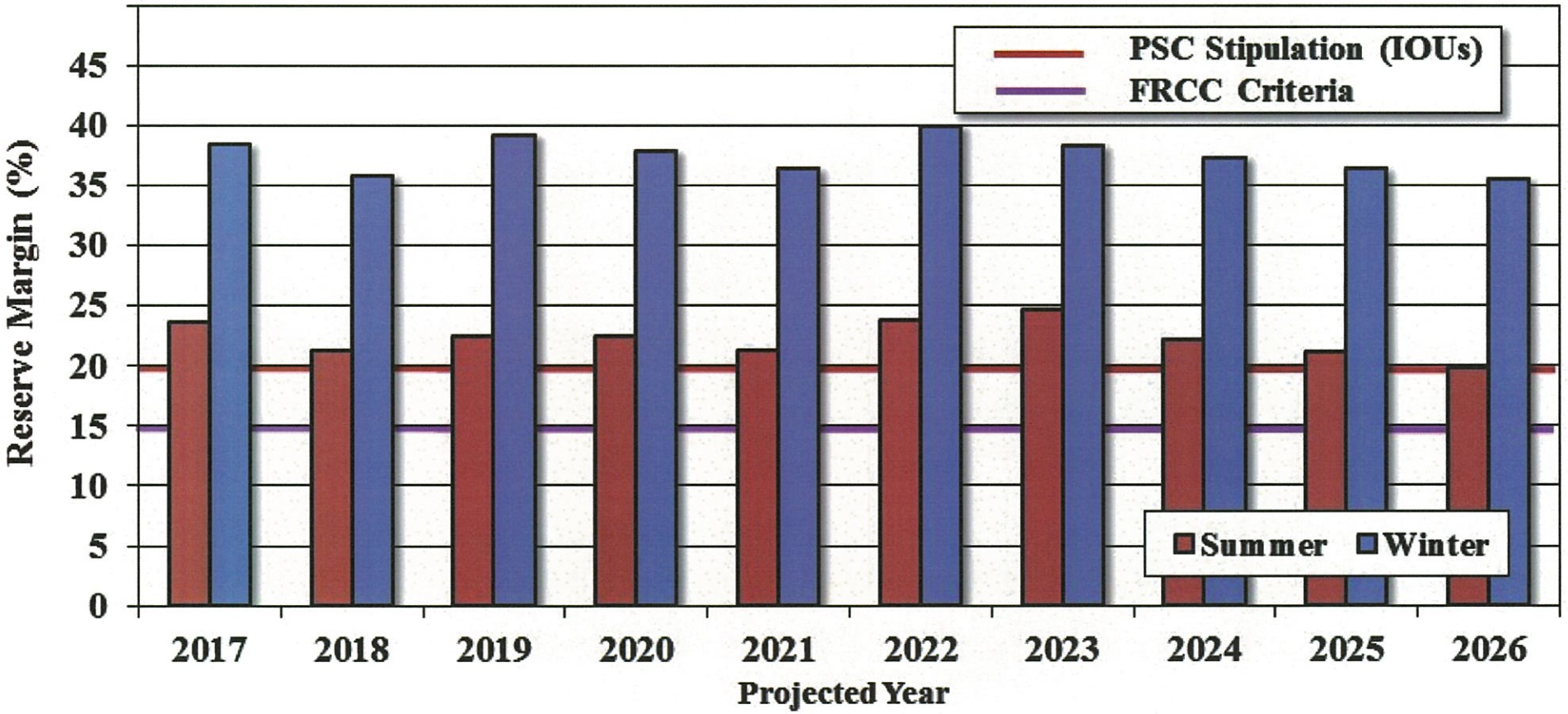
Planned Nuclear Capacity (Summer)

Turkey Point 3 Upgrade	(10/2018)	20 MW
Turkey Point 4 Upgrade	(5/2019)	20 MW
		40 MW

[1/]Existing generation as of December 31, 2016

Planned Reserve Margin[1/ 2/]

(Based on Firm Load)

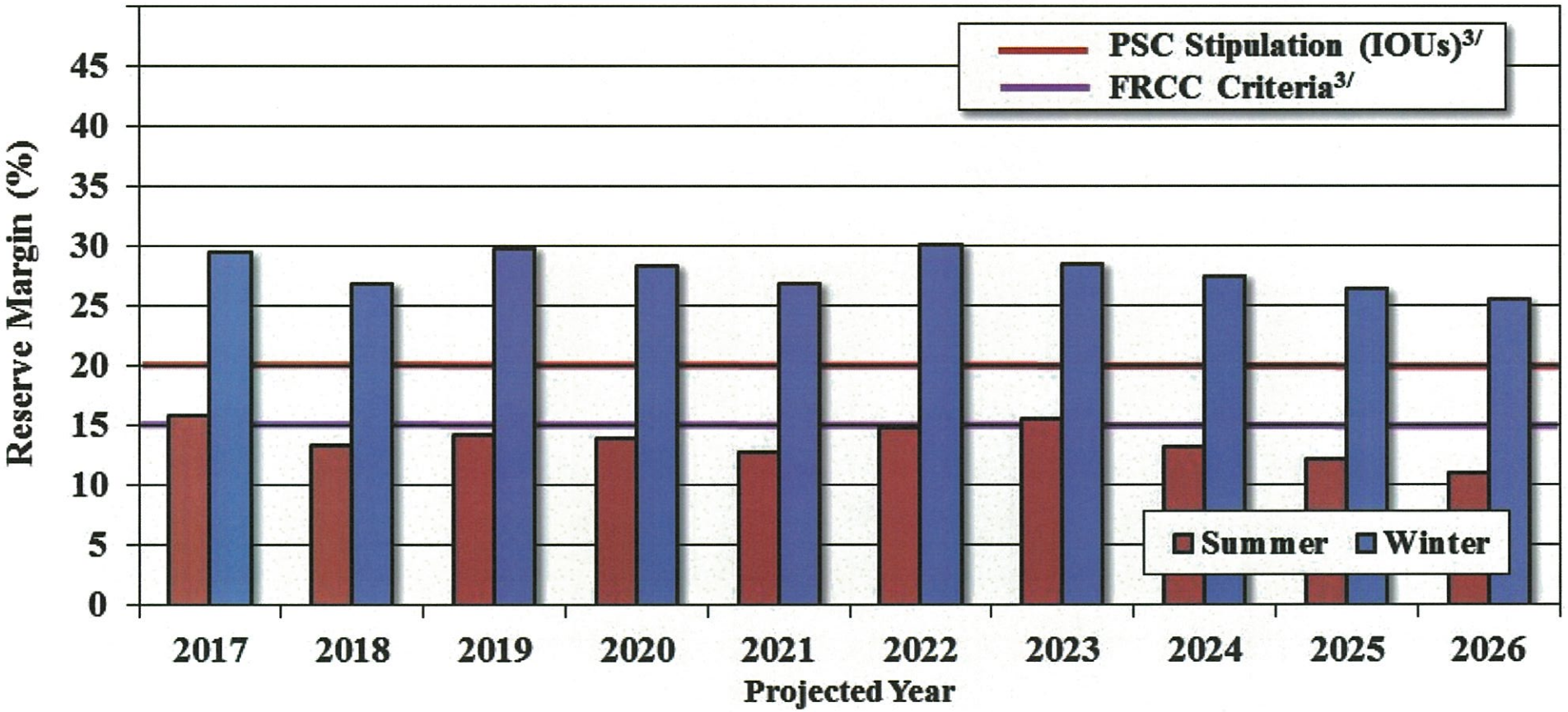


[1/] Projected impacts of Energy Efficiency codes and standards are included in all projections.

[2/] Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are included.

