IN RE: PETITION FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY, DOCKET NO. 20170266-EC

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR SHADY HILLS GENERATING FACILITY, DOCKET NO. 20170267-EC

DIRECT TESTIMONY AND EXHIBITS

OF

PAUL M. SOTKIEWICZ, Ph.D.

ON BEHALF OF QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Paul Sotkiewicz, and I am the Founder and President of E-Cubed Policy Associates, LLC. My business address is E-Cubed Policy Associates, LLC, 5502 N.W 81st Avenue, Gainesville, Florida 32653. As the President of E-Cubed, I provide expert advice, testimony, and policy research to private sector and government clients on a wide range of subjects relating to energy, electric utilities, electricity markets, environmental issues, and economic and regulatory policy relating to energy and electric issues.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Quantum Pasco Power, L.P. ("Quantum Pasco"), and two individuals, Michael Tulk and Patrick Daly. Quantum Pasco is the owner of the Quantum Pasco Power Plant ("Pasco Facility"), a dual-fueled combined cycle power plant located in Dade City, Florida. Quantum Pasco offered to sell the Pasco Facility's output to Seminole Electric Cooperative, Inc. ("Seminole") through purchased power agreement options and through an asset sale. Michael Tulk and Patrick Daly are “member-consumers” of Withlacoochee River Electric Cooperative, Inc. (“WREC”), which is one of the member cooperatives of Seminole, the principal petitioner in these dockets. As member-consumers of WREC, Mr. Tulk and Mr. Daly will have to pay the rates that result from the wholesale power furnished to WREC by Seminole, including the costs of the power plants that are the subject of these consolidated need determination dockets.

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

A. I received a Bachelor of Arts Degree in History and Economics from the University of Florida in 1991. I received a Master of Arts Degree in Economics from the University of Minnesota in 1995 and a Doctor of Philosophy Degree in Economics from the University of Minnesota in 2003.

Prior to founding E-Cubed Policy Associates, LLC, I have worked as a staff economist in the Office of Economic Policy, and later on the staff of the Chief Economic Advisor at the United States Federal Energy Regulatory Commission (“FERC”), served as the Director of Energy Studies at the Public Utility Research Center (“PURC”), University of Florida, and been a Senior Economist, Chief Economist, and Senior Economic Policy Advisor for PJM Interconnection, LLC (“PJM”). Since founding E-Cubed, my clients have included organized wholesale market operators New York Independent System Operator (“NYISO”) and the Alberta Electric System Operator (“AESO”) in Canada; industry trade associations

Electric Power Supply Association ("EPSA"), New England Power Generator Generators Association ("NEPGA") and the American Petroleum Institute ("API"); and merchant generation developers, natural gas mid-stream companies, and merchant transmission developers.

During my tenure as Director of Energy Studies at PURC, I advised and provided executive education in Latin America and the Caribbean, Southeast Asia, and Southern Africa. I also served as a private consultant to the Public Utilities Commission of Belize and the Florida Department of Environmental Protection ("FDEP") regarding their State Implementation Plan for the Clean Air Interstate Rule ("CAIR").

Including my dissertation work on the impact of public utility commission regulation on the cost-effectiveness of the Title IV SO_2 Trading Program, I have over 20 years of experience in working in the power industry and power sector regulation.

I have authored and co-authored numerous articles and chapters of books relating to electric policy issues, electric markets, energy and electric utility economics, and environmental policy impacts on the electricity market and electricity regulation.

Q. Please summarize your experience relating to electric system planning.

A. I have worked extensively in analyzing the impacts of environmental policy on power generation compliance choices, potential exit of generation and the effect on reserve levels, and the entry of new generation associated with environmental policies. This body of work includes modeling compliance with the Title IV SO_2 Trading Program as part of my doctoral dissertation examining choices between installation of scrubbers, fuel switching, and allowance purchases or sales. It also includes modeling joint sulfur dioxide and nitrogen oxide compliance for the CAIR as part of my work for the FDEP in its State Implementation Plan for CAIR.

While at PJM, this work continued with leading and co-authoring analyses of the impacts of Waxman-Market climate bill in 2008, the Mercury and Air Toxics Standards ("MATS"), and the recent Clean Power Plan.

Also, while at PJM, I co-authored work on transmission cost allocation as it relates to transmission planning and cost causality for new transmission upgrades.

Additionally, as the Chief Economist at PJM, it was my responsibility to provide advice on the capacity market construct that had the purpose of ensuring resource adequacy and provide expertise regarding the costs of potential new generation as well as the cost of keeping existing generation in service, and advice on load forecasting as needed.

Q. Please summarize your experience testifying in regulatory proceedings.

A. As the Chief Economist at PJM, I supplied testimony in high profile cases related to energy market pricing during operating reserve shortages and testimony in support of what is known as the Cost of New Entry ("CONE") for simple cycle and combined cycle gas turbines. The CONE testimony covers the cost of building new simple and combined cycle gas turbines in different areas of the PJM footprint with the help of EPC contractors and the consultants retained by PJM, The Brattle Group.

In the 2014 CONE proceeding, FERC relied upon my prepared testimony to approve PJM's filed CONE numbers. The FERC decision was appealed by a group of generation owners to the DC Circuit Court of Appeals, and the FERC ruling relying on my testimony was just recently upheld by the DC Circuit.

Prior to PJM, I provided oral testimony before an Administrative Law Judge in the FDEP CAIR proceeding in 2006 in support of the FDEP proposed State Implementation Plan.

Since founding E-Cubed, I have provided written testimony in the recent DOE NOPR proceeding requesting special compensation for generation with on-site fuel storage, and concurrent with this proceeding, I will be filing testimony in a case in at FERC regarding an update to a market power screen in ISO New England.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit PS-1	Resume' of Paul M. Sotkiewicz, Ph.D.;
Exhibit PS-2	Summary of Seminole's Winter Peak Forecast Errors, 2005-2016;
Exhibit PS-3	Summary of Seminole's Summer Peak Forecast Errors, 2005-2016;
Exhibit PS-4	Summary of Seminole's Total Energy Requirements Forecast Errors, 2005-2016;
Exhibit PS-5	Seminole Gap Chart (Seminole Exhibit JAD-2);
Exhibit PS-6	Peak Load, Energy, and Number of Customers History and Forecast Tables from Seminole's Ten Year Site Plans, 2005-2016;

Exhibit PS-7	Seminole's Existing Generating Facilities and Purchased Power Resources, Excerpt from Seminole's 2017 Ten Year Site Plan;
Exhibit PS-8	Seminole's Revised Economic Analysis Results of Portfolios (Seminole Exhibit JAD-6);
Exhibit PS-9	Specifications of FPL's Proposed Dania Beach Clean Energy Center, Schedule 9 from FPL's 2017 Ten Year Site Plan;
Exhibit 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;
Exhibit 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; and
Exhibit 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.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I have been engaged by Quantum Pasco Power, L.P., to analyze and provide my professional opinions regarding (1) whether Seminole Electric Cooperative's claims regarding its projected need for additional generating capacity, including Seminole's assertions regarding the timing of any such need, are reasonable and appropriate; (2) whether Seminole's choices of the Seminole Combined Cycle Facility and the Shady Hills Combined Cycle Facility represent the most cost-effective alternatives available to meet the needs of the end-use member-consumers (i.e., the retail electricity purchasers) who are served by the distribution cooperatives, including WREC, who receive their power supply from Seminole; (3) whether the resources proposed by Seminole are in the best interests of those end-use consumers, specifically including consideration of the risks that Seminole's proposals will impose on those end-use consumers; (4) whether better choices are available to Seminole; and (5) whether Seminole's proposed resources are in the public interest.

Q. What issues do you address in your testimony?

A. Seminole and Shady Hills have asked the Florida Public Service Commission ("PSC" or "Commission") to grant determinations of need for two new electrical power plants, the Seminole Combined Cycle Facility ("SCCF"), with a projected "net nominal" capacity of 1,050 megawatts ("MW") (1,122 MW of winter peak capacity according to Seminole's exhibits, and 1,183 MW "gross nominal"), and the Shady Hills Combined Cycle Facility ("SHCCF"), which has a projected winter peak capacity of 573 MW. Both the SCCF and the SHCCF are subject to the mandatory jurisdiction of the Florida Electrical Power Plant Siting Act and the PSC's need determination statute, Section 403.519, Florida Statutes (the "Need Statute"). The Need Statute sets forth several specific criteria that the PSC must consider in making its decisions on such petitions for determinations of need. Those criteria are:

a. the need for system reliability and integrity;

b. the need for adequate electricity at a reasonable cost;

c. the need for fuel diversity and supply reliability;

d. whether a proposed power plant is the most cost-effective alternative available for meeting the needs of the petitioning utility; and

e. the extent to which renewable resources and conservation measures that might mitigate the need for additional power plants are utilized to the extent reasonably available.

Consistent with the statutory criteria, my testimony mainly addresses Seminole's alleged need for the proposed SCCF and SHCCF relative to its "need for system reliability and integrity" and its "need for adequate electricity at a reasonable cost," touching briefly on fuel diversity and supply reliability, as well as the issue of whether these proposed power plants, both individually and collectively, represent the "most cost-effective alternatives" for meeting Seminole's alleged needs. My testimony also addresses whether the construction of the proposed power plants is in the best interests of the end-use consumers who will be called upon to pay for the plants. To the same point and effect, my testimony addresses Seminole's proposals in relation to the risks that Seminole's decisions will impose on the end-use consumers of the power that Seminole sells to its member cooperatives; this issue is particularly noteworthy given Seminole's claim that it has selected the best "risk-managed" resource plan or portfolio for meeting its needs.

Given the Commission's overarching interest in protecting consumers, and in ensuring the appropriate development of a coordinated power supply grid, specifically including the avoidance of uneconomic duplication of generating resources, my testimony also addresses the interests of the consumers who would be obligated to pay for the proposed plants – and the public interest generally, including whether the plants would represent uneconomic additions to the grid if they were brought on-line on the in-service dates proposed by Seminole.

Q. Please summarize the main conclusions of your testimony.

A. Because Seminole's forecasting errors have historically been extremely large, it is my opinion that the Commission should deny both the petition for determination of need for the SCCF and the petition for determination of need for the SHCCF. Indeed, the ***average error*** of Seminole's winter peak forecasts five years into the future, as measured using Seminole's own Ten Year Site Plans since 2005, ***1,420 MW***, has been greater than Seminole's asserted "Need Gap" projected in its filings through 2024, ***1,336 MW***. Moreover, previous instances of over-forecasting have resulted in Seminole being 500-600 MW over their reliability requirement through 2020 if the load forecast is accurate out to 2020. Seminole has ample capacity, considering its owned generating resources and its long-term power purchase agreements (through 2024), to meet reasonably projected peak demands through at least 2024 with only minimal additions of purchase power resources.

Moreover, Seminole's own analyses show that the most cost-effective portfolio – by approximately $136 Million on a Cumulative Present Value Revenue Requirements ("CPVRR") basis – for meeting even its overstated future needs is what Seminole calls the "No Build Risk: All-PPA Portfolio," when evaluated over a

10-year time horizon or analysis period. This shows that the All-PPA Portfolio is likely to be cost-effective for even longer than 10 years, quite possibly even 15 years or more, before any fuel cost savings would possibly catch up with the tremendous additional capital costs associated with the SCCF and the SHCCF.

