Hopping Green & Sams
Attorneys and Counselors

December 21, 2017

BY ELECTRONIC FILING

Carlotta S. Stauffer, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: *Petition of Seminole Electric Cooperative, Inc., for Determination of Need for Seminole Combined Cycle Facility*, Docket No._________-EC

Dear Ms. Stauffer:

Enclosed for filing on behalf of Seminole Electric Cooperative, Inc., are electronic copies of the following:

- Petition to Determine Need for Seminole Combined Cycle Facility in Putnam County by Seminole Electric Cooperative, Inc.;

- Pre-filed Direct Testimony of **Michael P. Ward II** with Exhibit Nos. __ (MPW-1 through MPW-4);

- Pre-filed Direct Testimony of **David Kezell** with Exhibit Nos. __ (DK-1 through DK-6);

- Pre-filed Direct Testimony of **Robert DeMelo** and Exhibit No. __ (RD-1);

- Pre-filed Direct Testimony of **David Wagner** and Exhibit Nos. (DW-1 & DW-2);

- Pre-filed Direct Testimony of **Kyle D. Wood** with Exhibit No. __ (KDW-1);

- Pre-filed Direct Testimony of **Jason Peters** and Exhibit No __ (JP-1);

- Pre-filed Direct Testimony **Julia Diazgranados** and Exhibit Nos. __ (JAD-1 through JAD-6);

- Pre-filed Direct Testimony of **Alan S. Taylor** and Exhibit Nos. __ (AST-1) (confidential portions redacted; and

- Pre-filed Direct Testimony of **Thomas Hines** and Exhibit Nos. (TH-1 through TH-3).

Please acknowledge receipt and filing of the above by return email or other means. If you have any questions concerning this filing, please contact me at 425-2359.

Thank you for your assistance in this matter.

Very truly yours,

HOPPING GREEN & SAMS, P.A.

By: s/*Gary V. Perko*______________
Gary V. Perko

Counsel for SEMINOLE ELECTRIC COOPERATIVE, INC.

GVP/
Enclosures
cc: Lee Eng Tan, Esquire (PSC)
Thomas Ballinger (PSC)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Seminole Electric Cooperative, Inc., for Determination of Need for Seminole Combined Cycle Facility.	DOCKET NO. 2017__________ DATE: December 21, 2017

PETITION FOR DETERMINATION OF NEED FOR
SEMINOLE COMBINED CYCLE FACILITY

Pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code ("F.A.C."), Seminole Electric Cooperative, Inc. ("Seminole"), by and through its undersigned counsel, hereby petitions the Florida Public Service Commission ("Commission") for an affirmative determination of need for a new combined cycle generating unit adjacent to Seminole's existing power plant in Putnam County, Florida. In support of this petition, Seminole states:

Introduction

Seminole is a not-for-profit generation and transmission cooperative, owned by the nine, not-for-profit rural electric distribution cooperatives it serves ("Members" or "Member Cooperatives"). Seminole has a significant need for additional resources in the 2021-2022 timeframe, and beyond. Seminole routinely assesses its resource portfolio against its load forecast and reliability criteria to determine when and how much capacity must be secured for reliability purposes. Based on that continuing evaluation, Seminole projects a need for 901 MW of additional resource capacity by the end of 2021, increasing to a projected need of 1,265 MW by the end of 2022, primarily due to the expiration of several purchased power agreements ("PPAs"). Given this need and the over-arching strategic priority to achieve the most cost-effective, risk managed resource solution for its Members, Seminole initiated a robust, competitive solicitation for resource alternatives which yielded 228 offerings from 41 counterparties. Seminole conducted extensive, multi-phase economic and risk analyses on each offering individually as well as the portfolios developed from combining multiple offerings. This combined evaluation of economic and non-economic attributes resulted in Seminole's selection of the most cost-effective, risk managed resource plan. This plan provides a balanced resource portfolio with the key attributes of diversity and flexibility, and is comprised of integral components including new, state-of-the-art natural gas combined cycle technology, purchased power resources, new solar resources, and a reduced reliance on coal. Therefore Seminole submits this Petition and accompanying Need Study and pre-filed testimony in support of a proposed 1,050 MW (net nominal) two-on-one ("2x1") natural gas-fired, combined cycle electric generating unit, to be known as the Seminole Combined Cycle Facility ("SCCF"), with an in-service date of December 1, 2022. The Need Study and supporting testimony demonstrate that the selected plan that includes the new SCCF in conjunction with the removal from service of one of the existing SGS coal-fired units, as well as the addition of another 573 MW (net nominal) combined cycle facility to be constructed, owned and operated by Shady Hills Energy Center, LLC ("SHEC"), a subsidiary of General Electric Company, is the most cost-effective way to meet the capacity needs of Seminole and its Members.

Contemporaneously with this Petition, Seminole and SHEC are filing a separate, joint petition for determination of need (and supporting testimony) for the Shady Hills Combined Cycle Facility (or "SHCCF"), which will provide generating capacity to

Seminole and its Members under a tolling agreement between SHEC and Seminole. Because the issues in this proceeding and the separate SHCCF proceeding are interrelated, Seminole respectfully requests that the two proceedings be consolidated for purposes of hearing. However, because the two proceedings will proceed separately under the Florida Electrical Power Plant Siting Act ("PPSA"), Seminole requests that the Commission issue two separate final orders pursuant to section 403.519, Florida Statutes.

Preliminary Information

1. Petitioner's full name and address are:

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

2. All notices, pleadings and other communications required to be served on the petitioner should be directed to:

Gary V. Perko
gperko@hglsaw.com
Brooke E. Lewis
blewis@hgslaw.com
Malcolm N. Means
mmeans@hgslaw.com
Post Office Box 6526
Tallahassee, Florida 32314
(850) 222-7500; (850) 224-8551 (fax)

with copy to:

David Ferrentino
Vice President and General Counsel
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618
Dferrentino@seminole-electric.com

Primarily Affected Utilities

3. Seminole and its Members are the "primarily affected utilities" within the meaning of Rule 25-22.081, F.A.C.

4. Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is an "electric utility" as defined in Section 403.503(13) and is an "applicant," as defined in Section 403.503(4), for purposes of Section 403.519, Florida Statutes.

5. Seminole's nine Members are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes. Seminole's Members are:

- Central Florida Electric Cooperative, Inc.,
- Clay Electric Cooperative, Inc.,
- Glades Electric Cooperative, Inc.,
- Peace River Electric Cooperative, Inc.,
- SECO Energy,
- Suwannee Valley Electric Cooperative, Inc.,
- Talquin Electric Cooperative, Inc.,
- Tri-County Electric Cooperative, Inc., and
- Withlacoochee River Electric Cooperative, Inc.

6. Each of Seminole's Members is a distribution cooperative serving retail end use member-consumers in Florida, and each has a long term Wholesale Power Contract with Seminole. Under those Wholesale Power Contracts, the Members purchase from Seminole all of their power requirements for distribution within the State of Florida, except for a small amount of power that is supplied to the Members under pre-existing contracts. Members also have the ability to own or lease renewable

or peak shaving generation with capacity amounts up to 5% of their 3-year average peak demand.

7. As discussed in greater detail in the Need Study, Seminole serves its Members' system load with a combination of owned generation and power purchase contracts for a variety of generating resources, including renewable energy resources.

8. Approximately 1.6 million people and businesses in parts of 42 of Florida's 67 counties rely on Seminole and its Member Cooperatives for electricity.

9. All of the generation capacity from the SCCF will be committed to Seminole's Members for retail sale to their end-use member-consumers.

The Proposed Power Plant

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

11. The SCCF will consist of two combustion turbine generators ("CTG"), two heat recovery steam generators ("HRSGs"), and one steam turbine generator ("STG"). Seminole has selected the advanced, large-frame GE Model 7HA.02 CTG for the SCCF. When operated in combined-cycle mode, these large CTGs create the most efficient electric generating technology currently available for utility-scale power plants. The

facility is expected to have a nameplate or "gross nominal" output of 1,183 MW and a "net nominal" output of 1050 MW, which it is anticipated to achieve across the entire range of ambient conditions typically experienced in Palatka, Florida. However, the facility will have significant flexibility in terms of its operational characteristics.

12. Locating the SCCF adjacent to the existing SGS site will allow Seminole to utilize the existing SGS infrastructure and thereby reduce overall impacts as compared to locating new generation on a greenfield site. The switchyard for the SCCF will be an extension of the existing SGS switchyard and electricity generated by the SCCF will be transmitted to the Florida transmission network through the existing 230 kV transmission lines running west from the SGS site. No new off-site associated transmission facilities are proposed as part of the SCCF.

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

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

The Need for Additional Capacity

15. Seminole primarily relies upon its reliability criteria to determine the amount of resource capacity needed in future years to meet forecast load. Those reliability criteria have two principal components: (1) a minimum reserve margin of 15% during the peak season, and (2) a Loss of Load Probability ("LOLP") criterion of one day in 10 years. These reliability criteria help to ensure that Seminole has adequate resource capacity to provide reliable service to its Members and to limit Seminole's emergency purchases from interconnected, neighboring systems.

16. Seminole routinely assesses its resource portfolio against its load forecast and reliability criteria to determine when and how much capacity must be secured for reliability purposes. Based on that continuing evaluation, Seminole projects a need for 901 MW of additional resource capacity by the end of 2021. This projected need results primarily from the expiration of power purchase agreements ("PPAs"), including the expiration of a 150 MW PPA on December 31, 2020, followed by the expiration of two more PPAs totaling 750 MW of winter capacity in May, 2021. Because an additional 300 MW PPA expires the following year, along with load growth, Seminole's projected need increases to 1,265 MW by the end of 2022.

17. By providing capacity necessary to meet Seminole's reliability criteria, the 1,050 MW (net nominal) of generating capacity associated with the SCCF will contribute to the reliability and integrity of Seminole's system.

Analysis of Generating Alternatives

18. Although Seminole is not subject to the Commission's "Bid Rule" (Rule 25-17.082, F.A.C.), Seminole issued a competitive request for proposals ("RFP") for power purchase options. The response was robust, with Seminole receiving a total of 223 proposals from 38 counterparties. The proposals included offers to provide generation from various renewable sources, existing and new gas-fired facilities, and system offers for both intermediate and peaking generation.

19. Based on the results of production cost modeling of several portfolios combining various alternatives, Seminole determined that the resource plan that includes the SCCF and SHCCF, along with the removal from service of one of the two existing 664 MW SGS coal units, provides the least cost portfolio. The next portfolio was approximately $363 million more expensive, in terms of net-present-value ("NPV") revenue requirements, over the study period.

20. In addition to the production cost modeling, Seminole performed risk analysis on individual alternatives and each of the remaining portfolios. Seminole produced scorecards on each portfolio which took into account a weighted risk rating, a strategic rating, operational flexibility ratings for fuel, real time operational flexibility, and an economic rating for a short-term (10 year) and long-term (30 year) net present value revenue requirement. Based on this combined evaluation of economic and non-

economic attributes, Seminole determined that the most cost effective, risk-managed resource plan for Seminole to meet the future needs of its Members includes the new SCCF in conjunction with taking one of the existing SGS coal units out of service, as well as the new SHCCF.

21. Seminole also contracted with independent evaluator, Mr. Alan Taylor of Sedway Consulting, to conduct an economic evaluation and review Seminole's overall RFP evaluation process. As discussed in his pre-filed direct testimony, Mr. Taylor concluded that the process treated proposers fairly and that Seminole's economic evaluation methodology and assumptions were appropriate. Moreover, his independent analysis confirms that the resource plan selected by Seminole represents the most cost-effective alternative to meet Seminole's projected needs for 2021 and beyond. Together with Seminole's analyses, Mr. Taylor's independent analysis demonstrates that the SCCF will help will satisfy the need for adequate electricity at a reasonable cost.

22. Seminole also considered the potential impact of the resource plan on fuel diversity and supply reliability. The SCCF will be solely fueled by natural gas, but it will serve to replace expiring purchased power generating resources that were also predominately natural gas-fired. Seminole's decision to maintain the operation of one SGS coal-fired generating unit will provide continued diversification in Seminole's fuel portfolio. Further, Seminole is implementing a natural gas transportation plan that contracts with four different counterparties for a variety of solutions to enhance the

diversification of its delivered gas supply. For these reasons, the selected portfolio is not expected to significantly impact fuel diversity or supply reliability.

<u>Analysis of Non-Generating Alternatives</u>

23. As a wholesale supplier of electric energy to its Member Cooperatives, Seminole is not directly responsible for demand side management ("DSM') programs. However, Seminole's wholesale rate structure provides Members price signals that reflect Seminole's cost of supplying power in aggregate. Under this rate structure, Seminole's billing is based on each Member's demand at the time of Seminole's peak. This encourages Members to concentrate their load management efforts on controlling Seminole's overall system peak rather than their separate peaks. Each Member may use this price signal to evaluate the cost-effectiveness of DSM and conservation measures for its own circumstances. To ensure Members have the opportunity to achieve maximum load-management benefit, Seminole's system operators develop and implement a coordinated load management demand, reduction strategy in real time to notify Members when Seminole's monthly billing peak is expected to occur.

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

consumers in order to promote energy conservation, efficiency and cost savings. As a result of these offerings, it is estimated that Seminole and its Members are achieving approximately 12,353 MWh in annual energy savings and approximately 85 MW in peak energy savings.

25. The DSM and conservation savings actually achieved by Seminole and its Members is reflected in Seminole's load forecast, yet Seminole will still need 901 MW of additional capacity by the end of 2021. Although Seminole continues to help its Members explore cost-effective conservation, efficiency and DSM measures, there is no reasonable basis to conclude that DSM or conservation measures are reasonably available to Seminole or its Members that would mitigate the need for the SCCF.

Adverse Consequences of Denial

26. Non-approval would mean that Seminole's Members and the Members' retail member-consumers would be denied the most cost-effective, risk managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021.

27. If the requested need determination for the SCCF was denied, Seminole would not be able to take an SGS coal unit out of service (664 MW) and would still have a capacity need, forcing Seminole to go to the market to find replacement capacity at a higher cost. Seminole estimates that if only the SCCF is denied, the NPV revenue requirements impact would be approximately $502 million along with the continuation of service of the coal unit.

Substantial Interests

28. The substantial interests of Seminole and its Members will be affected by the Commission's decision on this Petition. As above and in greater detail in the Need Study, if the Commission did not make an affirmative determination of need for the SCCF, there would be adverse impacts on Seminole system reliability and Seminole's cost of generating electricity.

Disputed Issues of Material Fact

29. Seminole is not aware of any dispute regarding any of the material facts contained in this petition.

Statutes and Rules That Warrant Requested Relief

30. Seminole is entitled to the determination of need requested in this Petition pursuant to Section 403.519, Florida Statutes, and Rule 25-22.080, Florida Administrative Code.

Statement of Relief Requested

WHEREFORE, based upon the foregoing and the more detailed information in the attached Need Study and pre-filed testimony submitted contemporaneously with this Petition, Seminole respectfully requests that the Commission grant an affirmative determination of need for the SCCF. Specifically, Seminole respectfully requests that:

(1) pursuant to Section 402.519, Florida Statutes, and Rule 25-22.080(2), Florida Administrative Code, the Commission set a date commencement of a hearing within 90 days of the filing of this Petition;

(2) the Commission give notice of the commencement of the proceeding as required by Rule 25-22.080(3), Florida Administrative Code;

(3) the Prehearing Officer issue an order consolidating, for purposes of hearing, this proceeding with the separate proceeding on the joint petition for determination of need contemporaneously filed by Seminole and Shady Hills Energy Center, LLC, for the Shady Hills Combined Cycle Facility; and

(4) the Commission determine that there is a need for the proposed electrical power plant described in this petition, and file its order making such determination with the Florida Department of Environmental Protection pursuant to Section 403.507(2)(a)2., Florida Statutes.

RESPECTFULLY SUBMITTED this 21st day of December, 2017.

HOPPING GREEN & SAMS, P.A.

By: *s/Gary V. Perko*

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Attorneys for SEMINOLE ELECTRIC COOPERATIVE, INC.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Petition for Determination of Need for An Electrical Power Plant was served upon the following by e-mail on this 21st day of December, 2017:

Lee Eng Tan, Esquire
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

______/s/*Gary V. Perko*_______
Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

MICHAEL P. WARD II

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF MICHAEL P. WARD II

DOCKET NO. __________-EC

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Michael P. Ward, II. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Vice President of Strategic Initiatives.

Q. Please describe your responsibilities in your current position.

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

Q. Please state your professional experience and education background

A. I have worked in the energy industry for over twenty five years. I have been with Seminole since 2013, and have held my current position at Seminole since October 2017. I hold a Bachelor of Science in Electrical Engineering from the University of Florida and a Masters of Business Administration from the University of Maryland University College. In addition, I hold a Certificate in National Security Affairs from the Naval War College and National Defense University. A current copy of my professional resume is attached as Exhibit No. ___ (MPW-1) to this pre-filed testimony.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my supervision and are attached to this pre-filed testimony:

- Exhibit No. __ (MPW-1) - Resume of Michael Ward;
- Sections 1, 2, 3.1, 3.2, and 3.3 of Seminole's Need Study, which is attached as Exhibit No. ____ (MPW-2) (Other witnesses will sponsor the sections of the Need Study within their areas of responsibility);
- Exhibit No. __ (MPW-3) - Seminole Electric Service Areas
- Exhibit No. __ (MPW-4) - Seminole's Power Purchase Contracts (as of December 31, 2016); and
- Exhibit No. _ (MPW-5) - Seminole's New Power Purchase Contracts.

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

A. The purpose of my testimony is to describe Seminole and its Members, and to provide an overview of Seminole's case supporting our request for a determination of need for the proposed Seminole Combined Cycle Facility ("SCCF"), which is more fully set forth in the Need Study attached as Exhibit No. ___ (MPW-2). I also will introduce Seminole's subject matter witnesses and discuss the adverse consequences of a denial of Seminole's need petition.

SEMINOLE & ITS MEMBERS

Q. Please describe Seminole and its Members.

A. Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales. It does not make retail sales.

Seminole’s nine Members are also not-for-profit rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use member-consumers in Florida. Seminole's members are: Central Florida Electric Cooperative, Inc., Clay Electric Cooperative, Inc., Glades Electric Cooperative, Inc., Peace River Electric Cooperative, Inc., SECO Energy, Suwannee Valley Electric Cooperative, Inc., Talquin Electric Cooperative, Inc., Tri-County Electric Cooperative, Inc., and Withlacoochee River Electric Cooperative, Inc.

Approximately 1.6 million people and businesses in parts of 42 Florida counties rely on Seminole's Member cooperatives for electricity. The areas which Seminole's Members serve are shown in Exhibit No. ___ (MPW-3).

Q. Please describe Seminole's purpose.

A. Seminole exists to provide reliable electric service at competitive rates to its Members. Seminole was organized in 1948, but remained relatively inactive until shortly after the 1973 oil embargo. In 1974, Seminole's Board determined that Seminole should develop independent power supplies for its Members. In 1975, each Member entered into a long term "All Requirements" contract with Seminole for the purchase of wholesale power. Under these contracts, each Member purchases from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts. Four of Seminole's Members had pre-existing contracts with the Southeastern Power Administration, which provide 26 MW of the total capacity required by these Members. Members also have the ability to own or lease renewable or peak shaving generation with capacity amounts up to 5% of their 3-year average peak demand.

Q. How is Seminole governed?

A. Seminole is owned by its Members and governed through a Board of Trustees. Each Member has two voting representatives and one alternate representative on Seminole's Board of Trustees. Our CEO and General Manager, Lisa D. Johnson, serves at the pleasure of the Board of Trustees.

Q. How does Seminole meet the power supply needs of its Members and their member-consumers?

A. Seminole meets the power supply needs of its Members and their member/consumers with Seminole-owned generation in combination with purchased power or tolling contracts with independent power producers, investor-owned and municipal utilities, and renewable energy providers.

Q. Please describe the generating units Seminole owns to meet the requirements of its Members and their members-consumers.

A. Seminole's existing owned generating resources are located at two sites. Seminole Generating Station ("SGS"), which is located in Putnam County near Palatka, Florida, includes two coal-fired generating units (Units 1 and 2), each with a net generating capacity (winter) of approximately 664 MW. Midulla Generating Station ("MGS"), which is located in Hardee County, Florida, includes a natural gas-fired combined cycle facility (Units 1-3) with a net (winter) generating capability of 539 MW and five twin-pack gas turbines (Units 4-8) with a combined net (winter) generating capability of 310 MW. All of the MGS units also have fuel oil capability. Each of these facilities is shown on Exhibit No. ___ (MPW-3).

Q. What are Seminole's current purchased power and tolling resources?

A. Exhibit No. ___ (MPW-4) is a table summarizing Seminole's purchased power agreements ("PPAs") and tolling contracts as of December 31, 2016. As a result of the Request for Proposals ("RFP") process discussed in the pre-filed testimony of Jason Peters and Julia Diazgranados, Seminole has extended the

Oleander PPA through December 31, 2021, and has entered into an additional system PPA for intermediate and peaking power with Duke Energy Florida (“DEF”), another system PPA with Southern Company Services (“SCS”), and a power purchase agreement for solar resources with Tillman Solar Center, LLC., a subsidiary of Coronal Energy. These new agreements are summarized in Exhibit No. ____ (MPW-5).

Q. Does Seminole’s generation portfolio currently include renewable energy?

A. Seminole's generation portfolio includes a mix of technologies and fuel types, including renewable energy resources. Seminole currently receives 87.8 MW from renewable energy sources including 13 MW from Biomass, 16.8 MW from landfill gas-to-energy, and 58 MW from waste-to-energy. In addition, Seminole operates a 2.2 MW Cooperative Solar facility located in Hardee County, Florida.

SEMINOLE'S REQUEST FOR NEED DETERMINATION

Q. What relief does Seminole request in this proceeding?

A. Seminole requests that the Commission grant an affirmative determination of need for the Seminole Combined Cycle Facility ("SCCF") with an in-service date of December 1, 2022. SCCF will be a state-of-the-art natural gas-fired two-on-one (“2x1”) combined cycle unit with a net generating capacity of 1,050 MW (net nominal). The new unit will be constructed adjacent to Seminole's existing SGS site in Putnam County, Florida. The projected cost of SCCF, which is presented in more detail in the testimony of David Kezell, will be approximately $727 million. Seminole intends to finance the project through long-term financing.

Q. What is the basis for Seminole's request for need determination?

A. As a result of moderately increasing load growth and the expiration of several purchased power and tolling contracts, Seminole determined a need for approximately 901 MW of additional generating capacity beginning in 2021 and that need was projected to grow to approximately 1,265 MW by the end of 2022. Seminole has determined that the most cost effective, risk-managed resource plan to meet this projected capacity need is a mix of resources consisting of:

- existing generation resources;
- the self-build 1,050 MW (net nominal) SCCF in conjunction with the removal from service of one of the two existing 664 MW SGS coal units;
- several power purchase agreements ("PPAs") for generating resources, including a tolling agreement supporting a new 573 MW (winter) 1x1 combined cycle facility to be constructed by Shady Hills Energy Center, LLC ("SHEC"), an indirect subsidiary of General Electric Company, at the existing Shady Hills power plant site (this facility is the subject of a separate determination of need proceeding jointly initiated by Seminole and SHEC).

Seminole's Board of Trustees selected the resource plan that includes the SCCF based on the results of a multi-stage resource planning process. That process included extensive economic analyses of self-build options and multiple power purchase alternatives, including numerous renewable energy proposals, identified during a robust RFP process, as well as careful consideration of non-economic attributes and risk factors.

Q. What were the results of Seminole's economic evaluations?

A. As discussed in the pre-filed testimony of Julia Diazgranados, the economic evaluation demonstrates that in net present value revenue requirement terms the selected resource plan is approximately $363 million less expensive than the closest alternative resource plan over the study period.

Q. What were the results of Seminole's evaluation of non-economic attributes?

A. In addition to evaluating the cost-effectiveness and risk impacts, Seminole considered our strategic objectives for our future resource portfolio to have the attributes of diversity, flexibility and optionality. As an example, one of the new long-term PPAs included in the selected resource plan provide Seminole with the advantage of optionality in terms of the amount of capacity available for purchase. This gives Seminole the flexibility to modify its commitment up or down. Given the vulnerability of load forecasts, the ability to modify resource commitments gives Seminole the ability to mitigate the impacts of economic acceleration/downturns or faster/slower load growth rates.

Q. Did Seminole consider the potential for new renewable energy resources as part of its evaluation?

A. Yes. As part of its need evaluation process, Seminole solicited proposals for renewable energy resources. The results of Seminole's economic evaluations show that additional renewable energy resources would not be cost-effective as compared to SCCF. Moreover, Seminole is a winter-peaking utility that experiences its highest end-use demand on winter mornings and nights when solar energy is not a viable capacity source to offset peak demand. Nevertheless, in recognition of the energy value and summer capacity value of solar, Seminole has included 40 MW of solar in the selected resource plan.

Q. Did Seminole consider whether additional conservation measures are reasonably available to mitigate the projected capacity need?

A. Yes. As explained in the pre-filed direct testimony of Kyle Wood, Seminole is a wholesale provider of electricity that does not directly implement demand side management ("DSM") and conservation measures. Through its rate structure, Seminole promotes conservation by providing its Members price signals that reflect Seminole's cost of supplying power; thereby providing an incentive for Members to implement cost-effective DSM and conservation measures to lower peak demand. The effect of the DSM and conservation measures offered by Seminole's Members is reflected in Seminole's load forecast, but we nevertheless project need for additional generation capacity. Seminole recently sponsored an evaluation of DSM potential to identify potentially cost-effective DSM measures for our Members to consider and further evaluate. While the results of this study may help Seminole's Members to identify new DSM opportunities, there is not a sufficient amount of reasonably achievable DSM potential to offset the need for SCCF.

Q. Did Seminole consider the potential impact of the selected resource plan on fuel supply reliability?

A. Yes. Seminole considered the potential impact of the resource plan on fuel diversity and supply reliability, particularly in light of the removal from service of one of the existing SGS coal-fired generating units. In order to enhance fuel supply reliability, Seminole is expanding its natural gas transportation plan to include capacity agreements with four different counterparties which ensures access to and delivery of a diverse gas supply. Seminole has supply agreements with over thirty natural gas suppliers. The retention in service of one of the coal-fired units at SGS provides additional mitigation of potential natural gas supply disruptions. Thus, the selected resource plan is not expected to significantly impact fuel diversity or supply reliability.