Planned Reserve Margin[1/]

(Excluding projected DR and Utility EE/EC Impacts) [2/]



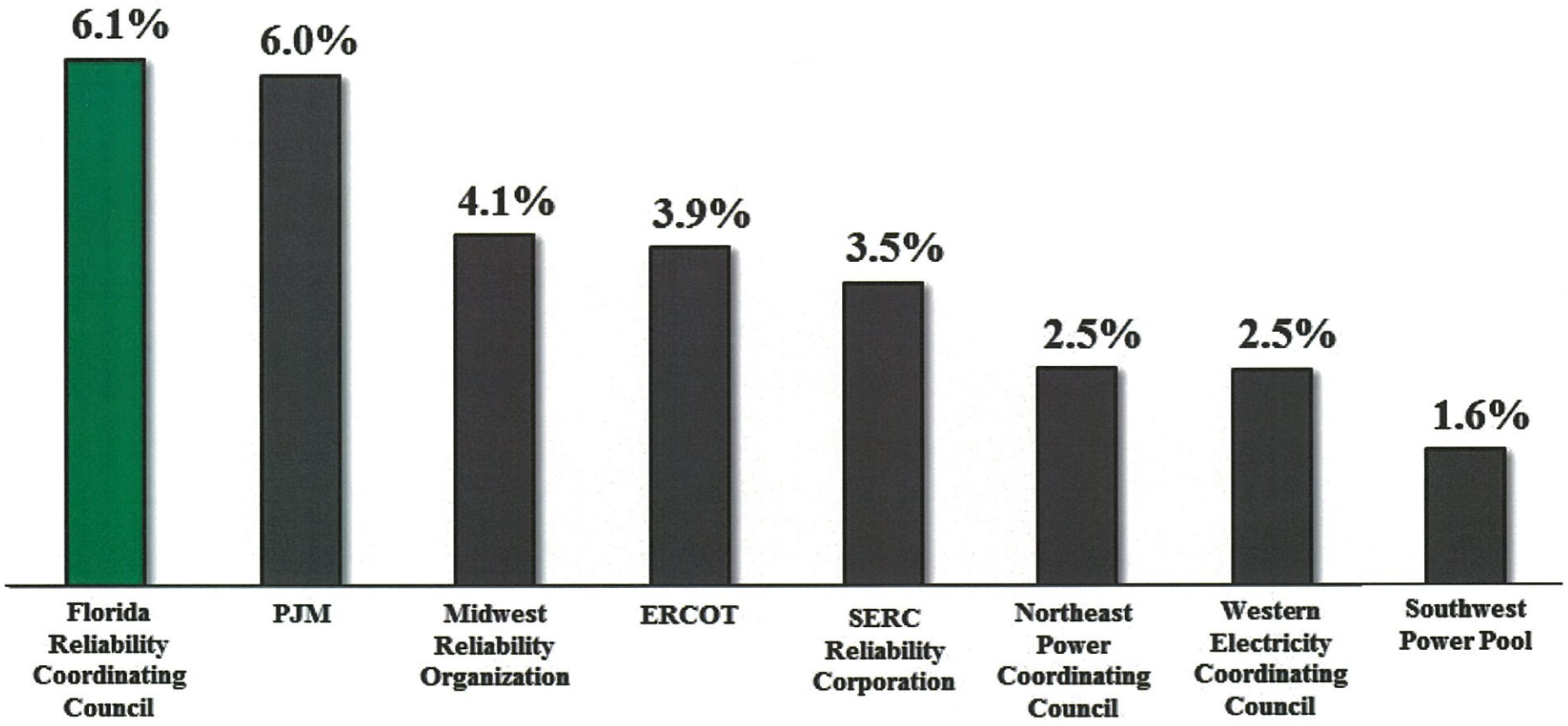
[1/] Projected impacts of Energy Efficiency codes and standards are included in all projections.

[2/] Impacts from cumulative Demand Response (DR) and incremental (2017-on) utility sponsored Energy Efficiency/Energy Conservation (EE/EC) programs are excluded.

[3/] PSC stipulation and FRCC criteria are based on firm load as per slide 22. The values shown on this slide are solely for illustrative purposes.

Demand Response as a Percentage of Peak Demand

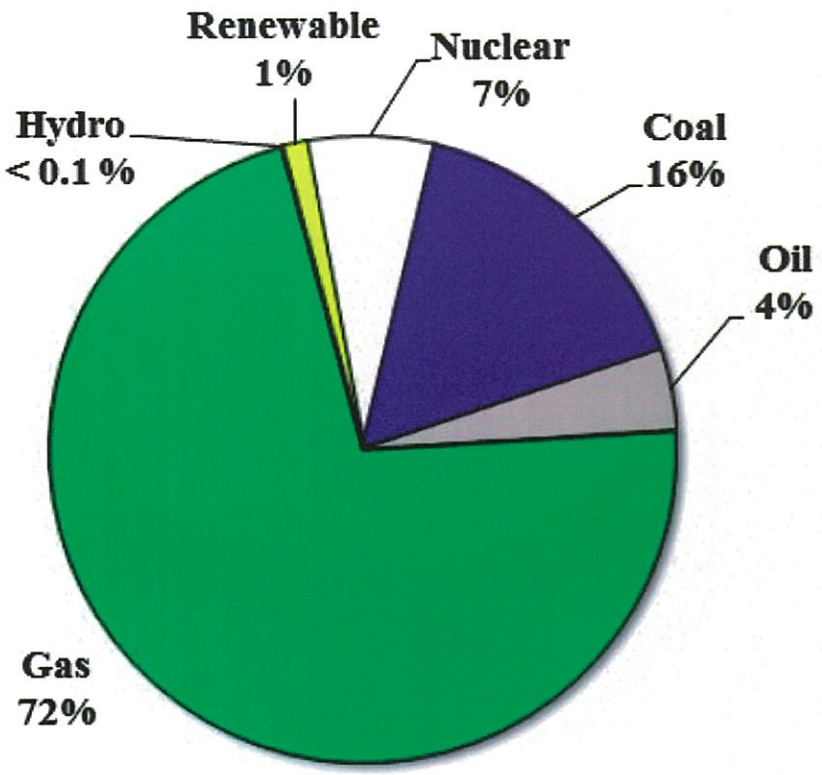
Summer 2017



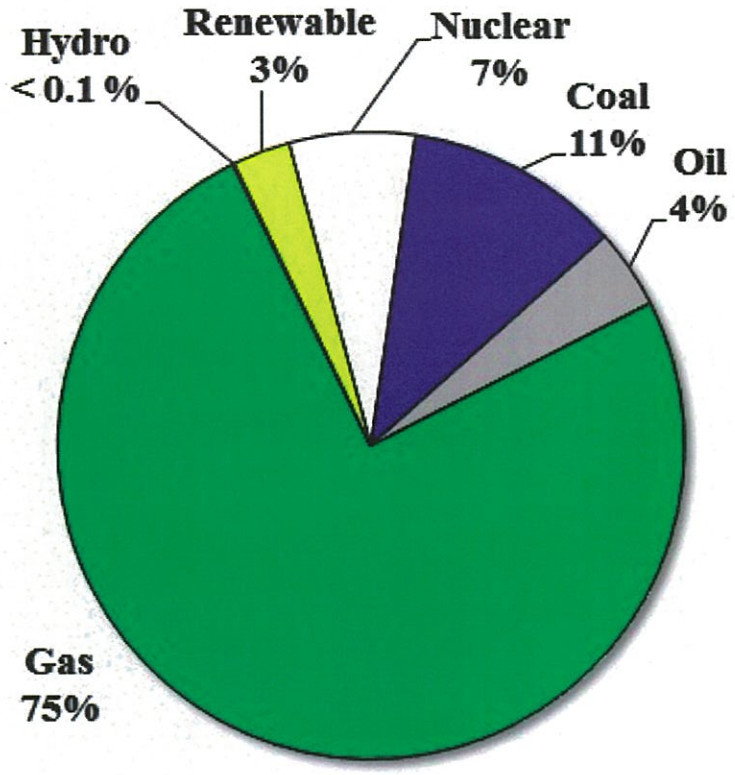
Source: North American Electric Reliability Corporation's (NERC) 2017 Summer Reliability Assessment (http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf)

Forecasted Fuel Mix

Summer Capacity[1/] (MW)