This further shows that Seminole's proposed plan – to build the SCCF and SHCCF – would impose substantial risks on the consumers who would have to pay for Seminole's decisions.

Q. Please state your main conclusions regarding the proposed power plants relative to the criteria in the Need Statute that you address.

A. 1. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for system reliability and integrity.

2. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for adequate electricity at a reasonable cost.

3. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for fuel diversity and supply reliability. In fact, taking a coal plant out of service, while probably desirable in some respects, is contrary to the need for fuel diversity.

4. Seminole's proposals to add the SCCF and SHCCF to its generating resources do not represent the most cost-effective alternative for meeting the needs of the consumers who would be obligated to pay for those plants.

Indeed, adding these two projects in the times proposed will impose significantly greater risks on those consumers than if Seminole were to continue using the resources it has available through at least 2024.

Q. Do you have a recommendation for the Commission on the petitions for need determinations for the SCCF and the SHCCF?

A. Yes. My recommendation is that the Commission should deny both petitions as proposed by Seminole and Shady Hills. While it may be desirable for Seminole to eventually add physical generating capacity to its resource mix, Seminole cannot credibly show that it needs approximately 1,700 MW of new gas-fired capacity to meet its needs based on its record of dramatic and systematic over-forecasting bias for peak loads and total energy. In fact, Seminole's own analyses show that adding the SCCF and the SHCCF would be uneconomic – as compared to an All-PPA Portfolio – until sometime after 2027. The Commission should invite Seminole to correct its forecasting methodologies and come back to the Commission with appropriate need petitions in the future. This will benefit the end-use consumers who would be called upon to pay for these plants by reducing risks and reducing costs well into the future; the Commission should keep clearly in mind that Seminole's own analyses show that an All-PPA Portfolio has significantly lower costs – CPVRRs – than Seminole's proposed portfolio for at least the first 10 years of Seminole's planning horizon, i.e., until sometime after 2027. Deferring the SCCF and the SHCCF, including deferring decisions to construct them, will not only allow Seminole to improve its forecasting methodologies, but it will also allow Seminole to take advantage of additional improvements in generating technologies and to plan for developments affecting other variables – e.g., carbon taxation or greenhouse gas regulation, additional penetration of conservation and end-use solar measures, and battery storage for solar generation alternatives – and potentially avoid the need to build new capacity before committing to a multi-billion dollar resource plan on the basis of flawed load forecasting.

III. SEMINOLE'S NEED FOR ADDITIONAL GENERATING CAPACITY

Q. Considering the factors in the Need Statute, does Seminole need either or both the SCCF or the SHCCF at the proposed in-service dates for those power plants?

A. No. Seminole's need forecasting has been systematically and consistently biased upward for years, such that Seminole cannot credibly show a reliability need for either plant. Further, Seminole's own analyses show that Seminole's total power supply costs would be lower for at least the first 10 years of its planning horizon if it were to use what it calls the "No Build Risk: All-PPA Portfolio," so Seminole cannot credibly claim to need either plant to meet consumers' needs for adequate electricity at a reasonable cost. For the same reasons, Seminole has not credibly shown and cannot credibly show that either project represents the most cost-effective alternative to meet the needs of the consumers who must pay the costs of power supplied by Seminole.

A. Need for System Reliability and Integrity

Q. Please describe your understanding of Seminole's asserted need for additional generating capacity and of Seminole's proposals to meet that need, including construction of the proposed Seminole Combined Cycle Facility ("SCCF"), the proposed Shady Hills Combined Cycle Facility ("SHCCF"), and certain purchases from a few wholesale suppliers.

A. Seminole asserts that it "needs" approximately 901 MW of additional generating capacity resources by December 2021, and 1,265 MW (total) by December 2022, in order to maintain reliable service. Seminole further asserts that this alleged need will increase to 1,698 MW by 2026. (These projections are shown in Exhibit MPW-2, page 49 of 153, to the testimony of Michael P. Ward.)

In addition, Seminole asserts that, in its view, the best way to meet its projected needs is by self-building the Seminole Combined Cycle Facility (1,122 MW of winter peak capacity), with an in-service date of December 2021, and by having Shady Hills Energy Center, LLC, build and operate the Shady Hills Combined Cycle Facility (573 MW of winter peak capacity), with Seminole buying the output of the SHCCF for 30 years, with an in-service date of December 2022, plus additional PPAs with GE Shady Hills for peaking purchases, peaking and intermediate purchases from Duke Energy Florida, and an additional purchase from a confidential supplier. This information is shown in the Sedway Evaluation Report, Exhibit No.

AST-1, page 22, Table A-13, which is an exhibit to the testimony of Seminole's witness Alan S. Taylor. Since the combined capacities of the SCCF and the SHCCF are significantly greater than Seminole's alleged "need gap" until 2025 or 2026, Seminole further asserts that it will close one of its coal-fired generating units and meet its projected needs with a combination of five power purchase agreements (PPAs) with four different counter-parties, with amounts of capacity ranging from 172 MW to 350 MW and terms ranging from 5 years to 23 (or 15) years. (This information is presented in Table A-13, found at page 22 of the Sedway Consulting Independent Evaluation Report.)

Q. Do you agree with Seminole's assertions regarding the timing of its claimed need and the amount of that need for additional generating capacity?

A. No, I do not. Seminole has consistently and significantly overstated its projected peak demands, both for summer and winter, and also its energy needs. Given that a lead period of 5 years for the permitting and construction of the SCCF and the SHCCF is reasonable, I looked at how accurate Seminole's forecasts of summer peak demand, winter peak demand, and energy requirements have been both 4 years into the future and 5 years into the future. Analysis of Seminole's record of overstating projected peak demands and energy requirements shows that:

a. Seminole has consistently and systematically over-forecast its winter peak demands, 5 years into the future, by an ***average*** of 1,420 MW, or 41%, and by an ***average*** of 1,114 MW, or almost 32%, 4 years into the future. Seminole's Winter Peak forecast errors are shown in tabular and graphic formats in my Exhibit No. ____ (PS-2).

b. Seminole has consistently and systematically over-forecast its summer peak demands 5 years into the future by an ***average*** of 679 MW, or 20%, and 4 years into the future by an ***average*** of 513 MW, or 15%. Seminole's Summer Peak forecast errors are shown in tabular and graphic formats in my Exhibit No. ____ (PS-3).

c. Seminole has also consistently and systematically over-forecast its energy requirements 5 years into the future by an ***average*** of 3,870 giga-watt hours ("GWH"), or 25%, and 4 years into the future by an ***average*** of 2,973 GWH, or 19%. Seminole's forecast errors for its total energy requirements are shown in tabular and graphic formats in my Exhibit No. ____ (PS-4).

These consistent, systematic, and dramatic over-estimates demonstrate that Seminole's forecasting cannot be used a basis for supporting the need for the combined capacity of SCCF and SHCCF. It is particularly telling that Seminole is a winter peaking utility, but its winter peak forecasting errors have ***averaged*** 1,420 MW, which is more than Seminole's projected "Winter Need Gap" of 1,336 MW for 2024, as shown in my Exhibit No. ____ (PS-5), which is a copy of Exhibit No. JAD-2 presented by Seminole's witness Julia Diazgranados, who is the utility's Director of Treasury and Planning. What is even more striking is that there has been a downward trend in the actual winter and summer peak loads since 2009, corresponding to the end of the last recession, which is a trend that has widely been seen across the United States, yet Seminole's new forecast is for peak load to start growing again as it had prior to the last economic downturn. In other words, if Seminole's current forecast has the same average error in MW that its forecasts made from 2005 through 2012 (the 4-years-out projection for 2016 was made in 2012) exhibited, Seminole would not need any new capacity until 2025. In fact, this ***average*** forecast error of 1,420 MW is nearly the total amount of capacity proposed for the SCCF and the SHCCF combined.

The forecasting errors, both in units (MW and GWH) and in percentages, are presented in my Exhibits Nos. PS-2 through PS-4. They are based on data obtained from Seminole's Ten Year Site Plans from 2005 through 2016; the source schedules from those 2005-2016 Site Plans are provided as Exhibit No. ____ (PS-6) to my testimony.

Q. What impacts would using more realistic peak demand projections have on Seminole's projected need?

A. If Seminole were to use more appropriate assumptions, e.g., by reducing its projected winter peak demands by the approximate amounts of its average forecasting errors, as shown by Seminole's own Ten Year Site Plans, it would be readily apparent that Seminole does not need either the SCCF in 2021 or the SHCCF in 2022. At most, Seminole might need 200 to 300 MW of additional winter capacity in that time frame, which it could easily meet with additional power purchases, at costs dramatically less than the costs of the SCCF and the SHCCF.

Q. How do you believe this need could be met?

A. Seminole presently owns 2,178 MW of its own generation resources, the two coal units at Seminole's Palatka site (1,329 MW winter), and the 8 units at the Midulla Generating Station in Hardee County (849 MW winter). Additionally, Seminole has (or will have as of 1/1/2021) approximately 1,603 MW of winter capacity available through purchased power resources through at least 2024. (These data are reported in Seminole's 2017 Ten Year Site Plan, Schedule 1 and Table 1.2, which are provided here as Exhibit No. ____ (PS-7) to my testimony.) Thus, Seminole has about 3,780 MW of capacity under control through at least 2024, with winter peaks that are currently in the range of 3,500 MW. Adding a 15 percent reserve margin onto Seminole's estimated 2017 3,523 MW winter peak (as reported in its current Ten Year Site Plan) indicates total need of about 4,051 MW, which is about 270 MW above its resources under control through 2024. This small amount of additional need could easily be met by PPAs (or tolling agreements). For example, Tables A-8 and A-12 in the Sedway Evaluation Report (Exhibit AST-1 to Mr. Taylor's testimony) show that there were literally hundreds of MW – in fact, more than 2,000 MW – of additional capacity offered to Seminole at apparently favorable costs, based on the rankings in those tables. These include an additional 343 MW available from the project coded as L-1, which was actually chosen to meet 172 MW of Seminole's proposed requirements; 235 MW from the project coded as O-1; 482 MW from the project coded as A-4; another 484 MW from the project coded as D-1; up to 1,000 MW from the project coded A-5; and others.

In the best interests of consumers and in the public interest, the Commission should reject both the need determination petition for the SCCF and the need determination petition for the SHCCF. Much better, more economic, and less risky opportunities are available for Seminole to meet the needs of the end-use consumers it serves – and who would be called upon to pay for Seminole's mistakes.

Q. What else does Seminole's record of forecasting need, and the amount of capacity that Seminole has procured, show?

A. Exhibit JAD-2 to the testimony of Julia Diazgranados (included as Exhibit No. ____ (PS-5) to my testimony) shows the direct results of Seminole's continuing forecasting errors, and thus directly shows how much unneeded capacity Seminole has been maintaining, presumably at the expense of its member cooperatives and the end-use consumers who ultimately bear the costs of Seminole's mistakes.