INTRODUCTION OF SEMINOLE'S WITNESSES

Q. Please identify Seminole's other witnesses in this proceeding and subjects each witness will address in his/her direct testimony.

A. The names and areas of responsibility for each of the other seven witnesses are (in alphabetical order):

Robert DeMelo, Seminole's Manager of Transmission Planning and System Protection, discusses Seminole's transmission planning process, the interconnection and transmission line facilities required to support the SCCF, and the transmission costs and impacts of the various alternatives considered to address Seminole's need.

Julia Diazgranados, Seminole’s Director of Treasury and Planning, addresses Seminole’s power supply planning process, the reliability and need assessment Seminole performed to identify its need for capacity, and Seminole’s economic evaluation of self-build and purchased power and tolling options. Importantly, she explains why the SCCF project is the most cost-effective, risk managed option to meet the reliability and economic needs of Seminole and its Members. She describes the Seminole Board approval process and addresses the adverse consequences that would result if the requested need determination is not granted.

Tom Hines, of Tierra Resource Consultants, describes the results of work that Tierra Consultants performed to quantify the energy savings that Seminole Members are achieving through implementation of conservation and DSM measures and to help Seminole evaluate other conservation measures that Seminole’s Members may choose to implement.

David Kezell, Seminole’s Director of Engineering and Capital Development, describes the SCCF project, including its site, technology, related facilities, operating assumptions and estimated total cost. He also presents Seminole's feasibility studies and technology assessment, and describes Seminole’s experience in the construction and operation of combined cycle plants and other fossil-fired units.

Jason Peters, Seminole's Portfolio Director (Power), addresses Seminole's capacity solicitations to meet forecasted needs, the request for proposals ("RFP") Seminole conducted to address its need for capacity, the bids Seminole received in response to its RFP, the technical and commercial screening of such bids in conformance with the requirements of the RFP, and other purchased power and tolling options considered by Seminole.

Alan Taylor, President of Sedway Consulting Inc., who conducted an independent evaluation and review of Seminole's overall RFP evaluation process, confirms that the resource plan selected by Seminole represents the best, least-cost alternative to meet Seminole's projected needs for 2021 and beyond.

David Wagner, Seminole's Portfolio Director (Gas), presents the natural gas supply and transportation plans for SCCF, as well as the fuel price forecasts used in the analyses that examined the various options for meeting Seminole's capacity needs. He also addresses fuel supply diversity.

Kyle Wood, Seminole's Manager of Load Forecasting and Member Analytics, presents Seminole's load forecast. He also explains how Seminole and its Members implement conservation and DSM measures and why additional conservation and DSM measures are not reasonably available to mitigate the need for SCCF.

ADVERSE CONSEQUENCES OF DENIAL

Q. Would there be any adverse consequences to Seminole and its Members if the Commission does not grant an affirmative determination of need for the SCCF project?

A. Non-approval would mean that Seminole's Members and the Members' end-use member-consumers would be denied the most cost-effective, risk managed power supply solution. Seminole's required reserve margin would fall below the minimum reserve level in 2021. While additional off-system purchases could perhaps be made to fulfill Member power requirements and maintain the target reserve margin, Seminole would not be able to remove a coal unit from service and the costs of the resulting resource plan would be substantially higher. As explained in the testimony of Julia Diazgranados, denial of the SCCF by itself would result in an NPV revenue requirements impact of $502 million.

Q. Does this conclude your testimony?

A. Yes.

Michael P. Ward II

Experience

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

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

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

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

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

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

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

- Plant Engineer for Combined Cycle facility.

Submarine Officer
1987-2014
UNITED STATES NAVY

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

Education

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

Skills

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

NEED STUDY

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

December 2017

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1.0 EXECUTIVE SUMMARY

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

1.1 The Primarily Affected Utilities

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

1.2 The Power Plant Siting Act and Need Determination Process

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

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

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

1.3 The Proposed New Facilities

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

1.4 Seminole's Need for Generation Capacity

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

1.5 Major Generating Alternatives

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

1.6 Non-Generating Alternatives

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

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

1.7 Adverse Consequences of Denial

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

1.8 Conclusion

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

2.0 PURPOSE AND OVERVIEW OF NEED STUDY

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

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

3.0 PRIMARILY AFFECTED UTILITIES

3.1 Seminole Electric Cooperative & its Member Cooperatives

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

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

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

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

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

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

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

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

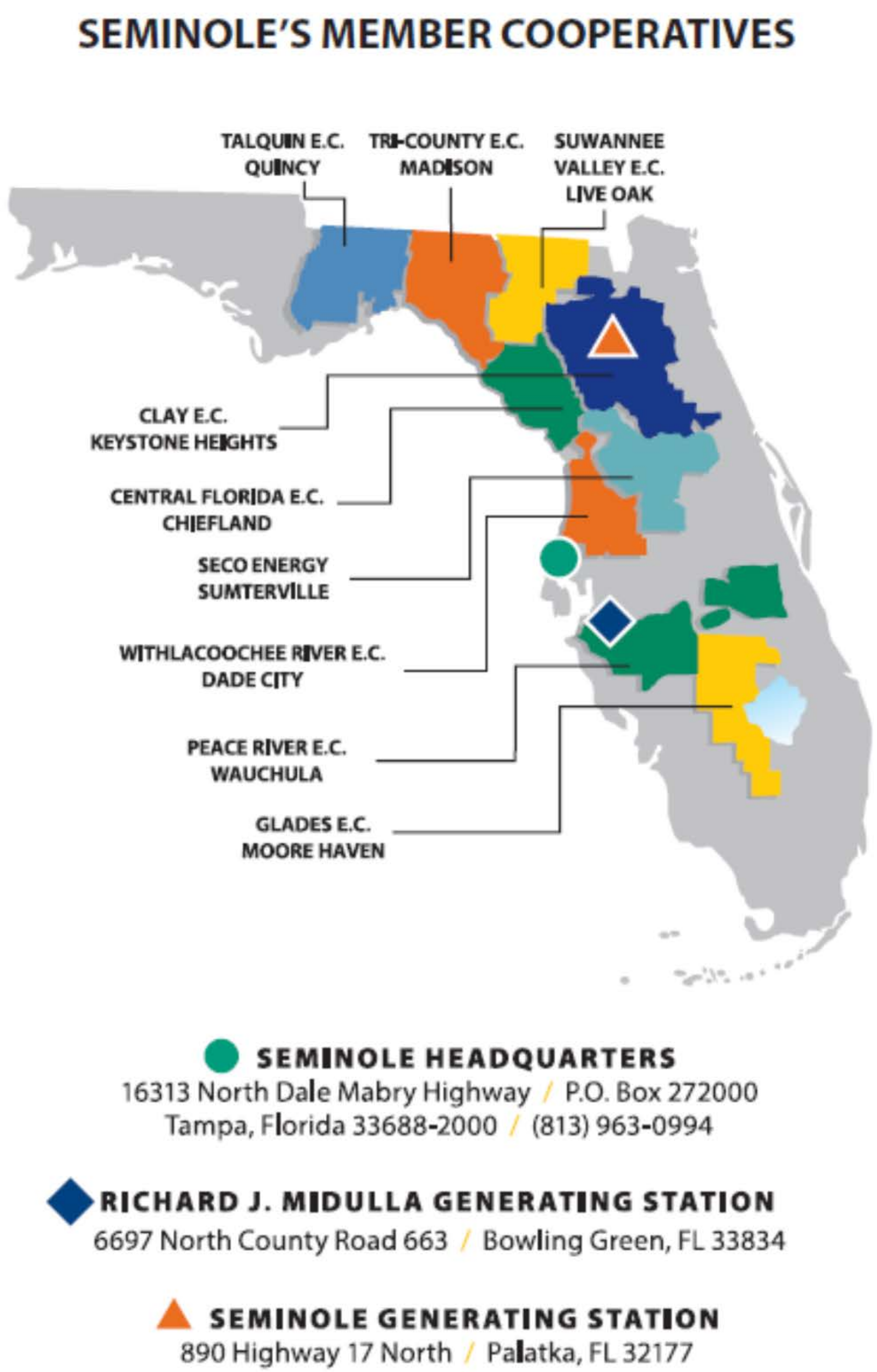
- Tri-County Electric Cooperative, Inc.
  Madison, Florida
  Counties: Dixie, Jefferson, Lafayette, Madison, Taylor

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

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

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

Figure 1 Seminole Member Service Areas



Seminole Electric COOPERATIVE, INC.

3.2 Load and electrical characteristics

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

3.3 Generating Capability

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

3.3.1 Seminole's Owned/Leased Generation Facilities

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

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

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

Table 1 summarizes Seminole's existing owned generating facilities.

Table 1 Seminole's Existing Owned Generation Facilities

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

Schedule Abbreviations:			
	General	Unk – Unknown N/A – Not applicable	
	<u>Unit Type</u> ST – Steam Turbine CC – Combined Cycle CT – Combustion Turbine PV – Photovoltaic	<u>Fuel Type</u> BIT – Bituminous Coal NG – Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy	<u>Fuel Transportation</u> PL – Pipeline RR – Railroad TK – Truck

3.3.2 Power Purchase Agreements

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

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

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

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

Table 3 Seminole's New Power Purchase Contracts

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

*Winter ratings
**Summer rating

3.3.3 Renewable Resources

Seminole's generation portfolio includes a mix of technologies and fuel types, including renewable energy. Seminole currently receives 87.8 MW from renewable energy sources via PPAs, including 13 MW from Biomass, 16.8 MW from landfill gas-to-energy, and 58 MW from waste-to-energy. Additionally, as a result of the RFP process explained in Section 6, Seminole has entered into a new PPA for 40 MWac of solar capacity beginning in January, 2021. Seminole may sell a portion of the renewable energy credits associated with its renewable generation to third parties. The third parties can use the credits to meet mandatory or voluntary renewable requirements.

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

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

3.4 Transmission Interconnections

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

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

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

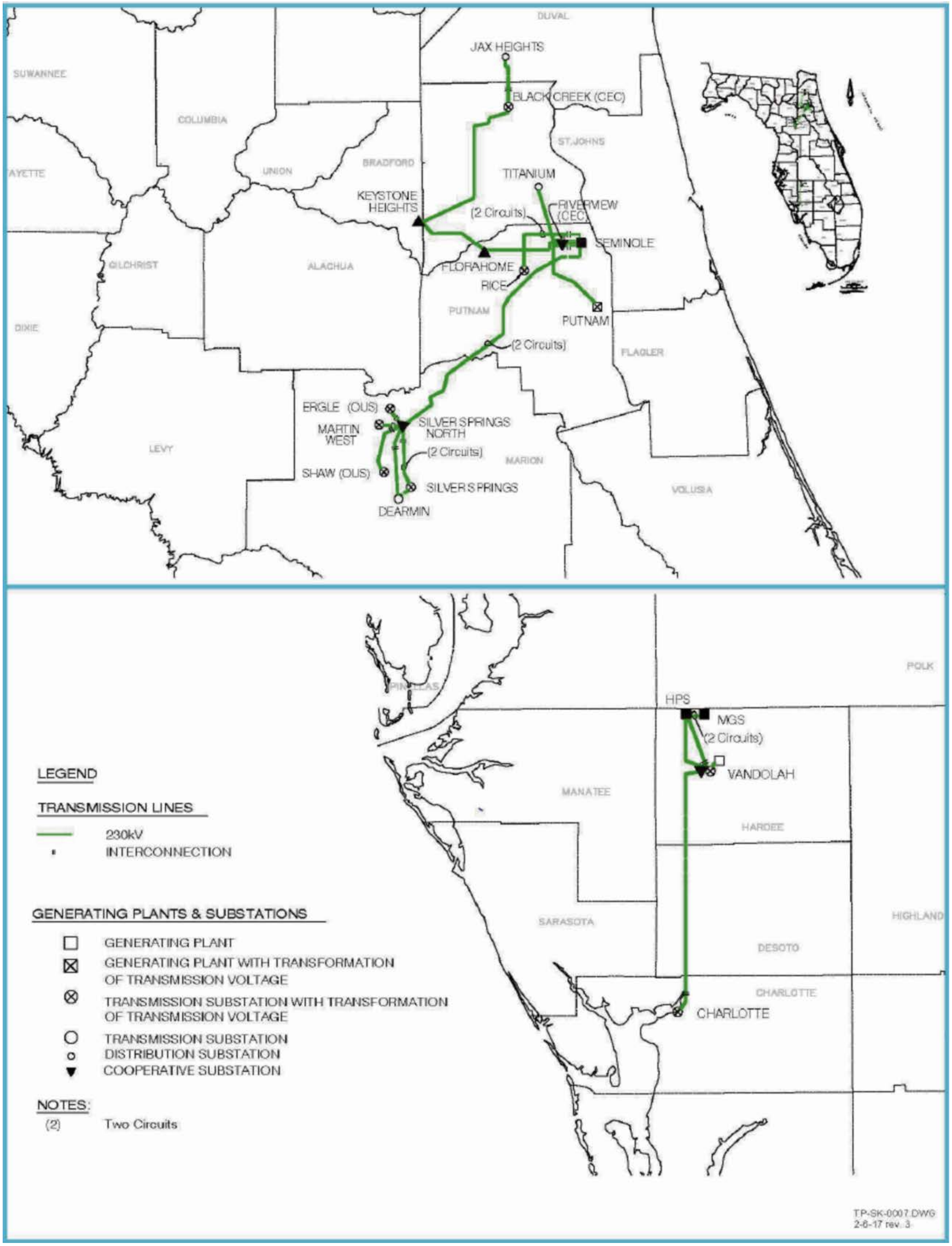
Table 4 Seminole's Transmission Interconnections

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

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

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

Figure 2 Seminole's Bulk Transmission Facilities



4.0 DESCRIPTION OF THE PROPOSED GENERATING UNITS

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

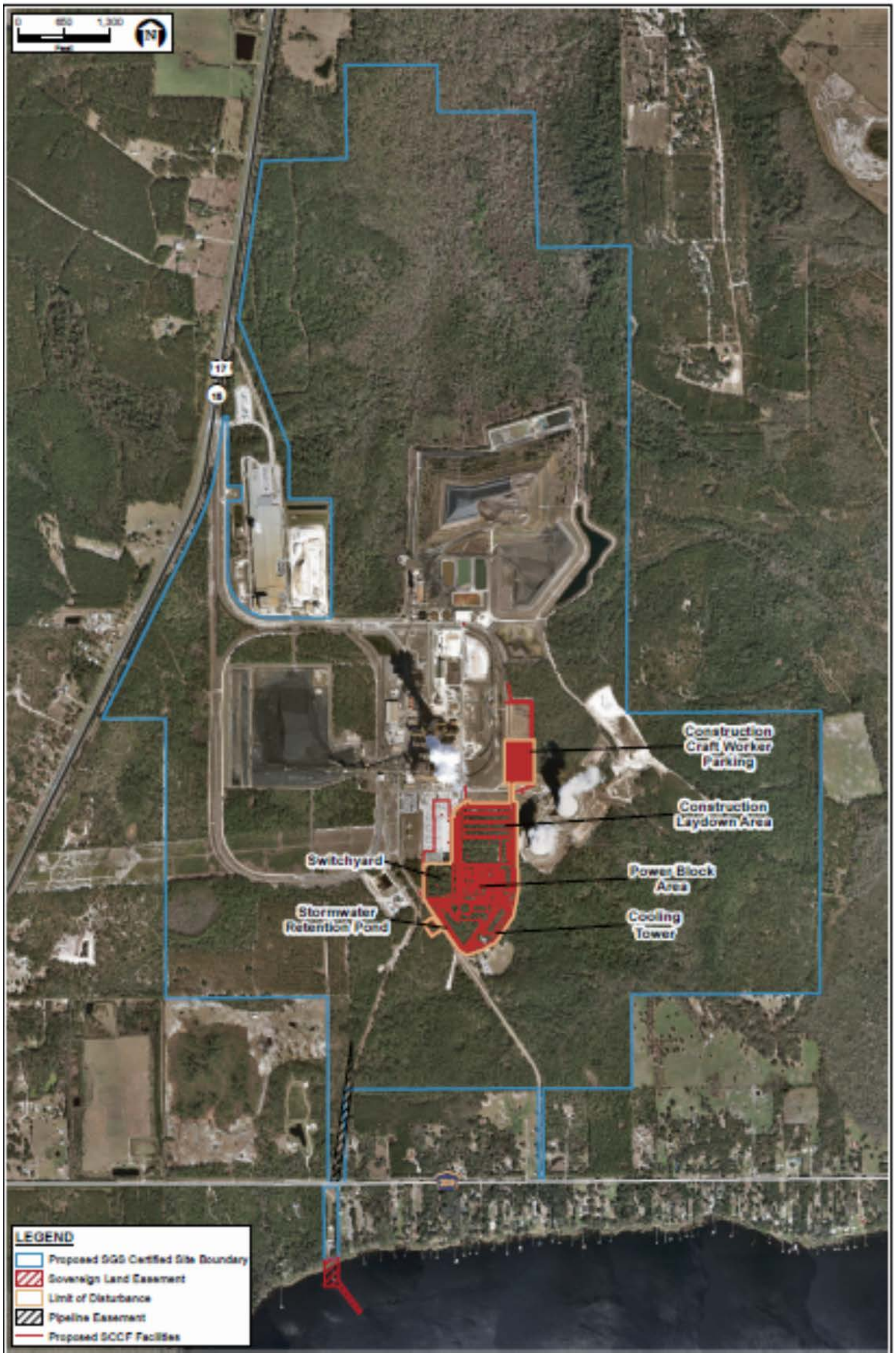
The SCCF involves construction and operation of a new state-of-the-art natural gas-fired "two-on-one" combined cycle generating facility and onsite associated facilities on an approximately 32 acre parcel adjacent to the existing SGS plant. The SCCF will have a nominal net generating capacity of 1,050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

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

4.1.1 The SGS Site

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

Figure 4 Proposed Location of SCCF



Seminole Electric
COOPERATIVE, INC.

4.1.2 Proposed Combined Cycle Technology

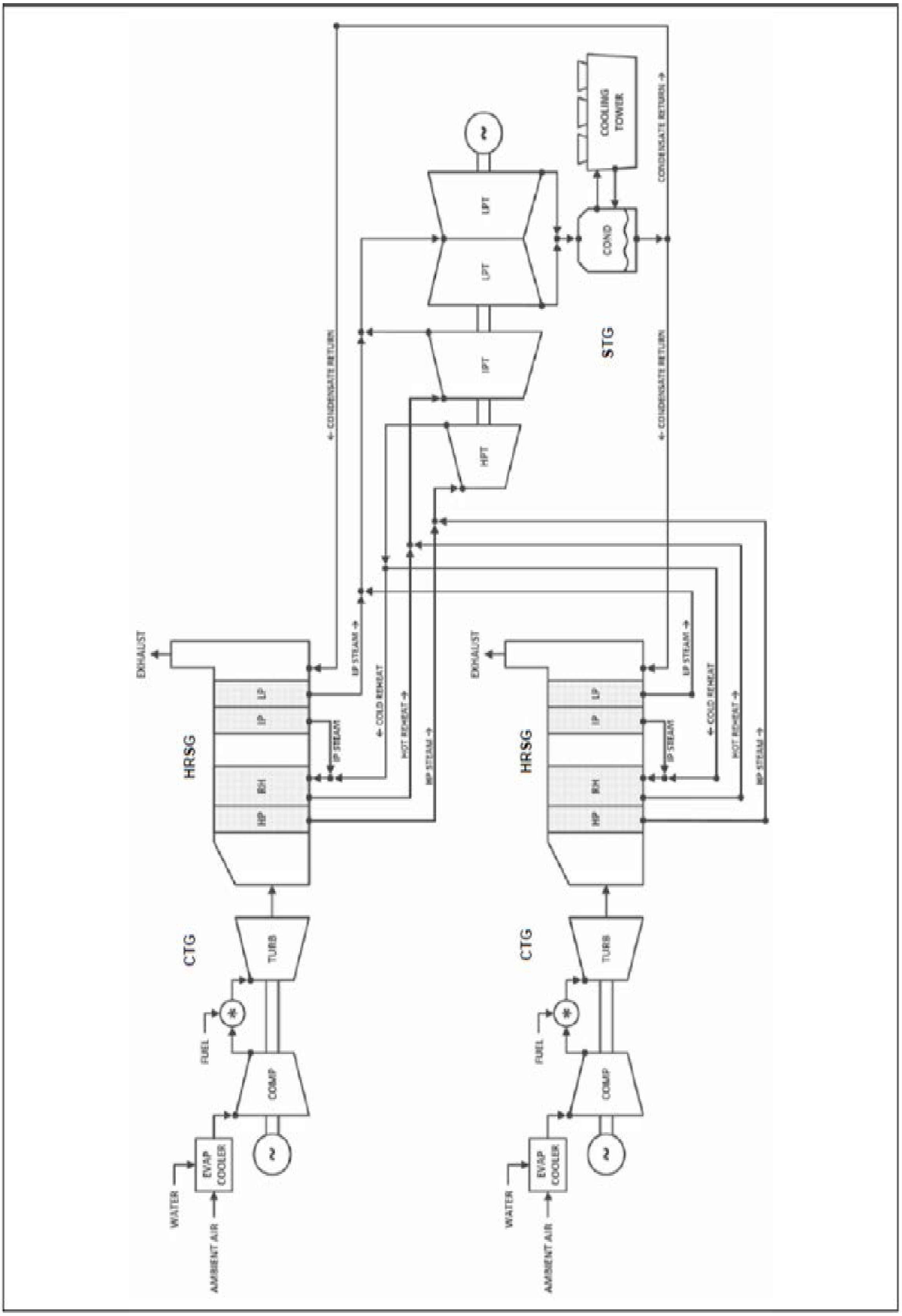
The SCCF will consist of two combustion turbine generators ("CTG"), two heat recovery steam generators ("HRSGs"), and one steam turbine generator ("STG"). Seminole has selected the advanced, large-frame GE Model 7HA.02 CTG for the SCCF. When operated in combined cycle mode, these large CTGs create the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

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

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

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

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



4.1.3 Existing Infrastructure

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

4.1.4 Associated Facilities

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

4.1.5 Air Emission Controls

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

4.1.6 Water Use and Supply

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

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

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

4.1.7 Stormwater Management

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

4.1.8 Fuel Type & Supply

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

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

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

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

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

4.1.9 Transmission Interconnections

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

In general, Seminole's transmission planning process includes the single contingency loss of any transmission circuit, transformer, bus section, shunt device, internal breaker fault, or generator. Such analysis is performed for multiple load levels, including but not limited to peak, off-peak, and high-import (Southern to Florida transfers) for select summer and winter conditions as modeled and made available by the FRCC. Additional analysis is performed to determine system response to credible, less probable extreme events, to assure the system meets Seminole, FRCC, and North American Electric Reliability Corporation ("NERC") transmission planning criteria. The additional analysis includes the loss of multiple elements, including the loss of multiple transmission circuits, transformers, generators, or the combination of each. Seminole utilizes planned operational system adjustments, corrective action plans which can include projects that require construction of new facilities or upgrades to existing facilities, and load loss if permissible by Seminole, FRCC, and NERC transmission planning reliability criteria.

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

Typically, new generation interconnections, such as for the SCCF, are evaluated for both interconnection and deliverability simultaneously. However, because Seminole is a TDU within the FRCC region, Seminole will be required to submit separate Transmission Service Requests ("TSR") to DEF and FPL after completion of the interconnection analyses, in accordance with their respective OATTs, for the deliverability of the SCCF to Seminole's Members' load in the respective control areas in order to determine transmission impacts on the systems of FPL and DEF, in addition to any impacts on neighboring systems that may result due to the SCCF. In order to request a TSR from DEF and FPL on their respective Open Access Same Time Information Systems ("OASIS"), via the designation of network resource ("DNR") process, Seminole is required to attest it either owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service, in accordance with FERC pro-forma OATT. Thus, Seminole could not submit the TSRs in advance of the interconnection process in order to obtain estimates of the costs for delivery of the SCCF on DEF's or FPL's systems. Consequently, when evaluating alternatives to meet its projected 2021 need, Seminole did not have alternatives to evaluate deliverability of the resource into the respective areas to determine transmission impacts on DEF, FPL and neighboring systems. Instead, Seminole was limited to evaluating the SCCF interconnection for short circuit and stability impacts, including limited steady-state load flow analysis across Seminole's own transmission system emanating from the SGS Switchyard.

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

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

4.1.10 Approximate Capital Costs

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

Table 5 SCCF Capital Cost Estimate

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

4.1.11 Construction Schedule & Projected In-Service Date

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

4.2 PROPOSED SHADY HILLS COMBINED CYCLE FACILITY

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

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

4.2.1 Proposed CC Technology

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

4.2.2 Existing Infrastructure

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

4.2.3 Other Facilities

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

4.2.4 Air Emission Controls

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

4.2.5 Water Use & Supply

Process water for the SHCCF (cooling water, demineralized water, and service water) will be sourced in the form of wastewater treatment effluent from Pasco County's Master Reuse System, of which the Shady Hills Wastewater Treatment Plant is adjacent to the SHPC site. In addition, supplemental sources may be utilized on an emergency basis in the event reclaimed or treated wastewater is not available. An onsite water treatment system will reduce the concentrations of calcium, magnesium, alkalinity, silica and suspended solids by adding hydrated lime, soda ash, ferric chloride and polymer to reduce these constituents in clarifiers. The onsite water treatment system will also include granular media filters, ultrafiltration trains and reverse osmosis ("RO") trains. Finally, RO reject and other concentrated process wastewater streams will be treated in brine concentrators and crystallizers. These treatment processes, and the reuse of process wastewater around the site, will be used to achieve zero liquid discharge from the site. The ZLD system will generate a solid waste byproduct that will be disposed offsite.