2017
55,120 MW

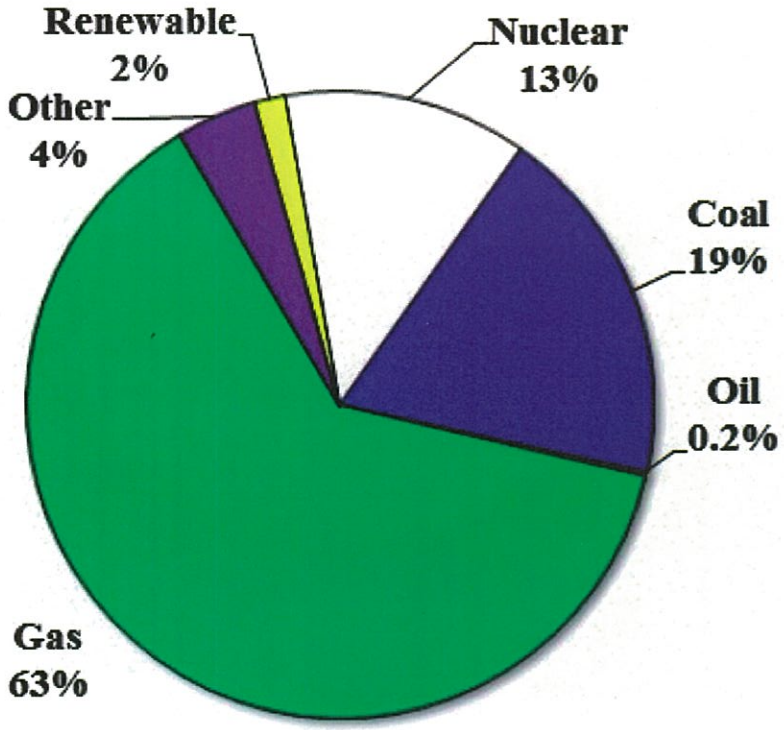


2026
59,028 MW

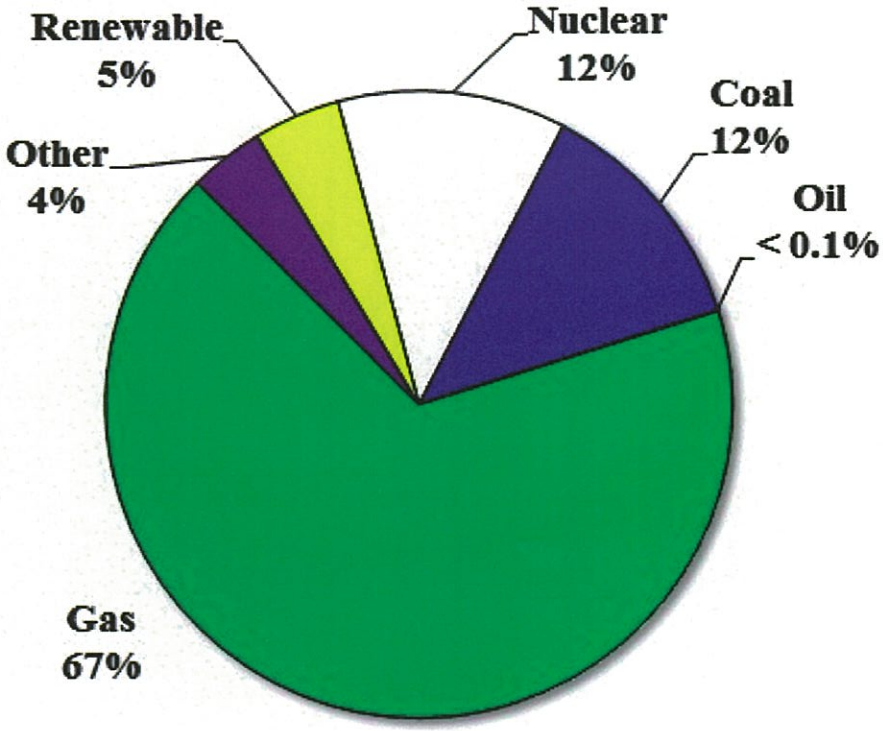
[1/] Only accounts for firm capacity

Forecasted Fuel Mix

Net Energy for Load (GWh)



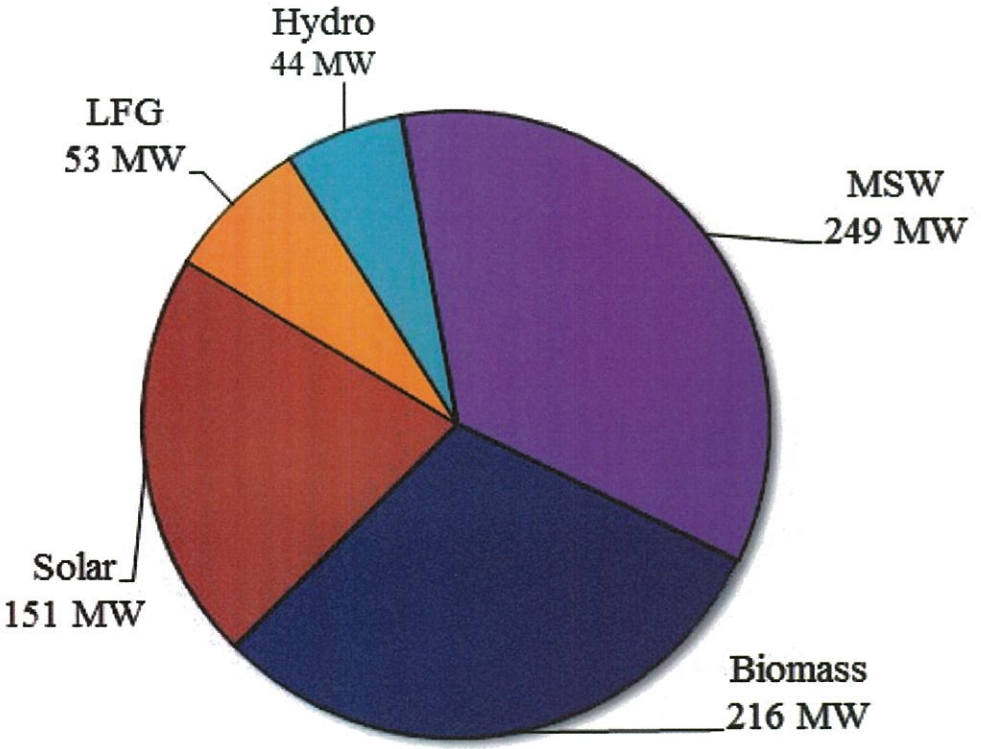
2017
230,868 GWh



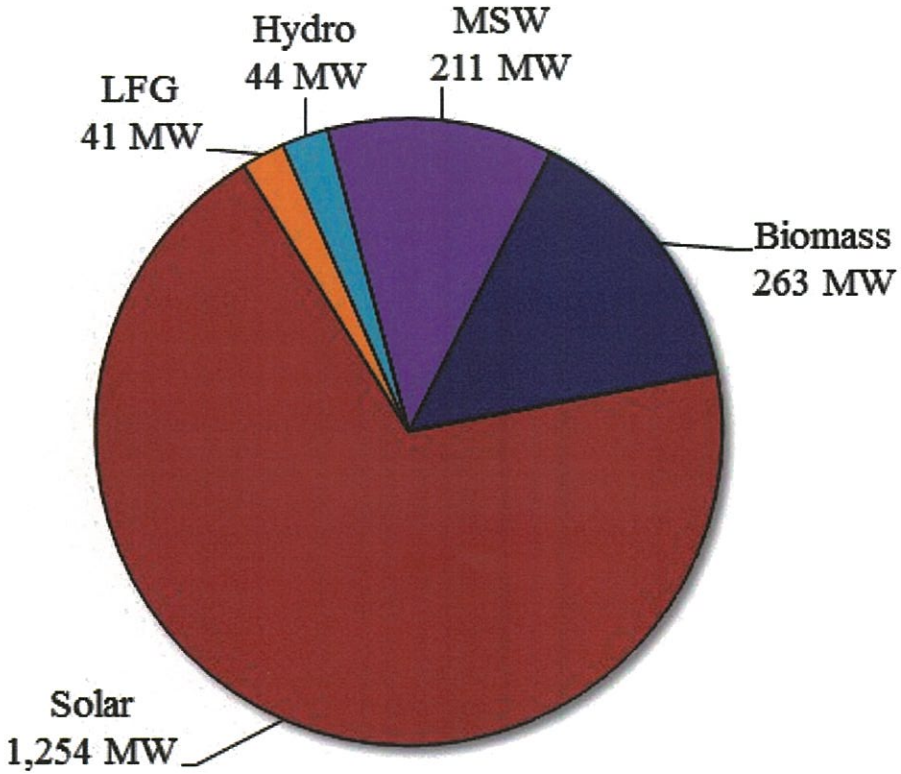
2026
250,948 GWh

Forecasted Renewable Mix

Firm Summer Capacity (MW)