Ms. Diazgranados's Exhibit JAD-2, titled "Seminole Need Gap Chart," shows the following:

a. In 2017, Seminole's "Total (Winter) Capacity Need <u>Including Reserve Requirements</u>" (underlining by the witness) was approximately 4,063 MW, but Seminole's resources totaled approximately 4,600 MW. Consumers were apparently paying for more than 500 MW of unneeded capacity.

b. In 2018, Seminole projects a Total Capacity Need, <u>Including Reserve Requirements</u>, of 3,986 MW, with consumers still paying for approximately 4,600 MW of resources.

c. In 2019, Seminole again projects a Total Capacity Need, Including Reserve Requirements, of 4,603 MW, with consumers still paying for approximately 4,600 MW of resources.

d. In 2020, Seminole projects a Total Capacity Need, Including Reserve Requirements, of 4,138 MW, with consumers having to pay for approximately 4,750-4,800 MW of capacity, such that consumers will still be paying for 600-plus MW of excess capacity.

The Commission should, of course, remember this is based on Seminole's historically inaccurate forecasts. In short, the consumers who depend on Seminole for bulk power supply have been paying for too much capacity for too long – the Commission should not allow Seminole to make it worse by adding 1,700 MW of unneeded, uneconomic capacity.

B. Need for Adequate Electricity at a Reasonable Cost

Q. Do you believe that the needs of Seminole, and of the end-use consumers who will be called upon to pay for Seminole's decisions, for adequate electricity at a reasonable cost, would be met by the proposed SCCF and SHCCF?

A. No, I do not. Seminole's proposed plan to build and pay for the SCCF and the SHCCF would impose tremendous costs and risks on the consumers who will have to pay for Seminole's decisions. Seminole did not provide annual revenue requirements for either the SCCF or the SHCCF as part of its filings, but using reasonable assumptions, it is safe to say that the additional capital revenue requirements would easily exceed $100 million or more per year. Since Seminole does not need these units for reliability purposes, it clearly does not need them to meet a need for adequate electricity.

Moreover, as explained below and elsewhere in my testimony, Seminole's own analyses show that Seminole's proposals will be more expensive for its customers over ***at least*** the first 10 years of Seminole's planning horizon, through at least 2027, and for at least some time thereafter. Given the large gap - $136 million – in CPVRRs between the All-PPA Portfolio and Seminole's proposed plan through 2027, I believe that it is highly likely that the savings (allegedly to be provided by more efficient generating technology at the SCCF and the SHCCF) would not catch up to the extra capital and operating costs of those units until sometime after 2030.

Q. What impacts would using more realistic projections of Seminole's energy requirements have on Seminole's projected need?

A. Energy requirements – the amount of energy load that a system must serve – generally do not impact the need for reliability in terms of having sufficient capacity to meet peak demands. However, energy requirements have a direct impact on the economics of generating resource choices, because the more an efficient plant runs, the more fuel savings it will produce, but the less it runs, the less savings it will produce. In this situation, Seminole's over-forecasting of its energy requirements will result in overstated fuel cost savings that would allegedly result from adding more efficient resources.

This is critical in this context, because Seminole's own analyses, presented in Exhibit No. JAD-6, which is included with my testimony as Exhibit No. ____ (PS-

8), shows that the energy savings that would allegedly be provided by the SCCF and SHCCF do not catch up to the significant additional capital and capacity costs of adding approximately 1,700 MW of capacity for at least 10 years. Ms. Diazgranados's Exhibit JAD-6 shows that, even after the first ten years of its proposed planning horizon, i.e., through 2027, the "No Build Risk" All-PPA Portfolio" is approximately $136 million less in CPVRRs than Seminole's proposed plan. This clearly demonstrates that the fuel savings don't catch up until sometime after 2027, and the availability of cost-effective purchased power options in this time frame should tell the Commission to reject Seminole's SCCF and SHCCF as proposed: at best, they might become economic if they were brought on line at later dates, but not in 2021 and 2022.

Q. Are there any other factors regarding either the SCCF or the SHCCF that cast doubt on whether they would actually contribute to consumers' needs for adequate electricity at a reasonable cost?

A. Yes. In the first instance, Seminole has not furnished projected revenue requirements by year for either project, on either a public or confidential basis. This makes any detailed analysis difficult, at best, although the summary information presented by Ms. Diazgranados clearly shows that postponing both units is in the best interests of Seminole and the end-use consumers ultimately served by Seminole's power supply. Seminole did furnish a total cost estimate for the SCCF, but I believe that that estimate is suspiciously low. Further, Seminole has not even furnished the Tolling Agreement by which it asserts it would obtain the SHCCF's capacity.

Q. Do you believe that Seminole's projected cost for the SCCF is reliable?

A. No, I do not. Seminole's projected cost of $727,000,000 for the SCCF combined cycle plant equates to approximately $648 to $692 per kW at the end of 2021. (The reason for the range given is that Seminole's petition indicates that the SCCF will have 1,050 MW of net nominal capacity, while the Sedway Consulting analysis of portfolios indicates that the SCCF will have winter capacity of 1,122 MW.) There is a readily available yardstick against which this can be measured, and that is Florida Power & Light Company's ("FPL") projected cost for what is essentially the same unit, FPL's proposed Dania Beach Clean Energy Center, which is projected to come on-line in June of 2022. FPL's projected costs must be considered a good yardstick because FPL has an extensive fleet of advanced-technology combined cycle plants, and obviously much greater experience building and operating such plants than Seminole. FPL's projected cost for the Dania Beach Clean Energy Center is $764 per kW, which is approximately 13 percent greater than Seminole's projected cost. My Exhibit No. ____ (PS-9) includes the cover sheet and the descriptive summary Schedule 9 from FPL's 2017 Ten Year Site Plan with this information. Using the greater capacity value of 1,122 MW for the SCCF indicates the lower cost per kW, i.e., $648 per kW, which appears to be comparable to FPL's value of $764 per kW for 1,163 MW of capacity. This lower cost value, $648 per kW, is approximately

15.2 percent less than FPL's value. The $692 per kW value is based on the 1,050 MW capacity value, which is still approximately 9.4 percent less than FPL's value.

Additionally, the installed cost of new advanced combined cycle plants reported by the U.S. Energy Information Administration ("EIA"), while not increasing in real terms during the 2010 to 2016 period, are reportedly in excess of $1000/kW, which makes the cost of the SCCF facility seem quite low relative to other similarly situated projects.

With the short time available to prepare my testimony, I have not had an opportunity to evaluate Seminole's estimates in detail, nor to examine any contracts that Seminole may have for the engineering, procurement, and construction of the SCCF.

What I can say at this point is that Seminole's claimed costs for the SCCF are suspect when compared to a known, reliable estimate from FPL. Additionally, Seminole's cost estimates in its 2017 Ten Year Site Plan for its own, albeit smaller, planned combined cycle plants were much greater, $942 per kW for its planned SGS CC Unit 1 with an in-service date of May 2021 and $980 per kW for its planned Unnamed Generating Station CC Unit 2 with an in-service date of December 2022, values that are much closer to the EIA values previously referenced. (These schedules are provided here as Exhibit No. ____ (PS-10). It is also worth noting that Seminole told the Commission that it was planning to construct both of these units less than a year ago, in its 2017 Ten Year Site Plan that was filed with the Commission on April 1, 2017.

Seminole's track record at forecasting its peak demands and energy requirements casts additional doubt on its ability to accurately predict power plant costs, especially without any information on the contract terms and conditions regarding the ability for the vendors and original equipment manufacturers ("OEMs") to pass on any additional costs to Seminole that may arise.

Q. Should the Commission give special attention to this issue in this case, because the petitioning utility is Seminole Electric Cooperative?

A. These concerns regarding Seminole's projected costs for the SCCF are especially significant for the Commission's consideration of Seminole's petitions in these consolidated dockets, because the PSC has no jurisdiction over any cost overruns that Seminole may experience. In other words, if the PSC were to sign off on the SCCF, or the SHCCF, or both, the end-use member-consumers of Seminole's member cooperatives would be entirely at the mercy of Seminole's projections and management; consumers would have no redress whatsoever before the Commission or any other agency or court to protect them from any overruns from the costs claimed by Seminole.

These facts further reinforce my concerns with Seminole's petitions in these consolidated dockets: Seminole's proposals, if allowed to proceed, would impose tremendous risks on the end-use consumers who would ultimately have to pay for the SCCF and the SHCCF. In my opinion, the risks of the Commission rejecting the petitions for the SCCF and the SHCCF are dramatically less than the risks of allowing Seminole to proceed.

Q. Do you have comparable concerns regarding the SHCCF?

A. Yes, but those concerns may be allayed by reviewing the Tolling Agreement, whenever it is made available to us through the discovery process. As of now, it is difficult to understand why or how a smaller combined cycle unit would have costs as low as a larger CC unit like FPL's Dania Beach Clean Energy Center, and so it is difficult to understand how or why, if at all, a private sector company like GE would agree to pricing that could be favorable compared to other options, but as I said, these are concerns that may be allayed by reviewing the Tolling Agreement.

C. Need for Fuel Diversity and Supply Reliability

Q. What impact, if any, do you believe that Seminole's proposed plans to add the SCCF and the SHCCF and close one of Seminole's coal plants would have on fuel diversity and supply reliability?

A. In the relevant time frame, it is clear that closing one of Seminole's coal units at the SGS would impact fuel diversity in that Seminole's portfolio would be even more heavily invested in natural gas. With regard to supply reliability, a shift toward more natural gas likely does not cause any issues as new pipeline capability via the Sabal Trail Pipeline to bring natural gas from the Marcellus and Utica shale plays in Pennsylvania, West Virginia, and Ohio has recently gone into service. However, given the availability of hundreds of MW of additional capacity through PPAs (as discussed above and shown in the exhibits to Mr. Taylor's testimony), if Seminole opts to close one of its coal units, it would be most economical to replace such capacity for at least several years with additional PPAs and understand there would be no fuel supply reliability issue if those options included gas-fired facilities, and they would have lower fuel costs according to Seminole's fuel price forecast, and certainly lower fixed O&M costs than any one of the Seminole coal units.

D. Conclusions Regarding the Need for the SCCF and the SHCCF

Q. What is your professional opinion as to whether Seminole needs the SCCF or the SHCCF, or both, to meet the needs of the end-use consumers who will have to bear the costs of Seminole's and the Commission's decisions?

A. Seminole does not need either the SCCF or the SHCCF to meet consumers' needs for reliable service or for reasonably priced electricity. Seminole has much more economical options available.

IV. COST-EFFECTIVENESS

Q. In your experience, how do utilities plan for new generating resources?

A. Generally, utilities determine whether they need additional capacity for reliability purposes. Occasionally, new plants or resources are considered if their addition will result in lower costs to consumers. After reliability needs are addressed, the utility will generally evaluate numerous options to determine which is most cost-effective, taking cost risk and other risk factors into account.

Q. Do you believe that either the proposed SCCF or the proposed SHCCF represents the most cost-effective alternative to meet Seminole's need for

reliability and bulk power supply for its member cooperatives and their end-use member-consumers at the "lowest feasible cost?"

A. No, I do not. Seminole's own analyses show that whatever fuel savings may accrue from the SCCF and SHCCF, which are allegedly more efficient than other available resources, will not outweigh the additional capital and operating costs of those units, on a CPVRR basis, until sometime after 2027. Again, this is clearly demonstrated by the fact that Seminole's All-PPA Portfolio, even using Seminole's own dubious forecasts, is significantly more cost-effective than Seminole's proposed plan until sometime after 2027. This is a painfully obvious demonstration that Seminole would be better off to postpone construction of these expensive units.