4.2.6 Stormwater Management

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

4.2.7 Fuel Type & Supply

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

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

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

4.2.8 Transmission Interconnections

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

4.2.9 Tolling Agreement

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

4.2.10 Construction Schedule & Projected In-Service Date

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

5.0 THE NEED FOR PROPOSED GENERATING UNITS

5.1 Overview of Need Assessment

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

5.2 The Load Forecast

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

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

5.2.1 Consumer Base

The combined service area of Seminole Members is primarily rural and extends into 42 of Florida's 67 counties. Seminole Members provide electricity to over 763,000 member-consumers, serving a population of approximately 1.6 million people and businesses. The combined service area encompasses a variety of geographic and weather conditions, as well as a diverse mix of economic activity and demographic characteristics.

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

5.2.2 Load Forecast Methodology & Assumptions

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

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

5.2.3 Energy and Demand Models

Seminole forecasts monthly energy sales at the Member-total and Member-rate class level with econometric models. Delivery point billing load and Member-rate class sales to end-use member-consumers grossed up for distribution losses are trained with a variety of explanatory variables in order to estimate future growth.

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

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

5.2.4 Historical Trends and Forecast Results

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

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

Table 6

Residential Consumers & Sales

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

Note: Estimated-Actual data through February 2017

Table 7

Residential Consumers & Sales

Excluding Lee County Electric Cooperative

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

Note: Estimated-Actual data through February 2017

Seminole Electric COOPERATIVE, INC.

Table 8

Commercial Consumers & Sales

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

Note: Estimated-Actual data through February 2017

Seminole Electric COOPERATIVE, INC.

Table 9

Commercial Consumers & Sales

Excluding Lee County Electric Cooperative

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

Note: Estimated-Actual data through February 2017

Seminole Electric COOPERATIVE, INC.

Table 10

Other Consumers & Sales

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

Note: Estimated-Actual data through February 2017

Table 11

Other Consumers & Sales

Excluding Lee County Electric Cooperative

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

Note: Estimated-Actual data through February 2017

Table 12

Total Consumers & Sales

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

Note: Estimated-Actual data through February 2017

Seminole Electric COOPERATIVE, INC.

Table 13

Total Consumers & Sales

Excluding Lee County Electric Cooperative

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

Note: Estimated-Actual data through February 2017

Seminole Electric COOPERATIVE, INC.

Table 14

Annual Net Energy for Load and Seasonal Net Firm Demand

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

Note: Actual data through February 2017;
All values exclude Southeastern Power Administration.

Table 15

Annual Net Energy for Load and Seasonal Net Firm Demand

Excluding Lee County Electric Cooperative

Net Energy for Load			
Year	Base (GWh)	Low (GWh)	High (GWh)
History			
2007	13,729	-	-
2008	13,567	-	-
2009	13,659	-	-
2010	14,658	-	-
2011	13,502	-	-
2012	13,256	-	-
2013	13,302	-	-
2014	13,854	-	-
2015	14,104	-	-
2016	14,471	-	-
Forecast			
2017	14,165	13,814	15,192
2018	14,655	13,954	15,635
2019	14,875	14,176	15,854
2020	15,023	14,325	15,997
2021	15,125	14,432	16,096
2022	15,337	14,644	16,306
2023	15,574	14,881	16,541
2024	15,805	15,112	16,770
2025	16,022	15,328	16,984
2026	16,249	15,556	17,209
2027	16,470	15,777	17,429
AAGR '07-'16	*0.6*	*-*	*-*
AAGR '12-'16	*2.2*	*-*	*-*
AAGR '18-'22	*1.1*	*1.2*	*1.1*
AAGR '18-'27	*1.3*	*1.4*	*1.2*

Summer Net Firm Demand			
Year	Base (MW)	Low (MW)	High (MW)
History			
2007	3,060	-	-
2008	2,915	-	-
2009	3,064	-	-
2010	3,011	-	-
2011	3,121	-	-
2012	2,890	-	-
2013	3,012	-	-
2014	3,088	-	-
2015	3,021	-	-
2016	3,243	-	-
Forecast			
2017	3,090	2,974	3,176
2018	3,140	3,025	3,228
2019	3,187	3,074	3,274
2020	3,238	3,124	3,325
2021	3,251	3,153	3,354
2022	3,297	3,198	3,399
2023	3,343	3,245	3,446
2024	3,388	3,290	3,489
2025	3,430	3,333	3,533
2026	3,474	3,375	3,577
2027	3,516	3,417	3,619
AAGR '07-'16	*0.6*	*-*	*-*
AAGR '12-'16	*2.9*	*-*	*-*
AAGR '18-'22	*1.2*	*1.4*	*1.3*
AAGR '18-'27	*1.3*	*1.4*	*1.3*

Winter Net Firm Demand			
Year	Base (MW)	Low (MW)	High (MW)
History			
2007/2008	3,343	-	-
2008/2009	3,817	-	-
2009/2010	4,224	-	-
2010/2011	3,685	-	-
2011/2012	3,383	-	-
2012/2013	3,229	-	-
2013/2014	3,240	-	-
2014/2015	3,593	-	-
2015/2016	3,307	-	-
2016/2017	3,018	-	-
Forecast			
2017/2018	3,398	3,063	3,856
2018/2019	3,466	3,131	3,922
2019/2020	3,531	3,200	3,985
2020/2021	3,588	3,258	4,038
2021/2022	3,643	3,314	4,091
2022/2023	3,699	3,371	4,145
2023/2024	3,749	3,422	4,194
2024/2025	3,802	3,477	4,244
2025/2026	3,857	3,532	4,298
2026/2027	3,909	3,586	4,351
2027/2028	3,955	3,633	4,397
AAGR '08-'17	*-1.1*	*-*	*-*
AAGR '13-'17	*-1.7*	*-*	*-*
AAGR '18-'22	*1.8*	*2.0*	*1.5*
AAGR '18-'27	*1.6*	*1.8*	*1.4*

Note: Actual data through February 2017;
All values exclude Southeastern Power Administration.

5.3 Seminole's Reliability Criteria

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

5.4 Seminole's Capacity Needs

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

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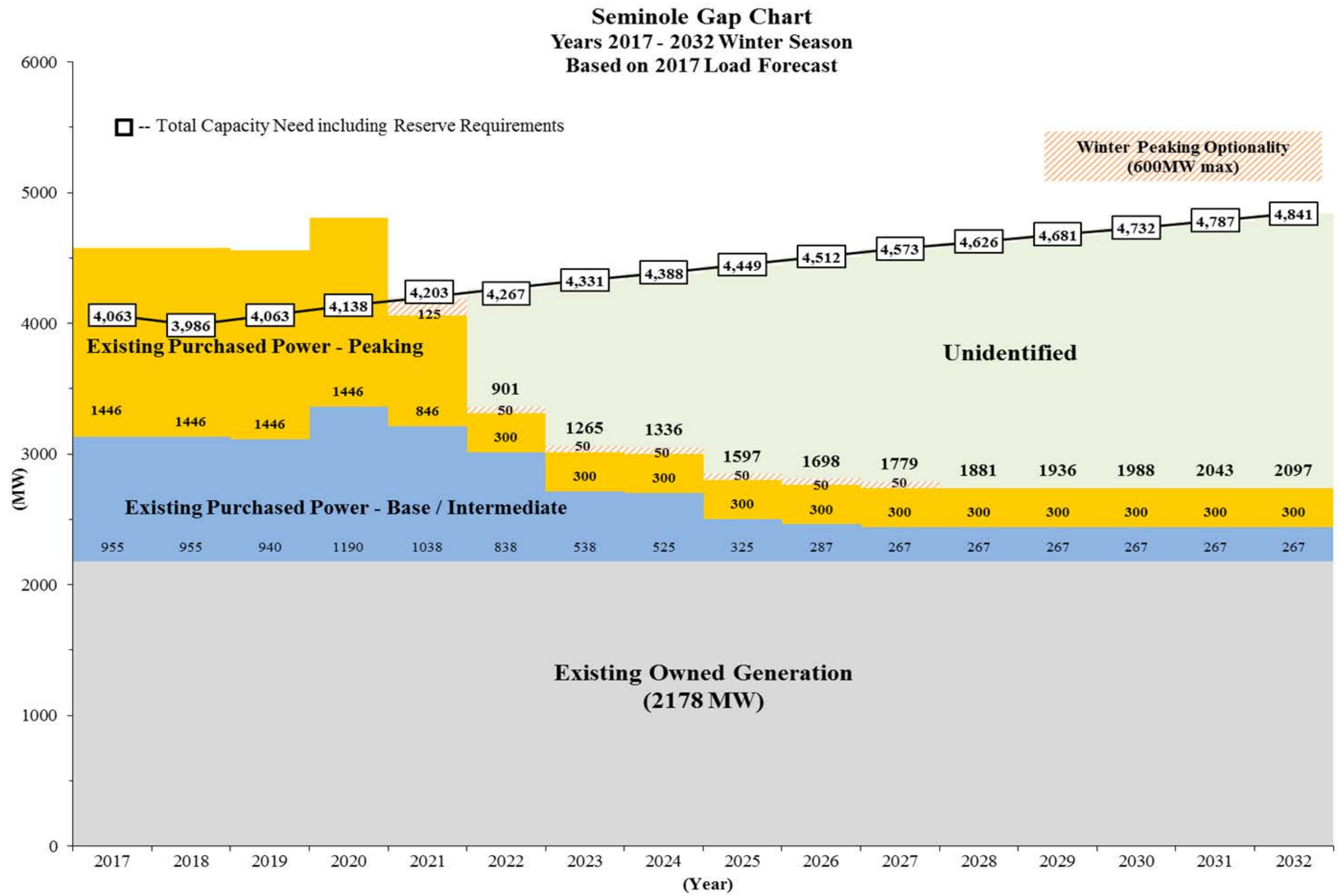


Figure 6 “Gap Chart” summarizing Seminole's Projected Need

6.0 EVALUATION OF MAJOR GENERATING ALTERNATIVES

6.1 Overview of Evaluation Process

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

6.2 Self-Build Alternatives Considered

6.2.1 Technology Assessment

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

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

6.2.2 Site Assessment

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

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

Based on the comparative analysis, the SGS site scored substantially better than the Gilchrist site for a combined cycle facility. In particular, the Gilchrist site posed significant issues relative to water availability and wastewater discharge options. In addition, the SGS site is a brownfield site with capability of utilizing existing water intake, water discharge, and electrical transmission infrastructure. Overall, the SGS site has significant economic and strategic advantages for siting a combined cycle facility.

6.3 Purchase Power Alternatives Considered

6.3.1 The Requests for Proposals ("RFP")

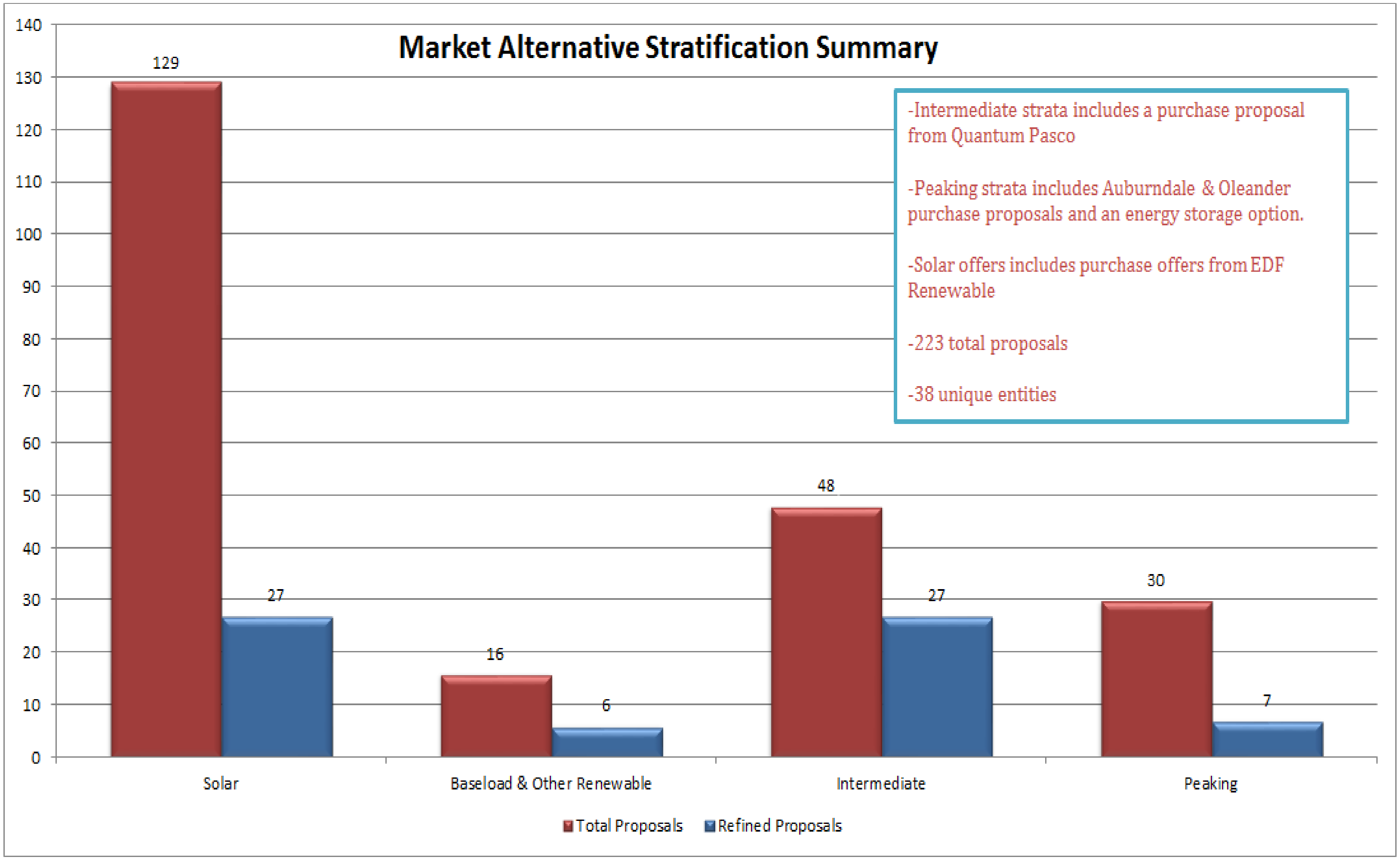
Seminole identified market alternatives by issuing an RFP in March 2016 for firm capacity up to 1,000 MW beginning as early as June 1, 2021. The RFP stated that the need for 600 MW of capacity would start in June 2021, with total needs increasing to 1,000 MW by June 2022. Seminole encouraged proposals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

6.3.2 Proposals Received & Initial Economic Evaluation

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

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

Figure 7 Summary of Proposals Received in Response to RFP



6.4 Economic Evaluation of Generation Alternatives

6.4.1 Methodology

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

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

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

6.4.2 Economic Parameters

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

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

6.4.3 Fuel Price Forecast

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

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

Table 16 - Fuel Price Forecast

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

Table 17 - Fuel Price Forecast – Updated

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

6.4.4 Results

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

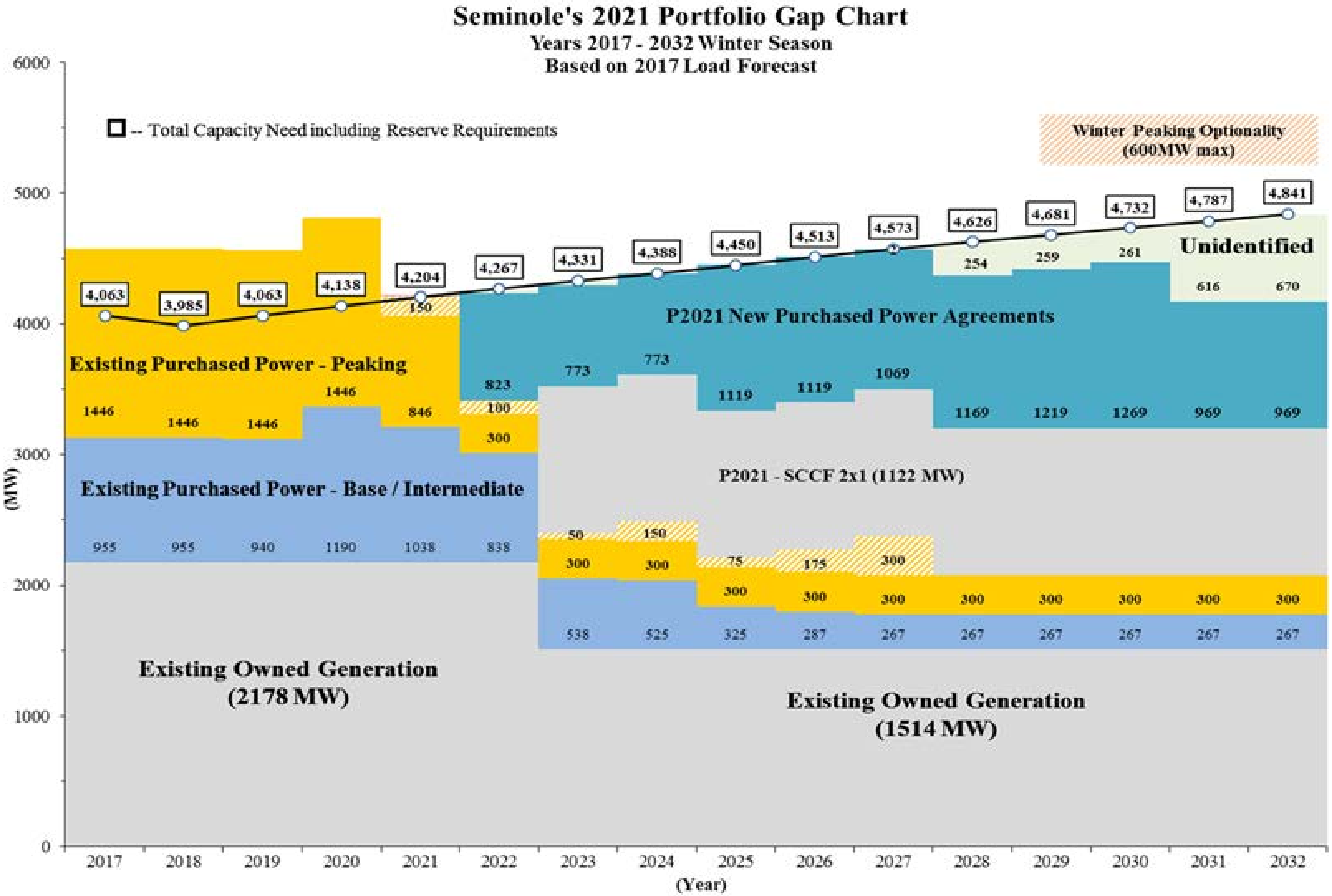
Figure 8 Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

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

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

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



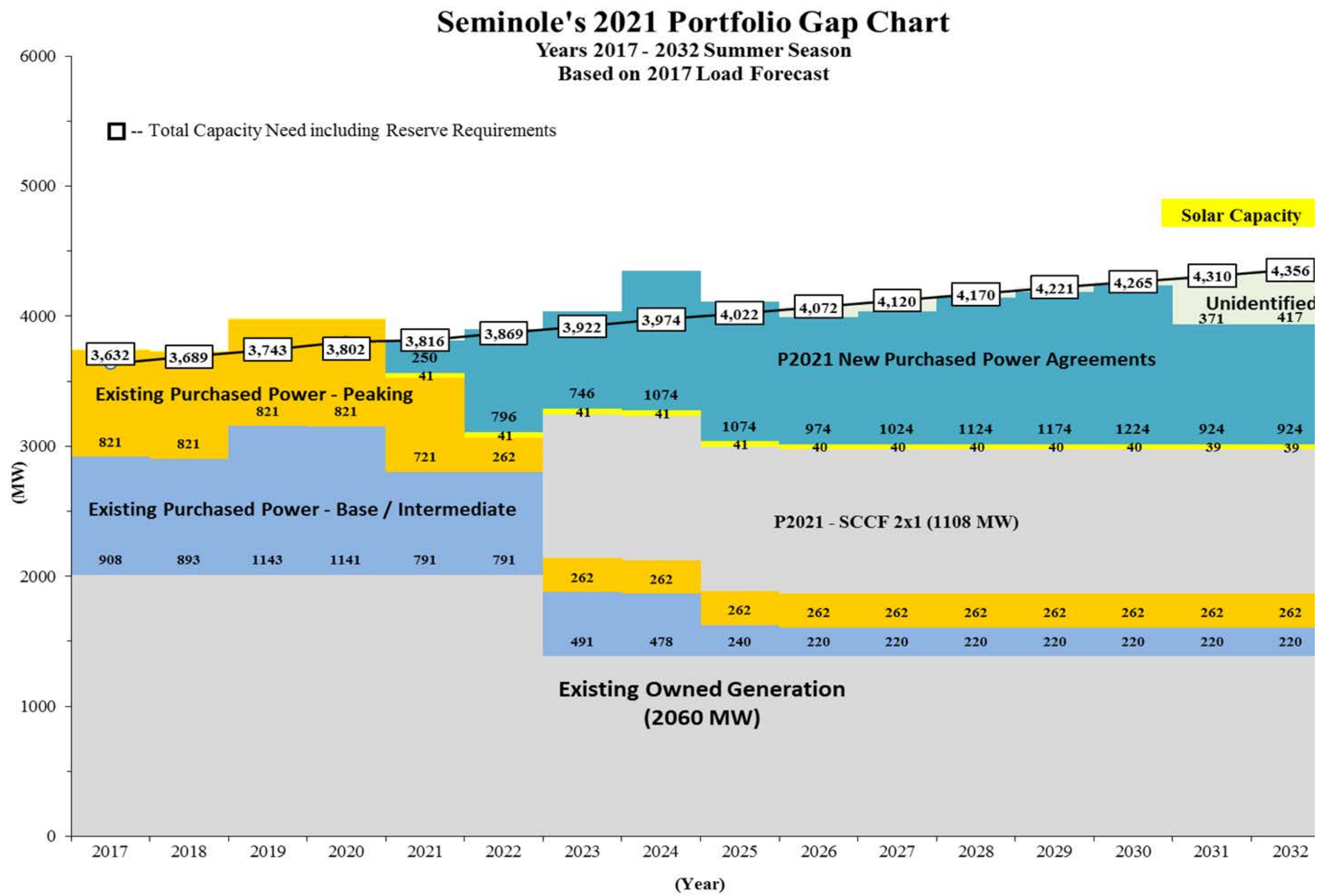


Figure 10 "Gap Chart" Showing Effect of Selected Portfolio (Summer)

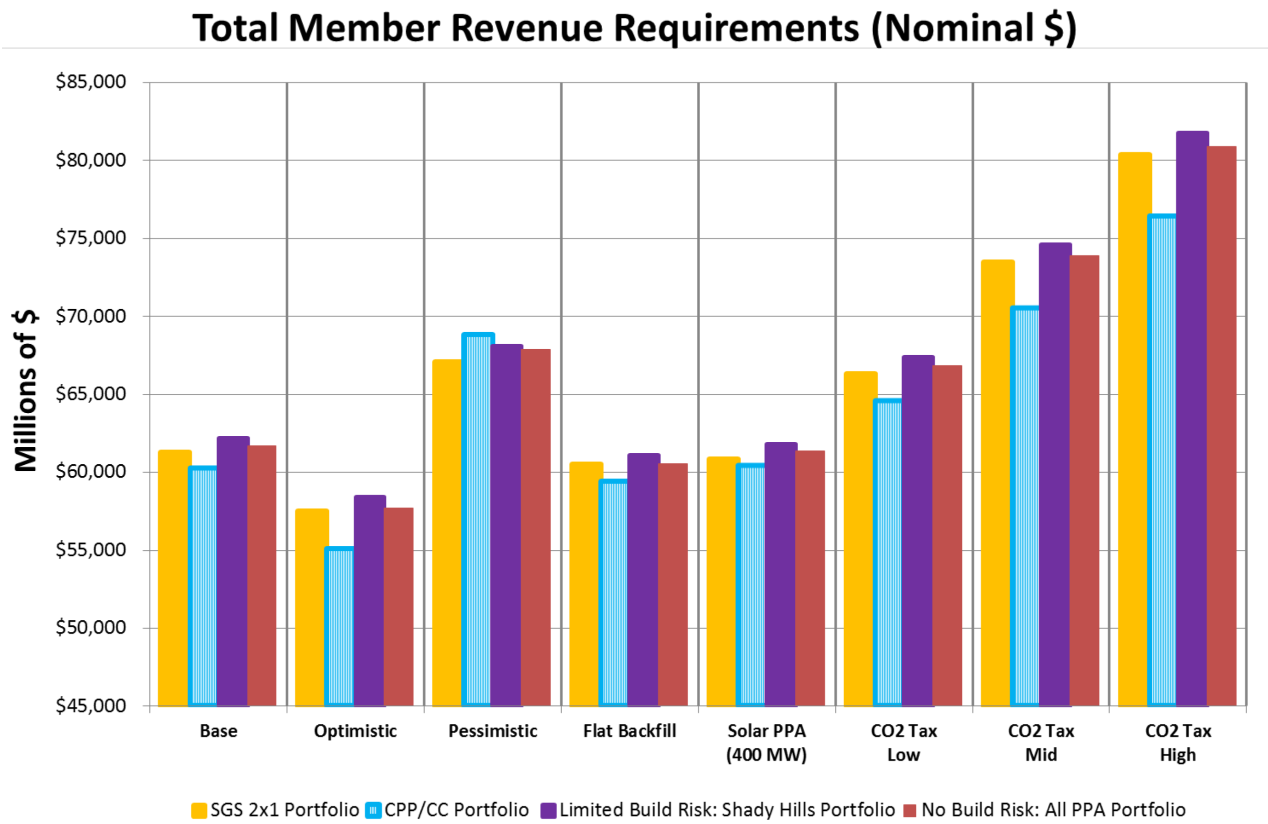
6.5 Sensitivity Analyses

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

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

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

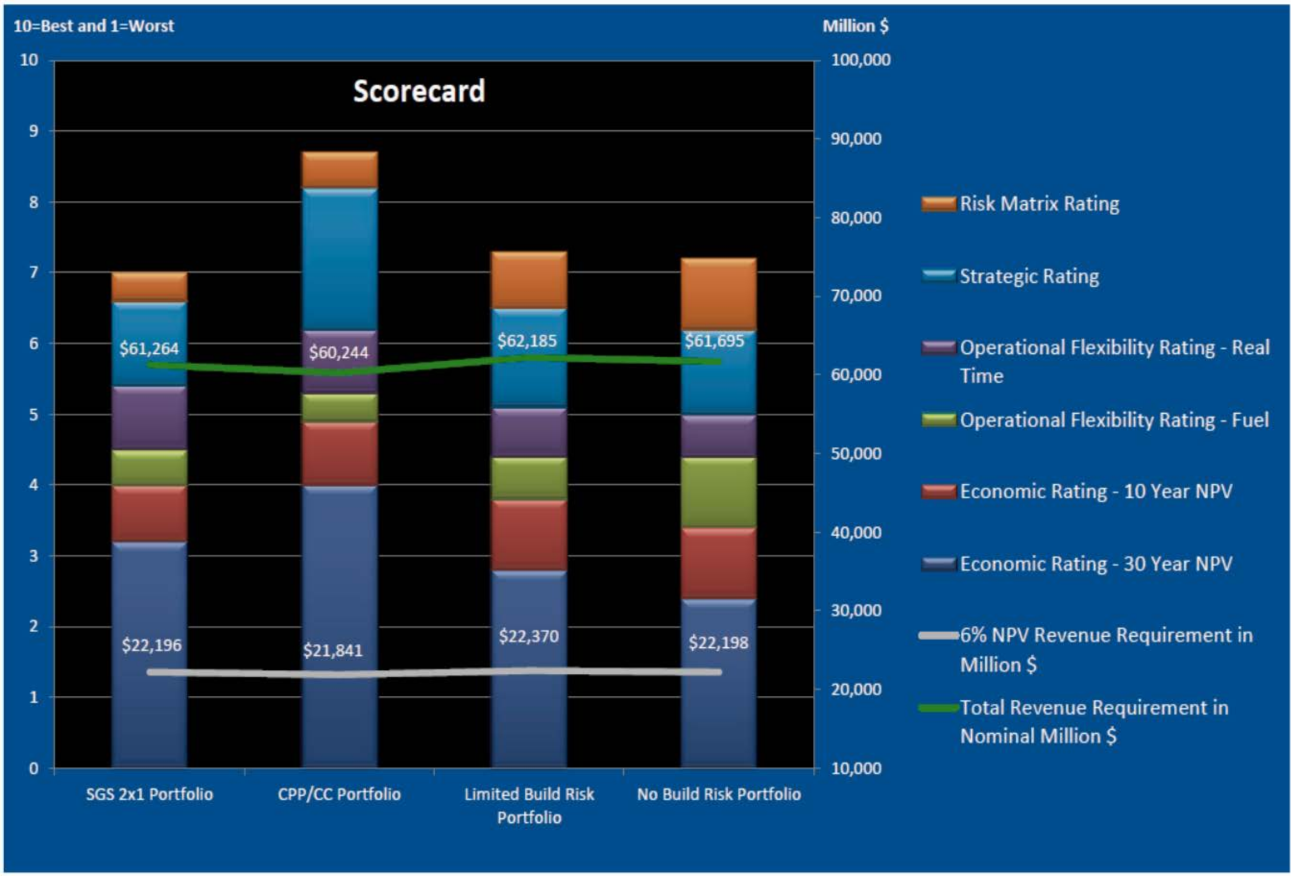
Figure 11 Results of Sensitivity Analyses



6.6 Consideration of Economic and Non-Economic Attributes

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

Figure 12 Portfolio Scorecard Assessment



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

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

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

6.7 Selection of SCCF and SHCCF

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

6.8 Updated Economic Assessment

Since the Board of Trustees' initial approval of the selected resource plan, Seminole conducted a present worth revenue requirements comparison for all four portfolios with the 2018 Budget assumptions approved in October 2017. While the total dollar values changed, the rankings between the portfolios did not. The CPP/CC Portfolio, which includes the SCCF and SHCCF along with the removal from service of one of the two existing 664 MW SGS coal units, remained the least cost portfolio. The next portfolio in NPV revenue requirement terms was approximately $363 million more expensive over the study period. Figure 13 shows the differential between the portfolios.