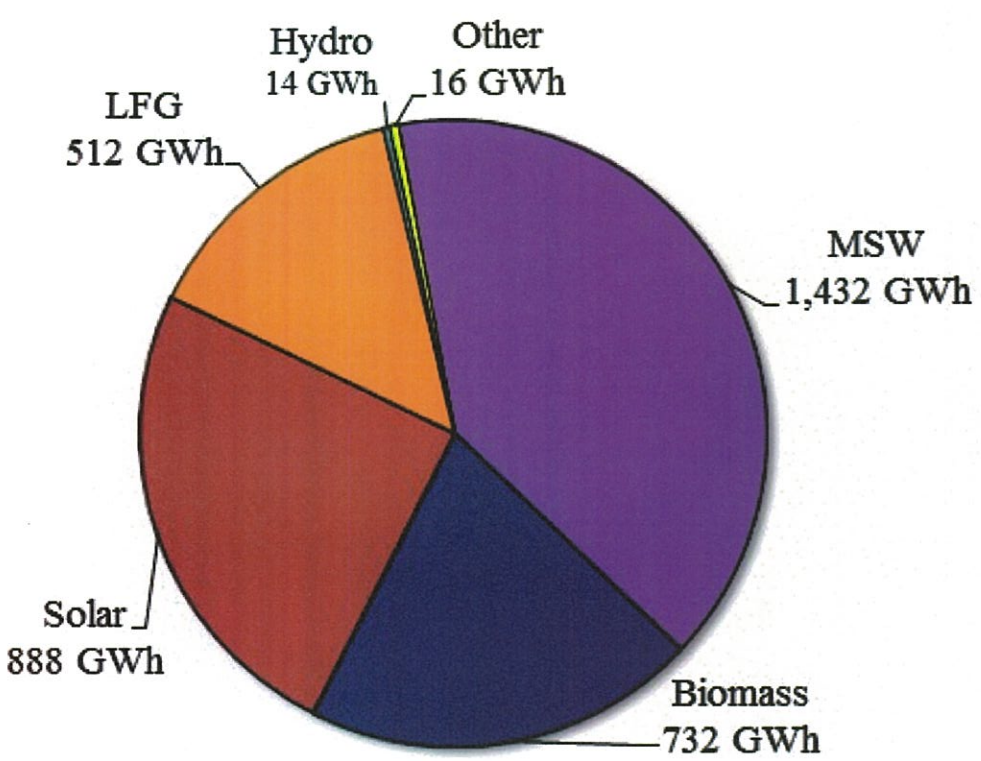
2017
713 MW



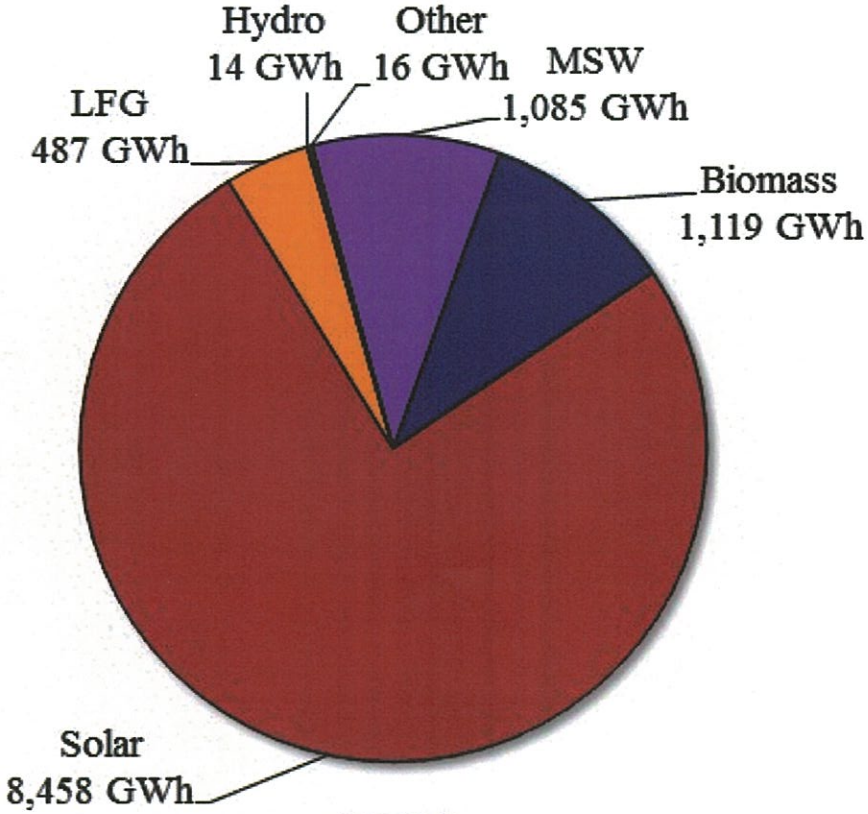
2026
1,813 MW

Forecasted Renewable Mix

Net Energy for Load (GWh)



2017
3,594 GWh



2026
11,179 GWh

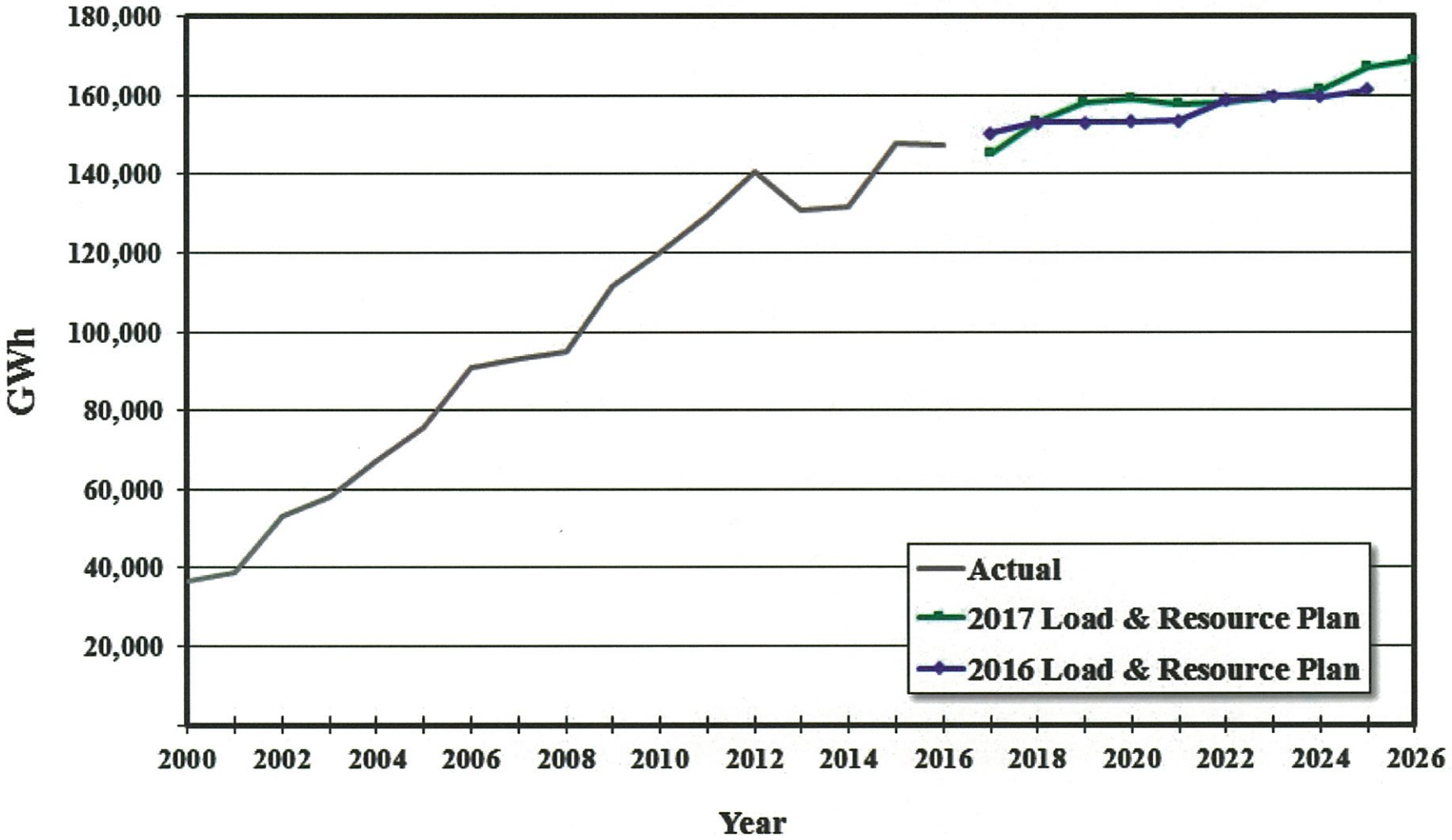
Natural Gas Infrastructure in Florida

- Three major pipelines supply natural gas to the region
  - Florida Gas Transmission
  - Gulfstream
  - Sabal Trail/Florida Southeast Connection
    - Commercial Operation Date: July 2017
- Gas infrastructure expansion and capabilities on pace with generation additions
- Over the 10-year forecast, natural gas generation with alternate fuel capabilities remains between 64-68%

2017 FRCC Fuel Reliability

- Fuel Reliability Working Group (FRWG)
  - Reviews existing interdependencies of fuel availability and electric reliability
  - Coordinate regional responses to fuel issues and emergencies
  - Commission periodic studies and analysis on FRCC gas infrastructure
  - Report findings to FRCC Operating Committee