Q. Isn't it true that most Florida utilities use a 30-year time horizon for evaluating the cost-effectiveness of major power plant commitments on a CPVRR or NPVRR basis? If so, why should the Commission reject Seminole's proposal to use a 30-year analysis period in these cases?

A. Yes, it is true that most utilities use a 30-year time horizon, or analysis period, for evaluating the cost-effectiveness of proposed major expenditures, typically power plants.

However, the dramatic, consistent, and persistent errors in Seminole's forecasts all militate toward using a shorter analysis period in these cases. In the simplest terms, if Seminole continues to ***overstate*** its peak load and total energy forecasts, as it has in virtually every cycle for the ***past twelve (12) years***, postponing the major commitments and expenditures that Seminole is proposing in these dockets would give Seminole valuable and needed time to better understand its future needs. From the perspective of retail consumers, this is obviously the sensible course of action, and the course that is in the best interests of the end-use member-consumers who would ultimately bear the costs that Seminole proposes to incur.

Furthermore, a utility such as Seminole could still plan 30 years out, but break the 30-year horizon up into smaller periods, e.g., 2018-2027, 2028-2037, and 2038-2047, where shorter-term options could be used in the near term and large capital investments could be undertaken later, if determined to be cost-effective at that time. Such an option should lead to even lower costs than Seminole has shown for its evaluated options, but Seminole chose not to evaluate such an option, it seems.

Q. What impact would deferring or postponing decisions to commit to the SCCF or the SHCCF, or both, have on the cost-effectiveness of long-term power supply for the end-use consumers who will have to pay for Seminole's resource decisions?

A. Deferring or postponing decisions to commit to the SCCF or the SHCCF, or both, for at least several years, would improve the cost-effectiveness – measured in CPVRRs – of such projects, even if Seminole's forecasts were to turn out to be relatively accurate. In other words, delay will improve the CPVRRs of these options, if they are ever determined to be needed and economic. This is because Seminole's discount rate of 6 percent is significantly greater than current, reasonable, and known escalation rates in the cost of new combined cycle capacity; said differently, any cost escalation would be more than offset by present value savings as measured by

Seminole's discount rate of 6 percent. Nationally, combined cycle costs have been flat or slightly declining during the 2010 to 2016 period according to the United States Energy Information Administration. This is shown in Exhibit No. ____ (PS-11) to my testimony. Within Florida, FPL's "annual escalation rate associated with the plant cost of the Company's Avoided Unit," which is 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" is 2.0%, and FPL's corresponding annual escalation rate for O&M costs is 2.50%. This information is shown in my Exhibit No. ____ (PS-12), which consists of copies of FPL's Tariff Sheet No. 10.311 and Sheet No. 10.311.1. The fact that these escalation rates are realistically projected, by a utility with tremendous expertise and experience with these matters, to be significantly less than Seminole's discount rate demonstrates that deferring these decisions will reduce CPVRR impacts.

V. BEST INTERESTS OF CONSUMERS, INCLUDING RISK FACTORS

Q. What does Seminole claim regarding its consideration of risk factors in its planning processes?

A. Seminole, through the testimony of Ms. Diazgranados (at page 9), asserts that "Seminole's staff performed risk analysis on both individual alternatives and each of the remaining portfolios," and that Seminole "produced scorecards for each portfolio which not only took into account a weighted risk rating but also a strategic rating" and other factors. However, as far as I can determine, Seminole has not provided any details of its asserted "weighted risk rating" in its filings, so I cannot tell what risk factors Seminole may have considered or how they applied them.

Seminole, again through Ms. Diazgranados's testimony (at page 5), then claims that its chosen plan – adding the SCCF and SHCCF, with some PPAs – is "[t]he "most cost-effective, risk-managed resource plan for Seminole to meet the future needs of our Members" and presumably those Members' end-use member-consumers.

Q. As an experienced energy, utility, and regulatory economist, how would you examine risk from the perspective of consumers?

A. From the perspective of the consumers who will have to bear the consequences of the utility's decisions, I would first and foremost examine the reliability and cost risks of alternatives. I would also examine the flexibility that any option affords the utility to deal with uncertainties and future contingencies. In this case, I believe that any of the alternatives, particularly Seminole's proposed plan and the "No Build Risk: All-PPA Portfolio" identified and supposedly considered by Seminole, will meet Seminole's realistic reliability needs.

That leaves me to examine the cost risks and flexibility of alternative plans. Here, the cost risk tells me, and should tell the Commission, that Seminole should have chosen the All-PPA Portfolio or something a lot like it, with only PPAs for the next 7 to 10 years, or longer. This is obvious, because at best, even Seminole's own analyses show that the fuel cost savings from the SCCF and the SHCCF, if they materialize at all, would not outweigh the additional capital and operating costs associated with those units until sometime after 2027.

Further, using an All-PPA Portfolio for the next 7 to 10 years (or longer) would give Seminole the opportunity to carefully evaluate its flawed forecasting processes and methodologies and try to get those right and incorporate the results into improved, more accurate forecasts. It would also give Seminole the opportunity to observe the track record of the new H-class technology and to see whether additional improvements in generating technologies come about, e.g., further improvements in combustion turbine-combined cycle technology, solar with battery storage, and other options. It would, of course, also give Seminole the opportunity to gather additional information about the electricity demands of its ultimate end-use consumers, as those evolve with new opportunities for energy conservation and end-use renewable generation opportunities.

It is important to note that choosing the All-PPA Portfolio for the next 7 to 10 years (or longer) would not result in Seminole forever giving up the opportunity to add a plant like the SCCF, or the SHCCF, at some point in the future. I believe that it is completely safe to say that GE and any other major manufacturer of generating equipment, e.g., combustion turbines, heat recovery steam generators, and steam turbine generators, would be more than happy to sell Seminole or any other utility that equipment for an in-service date in the middle or late 2020s. I further believe that it is completely safe to say that entities like GE Shady Hills would be happy to make proposals to sell power from new facilities like the SHCCF under long-term PPAs, or tolling agreements, beginning in that time frame.

The Commission should also note that delay will improve the CPVRRs of these options, if they are ever determined to be needed and economic. This is because

Seminole's discount rate of 6 percent is significantly greater than current, reasonable, and known escalation rates in the cost of new combined cycle capacity. For example, as shown in my Exhibit No. ____ (PS-12), FPL's escalation rates for both plant costs (2.0% per year) and O&M costs (2.50% per year) are significantly less than Seminole's discount rate of 6.0%. The fact that these costs are realistically expected, by a utility with significant expertise on these matters, to escalate at rates significantly less than Seminole's discount rate demonstrates that deferring these decisions will reduce CPVRR impacts.

Q. What value do you attribute to the "optionality" characteristics of Seminole choosing an All-PPA Portfolio for the next several years?

A. If Seminole were to proceed with an All-PPA Portfolio, it would preserve options for itself, and for the consumers who must pay for Seminole's decisions, to choose smaller resources rather than larger ones, with shorter or medium term financial commitments, as compared to the 30-year-plus commitment to the SCCF and the 20-year commitment to the SHCCF under the proposed Tolling Agreement. There are simply lower risks associated with a portfolio of smaller, shorter PPAs, than with long-term commitments like the SCCF and the SHCCF. Further, proceeding with the All-PPA Portfolio and deferring decisions on long-term projects like the SCCF and the SHCCF preserves additional options for Seminole to take advantage of improvements in generating technologies, including potential further improvements in combustion turbine or combined cycle technologies and improvements in other generating and power supply technologies such as solar with battery storage.

And again, Seminole's own analyses show that the All-PPA Portfolio is more cost-effective that Seminole's proposed SCCF-SHCCF plan until at least some time after 2027. Thus, the Commission should not worry that deferral will result in increased costs to the consumers who will be paying for these decisions.

Q. The PSC is also responsible to supervise the bulk power supply grid to avoid the uneconomic duplication of generating facilities. What, if anything, can you say about this factor relative to the SCCF and the SHCCF?

A. Given the significant amount of capacity – hundreds of MW – offered to Seminole from existing generating resources, mostly if not entirely in Florida, and again given the fact that Seminole's All-PPA Portfolio is more cost-effective than the SCCF/SHCCF portfolio until sometime after 2027, it is apparent that, at least over the next 10 years, the construction of the SCCF and the SHCCF would result in the uneconomic duplication of generating resources, not only for the end-use consumers who will have to pay for the new plants but also for Florida as a whole. The statutory reference here is to Section 366.04(5), Florida Statutes, which explicitly vests the Commission with the jurisdiction over the grid to assure adequate and reliable power supplies and the avoidance of further uneconomic duplication of generation and other facilities. I am not presenting a legal argument here: I am simply making the point that the Commission, as a matter of good economic sense and sound public policy as articulated by the Florida Legislature, has the authority to prevent uneconomic duplication of generating resources, and it is my opinion that the Commission should do exactly that in these consolidated cases.

VI. ADVERSE EFFECTS OF DENYING OR GRANTING THE REQUESTED NEED DETERMINATIONS

Q. Seminole asserts that there would be adverse consequences of the Commission denying its petitions for determination of need for the SCCF and the SHCCF. Do you agree with Seminole's assertions?

A. No, I do not. Seminole asserts that there would be adverse effects on reliability and the cost of power supply if the Commission were to deny the need petitions for the SCCF and the SHCCF. To the contrary, denying these need petitions will ensure that the consumers who must bear the consequences of these decisions – both Seminole's and the Commission's decisions – will be better off economically until at least sometime after 2027. The amount of the benefits to consumers will ultimately depend on the actual levels of peak demands and energy requirements, but even if Seminole's forecasts are accurate – which is extraordinarily unlikely given its abysmal track record – Seminole's own analyses show that customers would be better off with an All-PPA Portfolio, by $136 Million through 2027. If Seminole's forecasts are overstated, like its forecasts from the past twelve years, consumer savings will likely be even greater, because the PPA costs of meeting lower power supply requirements in this next decade would be even less.

Q. So are you saying that there would actually be benefits to consumers of denying the need petitions for the SCCF and the SHCCF?

A. Yes. The benefits would be at least the savings of $136 Million in CPVRRs from Seminole using the All-PPA Portfolio until at least the mid-2020s – until sometime after 2027 if Seminole's projections are accurate, probably longer.

And the Commission should note that this means that there will be ***significant adverse consequences of granting the requested need petitions*** for the SCCF and the SHCCF. Again considering Seminole's own forecasts and analyses, those adverse consequences would be at least an additional $136 Million in power supply costs, on a CPVRR basis, through 2027. Beyond those impacts, consumers would be deprived of potential advances and improvements in generating technologies, including gas-fired, solar, and potentially other technologies, because Seminole would then be locked into its proposed overly expensive portfolio with the SCCF and SHCCF.

CONCLUSIONS

Q. Please state the main conclusions of your testimony.

A. 1. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for system reliability and integrity.

2. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for adequate electricity at a reasonable cost.

3. Seminole does not need either the SCCF or the SHCCF, as of their proposed in-service dates, to meet the needs of the consumers who would be obligated to pay for those plants for fuel diversity and supply reliability. In fact, taking a coal plant out of service, while probably desirable in some respects, is contrary to the need for fuel diversity.