Figure 13 Summary of Updated Economic Analysis

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

7.0 EVALUATION OF NON-GENERATING ALTERNATIVES

7.1 Current Conservation & Demand-Side Management Efforts

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

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

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

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

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

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

Table 18 Conservation & Demand-Side Offerings of Seminole Members

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

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

Table 19 Annual Energy Savings

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

7.2 Potential for Conservation and DSM Savings to Mitigate Need

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

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

Seminole Electric
COOPERATIVE, INC.

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

8.0 ADVERSE CONSEQUENCES OF DENIAL

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

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

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

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

9.0 CONCLUSION

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

APPENDIX A

Seminole Electric Cooperative

Ten Year Site Plan

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

April 1, 2016

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

Dear Ms. Mtenga:

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

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

Sincerely,

Julia A Diazgranados

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

Enclosure

cc: M. Sherman
L. Johnson

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

Ten Year Site Plan

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

Submitted To:
State of Florida
Public Service Commission

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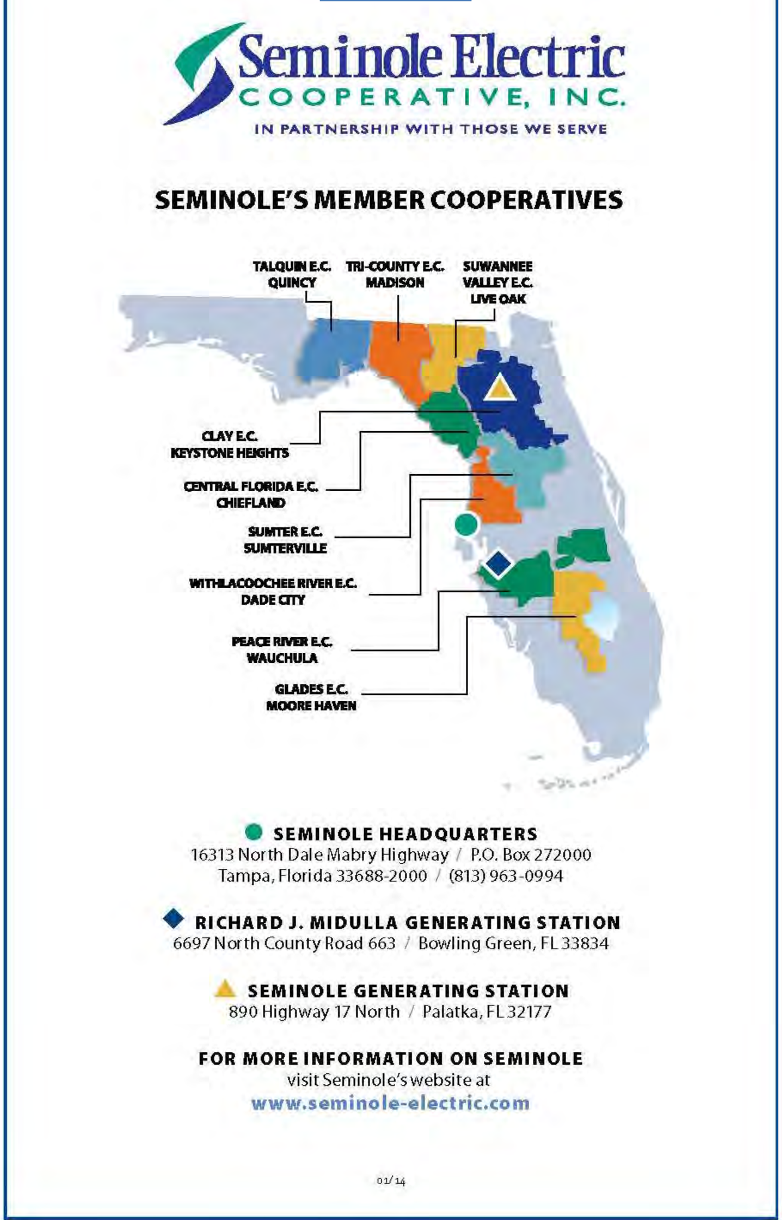
Seminole Electric COOPERATIVE, INC.

1. DESCRIPTION OF EXISTING FACILITIES

1.1 Overview

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

Map 1



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

1.2 Existing Facilities

1.2.1 Owned Generation

Seminole's existing generating facilities include:

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

Schedule 1
Existing Generating Facilities as of December 31, 2015

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

Schedule Abbreviations:			
	General	Unk – Unknown N/A – Not applicable	
	<u>Unit Type</u> ST - Steam Turbine CC - Combined Cycle CT – Combustion Turbine PV – Photovoltaic	<u>Fuel Type</u> BIT - Bituminous Coal NG - Natural Gas DFO – Ultra low sulfur diesel Sun – Solar Energy	<u>Fuel Transportation</u> PL – Pipeline RR – Railroad TK – Truck

1.2.2 Transmission

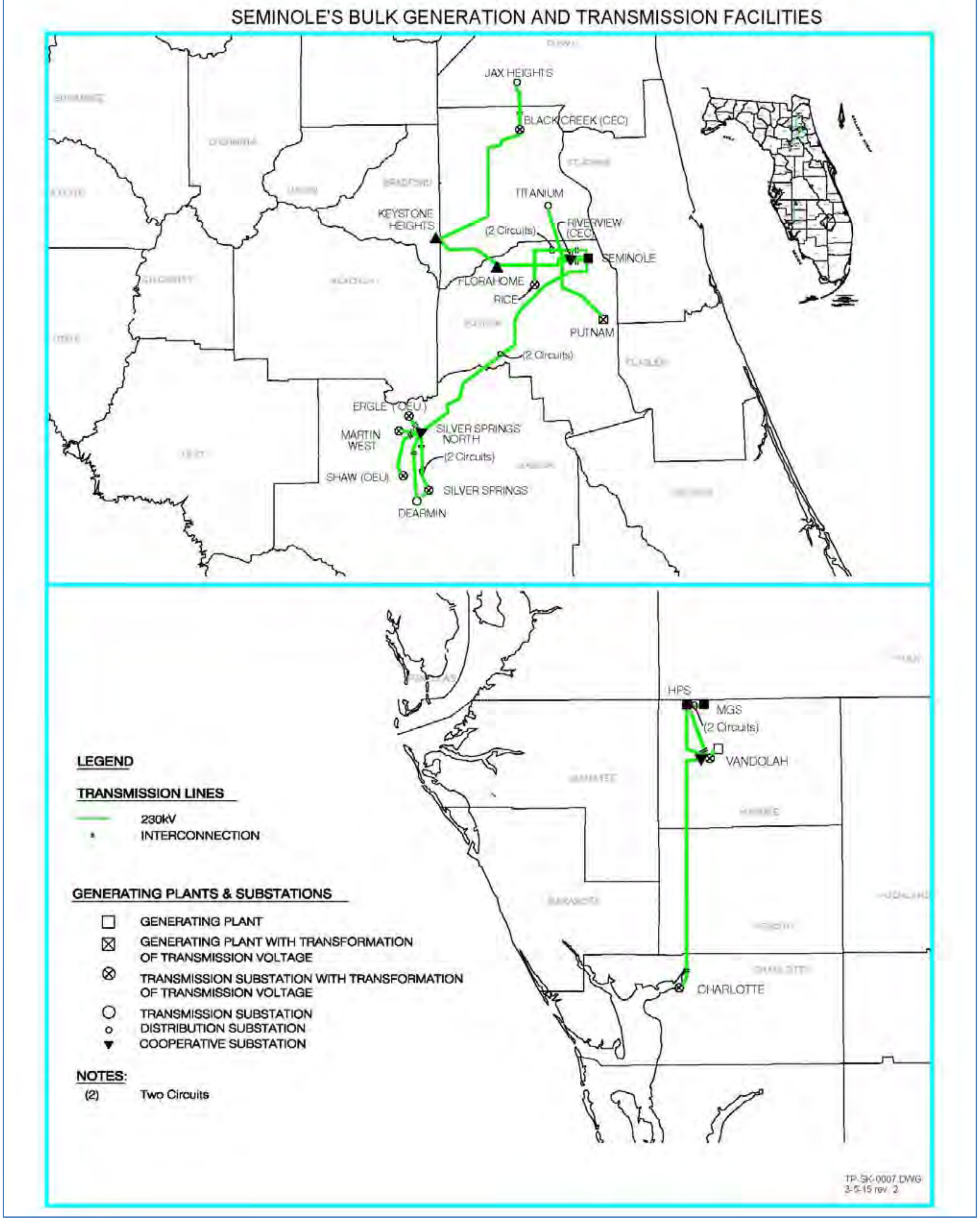
Seminole serves its Members' load primarily in three transmission areas: Seminole Direct Serve (SDS) system, Duke Energy Florida (DEF) system, and Florida Power & Light (FPL) system. Seminole's existing transmission facilities consist of 254 circuit miles of 230 kV and 141 circuit miles of 69 kV lines.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

Seminole Electric COOPERATIVE, INC.

Table 1.1 Transmission Grid Interconnections with Other Utilities		
Utility	**Voltage (kV)**	**Number of Interconnections**
Florida Power & Light	230	6
Duke Energy Florida	230	7
JEA	230	1
City of Ocala	230	2
Tampa Electric Company	230	1
Hardee Power Partners	230	3
Note: This table describes physical facility interconnections, which do not necessarily constitute contractual interconnections for purposes of transmission service or interconnections between balancing areas.		

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

Map 2


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

1.3 Purchased Power Resources

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

Table 1.2

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

2. FORECAST OF ELECTRIC DEMAND AND ENERGY CONSUMPTION

2.1 Energy Consumption and Number of Customers

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

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

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

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

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

Schedule 2.2 History and Forecast of Energy Consumption and Number of Customers by Customer Class					
Year	Commercial[1]			Other Sales (GWh)[2]	Total Member Sales to Ultimate Consumers (GWh)[3]
	GWh	Average Number of Customers	Average Consumption Per Customer (kWh)		
2006	4,634	84,345	54,941	158	15,945
2007	4,839	88,306	54,798	165	16,448
2008	4,894	86,121	56,827	163	16,161
2009	4,776	84,318	56,643	167	16,236
2010	4,525	78,788	57,433	158	16,052
2011	4,366	78,828	55,386	160	14,938
2012	4,456	80,598	55,287	164	14,599
2013	4,482	82,302	54,458	166	14,666
2014	4,001	72,632	55,086	151	12,960
2015	4,155	73,290	56,689	151	13,374
2016	4,146	74,567	55,600	142	13,268
2017	4,262	75,722	56,282	140	13,579
2018	4,364	77,002	56,676	142	13,885
2019	4,478	78,212	57,249	143	14,176
2020	4,562	79,377	57,467	145	14,437
2021	4,640	80,508	57,636	146	14,679
2022	4,712	81,613	57,738	148	14,900
2023	4,781	82,694	57,816	149	15,114
2024	4,848	83,749	57,884	151	15,319
2025	4,912	84,790	57,928	152	15,516

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

[1] Includes Industrial and Interruptible Customers.

[2] Includes Lighting Customers.

[3] Excludes Sales for Resale and includes SEPA.

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

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

2.2 Annual Peak Demand and Net Energy for Load

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

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)

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

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

[1] Excludes Wholesale Interruptible Purchases

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

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

[4] Excludes SEPA allocations.

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

Schedule 3.2 History and Forecast of Winter Peak Demand (MW)										
Year	Total	Wholesale	Retail	Interruptible Load[1]	Distributed Generation[2]	Residential Load Mgmt.[3]	Residential Cons.	Commercial Load Mgmt.[3]	Commercial Cons.	Net Firm Demand[4]
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"

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

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

* Estimated values for 2015

2.3 Monthly Peak Demand and Net Energy for Load

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

Schedule 4						
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month						
Month	**2015 Actual**		**2016 Forecast**		**2017 Forecast**	
	Peak Demand (MW)[1]	**NEL (GWh)**	**Peak Demand (MW)[2]**	**NEL (GWh)**	**Peak Demand (MW)**	**NEL (GWh)**
January	2,826	1,109	3,307	1,150	3,481	1,176
February	3,593	1,051	2,900	976	2,939	1,005
March	2,069	1,009	2,438	996	2,513	1,023
April	2,362	1,083	2,319	1,005	2,375	1,032
May	2,821	1,275	2,651	1,208	2,691	1,232
June	3,021	1,375	2,816	1,317	2,850	1,340
July	2,935	1,393	2,945	1,412	2,985	1,434
August	3,021	1,406	3,024	1,415	3,082	1,445
September	2,845	1,254	2,794	1,287	2,835	1,310
October	2,470	1,079	2,508	1,089	2,573	1,124
November	2,471	1,034	2,498	978	2,567	1,004
December	2,065	1,036	2,706	1,092	2,795	1,124
ANNUAL		**14,104**		**13,925**		**14,249**

[1] Peak Demand includes interruptible load; Excludes Distributed Generation, Load Management and SEPA allocations
[2] Peak Demand Excludes Interruptible Load, Distributed Generation, Load Management and SEPA allocations.
Note: Peak Demand for January 2016 is Actual.

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2.4 Fuel Requirements

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

Schedule 5
Fuel Requirements For Seminole Generating Resources

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

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

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2.5 Energy Sources by Fuel Type

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

Schedule 6.1
Energy Sources (GWh)

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

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

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Schedule 6.2
Energy Sources (Percent)

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

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

3. FORECASTING METHODS AND PROCEDURES

3.1 Forecasting Methodology

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

3.1.1 Consumer Model

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

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

3.1.2 Energy Model

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

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

3.1.3 Peak Demand Model

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

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

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

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

3.1.4 Alternative-Scenario Models

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

3.2 Load Forecast Data

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

3.2.1 Materials Reviewed and/or Employed

Load Data by Delivery Point

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

Retail Number of Consumers, Energy Sales by Rate Class:

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

Individual Large Consumer Loads Over 1000 kVA:

- Member provided

Demographic and Economic Indicators:

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

Weather Data:

- AccuWeather

3.3 Significant Load Forecast Assumptions

3.3.1 Economic Assumptions

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

This load forecast reflects expectations that the national economy, and Florida's economy in particular, will continue to recover from the Great Recession over the next several years. In addition, Member territories will likely benefit from consumer growth due to "baby-boomer" retiree migration into Florida from other states. Improving economic conditions and expected net migration are leading indicators for overall load growth. Despite the potential growth opportunities however, electricity usage per residential consumer trends over the last decade for electric utilities in the state of Florida are on average flat to negative and Seminole projects this trend will generally continue into the future.

3.3.2 Weather Assumptions

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

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

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

4. FORECAST OF FACILITIES REQUIREMENTS

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

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

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

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

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

NOTES:
1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.
2. Total Installed Capacity does not include SEPA or Solar.
3. Percent reserves are calculated at 15% of Seminole’s obligation and include any surplus capacity.

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

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

NOTES:
1. Total installed capacity and the associated reserve margins are based on Seminole's current base case plan and are based on a 15% reserve margin criterion.
2. Total Installed Capacity does not include SEPA or Solar.
3. Percent reserves are calculated at 15% of Seminole’s obligation and include any surplus capacity.

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4.1 Planned and Prospective Generating Facility Additions and Changes

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

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

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

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

4.2 Proposed Generating Facilities

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

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

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

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

Seminole Electric COOPERATIVE, INC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

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

Seminole Electric COOPERATIVE, INC.

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

4.3 Proposed Transmission Lines

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

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

5. OTHER PLANNING ASSUMPTIONS AND INFORMATION

5.1 Transmission Reliability

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

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

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

5.2 Plan Economics

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

5.3 Fuel Price Forecast

5.3.1 Coal

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

5.3.2 Fuel Oil

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

5.3.3 Natural Gas

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

5.3.4 Modeling of Fuel Sensitivity

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

5.4 Coal/Gas Price Differential

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

5.5 Modeling of Generation Unit Performance

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

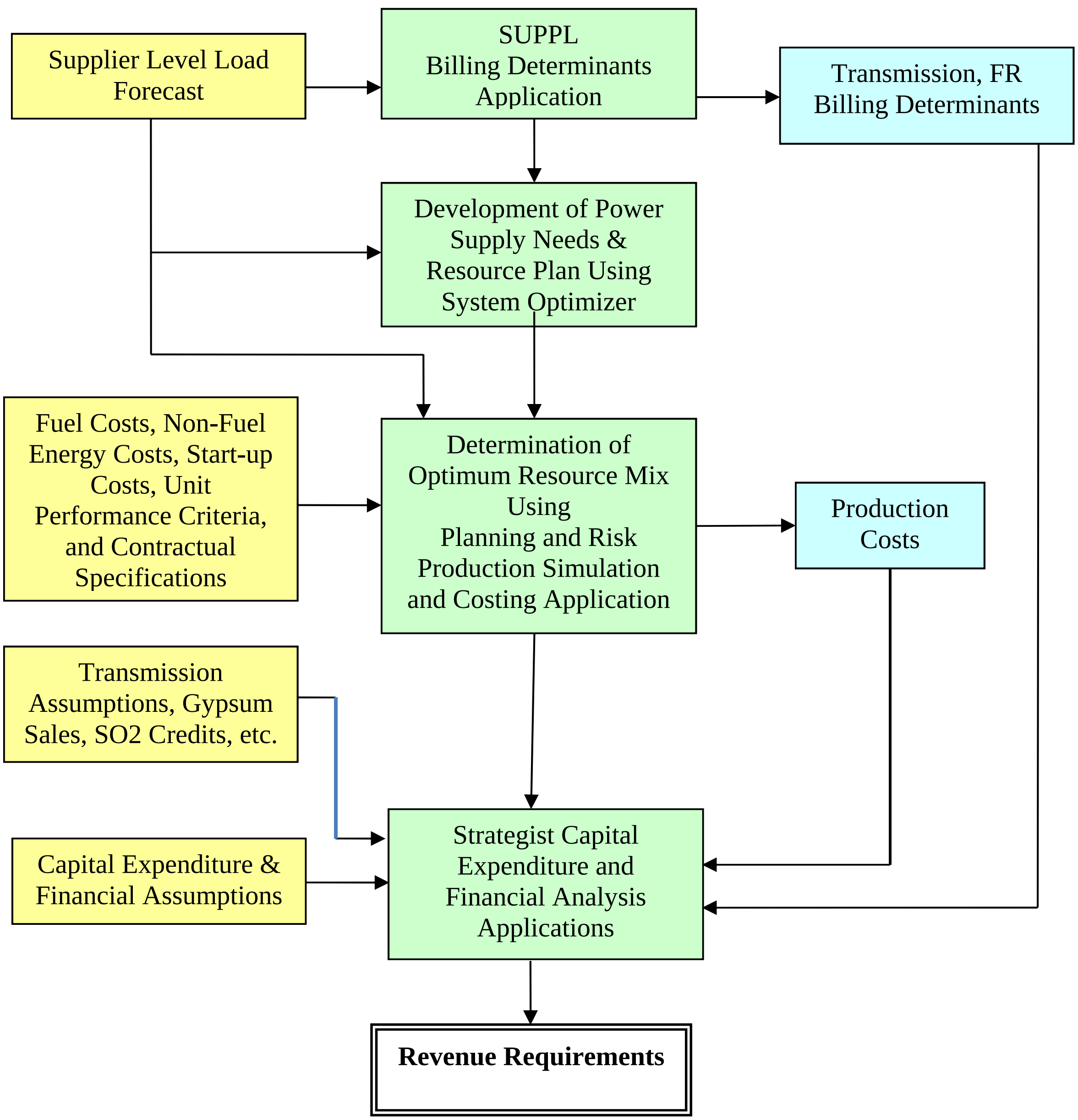
5.6 Financial Assumptions

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

5.7 Resource Planning Process

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

Figure 5.1
Resource Planning Process



5.8 Reliability Criteria

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

5.9 DSM Programs

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

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

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

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

5.10 Strategic Concerns

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

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

5.11 Procurement of Supply-Side Resources

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

5.12 Transmission Construction and Upgrade Plans

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

6. ENVIRONMENTAL AND LAND USE INFORMATION

6.1 Potential Sites

6.1.1 Gilchrist Site – Gilchrist County, Florida

Seminole owns land in Gilchrist County but has not made a final determination if or when the site will be used for any of Seminole's future resource requirements. The Gilchrist site is approximately five-hundred thirty (530) acres in size. The site is located in the central portion of Gilchrist County, approximately eight (8) miles north of the City of Trenton and may be suitable for installation of generation or transmission resources. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine communities. Few natural upland communities remain. Most of these large tracts have been harvested, leaving xeric oak and pine remnants. A few wetland communities remain on the east side of the site with relatively minor disturbances due to adjacent silvicultural activities.

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

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

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

The area around the SGS site includes mowed and maintained grass fields and upland pine flatwoods. Areas further away from the existing units include live oak hammocks, wetland conifer forest, wetland hardwood/conifer forest, and freshwater marsh. A small land parcel located on the St. Johns River is the site for the water intake structure, wastewater discharge structure, and pumping station to supply the facility with cooling and service water.

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

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

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

6.2 Preferred Sites

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

MGS is located in Hardee and Polk Counties about nine (9) miles northwest of Wauchula. The site is bordered by County Road 663 on the east and by The Mosaic Company on the south, north and west. Payne Creek flows along the site's south and southwestern borders. The site was originally strip-mined for phosphate and was reclaimed as pine flatwoods, improved pasture, and a cooling reservoir with a marsh littoral zone. The proposed solar project will be located on approximately 29-acres of land on the west side of the current plant entrance road and to the north of three onsite above ground storage tanks. A more detailed description of environmental, land use, as well as water use and supply, is available in the site certification application PA-89-25SA.

6.2.1.1 Land and Environmental Features

a. U.S. Geological Survey Map

See Map 5

b. Proposed Facilities Layout

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

c. Map of Site and Adjacent Areas

See Map 7

d. Existing Land Uses of Site and Adjacent Areas

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

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is currently made up of the MGS facilities, a 570-acre cooling reservoir, pastureland and some forested and non-forested uplands and wetlands interspersed. The PV site is to be built completely on an area that is currently pastureland.