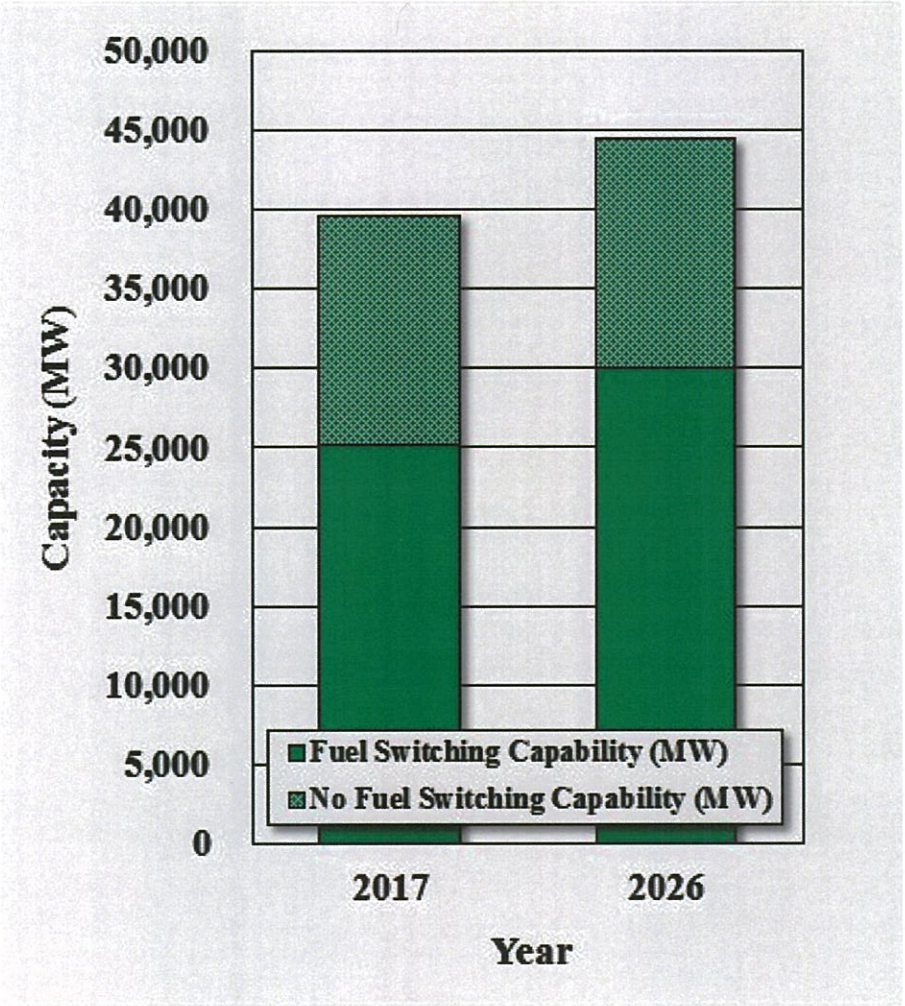
Energy Production from Natural Gas[1/]



[1/] Extended nuclear outages for uprate work resulted in higher gas usage in 2012

Natural Gas Alternate Fuel Capability

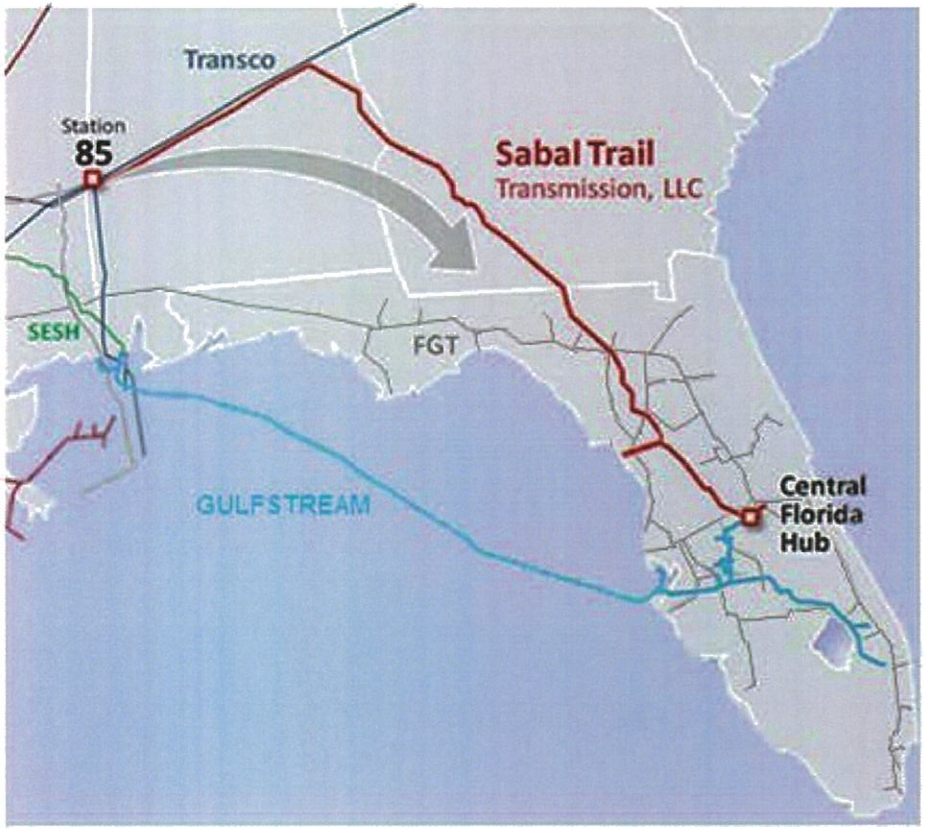
Summer Capacity (MW)



Third Gas Pipeline

(Commercial Operation Date: July 2017)

Sabal Trail



Florida Southeast Connection



Natural Gas Storage Outside of Florida

- Florida utilities have contracts with NG storage facilities out of state
  - Currently have rights to approximately 9.4 Bcf of NG storage which can generate a total of 936 GWh of energy
  - Able to withdraw approximately 0.94 Bcf per day which can generate 93 GWh per day
  - Important tool to manage supply disruptions

Data conversions are based on Energy Information Administration's average operating heat rate and average quality of fossil fuel receipts for natural gas units (http://www.eia.gov/tools/faqs/faq.cfm?id=667&t=2)

Reliability Assurance Processes – FRCC

April 2017 Energy Alert

FRCC Generating Capacity Shortage Plan

- Revised Plan was transmitted to Commission staff in November 2016
  - Implemented by FRCC on April 1, 2017 and adopted by Commission rule April 19, 2017
  - Included conceptual and terminology changes regarding generating capacity shortages
  - Incorporated NERC Reliability Standard concept of "Energy Emergency Alerts"
  - Replaced previous plan phases on "Alerts" and "Emergency" declarations and focused "Advisory" declarations on winter conditions only

Generating Capacity Advisory

- Declared by the FRCC RC when:
  a) Low temperatures (Jacksonville $\leq 21^{\circ}F$, Tampa $\leq 31^{\circ}F$, or Miami $\leq 40^{\circ}F$) or
  b) Operating Margin < 2 times the largest generating unit running or
  c) State-wide fuel supply or delivery issues
- Note: A Generating Capacity Advisory does not indicate an imminent threat of an Energy Emergency

Energy Emergency Alerts (EEA)

- EEA range in levels from low (1) to high (3)
- FRCC Operating Entities (OE) may implement the following during an Advisory or EEA to maintain reliability:
  - Awareness programs and public appeals to reduce demand
  - Demand Response (non-firm load)
  - Load conservation measures
  - Firm Load Interruption imminent or in progress to maintain load to generation balance and transmission system integrity
- Other OEs within the region communicate available generation capacity to assist

EEA Alert Levels

- EEA – 1: All available resources in use
- EEA – 2: Load management procedures in effect
- EEA – 3: Firm load interruption imminent or in-progress

April 28, 2017 EEA-1 Declaration

- At 12:43, FRCC RC declared an EEA-1 on behalf of one FRCC entity due to unexpected loss of generation and higher than normal forecasted peak loads
- Although additional generation became available prior to peak, the FRCC RC maintained the EEA-1 declaration over the peak
- At 17:00, the FRCC RC announced a return to normal operations

Conclusion

- Based on 2017 TYSPs, planned Reserve Margins at or above 20% for all peak periods for the next ten years
  - DSM projected to be a significant component of projected reserves
  - Energy Efficiency codes and standards continue to affect demand and energy forecasts

Conclusion (cont.)

- Changes to FRCC's fuel mix over the next ten years (as a % of total energy served):
  - Natural Gas increases from approximately 63% to 67%
  - Renewable increases from approximately 2% to 5%
  - Coal decreases from approximately 19% to 12%
- Gas infrastructure expansion and capabilities on pace with generation additions
- Peninsular Florida's natural gas pipeline capacity has increased to support electric generation

FRCC
Florida Reliability Coordinating Council

Questions ?