4. Seminole's proposals to add the SCCF and SHCCF to its generating resources do not represent the most cost-effective alternative for meeting the needs of the consumers who would be obligated to pay for those plants.
5. Indeed, adding these two projects in the times proposed will impose significantly greater risks on those consumers than if Seminole were to continue using the resources it has available through at least 2024.
6. Seminole's forecasting methodologies are so flawed that they are not reliable for decisions that would commit billions of dollars of consumers' money for future power supply options.
7. The All-PPA Portfolio, or a similar variant using only PPAs to meet Seminole's needs (to the extent even necessary) over the next 7 to 10 years (or longer), would minimize risks to consumers and be in the best interests of Seminole's consumers and the public interest generally.
8. If the Commission were to grant the need petitions requested here for the SCCF and the SHCCF, there would be adverse consequences to the consumers who depend on Seminole for their bulk power supplies. Stated differently, there would be benefits to consumers of denying Seminole's petitions for the SCCF and the SHCCF.

Q. What is your specific recommendation to the Commission with respect to the petitions for determination of need for the SCCF and the SHCCF?

A. My recommendation is that the Commission should deny both petitions as proposed by Seminole and Shady Hills. While it may be desirable for Seminole to eventually add physical generating capacity to its resource mix, Seminole cannot credibly show that it needs approximately 1,700 MW of new gas-fired capacity (or any other kind of capacity) to meet its alleged needs, which are based on its dramatically flawed forecasting record. The Commission should invite Seminole to correct its forecasting methodologies and come back to the Commission with appropriate need petitions in the future. This will benefit the end-use consumers who would be called upon to pay for these plants by reducing risks and reducing costs well into the future.

The Commission should keep clearly in mind that Seminole's own analyses show that an All-PPA Portfolio has significantly lower costs – CPVRRs – than Seminole's proposed portfolio for at least the first 10 years of Seminole's planning horizon. Waiting will allow for additional improvements in generating technology and for Seminole to correct its forecasting methodologies and to plan for other variables – e.g., carbon taxation or greenhouse gas regulation, additional penetration of conservation and end-use solar measures, and battery storage for solar generation alternatives – before committing to a multi-billion dollar resource plan on the basis of flawed forecasting.

Accordingly, the Commission should deny the petitions for determination of need for the SCCF and the SHCCF as proposed.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: PETITION FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY, DOCKET NO. 20170266-EC

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR SHADY HILLS GENERATING FACILITY, DOCKET NO. 20170267-EC

EXHIBITS

OF

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ON BEHALF OF QUANTUM PASCO POWER, L.P., MICHAEL TULK, AND PATRICK DALY

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EDUCATION

PhD, Economics, University of Minnesota, 2003
M.A., Economics, University of Minnesota, 1995
B.A. (High Honors), History/Economics, University of Florida, 1991

PROFESSIONAL AND ACADEMIC EXPERIENCE

2016- President and Founder, E-Cubed Policy Associates, LLC

- Founded to provide expert advice, testimony, and policy research to private sector and government clients at the intersection of energy, environmental, and economic policy and regulation
- Support merchant generation developers through the interconnection queue process and provide economic, policy, and regulatory advice and due diligence
- 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
- Regulatory policy and electricity market design advice and guidance as well as regulatory testimony for power and gas industry trade associations

2015-2016 Contractor, YOH Inc. and working under the title of Senior Economic Policy Advisor, PJM Interconnection, L.L.C., Audubon, Pennsylvania

2010-2015 Chief Economist, Market Services Division, PJM Interconnection, L.L.C., Audubon, Pennsylvania
2008-2010 Senior Economist, Market Services Division, PJM Interconnection, L.L.C., Norristown, Pennsylvania

- 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

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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

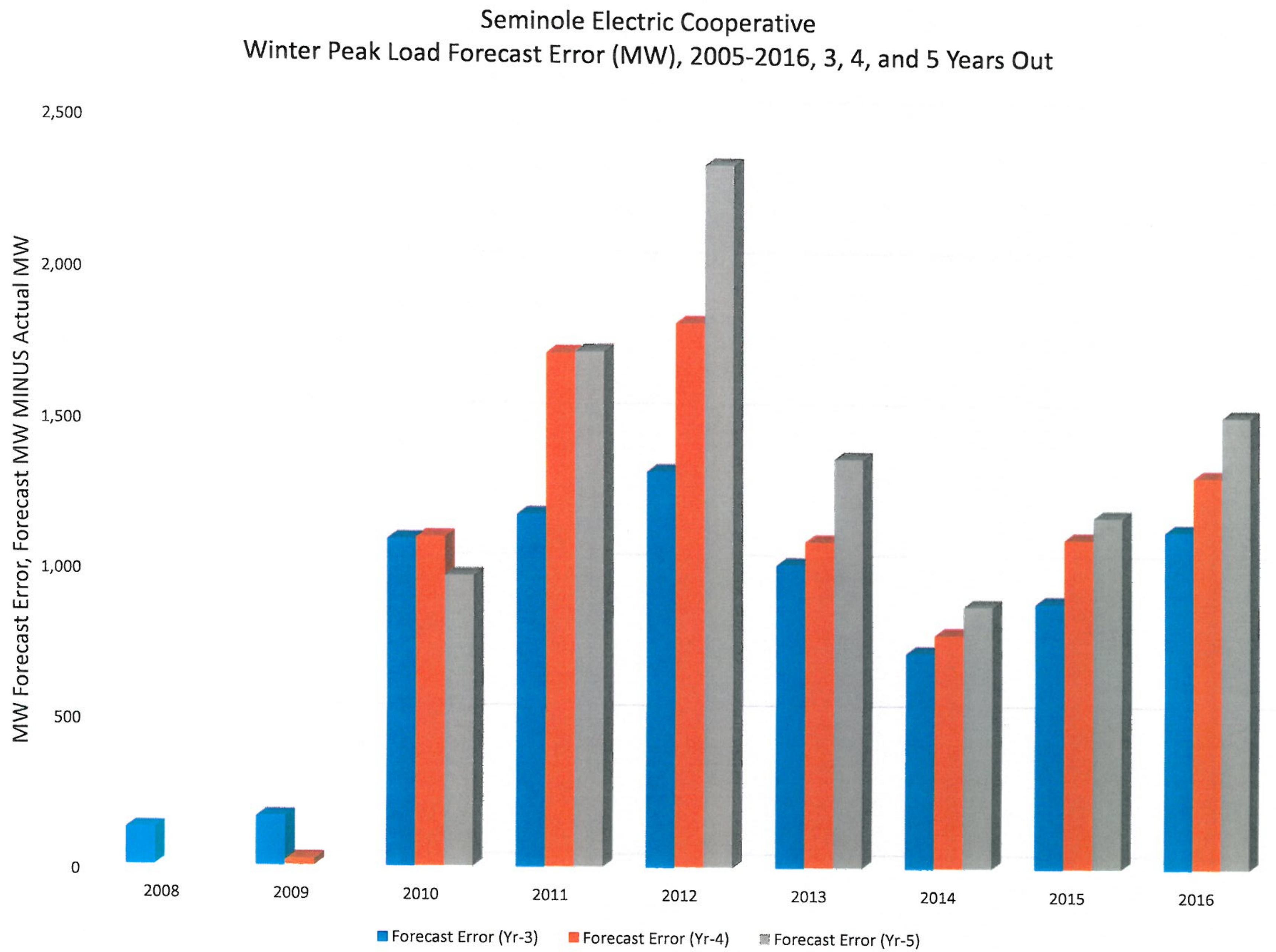
Seminole Electric Cooperative
Summary of Winter Peak Load Forecast Errors, 2005-2016
Megawatts & Percentages
(Forecast MW in Plan Year MINUS Actual MW in Given Year)

	Differences in MW		
	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			125
2009		21	166
2010	970	1,099	1,092
2011	1,715	1,708	1,177
2012	2,335	1,808	1,318
2013	1,362	1,087	1,010
2014	874	779	719
2015	1,174	1,099	885
2016	1,511	1,308	1,128
Average	1,420	1,114	847

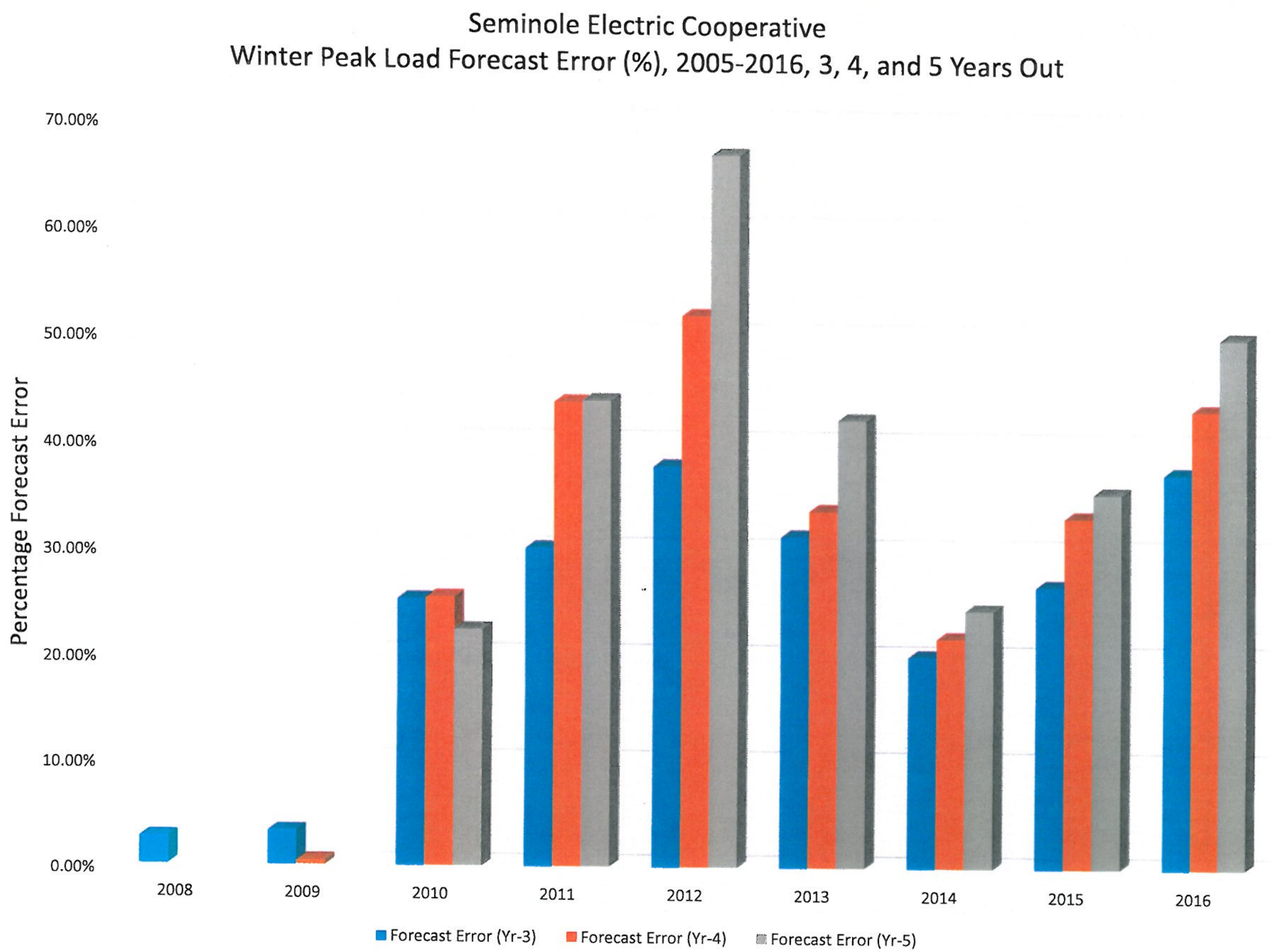
	Percentage Differences		
	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			2.64%
2009		0.42%	3.29%
2010	22.48%	25.47%	25.31%
2011	43.95%	43.77%	30.16%
2012	67.00%	51.88%	37.82%
2013	42.27%	33.74%	31.35%
2014	24.47%	21.81%	20.13%
2015	35.50%	33.23%	26.76%
2016	50.07%	43.34%	37.38%
Average	40.82%	31.71%	23.87%

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 2016.