2. Listed Species

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

3. Natural Resources of Regional Significance Status

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

4. Other Significant Features

Seminole is not aware of any other significant site features.

f. Design Features and Mitigation Options

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

g. Local Government Future Land Use Designations

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

h. Site Selection Criteria Process

The Seminole Solar site at MGS has been selected as the location of the PV facility based on various factors including system load, interconnection availability, and proximity to existing Seminole operations and maintenance personnel, as well as economics.

i. Water Resources

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

j. Geological Features of Site and Adjacent Areas

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

k. Projected Water Quantities for Various Uses

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

l. Water Supply Sources by Type

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

m. Water conservation Strategies Under Consideration

The PV site does not require a permanent water source. Water conservation strategies include minimizing water use by cleaning the panels with water only in the absence of sufficient rainfall and leaving the vegetation in and around the site as is with no required watering.

n. Water Discharges and Pollution Control

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

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

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

p. Air Emissions and Control Systems

Solar PV does not generate air emissions.

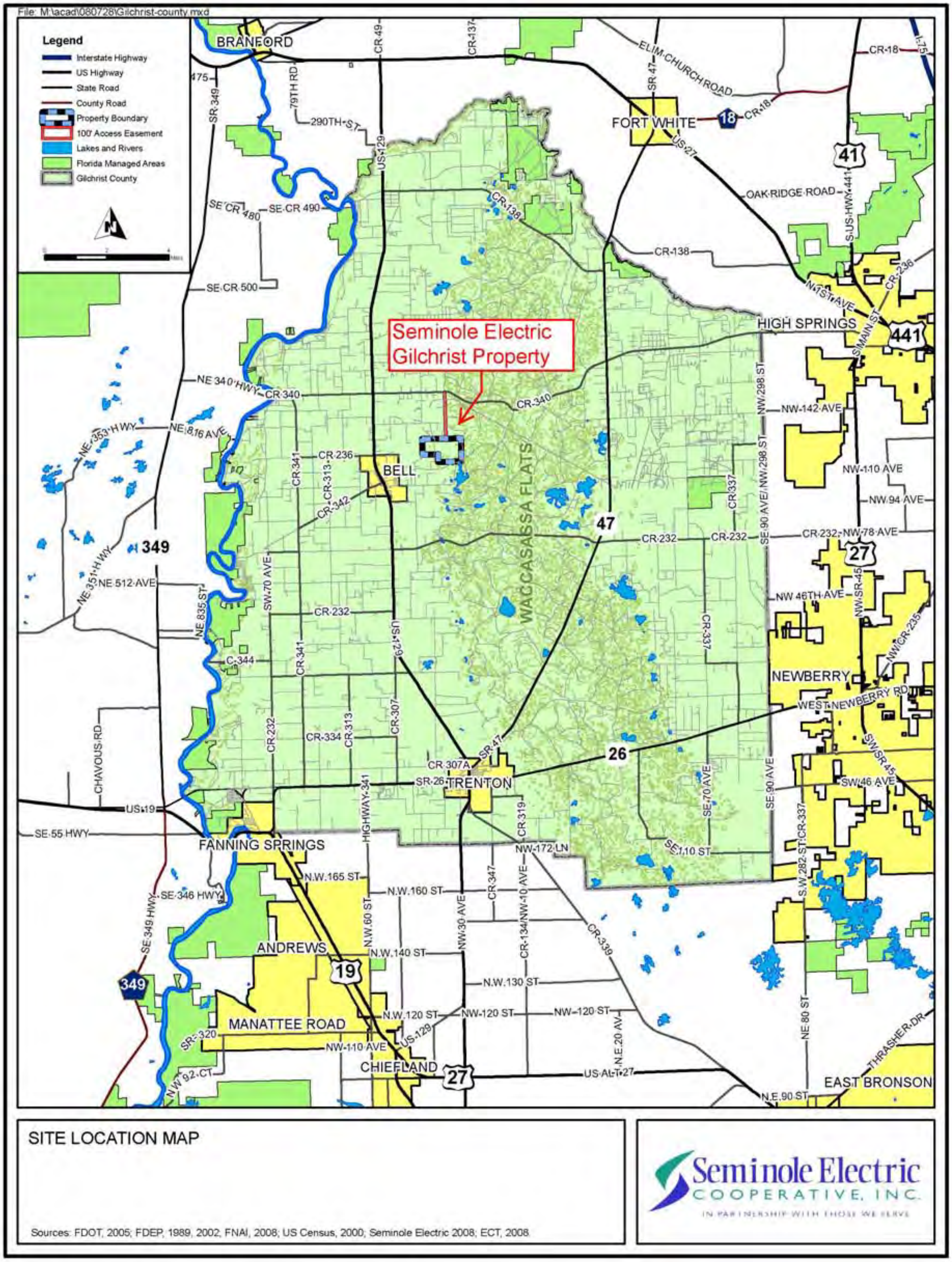
q. Noise Emissions and Control Systems

Solar PV does not generate noise.

r. Status of Applications

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

Map 3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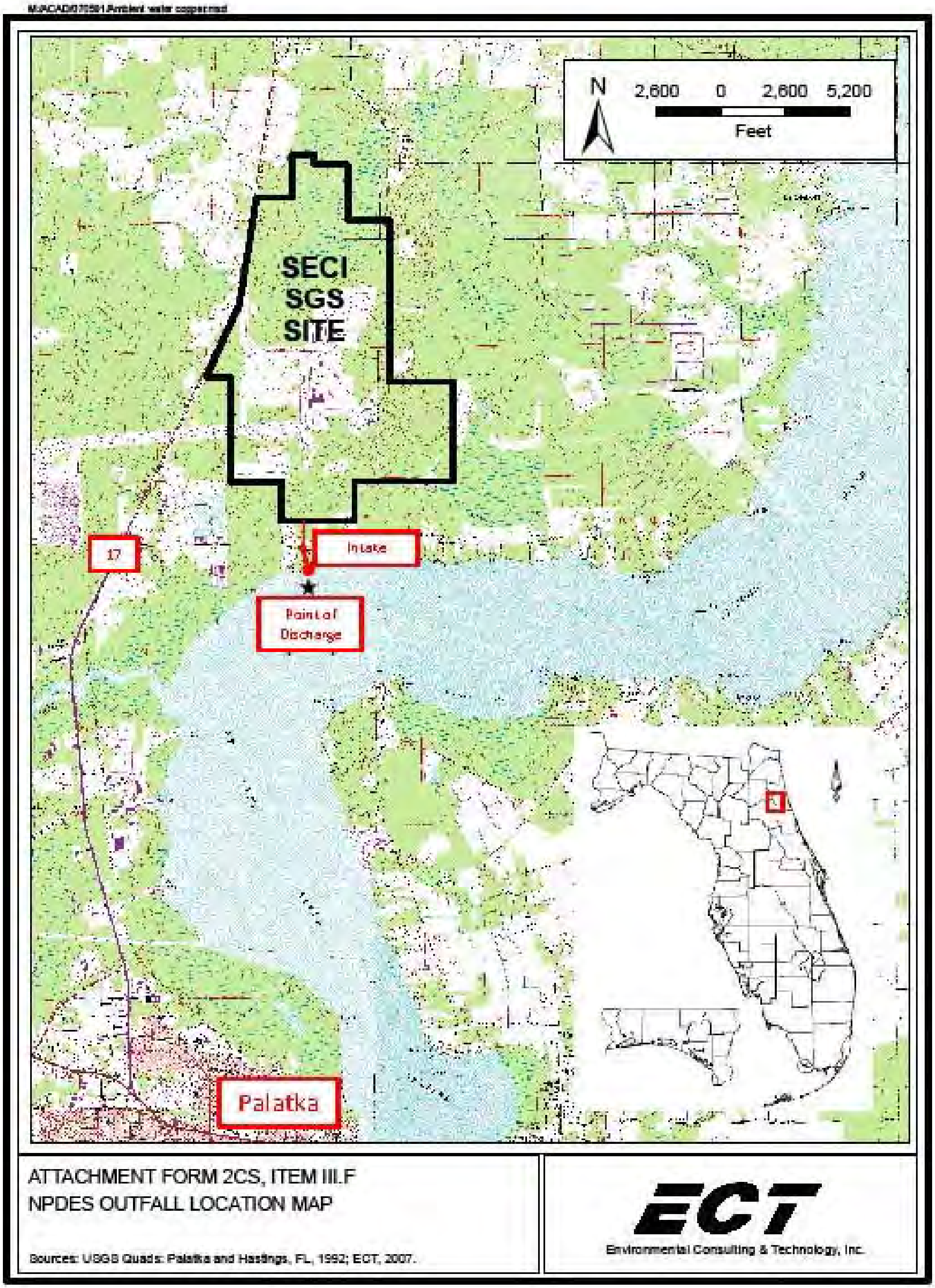
Legend
Interstate Highway
US Highway
State Road
County Road
Property Boundary
100' Access Easement
Lakes and Rivers
Florida Managed Areas
Gilchrist County
Seminole Electric
Gilchrist Property
BRANFORD
FORT WHITE
HIGH SPRINGS
BELL
WACCASASSA FLATS
NEWBERRY
TRENTON
FANNING SPRINGS
ANDREWS
MANATTEE ROAD
CHIEFLAND
EAST BRONSON
SITE LOCATION MAP
Sources: FDOT, 2005; FDEP, 1989, 2002; FNAI, 2008; US Census, 2000; Seminole Electric 2008; ECT, 2008.
Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Map 4



Seminole Electric
COOPERATIVE, INC.

Map 5

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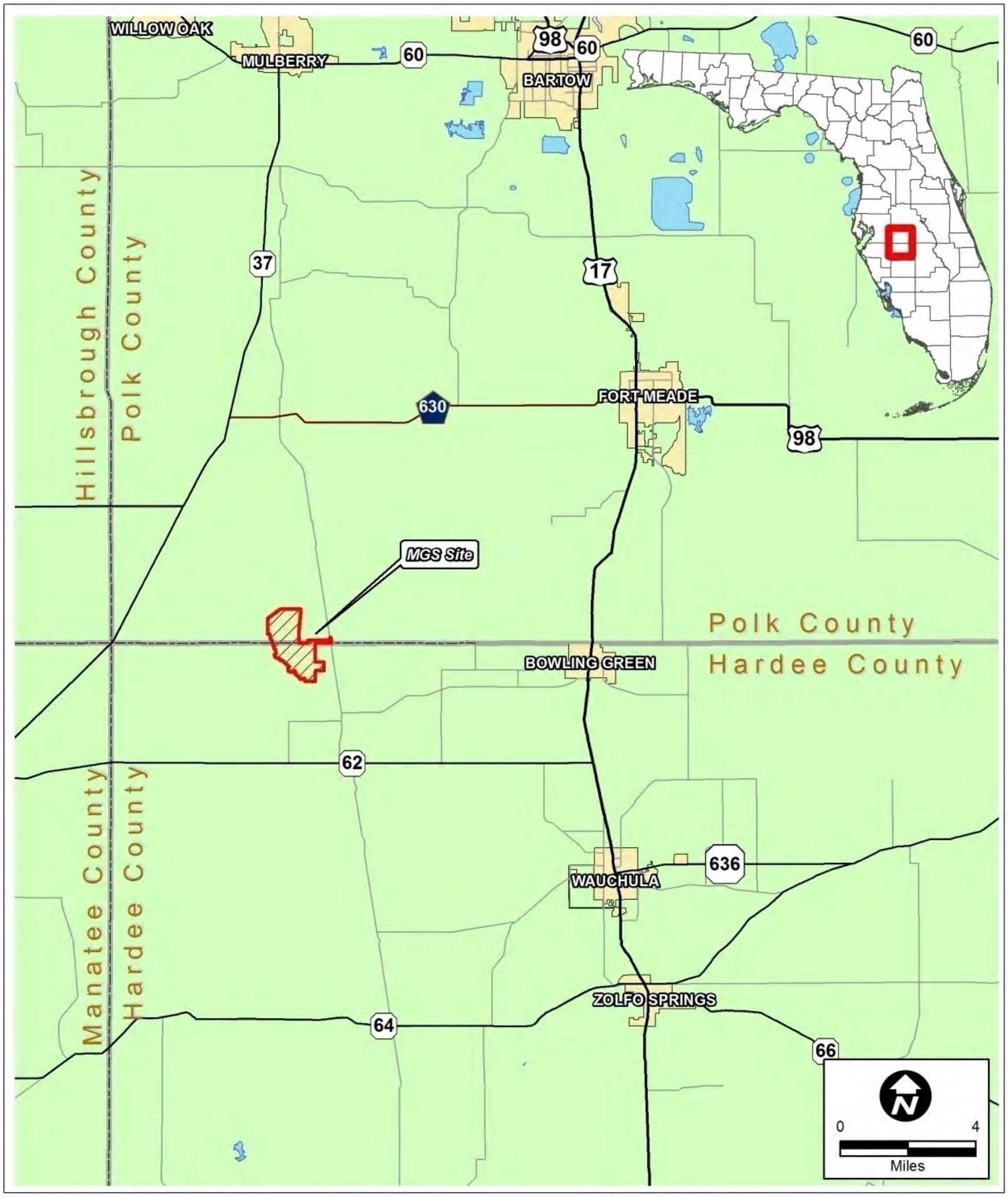


LOCATION OF MIDULLA GENERATING STATION

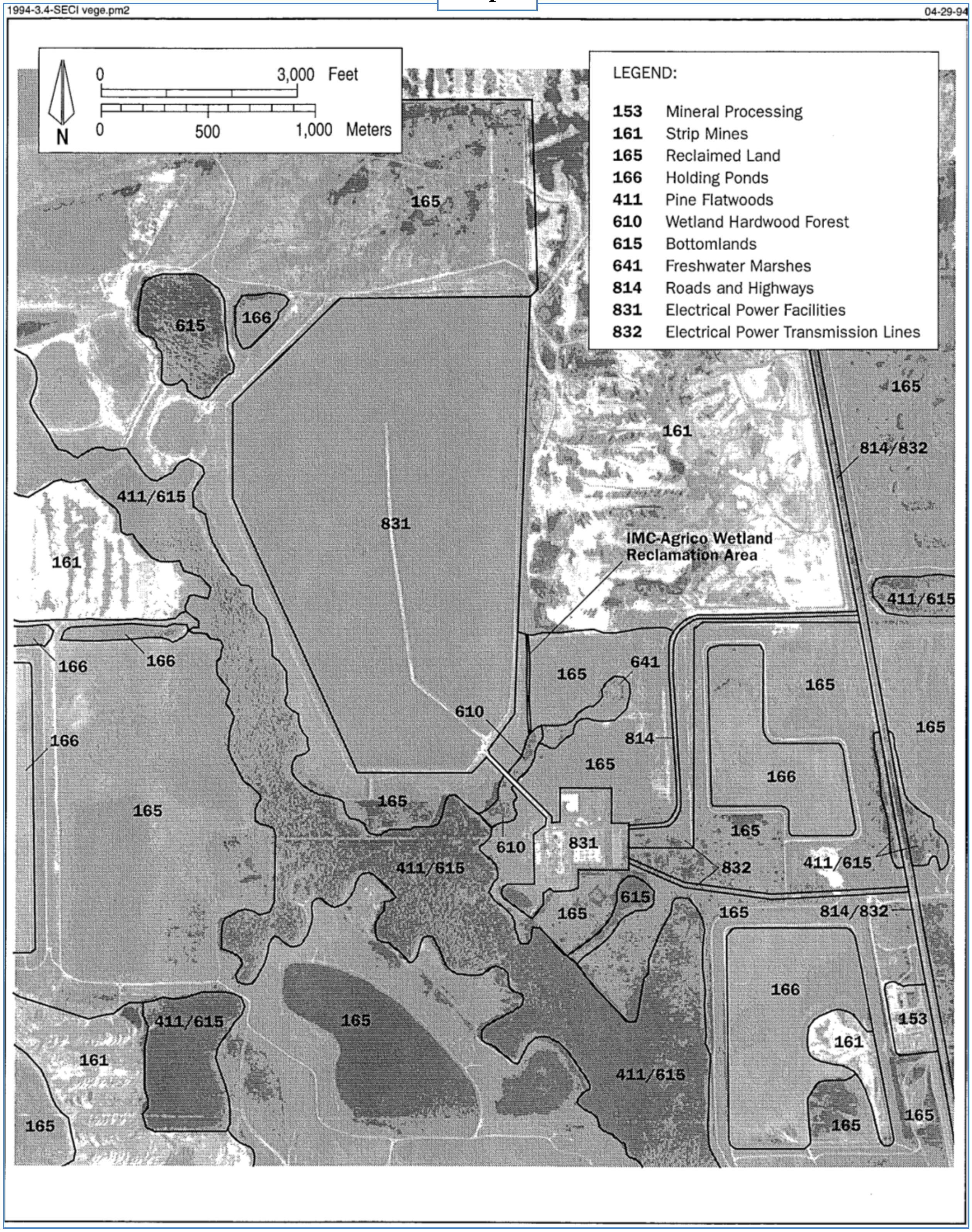
Source: ESRI, 2009; US Census, 2000; ECT, 2009.

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

Map 6

Seminole Electric
COOPERATIVE, INC.

Map 7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04-29-94
0
3,000 Feet
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500
1,000 Meters
N
LEGEND:
153 Mineral Processing
161 Strip Mines
165 Reclaimed Land
166 Holding Ponds
411 Pine Flatwoods
610 Wetland Hardwood Forest
615 Bottomlands
641 Freshwater Marshes
814 Roads and Highways
831 Electrical Power Facilities
832 Electrical Power Transmission Lines
IMC-Agrico Wetland
Reclamation Area
165
615
166
831
161
814/832
411/615
165
166
641
610
814
832
153

APPENDIX B

Seminole Electric Cooperative

Request for Proposal

& Addenda

Request for Proposals ("RFP")

Request for Firm Capacity
RFP No. FC 2021

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

March 1, 2016

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

Request for Proposals
RFP No. FC 2021

Table of Contents

Proposal Forms

Seminole Electric Cooperative, Inc.
RFP No. FC 2021

March 1, 2016
Request for Firm Capacity

1.0 Purpose

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

2.0 Description of Seminole Electric Cooperative, Inc.

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

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

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

3.0 RFP Provisions

3.1 This RFP is open to all parties, including, but not limited to: independent power producers, renewable energy providers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and electric utilities. Seminole will consider offers including purchased power proposals (system or tolling), generation proposals that include Seminole taking an ownership/equity position in a portion of a facility, facility acquisitions, or proposals for firm energy.

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

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

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

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

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

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

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

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

4.0 Delivery to the Seminole System

4.1 Seminole currently serves its load primarily through its own transmission system ("SSN") or through the transmission systems of Duke Energy Florida ("DEF") and Florida Power and Light Company ("FPL"). Wheeling and interconnection arrangements and all costs to deliver the capacity and energy to the Seminole, DEF or FPL balancing authority areas are the responsibility of the bidder.

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

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

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

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

5.0 Bidder Forms

5.1 Bidders should complete and submit a Seminole Bidder Qualification Questionnaire ("BQQ") and Schedules A and B as part of each submittal. Schedules C through D will be completed by the bidders as required by the structure of their proposal. If more than one submittal is made by a bidder, separate Schedules C through D must be prepared for each submittal.

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

6.0 Other Terms and Conditions

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

7.0 Reservation of Rights

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

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

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

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

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

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

8.0 Procedures for Application

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

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

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

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

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

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

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

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

9.0 Confidentiality

9.1 Seminole recognizes that certain information contained in proposals submitted may be confidential and, as permitted by applicable law, will use reasonable efforts to maintain the information contained in the proposal as confidential. Seminole will not treat submitted information as confidential if it already has the information, the information is clearly in the public domain or is readily available from public sources. However, Seminole reserves the right to submit the proposal to the Rural Utilities Service ("RUS") and to any other regulatory agency or judicial authority that may request it.

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

10.0 Bid Evaluation Process

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

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

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

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

conditions of this RFP.

10.3 Proposals may then undergo a review from a commercial perspective, which will include but not be limited to the following, to ensure that the bidder has:

- adequate and pertinent experience, resources, and qualifications;
- the necessary financial assurance and operational viability to sustain an offer;
- made a commitment of guaranteed firm capacity to Seminole with adequate availability/non-performance guarantees and remedies;
- either itself, or through its guarantor, an investment grade credit rating, or is willing to post a letter of credit or other security acceptable to Seminole.

10.4 Seminole may conduct scenario and sensitivity analyses of proposals to evaluate risks and strategic value. The results of these analyses may be considered in Seminole's evaluation of proposals, including the selection of proposal(s) for the short list, if applicable.

11.0 Communication

11.1 Seminole expects to identify a short list by **August 19, 2016**. Contracts detailing the terms and conditions of completed agreement(s), if any, are expected to be executed by **January 31, 2017**.

11.2 This RFP is available on the Internet at **http://www.seminole-electric.com**, or by e-mail or U.S. mail. Please routinely check this web site for addendums and/or clarifications to this RFP.

11.3 Prospective bidders will be placed on Seminole's RFP e-mail distribution list for RFP updates. If your company intends to submit a proposal, please send your contact information (name, company name, title, phone and fax numbers, and e-mail address) to "**SeminolePowerRFP@seminole-electric.com**" no later than **March 15, 2016**.

11.4 If any prospective bidder has any questions or desires additional information related to this request for proposals, **such questions or information requests should be made in writing and directed via e-mail at "SeminolePowerRFP@seminole-electric.com"** to Mr. Jason Peters, Portfolio Director. Any RFP addendum(s), or question(s) of general interest and the respective answer will be posted on the above web site and directly e-mailed to parties that have provided their contact information to Seminole per Section 11.3 above.

Thank you for your interest in this RFP.

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 1
ISSUED MARCH 18, 2016

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

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

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

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

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

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

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 2
ISSUED APRIL 7, 2016

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 3
ISSUED APRIL 19, 2016

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

8.0 Procedures for Application

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

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

By Courier:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

16313 North Dale Mabry Highway

Tampa, FL 33618

By U.S. Postal Service:

Seminole Electric Cooperative, Inc.

Attention: Mr. Timothy Nasello, Director of Supply Management

P.O. Box 272000

Tampa, FL 33688-2000

By E-Mail:

SeminolePowerRFP@seminole-electric.com

With a carbon copy to:

Alan.Taylor@sedwayconsulting.com

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

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

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

RFP FC 2021- ISSUED MARCH 1, 2016

ADDENDUM NUMBER 4 - OPERATING PERFORMANCE
ISSUED JULY 13, 2016

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

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

Seminole's additional questions regarding operational performance follow below:

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

   Answer:

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

   Answer:

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

   Answer:

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

   Answer:

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

   Answer:

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

   Answer:

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

   Answer:

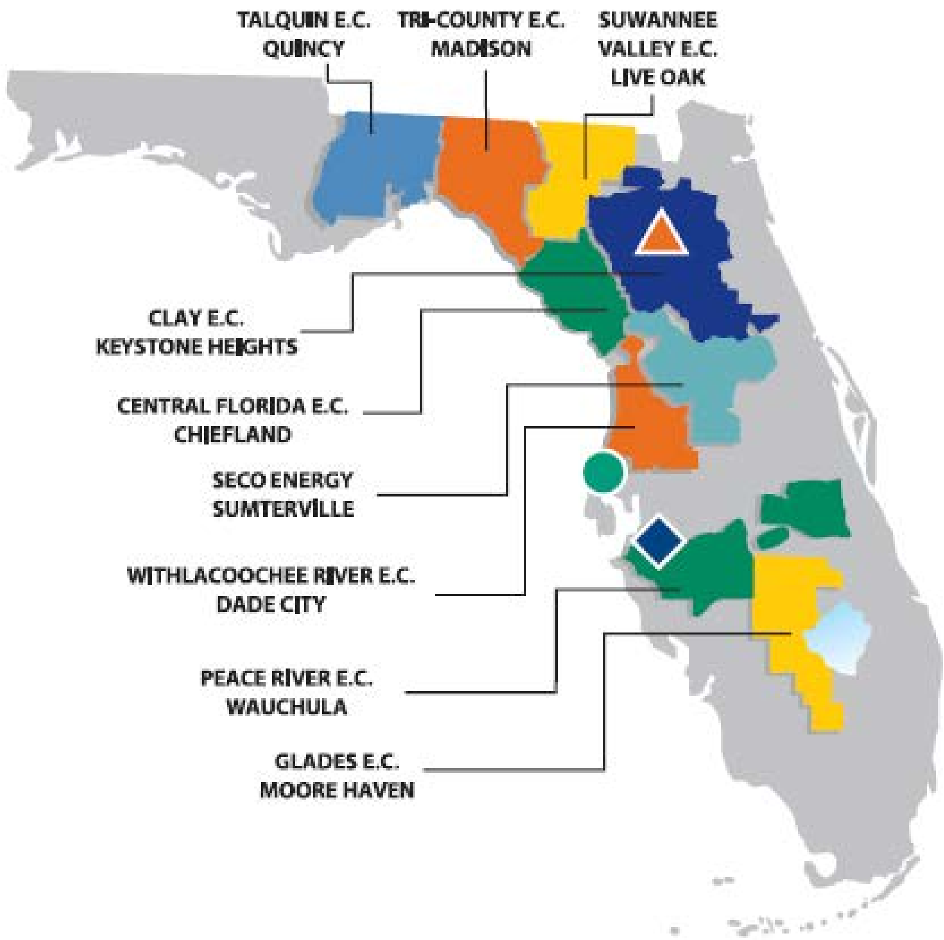
8. Question: Regarding the ramp in of energy schedules, please define a typical ramp in period for your proposal and any flexibility that may be available outside of ramping at the top and bottom of the hour. Seminole, as an FRCC entity, is accustomed to a 20-minute ramp schedule. Is dynamic scheduling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

   Answer:

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

   Answer:

SEMINOLE'S MEMBER COOPERATIVES



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

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

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

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

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

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

Seminole's New Purchase Power Contracts

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

* Winter ratings
** Summer rating

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

DAVID KEZELL

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF DAVID KEZELL

DOCKET NO. _________-EC

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is David Kezell. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618-2000.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Director of Engineering and Capital Development.

Q. What are your responsibilities in your current position?

A. As Seminole's Director of Engineering and Capital Development, I am responsible for the planning, development, and coordination of capital projects associated with existing and potential new generating facilities, coordination of the activities of the engineering resources team as well as development, maintenance and administration of Seminole's multi-year Construction Work Plan (CWP) and Capital Budget and Work Plan. I have management oversight responsibility for the development and execution of the Seminole Combined Cycle Facility ("SCCF") project.