EXHIBIT NO. 112

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: WOOD

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: STAFF EXHIBIT TITLED "WINTER PEAK DEMAND FORECAST CHANGES IN SEMINOLE'S LOAD FORECAST STUDIES" (1 PAGE)

DOCUMENTS:

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 112
PARTY: Staff
DESCRIPTION: Winter Peak Demand Forecast changes in Seminoles' load and forecast studies

Winter Peak Demand Forecast Changes in Seminole's Load Forecast Studies

Winter Peak Demand Forecasts

Row	TYSP	Winter Season - MWs (1)			Major Enhancement in Method Cited By Witness Woods - First Impacts on Forecast (2)
		2020-21	2021-22	2022-23	
1	2014 TYSP	4,431	4,540	4,651	
2	2015 TYSP	3,774	3,831	3,887	None
3	2016 TYSP	3,698	3,744	3,787	SAS on Windows PC replaces SAS on Windows PC; State of the Art Weather Station Selection
4	2017 TYSP	3,701	3,750	3,803	Residential and Commercial End-Use Intensity Variables
5	2017 LFS	3,588	3,643	3,699	Behind the Meter Distributed Solar Forecast

Year over Year Change in Winter Peak Demand Forecasts

Row	TYSP	Winter Season - MWs (1)			
		2020-21	2021-22	2022-23	
6	2015 TYSP - 2014 TYSP	-657	-709	-764	None
7	2016 TYSP - 2015 TYSP	-76	-87	-100	SAS on Windows PC replaces SAS on Windows PC; State of the Art Weather Station Selection
8	2017 TYSP - 2016 TYSP	3	6	16	Residential and Commercial End-Use Intensity Variables
9	2017 LFS - 2017 TYSP	-113	-107	-104	Behind the Meter Distributed Solar Forecast
10	2017 LFS - 2014 TYSP	-843	-897	-952	

Year over Year Percent Change in Winter Peak Demand Forecasts

Row	TYSP	Winter Season			
		2020-21	2021-22	2022-23	
11	2015 TYSP - 2014 TYSP	-14.8%	-15.6%	-16.4%	None
12	2016 TYSP - 2015 TYSP	-2.0%	-2.3%	-2.6%	SAS on Windows PC replaces SAS on Windows PC; State of the Art Weather Station Selection
13	2017 TYSP - 2016 TYSP	0.1%	0.2%	0.4%	Residential and Commercial End-Use Intensity Variables
14	2017 LFS - 2017 TYSP	-3.1%	-2.9%	-2.7%	Behind the Meter Distributed Solar Forecast
15	2017 LFS - 2014 TYSP	-19.0%	-19.8%	-20.5%	

(1) Sources of forecast data: SEC 2014-2016 TYSPs in (Exhibit PS-6); 2017 TYSP (Official Recognition) and 2017 LFS (Seminole Need Study, Exhibit MPW-2, Page 47 of 153)

(2) Source: Witness Wood's Exhibit KDW-2, page 17 of 18

Note: Negative numbers denote a reduction in the demand forecast; Positive numbers denote an increase in the demand forecast.

Exhibit Not Admitted

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 113
PARTY: Quantum, Daly, Tulk
DESCRIPTION: (Hines) Article AZ Corp Commission Andy Tobins Proposed Amendment Number 4

Exhibit Not Admitted

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 114
PARTY: Quantum, Daly, Tulk
DESCRIPTION: (Hines) 3.17.18 AZ Corp Commission ordering TEP & APS to add renewables and impose moritorium on gas

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 115
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL Quantum Pasco updated proposal 10.11.16

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 116
PARTY: Quantum, Daly, Tulk
DESCRIPTION: CONFIDENTIAL (Diazgranados) Seminole annual statement Revenue projections CPP and no build risk all PPA Portfolio for 2017 ti 2051

EXHIBIT NO. 117

DOCKET NO: 20170266-EC/20170267-EC

WITNESS: DIAZGRANADOS / _____

PARTY: SEMINOLE ELECTRIC COOPERATIVE, INC.

DESCRIPTION: DIRECT TESTIMONY OF TIMOTHY S. WOODBURY ON BEHALF OF SEMINOLE ELECTRIC COOPERATIVE, INC., 12/4/2000

DOCUMENTS: PSC DOCKET NO. 001748-EC, SEMINOLE/CALPINE OSPREY NEED DETERMINATION – DIRECT TESITMONY AND EXHIBITS OF TIMOTHY S. WOODBURY

PROFFERED BY: INTERVENORS (MICHAEL TULK, PATRICK DALY & QUANTUM PASCO POWER, L.P.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170266-EC EXHIBIT: 117
PARTY: Quantum, Daly, Tulk
DESCRIPTION: Direct Testimony of Timonthy Woodbury on behalf of SEC Inc 12.4.2000

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P.	)	**DOCKET NO. 001748-EC**
	)	**FILED: December 4, 2000**

DIRECT TESTIMONY AND EXHIBITS

OF

TIMOTHY S. WOODBURY

ON BEHALF OF

SEMINOLE ELECTRIC COOPERATIVE, INC.

DOCUMENT NUMBER-DATE
[redacted]EC-4 00
FPSC-RECORDS/REPORTING

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBITS OF TIMOTHY S. WOODBURY

ON BEHALF OF SEMINOLE ELECTRIC COOPERATIVE, INC.

DOCKET NO. _____-EC

DECEMBER 4, 2000

Q. Please state your name and business address.

A. My name is Timothy S. Woodbury; my business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

I. QUALIFICATIONS

Q. What is your current position?

A. I am Vice President of Strategic Services at Seminole Electric Cooperative, Inc. ("Seminole"). I have held the title of Vice President at Seminole since December 14, 1995. My responsibilities include, among other things, managerial oversight for activities related to rate design and development, strategic planning, power marketing, and the acquisition and administration of purchased power and transmission service contracts. I was the principal negotiator for Seminole in the development of the Memorandum of Understanding, or MOU, between Calpine Energy Services, L.P. ("Calpine") and Seminole regarding the purchase and sale of capacity and energy from Calpine's Osprey Energy Center ("Osprey Project").

Q. Please briefly describe your professional and academic background.

A. I have over twenty-three years of experience in the electric utility business. Prior to my employment at Seminole in August 1979, I was employed as an economist by Duke Power Company, and I worked in areas of rates and load forecasting. I have

a Bachelor of Science in Financial Management and a Master of Arts in Economics from Clemson University.

Q. Have you previously testified on behalf of Seminole before regulatory agencies?

A. Yes. I have provided written testimony and testified on behalf of Seminole before the Federal Energy Regulatory Commission ("FERC") and the Florida Public Service Commission ("FPSC") in a number of different regulatory proceedings concerning a variety of issues relating to my areas of responsibility at Seminole.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony has several purposes. First, I will describe Seminole. Second, I will provide an overview of the planning analyses that Seminole employed to identify its need for capacity in the 2004 time frame and the competitive process it used to determine that Calpine's proposal is the best alternative available to satisfy that need. I will introduce the witnesses for Seminole who conducted those analyses and who will support Seminole's conclusions. I will explain how the purchase of firm capacity and energy from Calpine will fit into Seminole's overall system. Finally, I will generally describe the advantages and benefits to Seminole of the terms and conditions contained in the MOU (soon to be incorporated in a definitive Power Purchase Agreement or PPA) between Calpine and Seminole.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I have attached to my testimony Exhibits Nos. ___ (TSW-1)-(TSW-2). I am also sponsoring Sections A, B, and C (6) of Volume I of the Exhibits to the Joint Petition as well as Appendix I-C, the Memorandum of Understanding.

III. BACKGROUND

Q. Please provide a brief overview of Seminole and its Members.

A. Seminole is a non-profit Generation and Transmission Cooperative organized under Chapter 425 of the Florida Statutes. Each of Seminole's Members is a distribution cooperative serving end users in Florida. Seminole was incorporated in 1948 to provide unified representation for its Members in wholesale purchased power negotiations.

Q. Which distribution cooperatives in Florida are Members of Seminole?

A. Seminole's Members are Central Florida Electric Cooperative ("Central"), Clay Electric Cooperative ("Clay"), Glades Electric Cooperative ("Glades"), Lee County Electric Cooperative ("LCEC"), Peace River Electric Cooperative ("Peace River"), Sumter Electric Cooperative ("Sumter"), Suwannee Valley Electric Cooperative ("Suwannee"), Talquin Electric Cooperative ("Talquin"), Tri-County Electric Cooperative ("Tri-County"), and Withlacoochee River Electric Cooperative ("Withlacoochee"). The Members serve over 680,000 end use consumers in 45 counties throughout the state. The map attached as Exhibit No. ___ (TSW-1) shows the location in the state of the areas served by Seminole's Members.

Q. Please describe Seminole's activities on behalf of its Members.

A. Seminole's activities were limited until 1974 when, following the 1973 oil embargo, its Board of Trustees determined that it should develop independent power supplies for the Members. In 1975, each Member entered into a long term contract with Seminole for the purchase of wholesale power ("Wholesale Power Contract" or "Contract"). The Wholesale Power Contracts require each Member to purchase from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts.

Q. Are there currently any applicable pre-existing contracts?

A. Yes. Four of Seminole's Members have pre-existing contracts with the Southeastern Power Administration ("SEPA") for a combined 26 MW of capacity. The capacity supplied from SEPA to these Members represents less than 1% of Seminole's Members' total capacity requirements.