Docket No. 20170266-EC
Summary of Seminole's Winter Peak Forecast Errors, 2005-2016
Exhibit ____ (PS-2), Page 2 of 3



Docket No. 20170266-EC
Summary of Seminole's Winter Peak Forecast Errors, 2005-2016
Exhibit ____ (PS-2), Page 3 of 3

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

	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			112
2009		71	176
2010	508	609	604
2011	652	646	378
2012	1,010	753	629
2013	799	704	582
2014	631	549	412
2015	713	557	329
2016	439	218	69
Average	679	513	366

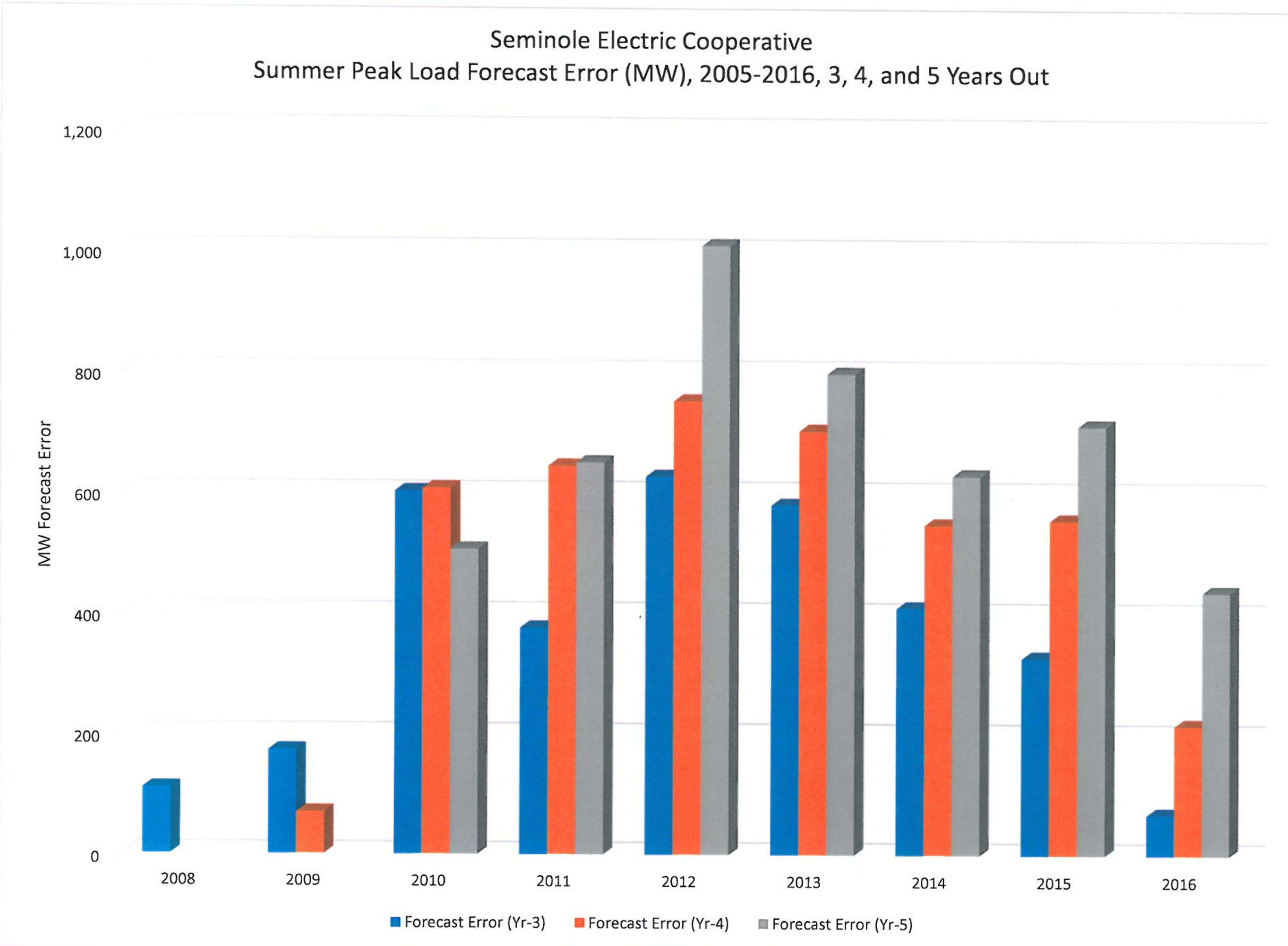
Percentage Differences

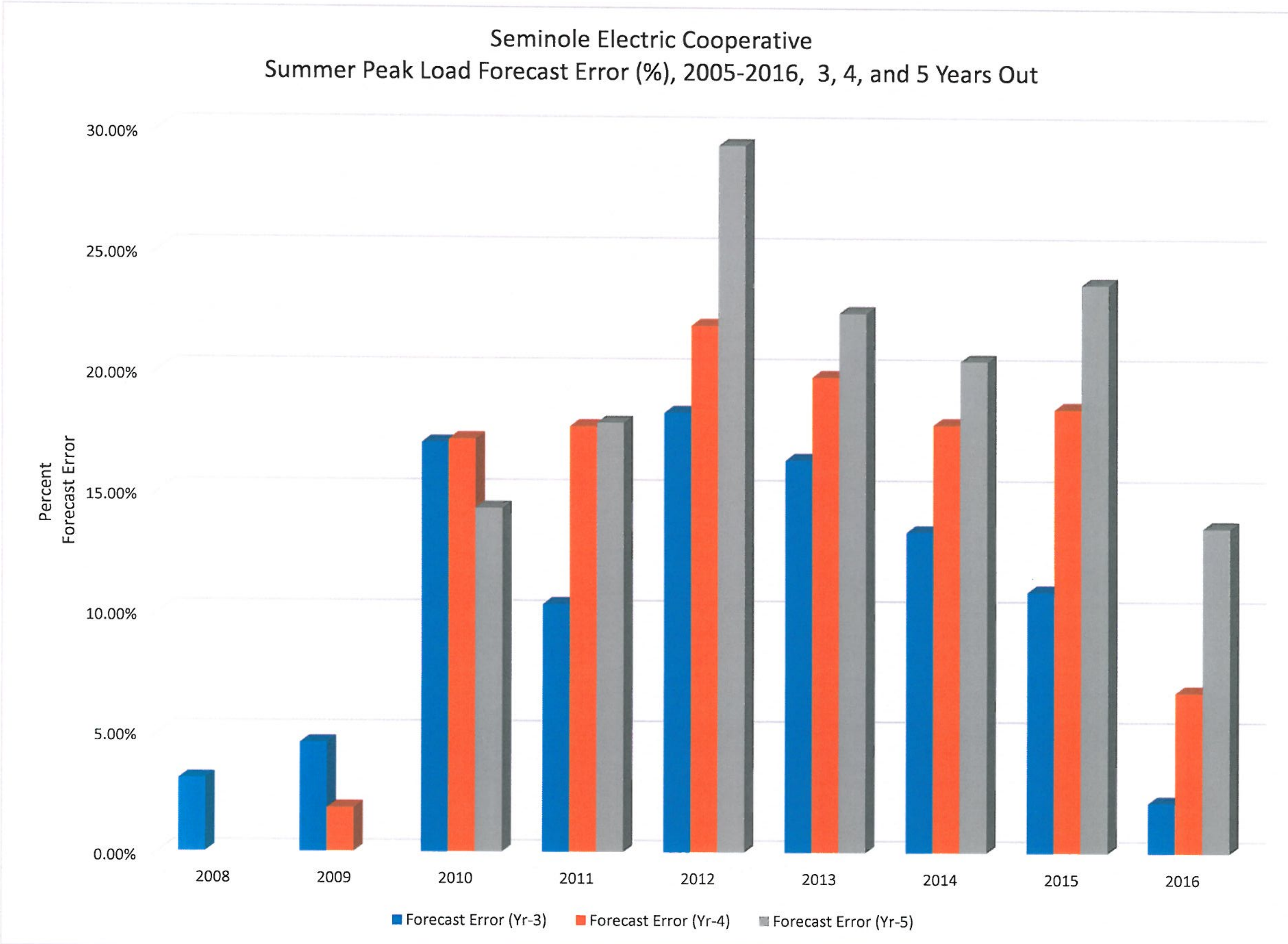
	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			3.09%
2009		1.86%	4.60%
2010	14.32%	17.16%	17.02%
2011	17.85%	17.68%	10.35%
2012	29.33%	21.86%	18.26%
2013	22.41%	19.74%	16.32%
2014	20.43%	17.78%	13.34%
2015	23.60%	18.44%	10.89%
2016	13.54%	6.72%	2.13%
Average	20.21%	15.16%	10.67%

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 2016.