Q. Please describe your professional experience and education background.

A. I have more than twenty six years of experience in the energy industry either as an engineering consultant or as an employee of a company involved in the generation of electrical energy. My roles have included Project Engineer, Engineering Supervisor, Project Manager, Operations Manager, Manager of Construction Management, General Manager, and Director of Engineering and Capital Development. I have personally managed the development and construction of two generating facilities and have had oversight responsibilities for the personnel managing the engineering, procurement and construction management of several more. I have served as Seminole's Director of Engineering since 2013.

I hold a B.S. in Mechanical Engineering and a B.A. in General Arts and Sciences from the Pennsylvania State University and an M.S. in Mechanical Engineering from Arizona State University. I also hold a certificate in Air Quality Management from the University of California at Berkeley and I am a licensed Professional Engineer in the state of California.

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

A. The purpose of my testimony is to provide an overview of the SCCF project and its development from a technical perspective in support of Seminole's Petition for Determination of Need for the SCCF. Specifically, I will describe the process utilized to select the project site, the project technology, and the business partners that will execute the project on behalf of Seminole. I will describe related facilities, operating assumptions, the development of estimated costs for the project, and its projected in-service date. I will also describe Seminole's experience in construction and operation of combined cycle units and other fossil-fired generation facilities.

Q. Are you sponsoring any exhibits in the case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. __ (DK-1), which is my professional resumé;
- Exhibit No. __ (DK-2) - Preliminary Arrangement of the SCCF at the SGS Site;
- Exhibit No. ___ (DK-3) - Summary of Estimated Capital Costs; and
- Exhibit No. __ (DK-4) - P2021 Single Fuel Facility Analysis;

I am also sponsoring Sections 4.1.1 through 4.1.7, 4.1.10, 4.1.11, and 6.2 of Seminole's Need Study (Exhibit No. ____ (MPW-2)), all of which were prepared by me or under my direct supervision.

Q. Please summarize your testimony.

A. The SCCF will be a highly efficient, cost effective new generation resource that will provide flexible quantities of reliable energy to Seminole’s Member cooperatives for decades to come. The facility will be located on the same property where the existing Seminole Generating Station (“SGS”) is located and will share that facility’s existing transmission and water resource infrastructure. This co-location reduces the overall impact from the new generation resource from that which would be required if it were to be located elsewhere. Seminole is partnering with very capable equipment suppliers, engineers, and constructors to bring the plant to commercial operation in 2022.

Q. Please describe the combined cycle technology that will be used for SCCF Project.

A. The SCCF will utilize two natural gas fired combustion turbine generators ("CTGs") each coupled with an associated heat recovery steam generator ("HRSG") that will produce steam to drive a single steam turbine generator ("STG"). This configuration is commonly referred to as a "two on one" or "2x1" combined cycle plant. The selected CTGs are advanced class General Electric ("GE") 7HA.02 gas turbines. The GE manufactured HRSGs are three-pressure, re-heat units that will deliver steam to a single GE D650 series STG. The HRSGs will be provided with duct burners to provide supplemental firing for additional steam production during peak demand periods. Steam exhausting from the STG will be condensed in a water cooled condenser which cools the steam by means of a 16 cell forced draft cooling tower utilizing water supplied from the St. John's River. Exhibit No. __ (DK-2) is a schematic showing the preliminary site arrangement for the SCCF.

Q. Beyond the combined cycle generating unit itself, what other facilities will be constructed as part of the SCCF?

A. A new natural gas lateral will be constructed by a third party within Putnam County to deliver fuel to the SCCF, as discussed in the testimony of Mr. David Wagner. No off-site new water lines will be required as the SCCF will utilize existing water infrastructure associated with the existing SGS facility. New connections to existing water pipelines on the SGS property will be installed to serve the SCCF. Network upgrades to the existing transmission system that may be required to facilitate the increased output from SGS/SCCF to serve

Seminole's Member load within the Florida Reliability Coordinating Council Region are discussed in the testimony of Mr. Robert DeMelo.

Q. What experience does Seminole have with the evaluation and construction of combined cycle plants and related facilities?

A. Seminole regularly develops generic power plant models with estimated thermodynamic and economic characteristics that are used in our generation planning process. These models allow the organization to stay abreast of technological developments in the industry and evaluate their potential contribution to our future portfolios. Seminole developed the 2x1 combined cycle Midulla Generating Station ("MGS") in Hardee County in 2002 and has operated this facility since that time. Seminole also installed ten additional simple cycle gas turbines at MGS in 2006.

Q. How did Seminole evaluate the feasibility and appropriateness of the combined cycle technology selected for the SCCF?

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

Seminole evaluated several different technologies from three different vendors, General Electric, Mitsubishi, and Siemens. Upon completion of the initial screening, Seminole issued an RFP in February of 2016 to the same three vendors; two of which, General Electric and Mitsubishi, responded with compliant bids. Both of these vendors submitted two proposals; one for a 1x1 configuration and the second for a 2x1 configuration. All four options were evaluated along with the market alternatives**.** We ultimately determined that the 2x1 GE 7HA.02 technology was the most economic option.

Q. What are the expected operational parameters for the SCCF?

A. The facility has a nameplate gross nominal output of 1,183 MW and a net nominal output of 1050 MW. The facility is anticipated to achieve the nominal output across the entire range of ambient conditions typically experienced in Palatka, Florida. It will have significant flexibility in terms of its operational characteristics. The 7HA.02 gas turbines have an extended "turndown" capability which will allow them to meet their required emissions levels while firing the turbines down to as low as 25% of their full-fire levels. This low turn-down capability is valuable as it will allow the SCCF to remain operational during low load periods typically experienced at night and avoid the thermal stresses, wear, and higher emission concentrations typically associated with a shut-down / start-up cycle. During peak load periods, the SCCF can fire supplemental natural gas in duct burners in the HRSGs to get additional generation out of the STG.

The facility will also be capable of running in a 1x1 mode with only one of the CTGs in operation. Finally, if the steam turbine trips, the facility will be able to continue to generate by bypassing the STG with steam generated in the HRSGs and sending it directly to the condenser.

The maximum output of the 2x1 facility at ISO conditions is expected to be approximately 1078 MW without supplemental duct firing and approximately 1131 MW with duct burners in operation. The heat rate of the facility in these same two conditions will be approximately 6,218 and 6,349 Btu/kW-hr higher heating value ("HHV") respectively. The minimum output of the facility at ISO conditions will be approximately 370 MW in 2x1 mode and 164 MW in 1x1 mode.

Q. Did Seminole consider the provision of a back-up fuel in the design of the SCCF?

A. Yes. Seminole considered utilizing diesel fuel oil as a secondary fuel at the SCCF to replace natural gas should that primary fuel be curtailed. Seminole determined that it was not cost-effective to include diesel fuel firing capability at the SCCF. This conclusion was based on consideration of a number of factors, including:

- the cost of the additional fuel delivery, storage, and combustion equipment (estimated at $15.2M);
- the additional operational costs (present worth estimated at $5.1M);
- the real and potential environmental impacts of the secondary fuel;
- the relative rarity of disruptions in Florida’s natural gas supplies;
- the level of natural gas-fired energy supplies within Seminole’s current portfolio that are already backed up with diesel fuel; and
- the proximity of the remaining SGS coal unit.

Seminole’s current portfolio of energy resources includes a variety of owned and purchased power assets including solar, landfill gas, waste-to-energy, coal, and natural gas resources. Included in that portfolio are the following dual fuel capable resources; 500 MW of combined cycle and 310 MW of peaking capacity at the Seminole owned Midulla Generating Station (MGS), 266 MW of combined cycle and 178 MW of peaking capacity through a PPA with Hardee Power Partners, and 546 MW of peaking capacity through a PPA with the Southern Company owned Oleander facility. This amounts to 40% of Seminole’s committed resources. Seminole also has access to 122 MW of widely distributed Member owned diesel fired generators (another 3% of our committed resources) that can be called upon in times of necessity. In the future, Seminole anticipates having a regularly changing set of owned and purchased power assets that will nevertheless maintain a level of diversity in our generation mix adequate to provide reliable energy to our Members, manage our risk of exposure to changing market conditions, and keep our rates competitive.

Seminole hired Black & Veatch to evaluate the pros and cons of a single versus dual fuel facility. As explained in Black & Veatch's report which is . attached as Exhibit No. ___ (DK-4), the need for backup fuel can appropriately be evaluated on a fleet rather than an individual plant basis and it should also take into account that natural gas supply impact events typically occur in Florida concurrently with transmission system impacts. During such events, Seminole's system is anticipated to be capable of meeting the load the impacted transmission system can deliver with energy generated either from diesel as a backup fuel or from coal or other resources until the natural gas availability is restored to its normal level. It is anticipated that a significant number of storm events will result in a system that is limited by transmission and distribution, rather than gas supply, limitations. Ultimately, as Black and Veatch concluded that, considering "the environmental and permitting impacts with dual fuel operation, the reliable nature of the natural gas supply in Florida, and the cost to add fuel oil to the facility, the incremental benefit to add fuel oil as backup for the [SCCF] facility would not result in a commensurate benefit to the [Seminole] system."

Q. Please describe how Seminole monitors the operational performance and reliability of its power plants.

A. Seminole uses various industry standard techniques to measure and report on the performance and reliability of its power plants. Daily, monthly and annual reports are created describing the availability factor, capacity factor, energy generated, heat rate, and fuel consumed for its generating plants. Furthermore, the generating facilities are monitored continuously by onsite instrumentation and control systems to assure that various critical operational parameters stay within safe operating limits. On specific units, Seminole also utilizes long-term service agreements ("LTSAs") with external providers for continuous monitoring and periodic maintenance.

Q. How did Seminole select the SGS site for location of the SCCF?

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

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

Based on the comparative analysis, the SGS site scored substantially better than the Gilchrist site for a combined cycle facility. In particular, the Gilchrist site posed significant issues relative to water availability and wastewater discharge options. In addition, the SGS site is a brownfield site with capability of utilizing existing water intake, water discharge, and electrical transmission infrastructure. Overall, the SGS site has significant economic and strategic advantages for siting a combined cycle facility.

Q. Please describe the advantages of locating the SCCF on the existing SGS site.

A. The SCCF will be located on the south side of the existing SGS property. This location takes advantage of the existing transmission and water resource infrastructure at SGS as well as the existing employee base. The Putnam County site will require a new natural gas lateral to be developed and installed as described in the testimony of Mr. David Wagner. However, even with the gas lateral, total installed costs were minimized with the selection of this site.

Q. Have you estimated the capital and operations and maintenance (O&M) costs for the SCCF facility?

A. Yes, Seminole started with capital cost estimates that were formed around major equipment estimates received from manufacturers and EPC estimates developed by Black & Veatch. The capital cost estimates became increasingly accurate as Seminole contracted for power island equipment and received competitive bids for EPC services. Seminole has also developed and refined operations and maintenance estimates for the SCCF that are based in part upon our experience with the MGS combined cycle facility.

Q. What are the estimated capital costs for the SCCF?

A. The estimate capital cost of SCCF is approximately $727 million. Exhibit No. __ (DK-3) is a summary table providing a breakdown of the estimated capital costs.

Q. What is the anticipated schedule for the SCCF Project?

A. Seminole anticipates completing the SCCF permitting activities in 2018 and achieving commercial operation in late 2022. Prior to that time any initial engineering work that is required to keep the overall project on schedule will be executed using Limited Notices to Proceed ("LNTPs") with the EPC Contractor and the power island equipment provider. Detailed engineering and balance of plant equipment procurement activities will occur in 2020. The EPC Contractor will likely mobilize to the site in 2020, major foundations will be completed in 2021 and equipment erection, piping, electrical, etc. work will occur primarily in 2021 and 2022.

Q. Does this complete your direct testimony?

A. Yes it does.

David L. Kezell, Seminole Electric Cooperative, Inc.

SUMMARY

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

EXPERIENCE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

David L. Kezell, Seminole Electric Cooperative, Inc.

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

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

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

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

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

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

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

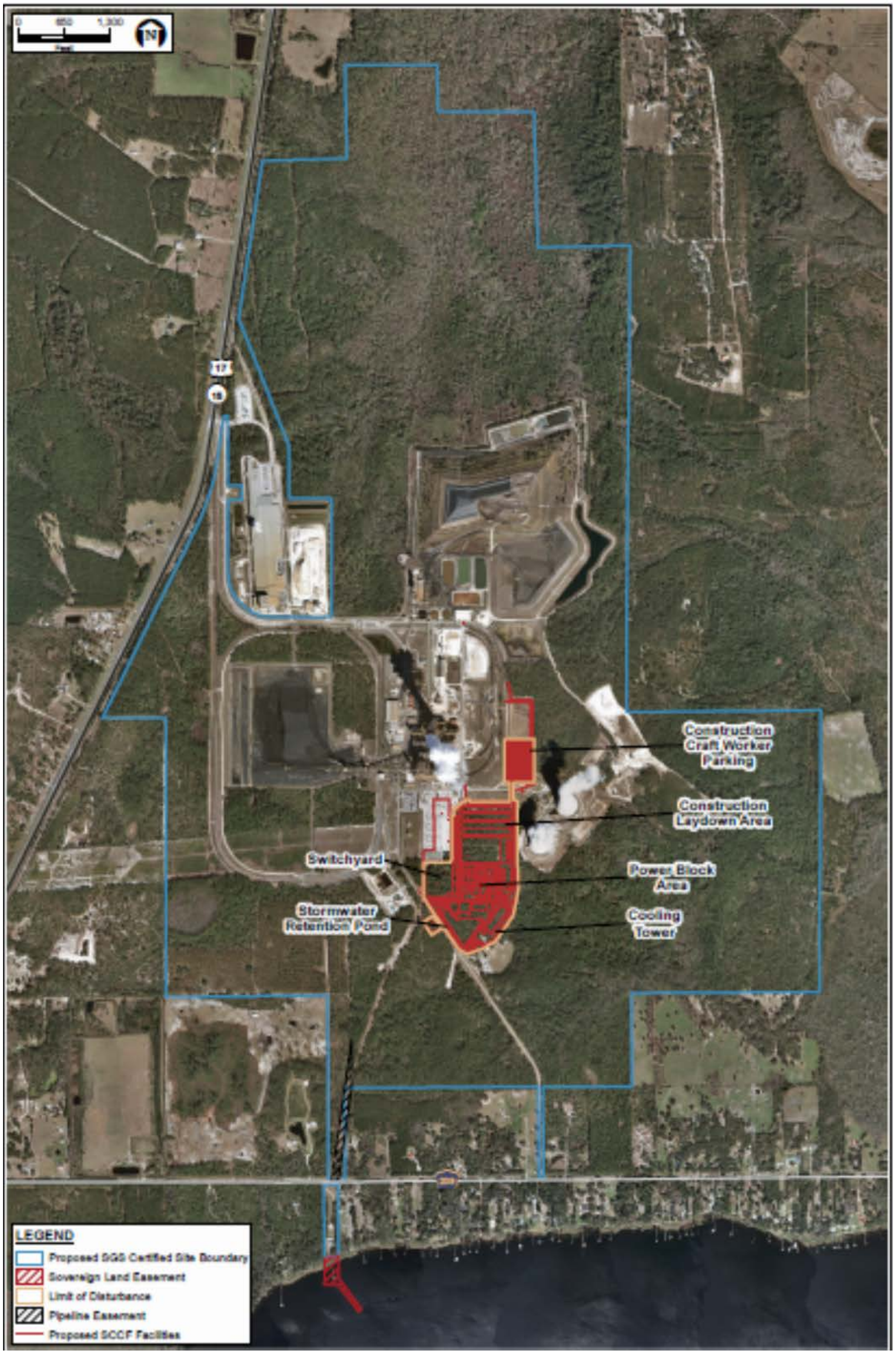
EDUCATION

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

REGISTRATIONS / AFFILIATIONS / PERSONAL

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

Preliminary Arrangement of the SCCF at the SGS site



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

P2021 SINGLE FUEL FACILITY ANALYSIS

BLACK & VEATCH PROJECT NO. 190285

PREPARED FOR

SEMINOLE ELECTRIC COOPERATIVE, INC.

8 AUGUST 2016

BLACK & VEATCH
Building a world of difference.

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Black & Veatch Statement

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

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

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1.0 Executive Summary

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

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

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

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

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

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

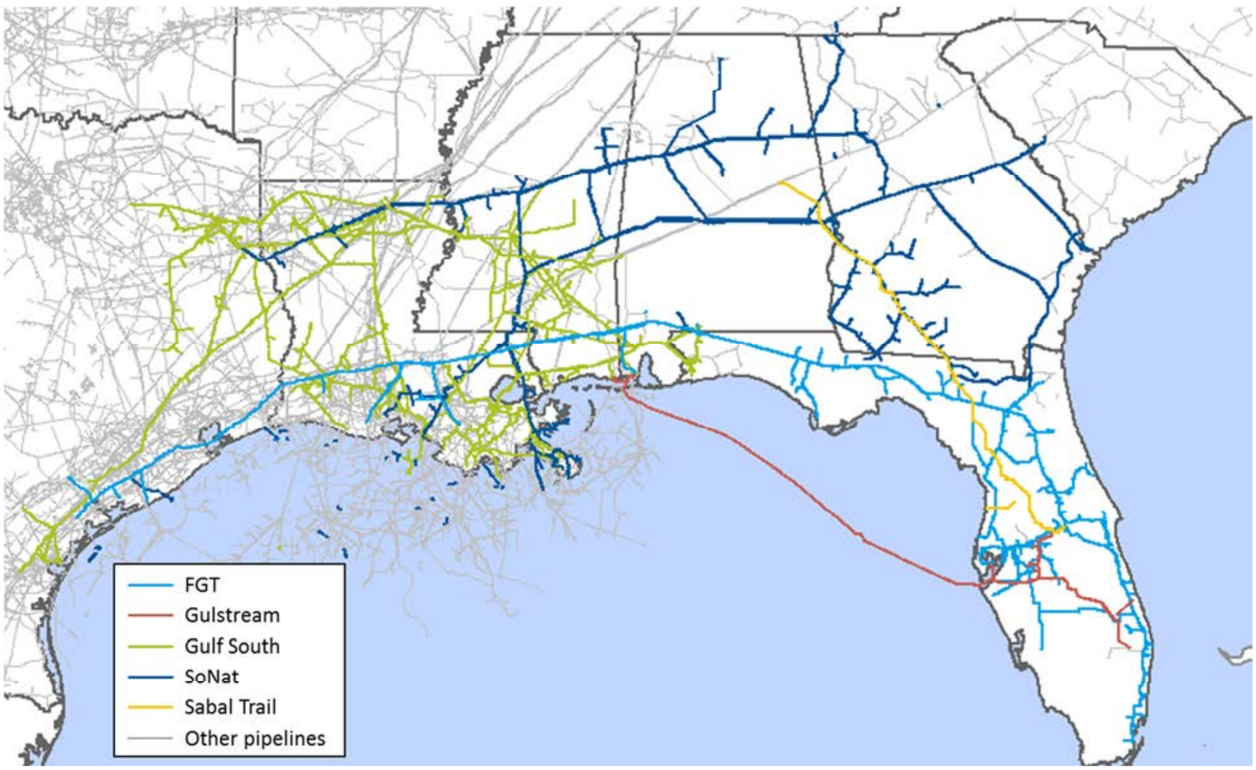
For SECI, this study will assume the addition of the 1,050 MW P2021 as a single fuel plant, and the retirement of SGS, approximately [49%] of its peak load will be met with owned generations. Within its own generation portfolio of approximately [1,860] MW, [44%] will have dual fuel capabilities, equivalent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

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

2.0 Natural Gas Infrastructure Serving Florida

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

Figure 1 Natural Gas Pipelines into Florida



Source: Velocity Suite, ABB Enterprise Software

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

[4] EIA Natural Gas Consumption data

Table 1.

Table 1 Pipelines Supplying Florida: Summary Information

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

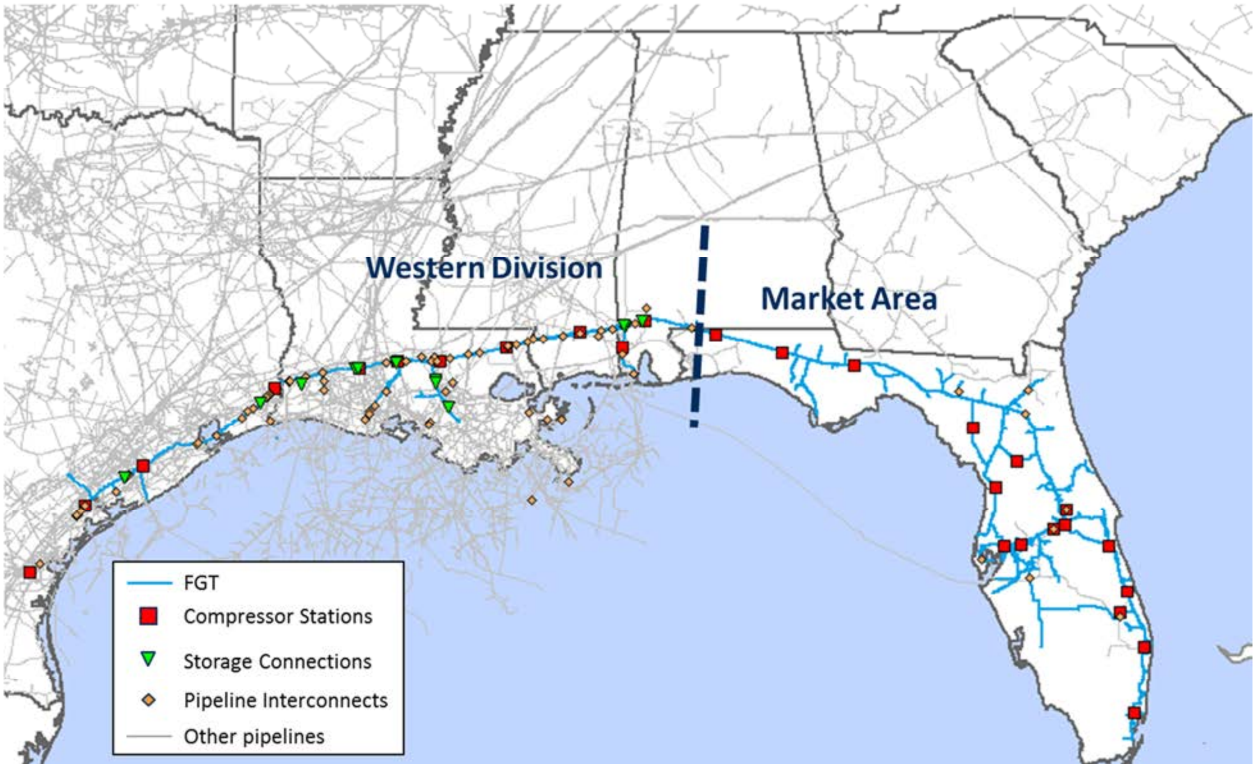
* Sum of three segments extending into Florida from Georgia, using highest recorded throughput as a proxy
** Excluding segment extending from Alabama that passes through Florida and back into Alabama
Source: PointLogic Energy

2.1 FLORIDA GAS TRANSMISSION

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

[5] Kinder Morgan website

Figure 2 Detailed FGT Infrastructure Map



Source: Velocity Suite, ABB Enterprise Software

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

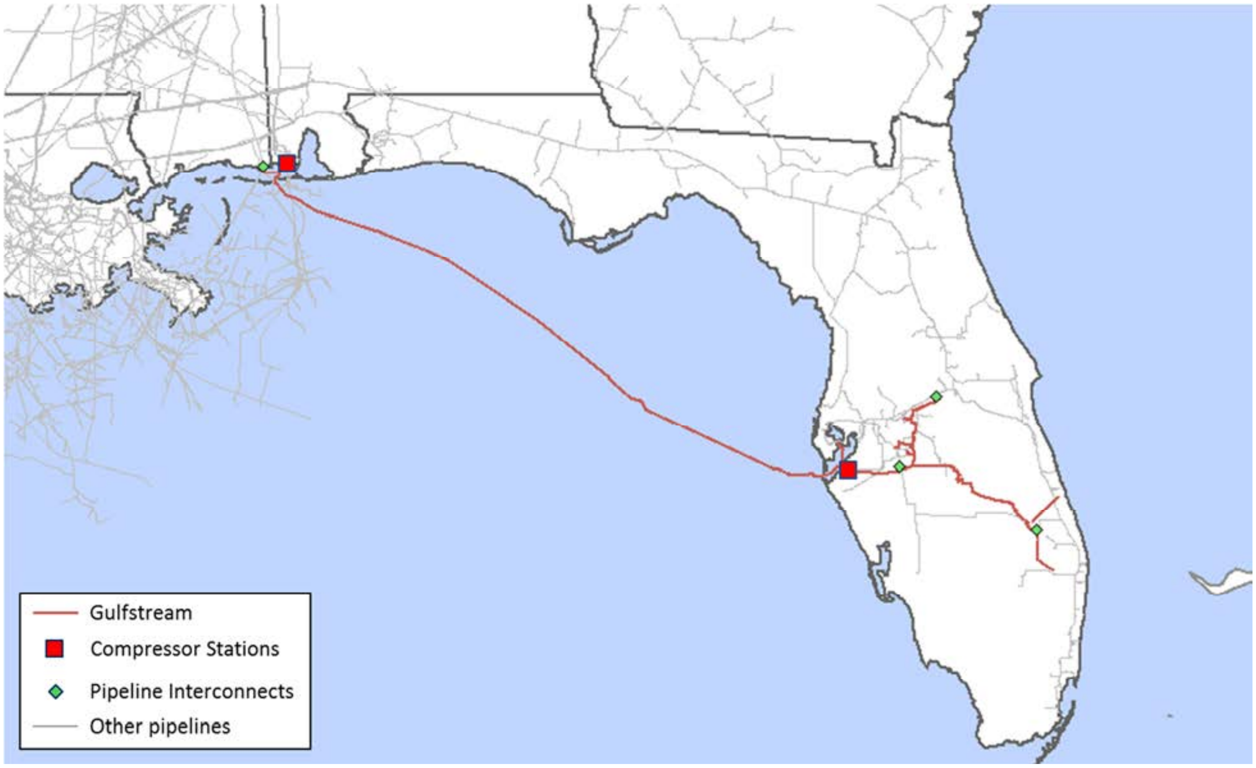
2.2 GULFSTREAM NATURAL GAS SYSTEM

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

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

[6] Spectra Energy Website

Figure 3 Detailed Gulfstream Infrastructure Map



Source: Velocity Suite, ABB Enterprise Software

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

2.3 SABAL TRAIL TRANSMISSION

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

[7] Williams EBB postings

Figure 4 Sabal Trail Proposed Project Infrastructure

Source: Velocity Suite, ABB Enterprise Software

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

2.4 INFRASTRUCTURE CONCLUSION

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

3.0 Natural Gas Curtailment

3.1 OVERVIEW OF NATURAL GAS SUPPLY VULNERABILITIES

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

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

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

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

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

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

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

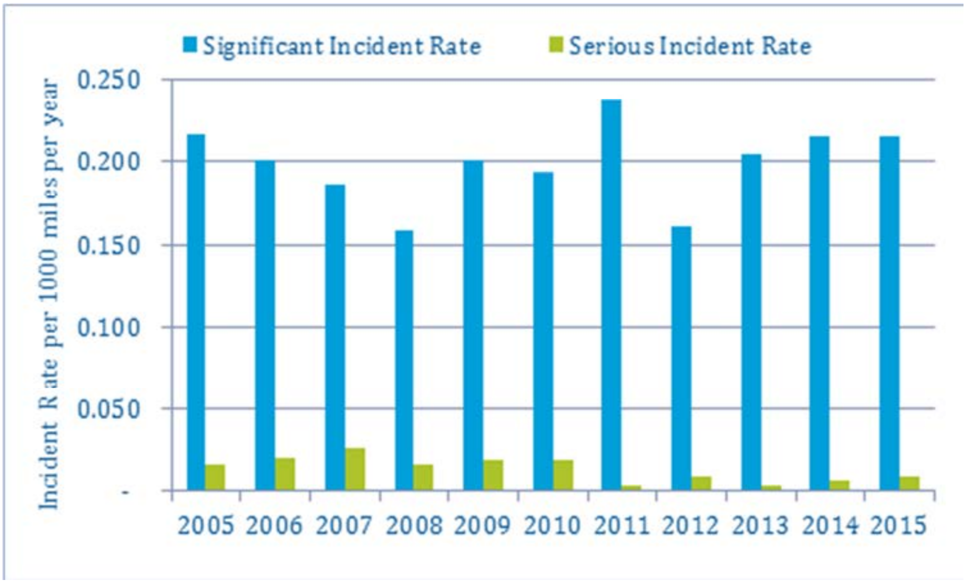
The North American Electric Reliability Corporation (NERC) special report also lists several notable historical incidents that have impacted gas supply reliability. A 1995 explosion on TransCanada's pipeline took out all six pipelines into New England, resulting in curtailment of 1.75 Bcf/day firm supplies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