Q. What is the term of the Wholesale Power Contracts between Seminole and its Members?

A. The Wholesale Power Contracts have an initial term of forty-five (45) years (i.e., through May 22, 2020). Thereafter, each Contract may be terminated upon three years' written notice by the party desiring termination.

Q. Please describe Seminole's current portfolio of power supply resources.

A. Seminole constructed and operates two nominally rated 650 MW coal-fired generating units ("Seminole Plant") in Putnam County, Florida. These units supply nearly 75% of the Members' energy requirements. The first of the two units began commercial operation on January 31, 1984; Unit No. 2 began commercial operation on December 31, 1984. Seminole also owns a 1.6994% (approximately 15 MW) undivided interest in Crystal River Unit No. 3 ("CR3"), an 890 MW nuclear power plant operated by Florida Power Corporation ("FPC"). The Seminole Plant is connected to the Florida bulk power grid at three locations through five 230 kilovolt ("kV") circuits and associated facilities. From these interconnections, Seminole transmits the output of the Seminole Plant to the Member delivery points and to other purchasers through the transmission systems of FPC and Florida Power & Light Company ("FPL"). The Seminole Plant is also tied directly to approximately 300 MW of Member load through Seminole's own 230 kV transmission facilities.

Seminole also has a contract with Siemens-Westinghouse and Overland Contracting to construct a new combined cycle facility ("Payne Creek") to be located

in Hardee County. Payne Creek, a 500 MW nominally rated facility, has an expected in-service date of January 2002.

In addition, Seminole has numerous short and intermediate term purchased power contracts with other entities in the state which provide for intermediate and peaking needs as well as reserves. Exhibit No. _____ (TSW-2) provides a summary of these purchased power resources.

Q. Please describe Seminole's electrical interconnections and transmission facilities.

A. Seminole owns 52 miles of 230 kV double circuit transmission line from the Seminole Plant to the Silver Springs North Switching Station, eight miles of 230 kV double circuit line from the Seminole Plant to FPL's Rice Substation, and nine miles of 230 kV double circuit line from the Hardee Power Station ("HPS") to FPC's Vandolah Substation. Seminole also owns 78 miles of 230 kV single circuit transmission line from the HPS to Lee County Electric Cooperative's Lee Substation (which is also an interconnection with FPL), and 63 miles of 230 kV single circuit line from the Seminole Plant to an interconnection with Jacksonville Electric Authority at the Clay-Duval County line. Seminole jointly owns, with FPC, two tie lines from Silver Springs North to FPC's Silver Springs Substation. Seminole also owns fourteen 69 kV transmission lines, which total 143.2 miles in length.

Q. Is Seminole represented on the Florida Reliability Coordinating Council?

A. Yes, Seminole participates actively within the Florida Reliability Coordinating Council.

Q. Please elaborate on the relationship between Seminole and its Members.

A. Seminole serves the electric service needs of its Members, all of which are engaged in the sale of electricity to end use customers who are, in turn, the Members'

respective owners/members. Therefore, like Seminole, each Member that Seminole serves is owned by and is answerable to its owners/customers. Seminole's governing Board of Trustees consists of representatives from the boards of the Members as well as each Member's general manager. Seminole's Board of Trustees consists of two voting trustees and one alternate from each of the ten Members. In short, the cooperative form of business is very different from that of an investor-owned utility. Investor-owned utilities must balance the often competing interests of shareholder and customer. In the case of cooperatives such as Seminole, customers' and owners' interests are one and the same.

Q. Please elaborate on the areas served by Seminole's Members.

A. Seminole's Members provide service to approximately half of peninsular Florida's land area. As a result, Seminole's overall service area experiences a variety of geographic and weather conditions that provide for a diverse mix of economic activity and demographic characteristics. All end use consumer classes have shown strong growth. Seminole's overall growth rate has consistently exceeded the growth experienced by most, if not all, of the other utilities in Florida. Over 90% of the combined end use consumers served by Seminole's Members are residential. This class of consumers accounts for over 70% of the Members' total energy requirements.

IV. SEMINOLE'S PLANNING PROCESS

Q. Generally describe Seminole's planning process.

A. Our planning process involves an examination of current data and of assumptions about future conditions, coupled with an analysis of how potential additions would mesh with the existing system under those future conditions. Two important inputs to the process are the assumptions about system load growth and future fuel prices.

In this proceeding, Bob Woodall will testify concerning the fuel price forecast that was employed in the analysis that led Seminole to identify a need for capacity in 2004. Bill Lawton will address the methodology that Seminole and its Members used to project future peak demand and energy requirements, and will report the results of the load growth study.

Given assumptions about load growth, energy consumption, fuel prices, and the known capabilities of current resources, it is possible to model or simulate the system over time, and to measure both the reliability of the system and the cost of providing service associated with alternative power supply options. In this way, Seminole determines when load growth, the expiration of contracts, plant retirements, and/or other changes will overcome the ability of the system to meet Members' needs with an acceptable level of reliability, and Seminole identifies the appropriate type, size, and timing of the next capacity addition. Garl Zimmerman will describe in his testimony the analysis that Seminole made of the capabilities of existing resources to meet future requirements. He will quantify the need that the analysis identified. Finally, he will describe in detail the Request for Proposals ("RFP") that Seminole issued, the responses obtained, and the evaluation of responses that led Seminole to conclude that the Calpine Osprey Project best meets Seminole's needs.

Q. **Earlier you identified the power purchase agreements that comprise a portion of Seminole's existing supply portfolio. When Seminole gauges the capabilities of existing resources during its planning exercises, do any of these contracts present special considerations?**

A. Yes. Unlike the more typical unit power or system power transactions, which provide the purchaser with blocks of available power, the partial requirements service

that Seminole receives from FPC and our contractual arrangement with TECO Power Services for the purchase of capacity from the Hardee Power Station both have some unique features. Those features were designed to, and do, serve valuable purposes specific to the needs of Seminole's system. However, because they are different from the typical power supply arrangement, they also add a degree of complexity to our planning efforts.

Q. Please provide an overview of the partial requirements service that Seminole receives from FPC and explain how it affects the planning of Seminole's system.

A. In 1983, Seminole executed a long term contract covering partial requirements ("PR") and transmission service with FPC ("Agreement"). The Agreement has an initial term through 2013. The Agreement obligates Seminole to supply the Members' aggregate load in FPC's control area, up to a specified MW commitment level ("Capacity Commitment"), using resources it owns or otherwise acquires. FPC, in turn, is obligated to supply Seminole's load requirements in excess of this commitment level from its system resources under PR rates contained in the Agreement. Said differently, in contrast to the more typical "block of power" arrangement, under the PR contract FPC provides a *load following* service. Consequently, when planning the system, Seminole does not plan to meet the peak load requirements of Members located in FPC's control area. Under the Agreement, Seminole has the ability, with three years' notice, to increase the Capacity Commitment by 150 MW; by giving five years' notice, increase the commitment level by 470 MW; and, by giving seven years' notice, increase the Capacity Commitment in any future calendar year without limitation. Accordingly, in its planning, Seminole must analyze the most cost-effective manner to serve its Capacity Commitment in FPC's control area. It must also consider the most cost-effective

Capacity Commitment level by comparing the differences between the cost of continuing PR purchases and the cost of other alternative power supply resources, either owned or purchased.

Q. Please describe the principal features of Seminole's contractual arrangement with TECO Power Services.

A. Under this contract Seminole has "first call" on 295 MW of capacity from the Hardee Power Station when Seminole experiences an outage (partial or full) of one of its coal-fired base load units, Seminole 1 and Seminole 2, or of its Crystal River 3 resource.

Q. Why is this feature novel for planning purposes?

A. Under a typical purchase of system or unit power, the availability of the purchased capacity is limited only by the extent to which the source of the power is affected by outages on the seller's applicable resource(s). In the case of the Hardee Power Station purchase, the limitation is different. With regard to serving its Members' needs, the Hardee Power Station capacity is available to Seminole as a matter of contractual right, on a first call basis, when *Seminole* experiences a planned or forced outage or derating of its Seminole Plant or Crystal River 3. In other words, the contract with TECO Power Services fulfills a specific need, but there are limitations on the use of the resource. The constraint is, of course, well understood, but it is not as easily expressed or quantified in certain steps of the planning analysis. In his testimony, Garl Zimmerman will elaborate on how Seminole considers these more unusual contractual features in the planning process.

V. SELECTION PROCESS

Q. Does Seminole typically employ a competitive procurement process?

A. Yes. Although Seminole is not subject to this Commission's RFP rule, for years Seminole has solicited and evaluated proposals from others prior to selecting a specific capacity addition. Seminole views such a competitive process as the best way to secure the most economical source of power and also to reduce risk. In fact, to my knowledge, the RFP that Seminole issued in 1988, prior to entering a contract with TECO Power Services, was the first of its kind in Florida. Seminole has been committed to a competitive power supply procurement process since that time, and it has served Seminole's Members' interests well.