Docket No. 20170266-EC
Summary of Seminole's Summer Peak Forecast Errors, 2005-2016
Exhibit ___ (PS-3), Page 2 of 3




Seminole Electric Cooperative
Summer Peak Load Forecast Error (%), 2005-2016, 3, 4, and 5 Years Out
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
Percent
Forecast Error
2008
2009
2010
2011
2012
2013
2014
2015
2016
Forecast Error (Yr-3)
Forecast Error (Yr-4)
Forecast Error (Yr-5)

Docket No. 20170266-EC
Summary of Seminole's Total Energy Requirements Forecast Errors, 2005-2016
Exhibit ___ (PS-4), Page 1 of 3

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)

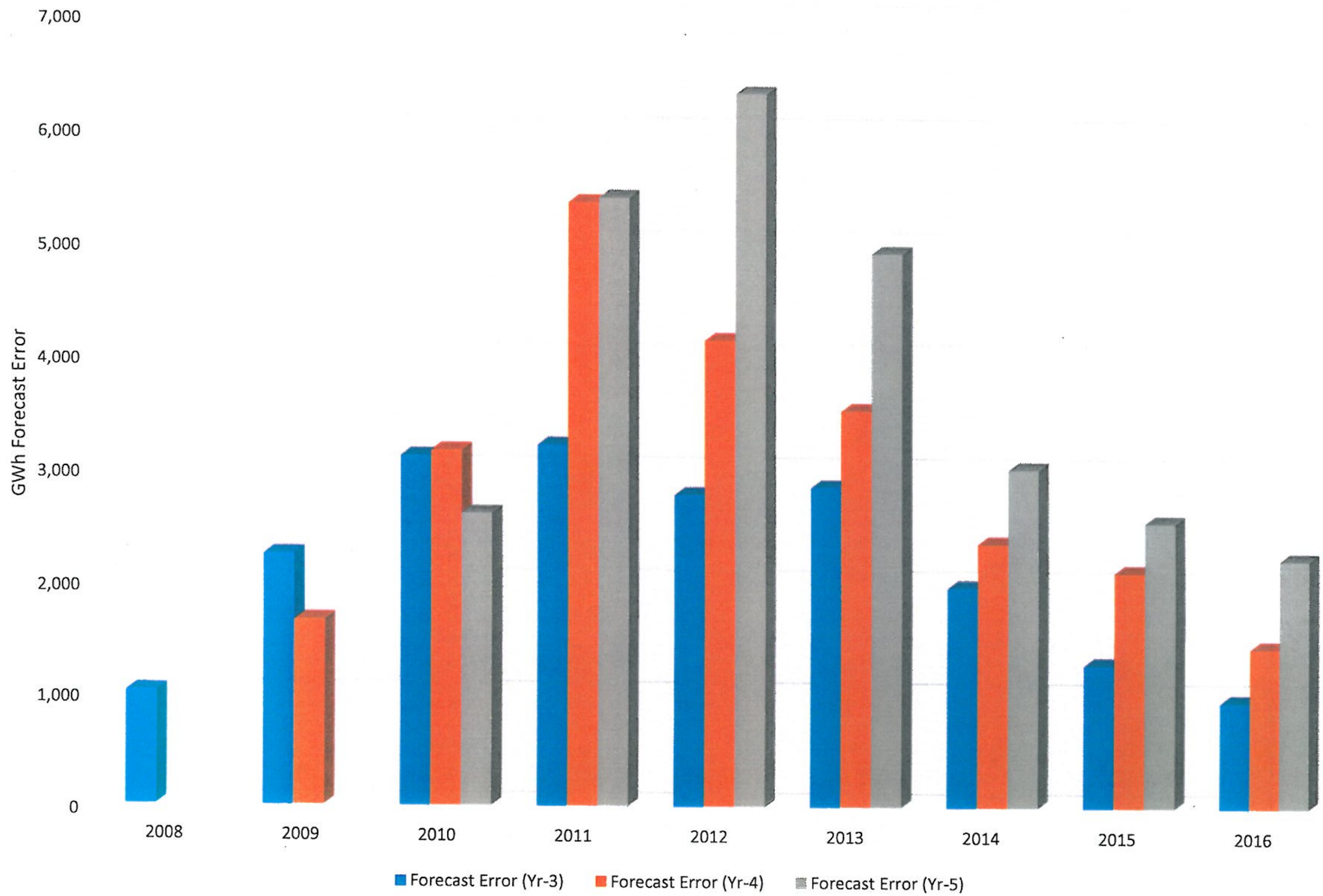
	Difference in GWh		
	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			1,029
2009		1,674	2,248
2010	2,614	3,168	3,123
2011	5,411	5,365	3,222
2012	6,338	4,150	2,787
2013	4,932	3,528	2,859
2014	3,024	2,358	1,974
2015	2,552	2,108	1,286
2016	2,222	1,435	963
Average	3,870	2,973	2,166

	Percentage Differences		
	5 Years Out	4 Years Out	3 Years Out
2005			
2006			
2007			
2008			5.94%
2009		9.59%	12.88%
2010	15.07%	18.26%	18.00%
2011	34.07%	33.78%	20.29%
2012	40.19%	26.32%	17.67%
2013	31.19%	22.31%	18.08%
2014	21.83%	17.02%	14.25%
2015	18.09%	14.95%	9.12%
2016	15.35%	9.92%	6.65%
Average	25.11%	19.02%	13.65%

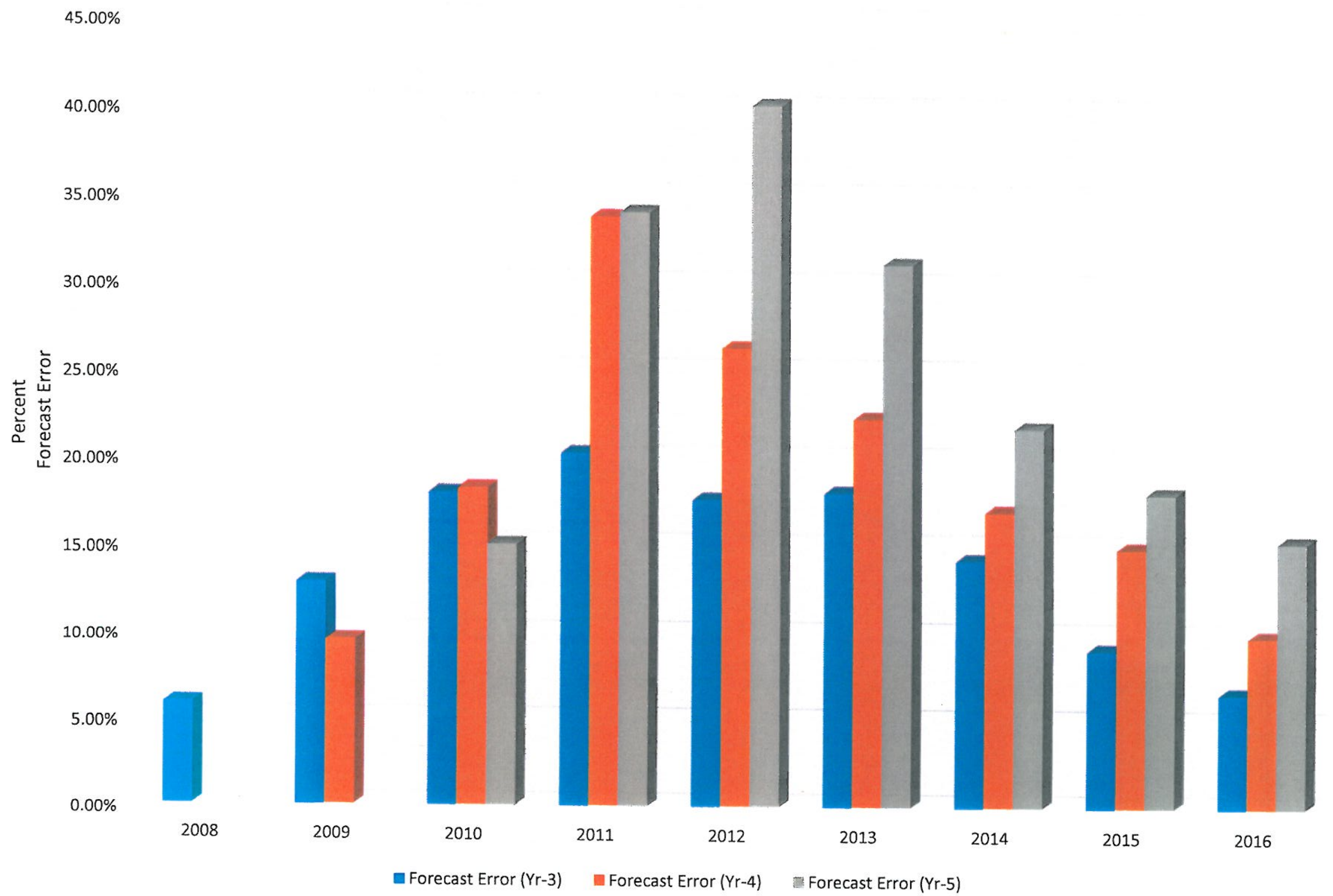
NOTES: Positive values indicate forecast GWh was greater than actual GWh in the forecast year; negative values indicate forecast was less than actual in the forecast year.
SOURCES: Seminole Electric Cooperative Ten Year Site Plans, 2005 through 2016.

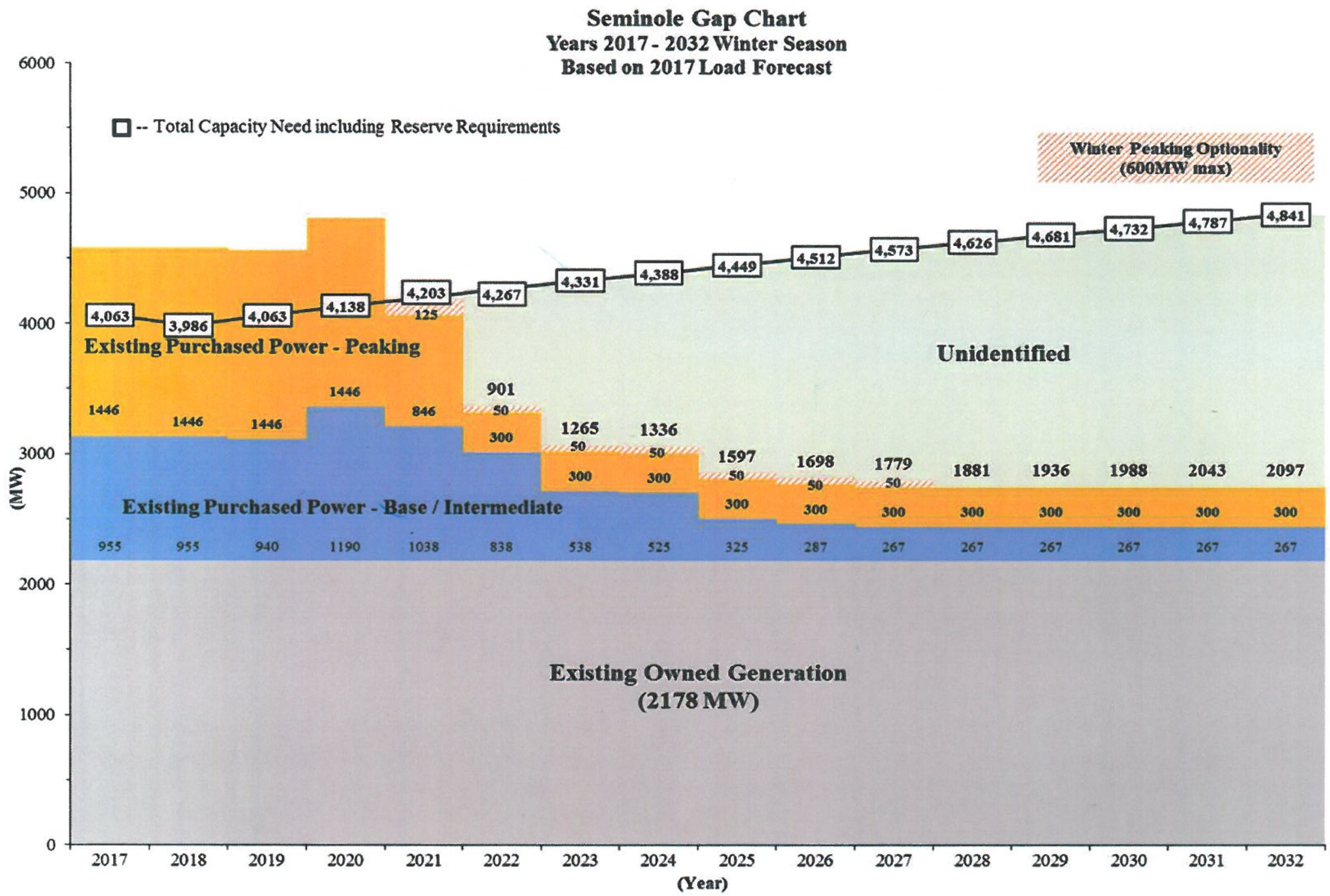
Docket No. 20170266-EC
Summary of Seminole's Total Energy Requirements Forecast Errors, 2005-2016
Exhibit ___ (PS-4), Page 2 of 3

Seminole Electric Cooperative
Energy Load Forecast Error (GWh), 2005-2016, 3, 4, and 5 Years Out



Seminole Electric Cooperative
Energy Load Forecast Error (%), 2005-2016, 3, 4, and 5 Years Out





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

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

					Residential		Commercial		
Year	Total	Whole-sale	Retail	Distributed Generation	Load Manage-ment (1)	Conser-vation	Load Manage-ment	Conser-vation	Net Firm Demand
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

					Residential		Commercial		
Year	Total	Whole-sale	Retail	Distributed Generation	Load Manage-ment 1	Conser-vation	Load Manage-ment	Conser-vation	Net Firm Demand
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.