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

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

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

Figure 5 US Gas Transmission System Incident Rates



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

3.2 HISTORICAL FLORIDA GAS SUPPLIES INTERRUPTIONS

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

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

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

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

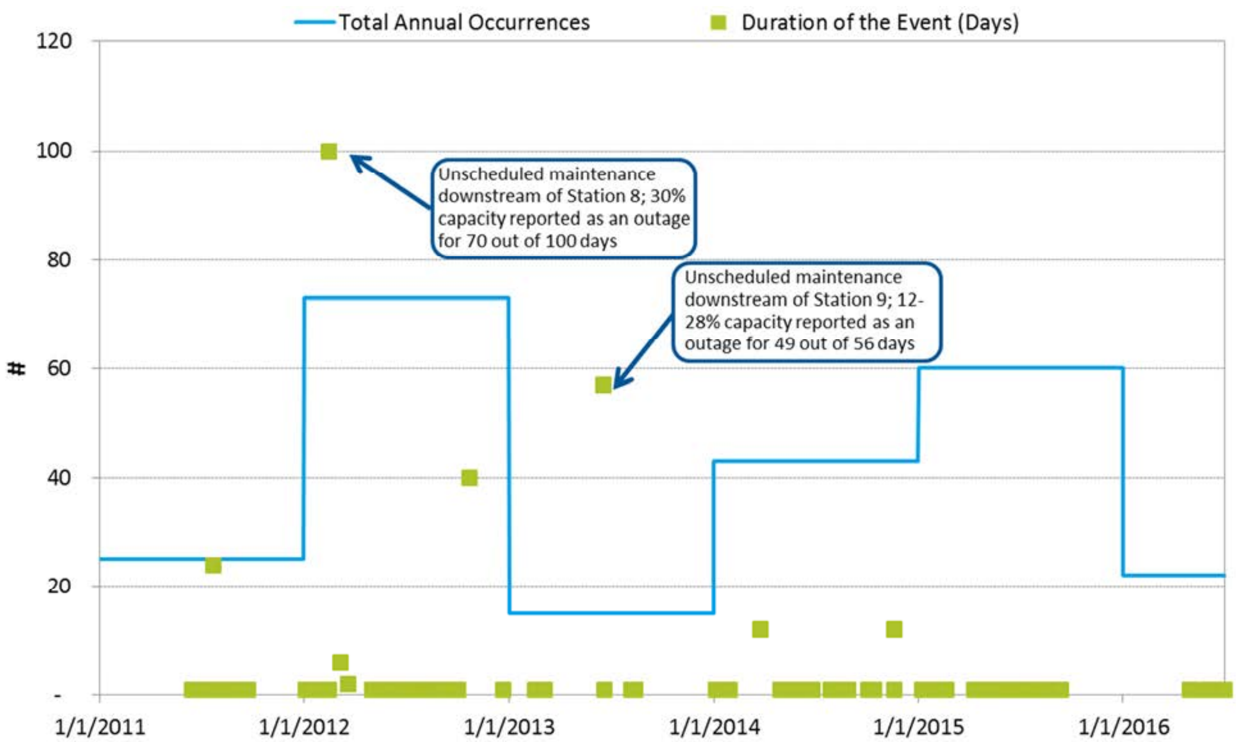
[14] US DOT Pipeline and Hazardous Materials Safety Administration, Gas Transmission Performance Measures, http://www.phmsa.dot.gov/pipeline/library/data-stats/performance-measures
[15] 2013 Special Reliability Assessment, NERC, 2013
[16] HMSA Pipeline Safety Flagged Incidents, http://www.phmsa.dot.gov/pipeline/library/data-stats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

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

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

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

Figure 6 FGT Critical Notices Occurrence and Duration

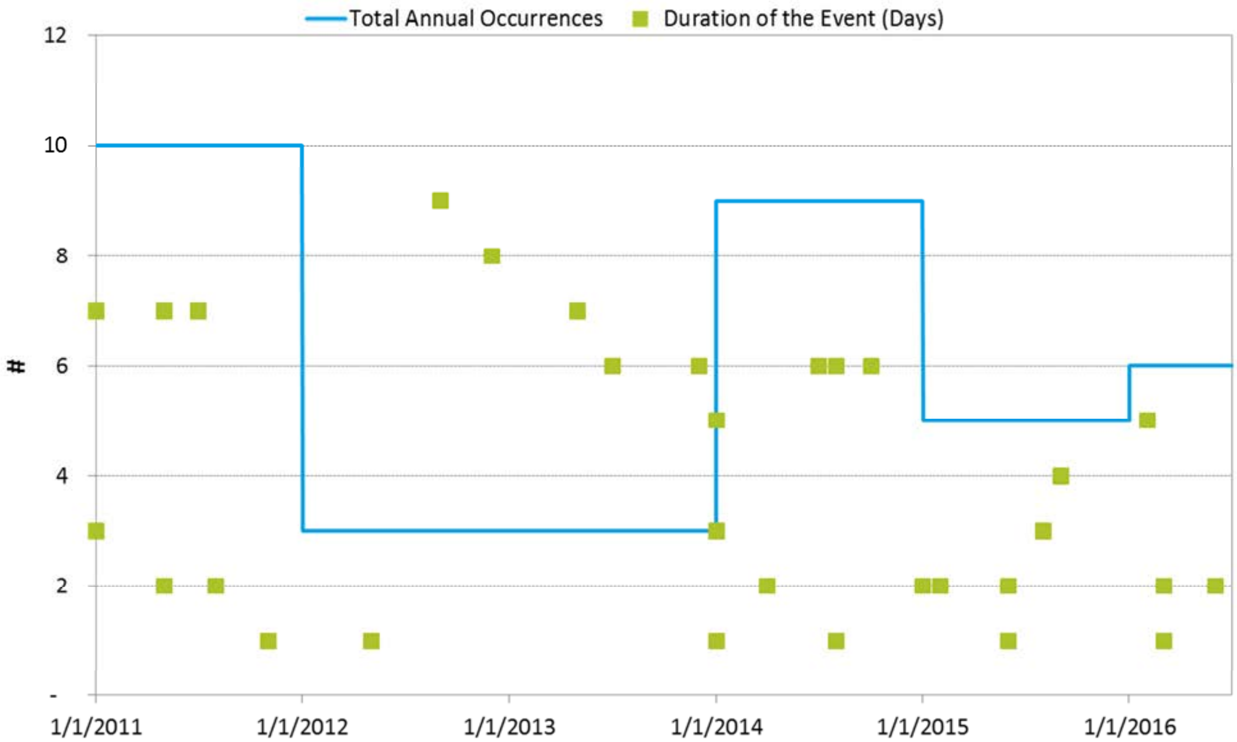


Source: Velocity Suite, ABB Enterprise Software (2011-2015); PointLogic Energy (2015-2016). Includes critical notices that could potentially impact system throughput.

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

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

Figure 7 Gulfstream Critical Notices Occurrence and Duration



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

3.3 FUTURE FLORIDA GAS SUPPLIES REALIBILITY ASSESSMENT

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

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

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

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

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

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

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

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

4.0 Environmental Considerations for Dual Fuel Operation

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

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

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

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

5.0 Evaluation of Fuel Oil Usage

5.1 DUAL FUEL PLANTS IN FRCC

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2 FUEL OIL USAGE – UNITED STATES

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

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

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

5.3 HISTORICAL FUEL OIL USAGE AT SECI FACILITIES

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

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

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

5.4 NEED FOR FUEL OIL AT THE SECI P2021 FACILITY

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

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

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

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

[21] Seminole Electric Cooperative Inc. 2015 Annual Report

6.0 Cost Evaluation

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

Table 5 Fuel Oil Price Adder

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

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

7.0 Conclusion

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

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

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

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

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

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

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

ROBERT DEMELO

EFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF ROBERT DEMELO

DOCKET NO. __________-EC

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Robert DeMelo. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Manager of Transmission Planning and System Protection.

Q. Please describe your responsibilities in your current position.

A. As Manager of Transmission Planning and System Protection, my responsibilities encompass a range of transmission-related responsibilities, including transmission planning for Seminole and its Members, transmission, generation, and system protection NERC compliance, system protection and controls for the Seminole transmission system, and transmission reliability for Seminole's Member delivery points. I also serve as Seminole's representative on multiple Florida Reliability Coordinating Council ("FRCC") standing committees and subcommittees, including current Vice-Chair of the FRCC Planning Committee.

Q. Please state your education and background professional experience

A I hold a bachelor's of science degree in Electrical Engineering from the University of South Florida ("USF"). During my studies at USF, I received top honors for my senior design which encompassed various facets of transmission load flow studies. Since obtaining my degree in 2007, I have held positions with increasing responsibility within Seminole's transmission organization. I was promoted to Lead Transmission Planning Engineer in 2011 and to Supervisor of Transmission Planning in 2014. I assumed my current role as Manager of Transmission Planning and System Protection in July 2015. In February of 2016, I was awarded the Young Engineer of the Year Award from the Institute of Electrical and Electronics Engineers ("IEEE"), Florida West Coast Section.

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

A. The purpose of my testimony is to describe the process for determining the transmission plan and associated costs for the interconnection of those alternatives evaluated as part of Seminole's Request for Proposals ("RFP") process. In particular, I will summarize the identified transmission upgrades, provide the preliminary estimated transmission costs and address the reasonableness of the preliminary project schedules for the Seminole Combined Cycle Facility ("SCCF").

Q. Are you sponsoring any exhibits in the case?

A. I am sponsoring Exhibit No. ___ (RD-1), which is a copy of my professional resume. I also am sponsoring Sections 3.4 and 4.1.9 of the Need Study

(Exhibit No. __ (MPW-2)), all of which were prepared by me or under my supervision.

Q. How does Seminole transmit electric service to its Members?

A. Seminole owns and operates approximately 127 circuit miles of 69 kV and 254 circuit miles of 230 kV transmission lines, via a total of nineteen (19) 230 kV points of interconnection with six (6) neighboring entities. However, Seminole's transmission facilities have limited direct interconnections with Seminole's Members' load. Seminole is therefore primarily a transmission dependent utility ("TDU") that relies mainly upon the transmission systems of Duke Energy Florida ("DEF") and Florida Power & Light Company ("FPL") for the delivery of Seminole's owned and/or contracted power supply resources to Seminole's Members' load. Seminole is a Network Integration Transmission Service ("NITS") customer of DEF and FPL under each of their respective Open Access Transmission Tariffs ("OATT"). Approximately 76%, or 2,294 MW, (based on 2016-17 actual winter net firm peak demand) of Seminole's Members' load is served by DEF's transmission system, approximately 16%, or 483 MW, is served by FPL's transmission system, and approximately 8%, or 241 MW, is served directly by Seminole's transmission system.

Q. Please describe Seminole's transmission interconnection process.

A. Seminole's transmission interconnection process is based on prudent utility practice and is consistent with the reliability requirements and guidelines set forth by the FRCC, the North American Reliability Corporation ("NERC"), and the Federal Energy Regulatory Commission ("FERC"). Seminole's planning criteria is outlined in the FERC Form 715 filing that is updated annually and submitted to the FERC. The transmission interconnection process involves a System Impact Study that identifies potential impacts and mitigation plans for addressing such impacts on Seminole's transmission system as well as neighboring systems. The analysis is performed by Seminole in coordination with the FRCC through the FRCC's Reliability Evaluation Process for Generator and Transmission Service Requests.

The System Impact Study incorporates the use of steady-state load flow, short circuit, and stability analysis using industry standard tools and software programs to ensure that Seminole's transmission system operates reliably over a broad spectrum of system conditions and following a wide range of probable planning and extreme events. In general, Seminole's transmission planning process includes the single contingency loss of any transmission circuit, transformer, bus section, shunt device, internal breaker fault, or generator. Such analysis is performed for multiple load levels, including but not limited to peak, off-peak, and high-import (Southern to Florida transfers) for select summer and winter conditions as modeled and made available by the FRCC. Additional analysis is performed to determine system response to credible, less probable extreme events, to assure the system meets Seminole, FRCC, and NERC transmission planning criteria. The additional analysis includes the loss of multiple elements, including the loss of multiple transmission circuits, transformers, generators, or the combination of each. Seminole utilizes planned operational system adjustments, corrective action plans which can include projects that require construction of new facilities or upgrades and load loss, if permissible by the applicable NERC Reliability Standards, to mitigate exceptions to transmission planning reliability criteria.

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

Q. How have you analyzed the extent to which interconnection upgrades may be needed for the SCCF?

A. Typically, new generation interconnections, such as for the SCCF, are evaluated for both interconnection and deliverability simultaneously. However, because Seminole is a TDU within the FRCC region, Seminole is required to submit separate Transmission Service Requests ("TSR") to DEF and FPL after completion of the interconnection analyses, in accordance with their respective OATTs, for the deliverability of the output from the SCCF to Seminole's Members' load in the respective balancing areas in order to determine transmission impacts on the systems of FPL and DEF, in addition to any impacts on neighboring systems that may result due to the SCCF. In order to request a TSR from DEF and FPL on their respective Open Access Same Time Information System ("OASIS"), via the designation of network resource ("DNR") process, Seminole is required to attest it either owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service, in accordance with the FERC pro-forma OATT. Thus, Seminole could not submit the TSRs in advance of the interconnection process in order to obtain estimates of the costs for delivery of the SCCF on DEF's or FPL's systems. Given this situation, Seminole was limited to evaluating the SCCF interconnection for short circuit and stability impacts, including limited steady-state load flow analysis across Seminole's own transmission system emanating from the SGS Switchyard.

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

As a result of Seminole's Board of Trustees decision of the most cost effective and risk managed solution on September 27, 2017, which included the plan to construct the SCCF and removal from service of one of the two existing coal units at the existing SGS site, Seminole was able to work with the FRCC TTS and SAS to perform an Energy Resource Interconnection Study ("ERIS Study"). The ERIS Study included a short circuit review by the FRCC TTS and a stability analysis review by the FRCC SAS. Seminole consulted with Burns & McDonnell for the stability analysis portion of the ERIS Study for the SCCF, including the removal from service of one of the two existing coal units. The ERIS Study resulted in no short circuit impacts to Seminole or any of the entities within the FRCC Region. The stability analysis portion of the ERIS Study resulted in the need for the SCCF to have a tuned and commissioned power system stabilizer, in addition to reduced total breaker failure clearing times associated with breaker failure scenarios at the existing SGS Switchyard. On November 6, 2017, the FRCC PC unanimously approved the ERIS Study for the SCCF. On November 29, 2017, Seminole submitted DNR requests to deliver the output of the SCCF into the DEF and FPL balancing areas to serve Seminole Member load embedded within the two respective areas.

Q. What transmission system improvements will be necessitated by the addition of the SCCF?

A. Seminole's interconnection evaluation of the SCCF identified the required expansion of the existing Seminole Generating Station ("SGS") Switchyard, including the addition of ten (10) new 230 kV circuit breakers and associated relay protection, and twenty (20) new circuit breaker disconnect switches. The "quasi" deliverability steady-state load flow results identified the need for upgrade of seven facilities.

As stated above, the "quasi" FRCC deliverability study assumed that both SGS Unit 1 and Unit 2 were at full output in addition to the SCCF. The aggregate net nominal winter output of the two existing SGS units and the SCCF emanating from the SGS Switchyard totaled approximately 2,379 MW. As Seminole performed its economic analysis in light of the overall portfolio and mix of resources, it was made known that the study assumptions would change to include the removal from service of one existing SGS unit. The new aggregate net nominal winter output including only one of the two existing SGS units and the SCCF totals 1,715 MW, a net nominal winter incremental difference of 386 MW from the existing installed capacity. This change significantly changes the amount of net site output at SGS such that, given engineering judgment and the magnitude of overloads only three upgrades required to be evaluated further during the TSR process with FPL and DEF for the evaluation of the delivery of the SCCF.

Q. What are the projected costs of those transmission system improvements to facilitate the interconnection of the SCCF?

A. Seminole's cost estimates for the potential network upgrades needed on FPL's and DEF's transmission systems to facilitate delivery of the SCCF total approximately $54 million. The projected costs for all Seminole facilities at the SGS Switchyard is approximately $3.1 million. All preliminary cost estimates above were developed using reasonable engineering assumptions, using the best available information to Seminole, consistent with how other entities in the industry develop cost estimates for similar projects.

Q. Have you analyzed the projected costs and impacts of the transmission improvements that would be required for the various alternatives considered during the RFP process?

A. Seminole, as part of its RFP that was released to the public in March of 2016, requested that respondents acquire NRIS status for all projects interconnected to DEF and FPL. Given that understanding, all applicable responses were evaluated based upon transmission assumptions, including costs and impacts provided by each respondent as they worked through the NRIS process with DEF and FPL. For those offers that were directly interconnecting to Seminole transmission, Seminole followed the same process described above.

Q. Does this complete your testimony?

A. Yes.

ROBERT DEMELO

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

Education

Bachelor of Science, Electrical Engineering December 2007

University of South Florida (USF), Tampa, Florida
Awarded First Place in USF Senior Design Project Presentation

Ken Chapman and Associates Leadership Development December 2013

Professional Experience

Seminole Electric Cooperative, Inc. Tampa, Florida

Manager, Transmission Planning & System (Power Delivery & Technical Services) June 2014 to Present

Key Responsibilities

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

Seminole Electric Cooperative, Inc. Tampa, Florida

Lead Transmission Planning (Power Delivery & Technical Services) September 2011 to June 2014

Key Responsibilities/Projects

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

Seminole Electric Cooperative, Inc. Tampa, Florida

Engineer III - Transmission Planning (Power Delivery & Technical Services) July 2010 to September 2011

Key Responsibilities/Projects

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

Seminole Electric Cooperative, Inc. Tampa, Florida

Engineer II - Transmission Planning (Power Delivery & Technical Services) June 2009 to July 2010

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

Seminole Electric Cooperative, Inc. Tampa, Florida

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

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

Skills

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

2016 IEEE Florida West Coast Section Young Engineer of the Year

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

DAVID WAGNER

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF DAVID WAGNER

DOCKET NO. _________-EC

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is David Wagner. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Portfolio Director.

Q. What are your responsibilities in your current position?

A. My primary responsibility is to ensure reliable, cost-effective natural gas delivery to Seminole's owned and purchased electric generating units. This includes oversight of natural gas supply procurement and scheduling activities along with the development of natural gas planning strategies and the negotiation of long-term gas transportation, supply and storage agreements.

Q. Please describe your professional experience and education background.

A I graduated from the University of Florida with a Bachelor of Science degree in Food and Resource Economics in 2000 and a Master of Agri-business degree in 2001. I joined Westar Energy, Inc. in 2002 as an analyst for the energy marketing and fuel procurement business unit. In 2004, I joined Florida Municipal Power Agency as a risk analyst to support the company's mitigation of price and supply risk in the natural gas market. In 2006, I moved into a gas trading role at Florida Gas Utility ("FGU") where my responsibilities included physical gas procurement, short-term optimization of FGU's gas transportation and storage assets, and supply and price risk mitigation. In 2010, I became the Supervisor of Gas Supply at Seminole, where I have held positions of increasing responsibility.

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

A. The purpose of my testimony is to present the fuel price forecast used in Seminole's Need Study, as well as the natural gas supply and transportation plans for SCCF. I also will discuss how the SCCF project impacts the diversity of Seminole's fuel supply.

Q. Are you sponsoring any exhibits in the case?

A. I am sponsoring the following exhibits, which were prepared by me or under my supervision and are attached to my pre-filed testimony:

- Exhibit No. ___ (DW-1) - Professional resume of David Wagner; and
- Exhibit No. ___ (DW-2) - Seminole Fuel Price Forecast.

I also am sponsoring Sections 4.1.7, 4.2.7, and 6.4.3 of the Need Study (Composite Exhibit No. __ (MPW-1)), all of which were prepared by me or under my supervision.

FUEL PRICE FORECAST

Q. Did you develop the fuel price forecast used in the Need Study?

A. Yes.

Q. For what fuels did you develop forecasts?

A. I supported the development of the price forecasts for natural gas, coal and No 2 oil.

Q. What methodology did you use in developing the fuel price forecast?

A. Seminole's fuel price forecasts are derived from a combination of published market indices, independent price forecasts, and escalators where necessary to extend the price forecast beyond the horizon of available values. For its fuel forecasts, Seminole uses the NYMEX futures forward market prices, price forecasts provided by the Energy Information Administration ("EIA"), Energy Research Company LLC, and L.E. Peabody & Associates, Inc., projections of fuel transportation and other variable costs related to fuel delivery, and forecasted escalation factors. These sources of forward energy prices are commonly accepted in the utility industry.

Q. Please describe the specific steps used in preparing the fuel forecast.

A. For projecting future natural gas prices, Seminole uses the following methodology: (i) for the initial years of Seminole's forecast, the methodology uses the NYMEX forward curve for Henry Hub natural gas; (ii) for years beyond the availability of forward NYMEX prices, the methodology escalates the gas price annually at a rate equal to the rate of escalation of projected gas prices in the EIA's Annual Energy Outlook ("AEO") for their reference case for the same years; and (iii) for any years beyond the availability of projected gas prices in the EIA's AEO, the methodology escalates the gas price at a constant rate equal to the annualized rate of escalation of the EIA's AEO reference case escalation for the final five years of projected prices. Seminole also includes a 'basis' adder to account for the projected difference in gas pricing between the Henry Hub geographic location and the Florida Gas Zone 3 geographic area.

For coal, the price forecast is based on commodity coal prices provided by Energy Research Company LLC. Seminole updates its coal transportation cost estimates based upon the annual forecast provided by L.E. Peabody & Associates, Inc.

For No. 2 oil, the price forecast is based on distillate fuel oil price projections provided by the EIA, plus a small adder for delivery. These methodologies are consistent with the fuel forecasting approach used in Seminole's 2017-2026 Ten Year Site Plan.

Q. Did you develop any alternative fuel forecasts for sensitivity analyses?

A. Yes, for natural gas Seminole uses a statistical based approach, similar to that used by the EIA, to formulate high and low forward price curves, relative to the base forward price curve.

Q. Have you prepared an exhibit showing the results of your fuel forecasts?

A. Yes. Exhibit DW-2 presents the results of Seminole's fuel forecast, including the alternative forecasts for natural gas. During the course of the past year, Seminole updated its fuel forecasts for natural gas and coal as a part of the updated economic analyses discussed in the pre-filed testimony of Julia Diazgranados. Exhibit DW-2 contains both the updated and prior fuel prices.

NATURAL GAS SUPPLY & TRANSPORTATION

Q. What are the fuel requirements for SCCF?

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

Q. What steps has Seminole taken to determine that natural gas will be available for the SCCF?

A. Seminole is finalizing negotiations with multiple entities for natural gas transportation service and/or natural gas supply for delivery to Putnam County, Florida and ultimately to the SCCF via the gas pipeline lateral discussed below. Seminole anticipates that these arrangements will provide for up to 187,000 MMBtus per day of gas transportation service having delivery rights to the lateral serving the SCCF, a portion of which will have delivery rights to other generating resources in Seminole's portfolio. Part of this transportation service will come from existing capacity that will be re-purposed for the SCCF, some will be existing capacity that will require additional facilities on the Florida Gas Transmission ("FGT") system to provide the incremental delivery rights specifically to Putnam County, Florida, and some will be new transportation service into Florida enabled by additional facilities on existing pipeline(s).

Q. What purchase arrangements will be used to procure the necessary gas?

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

Q. Has Seminole evaluated whether there is sufficient natural gas pipeline capacity to transport natural gas to the SCCF?