VI. OVERVIEW OF THE MEMORANDUM OF UNDERSTANDING

Q. What were Seminole's objectives in negotiating the MOU with Calpine?

A. Very simply, our objective was to find a reliable source of capacity and energy that provided economic and strategic advantages relative to other available options.

Q. Please describe the MOU.

A. The MOU is an interim document that serves to memorialize the fundamental commercial terms to which Calpine and Seminole have agreed. Within the MOU, the parties have agreed to negotiate in good faith the terms of a definitive agreement. That definitive agreement will incorporate the items in the MOU.

Both parties to the MOU regard the commercial details as confidential and proprietary. (The complete MOU has been submitted to the Commission under a claim of confidentiality.) However, a general description will convey the manner in which Seminole achieved its objectives. The MOU contains specific pricing provisions. The terms require Calpine to furnish the firm capacity to Seminole at very high levels of availability. Energy will be delivered to Seminole when called upon by Seminole subject to specific scheduling provisions. The MOU provides for

the purchase and sale of 350 MW of firm capacity and associated energy during the period 2004-2020, subject to periodic contractual "reopeners."

Q. Given these reopener provisions, what is the minimum term over which the agreement might remain in effect?

A. The minimum term is five years from the later of the commercial operation date of the Osprey unit, and June 1, 2004.

Q. Does Seminole have options to acquire greater amounts of capacity than the initially specified 350 MW amount?

A. Yes. In addition to the 350 MW of firm capacity, Seminole has the right to acquire optional firm capacity in any amount, up to the full remaining generating capability of Calpine's Osprey unit, to the extent Calpine has not sold such capacity on a firm basis to another party at the time Seminole exercises its option. Seminole must give notice of its decision to exercise its option to purchase such additional capacity 6 months ahead of time. The optional firm capacity designated in this notice by Seminole would then be secured for Seminole in twelve month increments.

VII. STRATEGIC CONSIDERATIONS

Q. Please identify the strategic advantages to which you referred earlier.

A. First, by contracting with Calpine, Seminole is able to secure 350 MW of needed firm capacity and associated energy at a cost that reflects the economies of scale associated with a new 500 MW class, efficient combined cycle facility. Second, the "reopener" provision enables Seminole to renegotiate, and if such negotiations are, in Seminole's view, unsuccessful, terminate the Agreement after any 60-month period--a valuable advantage over any self-build option. By acquiring 350 MW, Seminole will gain the flexibility of either terminating (with advance notice of three years) a more expensive purchase from FPC, or of maintaining (perhaps at a reduced

level) the purchase from FPC as an additional contribution to reliability and a hedge against unforeseen contingencies. The ability to acquire "optional firm capacity" further enhances Seminole's flexibility to meet changes in circumstances over time. Taking into account the committed capacity and the reserved firm capacity option provision, Seminole has negotiated the ability to avail itself of the full capacity of the Osprey Project, subject only to the possibility of firm commitments to others made prior to Seminole's exercise of its option. Under the terms to which Calpine and Seminole have agreed, Seminole may elect to purchase energy from the Osprey project and resell it in the wholesale market. This ability provides Seminole with a potential opportunity to reduce its Members' revenue requirements by realizing margins on off-system sales during periods when more economical energy is available to Seminole or when its Members' requirements do not support the full utilization of its rights to the Osprey unit. Finally, unlike some of the other options--including Seminole's self-build option--Calpine intends to bring the Osprey unit on line in advance of the time when Seminole will require the capacity to maintain standards of reliability. For that reason, the arrangements with Calpine reduce the risk that the selected capacity may not be in place in the time frame required by Seminole.

Q. Please summarize your direct testimony.

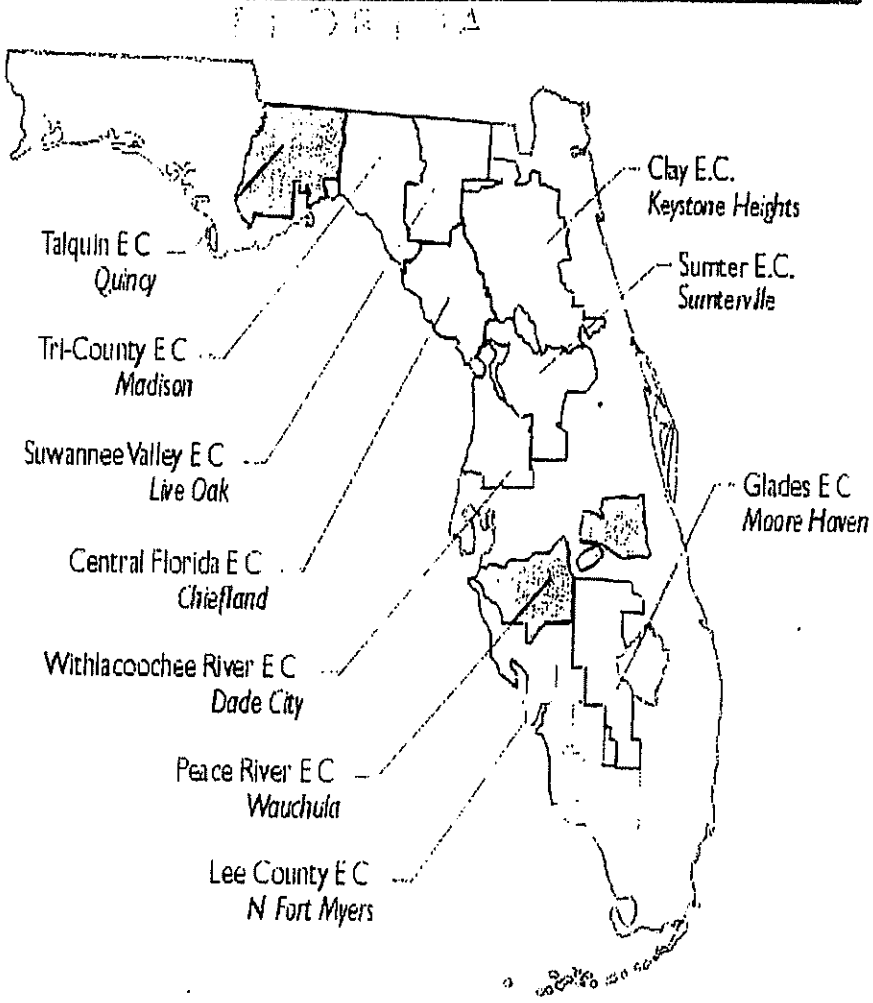
A. Seminole's system is unique in Florida. The arrangements between Calpine and Seminole are designed to meet the needs of that system well. In addition to being the lowest cost alternative available to Seminole, Calpine and Seminole have agreed to non-price terms and conditions that provide valuable strategic advantages to Seminole.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. _____
Witness: Timothy S. Woodbury
Exhibit No. _____ (TSW-1)

Seminole's Member Distribution Cooperatives



SEMINOLE'S PURCHASED POWER RESOURCES[1]		
Resource	**MW**	**Term**
FPC Partial Requirements (FPC supplies Seminole's load requirements in the FPC control area that are above an annually defined commitment level (1,327 MW for 2001) that is supplied by Seminole resources.)		Initial term through 2013[2]
1995 FPC Agreement - Structured System Capacity System Peaking Capacity (305 MW in 2000, 455 MW in 2001 & 300 MW in 2002) System Intermediate Capacity	 300 up to 455 150	 Through December 31, 2001 Through December 31, 2002 Through December 31, 2013[3]
TECO Power Service Agreement (Entitlement to 145 MW (with annual MWh limitations) of capacity from Tampa Electric's Big Bend Unit No. 4 facility.)	145	Through December 31, 2002
Orlando Utilities Commission Capacity	75	Through May 31, 2004
JEA Capacity Purchase	63	Through May 21, 2004
Lee County Resource Recovery Facility	35	Initial term through 11/30/04[4]
Reliant Energy Power Generation Capacity	364	12/01/01 through 12/31/06
Constellation Power Development Capacity (364 MW for 12/01/02 through 5/01/03 period)	546	12/01/02 through 12/31/09

[1] Excludes seasonal capacity purchases.

[2] The partial requirements service from FPC may be terminated by either party giving notice in any calendar year after calendar year 2007 that it wishes to terminate the agreement at end of the fifth future calendar year (i.e., notice in 2008 to terminate at end of 2013).

[3] FPC System Intermediate Capacity may be terminated or reduced before 12/31/13 by Seminole upon three years notice to FPC.

[4] The Lee County Resource Recovery Agreement's obligations will continue through 12/31/15 with provisions to alter the arrangement after the inital period.

TECO Power Service Agreement (Provides backup power for Seminole's Units 1 & 2 and Seminole's Crystal River 3 entitlement)	362	Through December 31, 2012