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 Load Manage-ment [1]	Residential Conser-vation	Commercial Load Manage-ment	Commercial Conser-vation	Net Firm Demand
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. Forccast data is the maximum amount available.

Seminole Electric
COOPERATIVE, INC.

Schedule 3.2.1

History and Forecast of Winter Peak Demand (MW)

Base Case

Year	Total	Whole-sale	Retail	Distributed Generation	Residential Load Management [1]	Residential Conservation	Commercial Load Management	Commercial Conservation	Net Firm Demand
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: Load Manage-ment (1)	Residential: Conser-vation	Commercial: Load Manage-ment	Commercial: Conser-vation	Net Firm Demand
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 Load Manage-ment 1	Residential Conser-vation	Commercial Load Manage-ment	Commercial Conser-vation	Net Firm Demand
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

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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

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

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

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

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

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.
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Ten Year Site Plan

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Seminole Electric
COOPERATIVE, INC.

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 Load Mgmt.	Residential Cons.	Commercial Load Mgmt.	Commercial Cons.	Net Firm Demand
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
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Ten Year Site Plan

2012 - 2021
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COOPERATIVE, INC.

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

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
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

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 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

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

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.

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 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.

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

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 Load Mgmt.[3]	Residential Cons.	Commercial Load Mgmt.[3]	Commercial Cons.	Net Firm Demand[4]
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

Seminole Electric
COOPERATIVE, INC.

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

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 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

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	11,571
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

Ten Year Power Plant Site Plan
2017 – 2026

FPL

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.

Ten Year Site Plan

2017 – 2026

(Detail as of December 31, 2016)

April 1, 2017

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

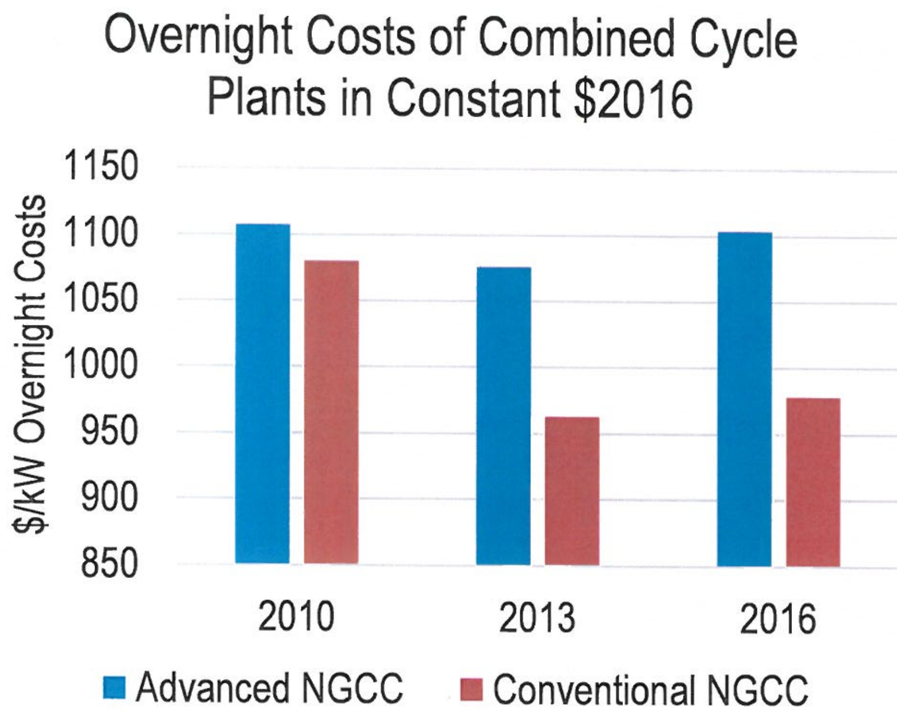
Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
1	Plant Name & Unit Number	Unnamed Generating Station CC Unit 2
2	Capacity a. Summer (MW): b. Winter (MW):	 593 592
3	Technology Type:	Combined Cycle
4	Anticipated Construction Timing a. Field construction start-date: b. 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

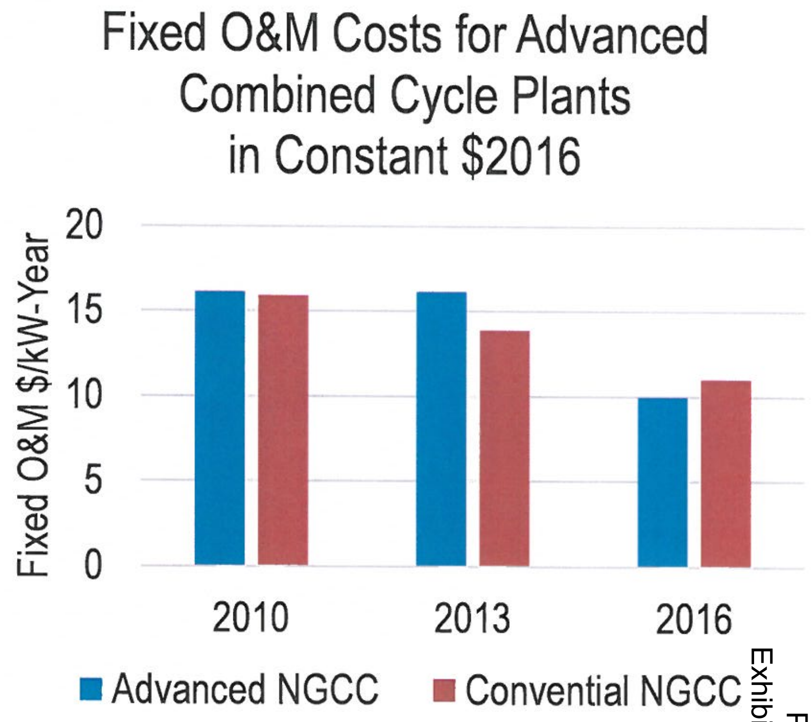
Does it Matter if the Clean Power Plan Goes Away?...Probably Not

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

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



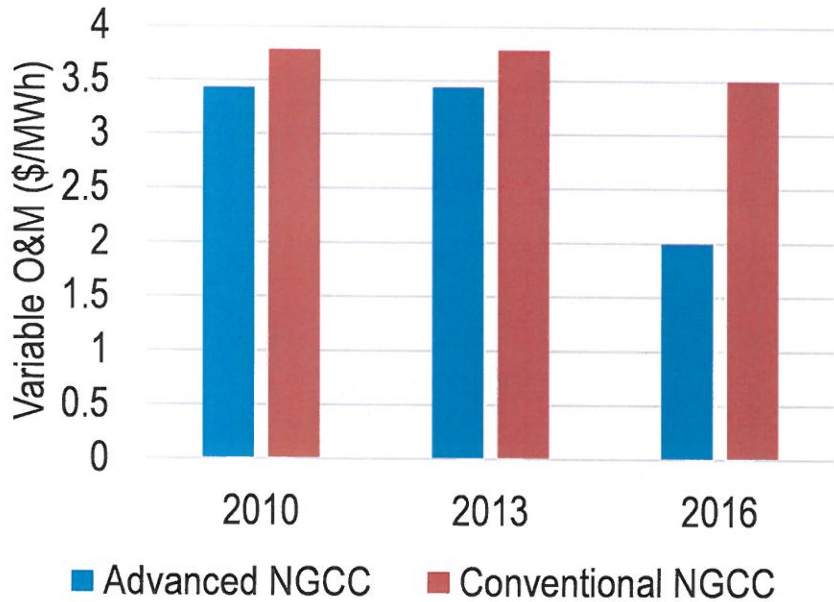


CPI inflation was 10% between 2010 and 2016…combined cycle costs are flat to declining

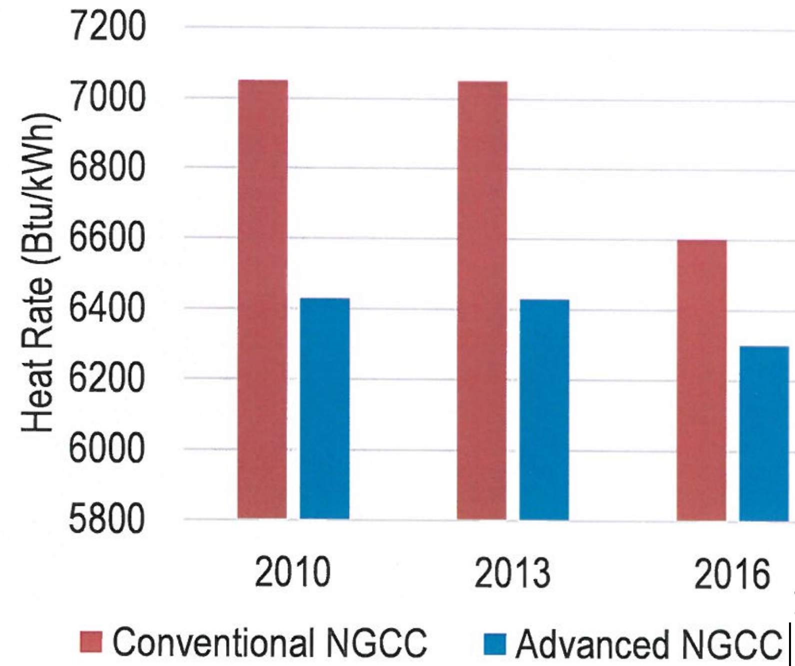
<u>Source:</u> United States Energy Information Administration, Capital Costs Reports 2010, 2013, 2016. CPI used to compare in constant dollars.

E-Cubed Policy Associates, LLC

Natural Gas Combined Cycle Variable O&M Costs in Constant $2016



Natural Gas Combined Cycle Heat Rates over Time



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 3 of 3

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.

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was furnished to the following by electronic mail on this 29th day of January 2018.

Rachael Dziechciarz (rdziechc@psc.state.fl.us)
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