A. With the additional gas transportation arrangements discussed above, we are confident that sufficient natural gas pipeline capacity will exist to serve the SCCF. Further, the capacity on the gas pipeline lateral from FGT to the SCCF will be adequate.

Q. How will natural gas be transported to the SCCF?

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

Q. In your opinion, will there be an adequate and reliable supply of natural gas for the SCCF?

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

FUEL DIVERSITY

Q. How will SCCF affect the diversity of Seminole's fuel supply?

A. Seminole seeks to maintain a diversified portfolio of owned and purchased generating assets with a variety of fuel types, supply sources and delivery options. Such a portfolio functions as a tool to manage fuel price stability and reliability. The SCCF will be solely fueled by natural gas but is serving to replace expiring purchased power generating resources that were also predominately natural gas fired as their primary fuel source. Seminole’s decision to maintain the operation of one SGS coal-fired generating unit will continue to provide diversification in Seminole’s fuel portfolio. In addition, Seminole is implementing a natural gas transportation plan that contracts with four different counterparties for a variety of solutions to enhance the diversification and reliability of our delivered gas supply. For these reasons, the addition of the SCCF is not expected to significantly impact fuel diversity or supply reliability.

Q. Does this conclude your testimony?

A. Yes.

David Wagner

Experience

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

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

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

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

Gas Buyer; Senior Trader

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

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

Energy Risk Analyst

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

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

Energy Market Analyst

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

Education

University of Florida

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

Fuel Price Forecast – Updated

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

Fuel Price Forecast

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

JASON PETERS

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF JASON PETERS

DOCKET NO. __________

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Jason Peters. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as a Portfolio Director.

Q. Please describe your responsibilities in your current position.

A. In my role as a Portfolio Director, I lead, manage and provide strategic direction to the power marketing and portions of the fuel supply (coal, fuel oil and certain coal combustion residuals) team at Seminole. I also develop and implement strategies for the aforementioned power and fuel supply portfolios, including pricing, optimization, risk management, transportation and trading. I lead a team of three professionals and manage a budget of $400-600 million annually.

Q. Please state your professional experience and education background

A I hold a B.A. and Masters in Business Administration from the University of South Florida. I have been employed by Seminole for 16 years, in roles of increasing responsibility. During those 16 years, I have either been directly involved or led our activities related to the procurement of wholesale power supply from the Florida and southeast markets.

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

A. The purpose of my testimony is to describe Seminole's assessment of market alternatives, including the Request for Proposals ("RFP") process that was used to identify the available purchased power alternatives. Historically, Seminole has purchased wholesale power both via an RFP process and also as a result of bilateral negotiations. I will describe the bids Seminole received in response to the RFP, and how those bids were initially evaluated by Seminole from both a technical and commercial perspective.

Q. Are you sponsoring any exhibits in the case?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my direct supervision:

- Exhibit No. __ (JP-1) - Resume of Jason Peters; and
- Exhibit No. __ (JP-2) - Summary of RFP Responses.

I am also sponsoring Section 6.3 of Seminole's Need Study, which is identified as Exhibit No. ____ (MPW-2), as well as Appendix B to the Need Study, which is the RFP that Seminole issued in March 2016, along with addenda to the RFP issued during the course of the process.

Q. Please describe Seminole's philosophy in using purchased power RFPs.

A. Seminole uses wholesale market purchases to maintain competitive flexibility in our power supply portfolio, and the RFP process is one of the tools we use to determine which wholesale market purchases best fit our portfolio. To provide some perspective on the importance of purchased power in Seminole's portfolio, in 2016, Seminole purchased approximately 26% of our energy and 54% of our capacity from wholesale purchased power. Historically, Seminole has acquired resources from Hardee Power Partners, Reliant Energy, Constellation, Duke Energy and from various biomass renewables via the RFP process. Several of these resources remain in Seminole's portfolio today.

Via the RFP process, Seminole seeks to find power supply resources that provide the most cost effective, risk managed resources for our member systems. To find those resources, Seminole evaluates the economic value of the RFP proposals, and the flexibility offered in the agreements, versus other resource alternatives. Additionally, Seminole conducts a risk assessment of the RFP proposals. Some of the risks reviewed in our process include intangible considerations, such as construction timeline, flexibility of the contract, energy scheduling rights, and firmness of the output from the resource. For example, Seminole evaluates the flexibility of a resource by determining whether Seminole has the ability to increase or lower the purchased amount of capacity at a predetermined price, and would also value the scheduling rights for a resource by how quickly Seminole can call upon energy from a resource during a given day.

Q. What experience does Seminole have with RFPs for purchased power?

A. Seminole has incorporated the RFP process into its resource planning development numerous times throughout its history. Prior to the March 1, 2016 RFP, Seminole issued a solar RFP in 2015 that led to the construction of a 2.2 MW solar farm at Seminole's Midulla Generating Station ("MGS"). The solar facility went commercial in August 2017. In addition to the solar facility, Seminole's use of RFPs also led to the emergence of independent power producers ("IPPs") into Florida, beginning with the Hardee Power Plant, an RFP issued in 1988 that was awarded to and built by TECO Power Services (Hardee is now owned by Invenergy) and completed in 1993. Other IPPs contracted by Seminole via our RFP process include Reliant's Osceola plant (three combustion turbines totaling 546 MW), Southern Power Company's ("SPC's") Oleander facility (Seminole contracted for three combustion turbines totaling 546 MW), and Duke Energy Florida's ("DEF's") Osprey 580 MW combined cycle power plant (formerly owned by Calpine).

Q. Does Seminole restrict its consideration of purchased power alternatives to the issuance of formal RFPs?

A. No, Seminole does not restrict its evaluation of resources to only RFP proposals. Seminole utilizes a variety of options including RFPs, bilateral discussions with current and historical wholesale market suppliers, and review of unsolicited offers to determine which resources best fit into its portfolio. As I mentioned previously, Seminole has consistently used the IPP market to fulfill its resource portfolio and supplement its owned generation resources.

Through a combination of RFPs and bilateral discussions, Seminole has procured power supply from a number of entities. In addition to the RFP additions mentioned above, Seminole also has executed agreements for term power supply with DEF and Florida Power and Light Company ("FPL"). Oftentimes, selected resources included in Seminole's portfolio are extended beyond the initial agreement, as Seminole did with the DEF Osprey, Reliant Osceola and SPC Oleander resources.

Seminole has also included resources in our portfolio from several unsolicited offers, including the Hillsborough County waste-to-energy facility, a 40 MW waste-to-energy facility, and the City of Tampa's McKay Bay facility, a 20 MW waste-to-energy facility.

Q. Please describe the RFP that Seminole issued on March 31, 2016.

A. Seminole issued the RFP outlining that it was looking for up to 600 MW starting June 1, 2021 with needs up to 1,000 MW by June 2022. Seminole was receptive to offers from typical fossil fuel generation, including existing tolling resources, new builds by IPPs and existing utilities, system proposals, and renewable generation. All offers were required to be a minimum of 25 MW given the significant capacity need, and we requested a minimum two year term for any proposals. We were purposefully not restrictive in our criteria in an attempt to draw as many proposals as possible from the market for our evaluation. Seminole also welcomed demand side management proposals in response to the RFP.

The RFP laid out the desired qualifications for each bidder and the necessary requirements for a proposal submittal including financial viability, credit worthiness, references, and experience. For new generation, including renewables, site control was a requirement to proceed to the short list.

Seminole also asked for fixed and variable pricing, scheduling, output, heat rates, and start/scheduling charges to determine the economics of energy dispatch. Lastly, the RFP required the identification of transmission interconnection location and/or delivery points to receive the capacity and energy.

Q. **Please describe the process by which the March 2016 RFP was issued to potential market counterparties.**

The RFP was distributed through a multifaceted approach. Seminole simultaneously emailed its current suppliers and contacts while it issued the RFP via newswire and industry trade publications including MW Daily, an S&P Company. Seminole also published all of its documents on its external website where it was publically available.

Q. Did Seminole receive any questions from potential bidders on the March 2016 RFP?

A. Seminole received many questions regarding the RFP. Seminole collected all of the bidder questions and published all the responses via our website (as addenda) for viewing by all respondents. Seminole also emailed the questions to all potential bidders and instructed them to view the website for any additional clarifications and answers.

Q. Please describe the proposals that Seminole received in response to the RFP.

A. Seminole received over two hundred proposals that spread across a wide spectrum of alternatives. The proposals were for different stratifications (baseload, intermediate or peaking) and had varying commercial terms, including term lengths, MW size, and generation type. Renewable proposal types included solar, wind, battery storage, landfill gas, and waste to energy. The other offers were for traditional fossil-fueled generation, but varied in structure, with the majority of the offers classified as baseload/intermediate or combined cycle. Exhibit No. __ (JP-2) provides a summary of the different proposals received in response to the RFP.

Q. Did Seminole receive any proposals for renewable resources or demand side measures?

A. Yes. Seminole received renewable offers that included solar, wind, waste to energy, and battery storage. The majority of the renewable proposals were from solar resources. Seminole did not receive any proposals for demand side management.

Q. Please describe the screening process that Seminole followed upon receipt of the proposals.

A. To evaluate the large number of RFP responses, Seminole brought together subject matter experts ("SMEs") from various parts of the company to evaluate the proposals. The SMEs encompass the following areas of responsibility: supply management, transmission, fuels (including natural gas, coal, and fuel oil), contract administration, power marketing, treasury services, accounting, system operations, and environmental services. At first, the SME group reviewed all of the proposals to determine if the proposal had all of the required information, such as appropriate qualifications, economics, scheduling rights, and transmission information. Our team then worked with the bidders to obtain any missing or incomplete information in order to keep the proposal list as robust as possible. Proposals that were not approved under the bidder qualification standards were removed from the process.

Once the qualified offers were identified, the SME group segregated the renewable offers for solar and wind (due to the variable nature of their energy output) from traditional fossil-fueled generation to compare economics, transmission, size, viability and timing. Seminole further categorized the traditional offers into three different stratifications, baseload, intermediate and peaking. Offers for asset purchases were evaluated differently than the initial assessment of PPAs. The waste to energy proposal was bundled with other fossil baseload generation due to its plant operating characteristics.

Seminole's initial analysis compared each proposal's busbar cost in their designated stratification to narrow down uneconomic and outlier offers. Seminole also analyzed the operational and transmission risks of the proposed resource at a high level. Seminole removed both the offers with undesirable economics based upon the busbar analysis results and any offers that posed significant operational and transmission risks.

Seminole then continued to narrow the remaining list down by evaluating proposals in regards to the way they would interact with Seminole's entire portfolio. Seminole used Planning and Risk ("PaR") and System Optimizer software tools to select and choose which generation/power purchase agreement provided the greatest overall economic value within an entire portfolio with varying combinations of start dates, term lengths, and MW size. All acquisition offers were then evaluated to understand the potential benefits to the system, and to assess the impact of buying the asset earlier than Seminole's identified capacity needs.

Economics was not the only considered factor that reduced the number of proposals down to a manageable short-list. Seminole incorporated a risk analysis on the individual offers and also produced a comprehensive portfolio risk assessment based on the group of selected proposals. The SMEs investigated in greater detail transmission availability, fuel accessibility and availability, build and construction risks, technological/commercial risks, environmental factors, credit capabilities, term flexibility, and scheduling flexibility. Seminole concentrated on proposals that used available and proven technology.

The team evaluation results were compiled into a comprehensive rating scorecard. The comprehensive rating scorecard weighted a mix of short-term and long-term economics, individual and portfolio risks, strategic outlook, fuel flexibility, and real time operational functionality.

Q. Were any of the proposals eliminated from further consideration as a result of the technical and commercial evaluation?

A. Seminole did eliminate one conventional generation proposal from consideration due to the specialization of the technology; the unit was a one-of-a-kind unit and did not have an abundant spare part market. Battery storage proposals were eliminated not because of the technical evaluation, but because of the undesirable economics.

Q. What did Seminole do upon the completion of this economic evaluation?

A. Throughout the RFP process, Seminole notified participants of the ongoing evaluation. Once a short-list was finalized, Seminole notified participants of their status, either removed from evaluation or subject to continued evaluation. Those that remained were given an opportunity to present their best and final offers. In addition to their final proposals, the short-list participants were asked for drafts of their related power purchase agreements. Negotiations continued on the potential PPAs until a final decision was presented and approved by the Seminole Board of Trustees. Throughout the process, Seminole staff updated the Board of Trustees on the proposals, risks, economics, evaluations, and suggested recommendations.

Q. What was the end result of the RFP process?

A. When the comprehensive evaluation was complete, Seminole entered into PPA negotiations with several counterparties. The Board of Trustees approved a portfolio of resources which included a new Seminole self-build resource and several PPAs with GE Capital, Southern Company Services (Southern Company Wholesale), DEF, SPC and Coronal Energy.

Q. Has Seminole considered potential purchased power options outside the RFP process?

A. Seminole continually receives offers for solar and traditional fossil fueled/system generation and evaluates them at a high level when received. As per our normal practice, Seminole did not include unsolicited offers sent following our RFP close date in the RFP short list. Via our high level evaluation, we did note that the unsolicited proposals did not provide any significant economic or risk benefit in comparison to the RFP proposals.

Q. Does that conclude your testimony?

A. Yes.

JASON PETERS

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

PROFESSIONAL EXPERIENCE

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

Various titles, currently a Portfolio Director

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

FLORIDA POWER CORPORATION **1997 – 2001**

Power Trader

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

Manager, Automated Payment Processes

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

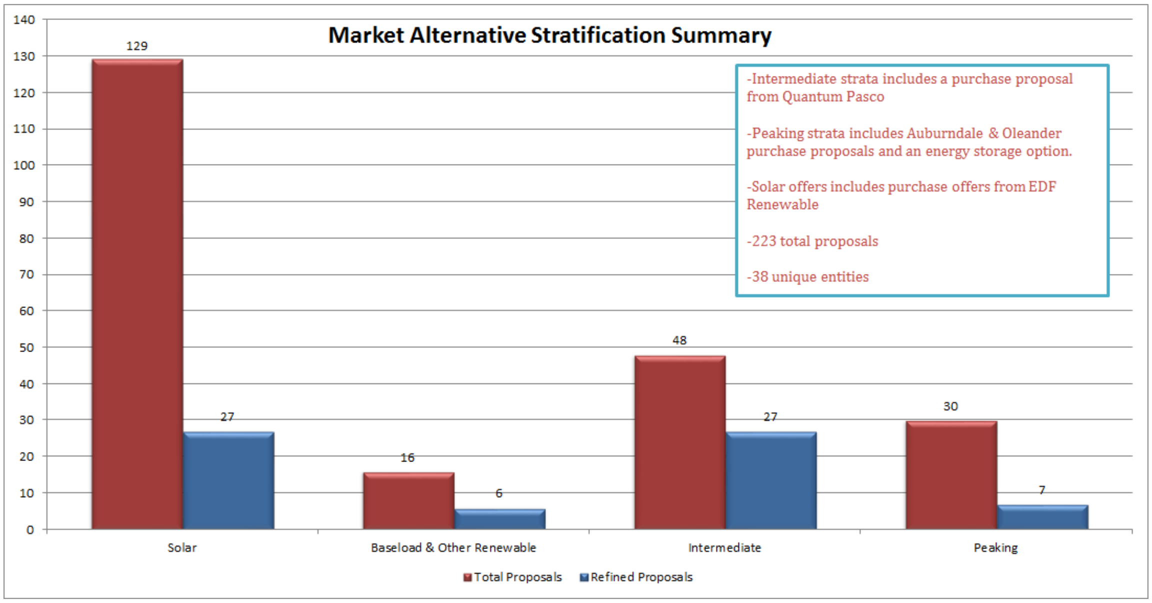
BARNETT BANK **1993 - 1997**

Business Banker

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

Sales and Service Coordinator

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


Market Alternative Stratification Summary
-Intermediate strata includes a purchase proposal from Quantum Pasco
-Peaking strata includes Auburndale & Oleander purchase proposals and an energy storage option.
-Solar offers includes purchase offers from EDF Renewable
-223 total proposals
-38 unique entities
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
129
27
16
6
48
27
30
7
Solar
Baseload & Other Renewable
Intermediate
Peaking
Total Proposals
Refined Proposals

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

JULIA A. DIAZGRANADOS

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF JULIA DIAZGRANADOS

DOCKET NO. __________

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Julia Diazgranados. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Director of Treasury and Planning.

Q. Please describe your responsibilities in your current position.

A. As Director of Treasury and Planning, I am responsible for coordinating, managing and directing Seminole's planning process. My team produces study results used to assist executive staff in establishing long-term plans to meet our Members' energy needs while maintaining competitive rates, mitigating risk, and preserving reliability. We evaluate existing available resources along with proposed resources over our planning horizon and in line with Seminole's load forecast. In my role, I have overseen the completion and filing of Seminole's most recent Ten-Year Site Plan ("TYSP") provided as Appendix A to Seminole's Need Study, which has been submitted as Composite Exhibit __

(SECI-1). I also represent Seminole on the Florida Reliability Coordinating Council's Resource Subcommittee.

Q. Please state your professional experience and education background.

A I have over twenty years of experience in the electric utility industry. I began my career in 1991 as a financial analyst for eight years with Allegheny Energy. From 1999 until 2004, I was a principal in a consulting company that specialized in electric utility planning software. I joined Seminole in 2005 as a Senior Strategic Planning Analyst with the lead role in the development of annual long-term strategic plans. In 2007, I was promoted to Lead Generation Planning Analyst. I was promoted in 2010 to Supervisor of Generation Planning, and advanced to Manager of Generation Planning in 2013. In 2017, I assumed my current position as Director of Treasury and Planning. I hold a Bachelor of Science degree in Business Management and an Associate degree in Electronic Data Processing from Fairmont State University.

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

A. The purpose of my testimony is to address three areas. First, I will describe the power supply planning process and need assessment that Seminole performed to identify its need for capacity in 2021 and beyond. Next, I will review Seminole's economic evaluation of self-build and purchased power alternatives along with risk assessments to explain why the Seminole Combined Cycle Facility ("SCCF") and the Shady Hills Combined Cycle Facility ("SHCCF") are the best, most cost-effective, risk-managed options to meet the reliability and economic needs of Seminole and its Members. Finally, I will discuss the unfavorable consequences if the requested need determination is not granted.

Q. Are you sponsoring any exhibits in the case?

A. Yes, I am sponsoring the following exhibits, which were prepared by me or under my supervision and are attached to my pre-filed testimony:

- Exhibit No. ___ (JAD-1) – Resume
- Exhibit No. ___ (JAD-2) – Seminole's gap chart (forecasted winter peak demands plus reserves vs. committed resources)
- Exhibit No. ___ (JAD-3) – Seminole's initial economic analysis results
- Exhibit No. ___ (JAD-4) – Seminole's scorecard analysis
- Exhibit No. ___ (JAD-5) – Seminole's sensitivity analysis; and
- Exhibit No. ___ (JAD-6) – Seminole's revised economic analysis results.

I also am sponsoring Sections 5.1, 5.3, 5.4, 6.1, 6.4.1, 6.4.2, 6.4.4, 6.5, 6.6, 6.7, 6.8, 8 and 9 of the Need Study (Exhibit No. __ (MPW-2)), as well as Appendix A to the Need Study, all of which were prepared by me or under my supervision.

<u>POWER SUPPLY PLANNING PROCESS & PROJECTED NEED</u>

Q. What is the objective of Seminole's power supply planning process?

A. The objective of Seminole's power supply planning process is to provide a portfolio of resources that will satisfy two criteria: (1) to satisfy Seminole's reliability criteria; and (2) to provide our nine Members with reliable wholesale energy to serve their member-consumers' future electrical needs in the most cost-effective and risk-managed manner.

Q. What reliability criteria does Seminole use to determine the need for additional resources?

A. Seminole uses utility industry planning practices and tools which utilize both deterministic and probabilistic approaches for planning a resource mix that satisfies a Reserve Margin criterion of 15 percent and achieves a Loss of Load Probability ("LOLP") of one day in 10 years. The Reserve Margin is a percentage of the load forecast peak demand and is the additional amount of capacity that a utility maintains above the forecasted peak demand. Reserves are necessary to accommodate generator outages, load forecast uncertainty, and abnormal weather. The Reserve Margin considers only the forecasted peak demand versus the amount of generation resources, but the LOLP criterion takes into account load shape, unit sizes, unit availability, and capacity mix when calculating the probability of a utility not adequately meeting load. These reliability criteria help to ensure that sufficient generation capacity is available to meet our Members' load forecast needs.

Q. Please describe Seminole's power supply planning process.

A. Seminole's power supply planning process begins with the development of the peak demand and energy forecasts ("load forecast") for each of our nine Members, which are aggregated into a Seminole load forecast. The Seminole load forecast's coincident peak demands are used to determine the amount of capacity needed to meet our Members forecasted demand plus an additional 15 percent to satisfy Seminole's Reserve Margin requirement. A gap analysis is used to identify deficiencies between forecasted requirements and current available capacity. When a deficiency is identified, Seminole evaluates all available alternatives (purchased power, acquisitions, and self-build) to establish a portfolio that provides a cost-effective and reliable generation mix to meet our Members' needs.

Q. What is Seminole's future capacity need?

A. Seminole's future capacity need results primarily from the expiration of purchased power agreements ("PPA"). These PPAs consist of multiple system deals starting with the expiration of 150 MW from Duke Energy Florida on December 31, 2020, followed by expiration of 200 MW from Florida Power & Light on May 31, 2021. Additionally in May of 2021, Seminole has the expiration of a PPA with Southern Power Company for three of their Oleander peaking units with total capacity ratings of 550 MW winter and 460 MW summer. In total, Seminole will lose 900 MW of purchased power in 2021.

When forecasted load is taken into account, by the end of 2021, Seminole will need 901 MW of generation to meet its Members' energy needs along with its Reserve Margin requirements. That need will grow to 1,265 MW the next year due to load growth and the expiration of a 300 MW PPA with Duke Energy Florida. This is reflected in Exhibit No.___ (JD-2).

Q. How does Seminole plan to meet that need?

A. The most cost effective, risk-managed resource plan for Seminole to meet the future needs of our Members is a mix of resources consisting of existing generation resources, PPAs, and the construction of two natural gas-fired combined cycle units. The first combined cycle unit (SHCCF) will be a 573 MW (winter) 1x1 unit to be constructed by GE Capital at its existing Shady Hills site in Pasco County pursuant to a tolling facility agreement with Seminole. The second combined cycle plant (SCCF) will be a self-build 1,122 MW (winter) 2x1 combined cycle plant at our existing Seminole Generation Station ("SGS") site, along with taking one of the two existing 664 MW (winter) SGS coal units out of service.

ECONOMIC EVALUATION AND RISK ASSESSMENT

Q. How did Seminole determine that a combined cycle tolling facility and self-build combined cycle facility along with taking a SGS coal unit out of service should be pursued to meet the projected need in 2021 and beyond?

A. The process began over two years ago. Seminole first determined which self-build alternatives would be evaluated. We then issued a request for proposals ("RFP") for firm capacity to solicit alternative proposals from the market. Lastly, we performed economic and risk evaluations on all available alternatives and developed portfolios of generation resources to fulfill Seminole's need.

Q. What self-build alternatives did Seminole consider?

A. Due to the high costs and regulatory uncertainties associated with new nuclear and coal-fired generation, Seminole limited its analysis of self-build alternatives to natural gas-fired generation. As discussed in Mr. Kezell's testimony, Seminole evaluated several different gas-fired technologies from three different vendors.

Q. Please, describe Seminole's evaluation process of its self-build generation alternatives along with its market alternatives.

A. Seminole identified market alternatives by issuing an RFP in March 2016 for firm capacity up to 1,000 MW beginning as early as June 1, 2021. The RFP stated that the need for capacity of 600 MW would start in June 2021, with total needs increasing to 1,000 MW by June 2022. Seminole encouraged proposals of base, intermediate, and/or peaking capacity, as well as renewable resources. The RFP also stated that proposals providing demand side options would be considered, although no such proposals were received. In May 2016, Seminole received proposals for purchased power alternatives in response to its RFP. The response was robust, with Seminole receiving responses from 38 counterparties for a total of 223 proposals with offers providing generation from renewables, existing and new gas-fired facilities, and system offers. Following receipt of the bids, Seminole's staff reviewed the proposals for completeness along with technical and operational viability. We performed an initial economic screening using bus bar cost analysis (i.e., the total cost to operate a resource on a $/MWh basis) of all alternatives within a stratification (base, intermediate, or peaking). Those with significantly higher operating cost based on a typical capacity factor within a stratification were eliminated.

Next, all remaining alternatives, including self-build options, were modeled and analyzed using System Optimizer. System Optimizer is an ABB tool that is an industry-recognized utility model used to develop an optimal resource mix to satisfy future needs. The model simulates how each generating resource, potential resources along with existing resources, will be used to serve the forecasted peak demand and energy requirements in the load forecast. System Optimizer's inputs include the demand and energy forecast, Reserve Margin requirements, fuel price forecast, plus the individual resource's cost and performance characteristics (e.g. fixed cost, variable cost, heat rates, forced outage rates, and maintenance schedules). Seminole used System Optimizer to develop economical portfolios of resources to meet the projected future need.

Seminole ran multiple iterations through System Optimizer. The first iteration was to develop a portfolio for the need starting in winter of 2022 with all resources available ("SGS 2x1 Portfolio"). We then developed a limited build portfolio which allowed one 1x1combined cycle unit to be built ("Limited Build Risk: Shady Hills Portfolio"). We also developed a no build portfolio consisting of only PPAs ("No Build Risk: All PPA Portfolio"). In addition, due to the regulatory uncertainty and long-term economics of coal-fired generation, Seminole also developed a portfolio taking into account the removal of one coal unit from service ("CPP/CC Portfolio"). The components of the various portfolios are summarized in Exhibit No. ___ (JD-3).

Once the optimal portfolio candidates were identified via System Optimizer, Seminole used Planning and Risk (“PaR”), another industry-recognized utility model from ABB, to further evaluate the production cost. PaR is a detailed production cost model, which commits resources in each hour over the thirty-three year study period from 2018-2051 based on costs and operational constraints. The operational constraints are similar to those in System Optimizer but more extensive, including such constraints as minimum up and down times, must run requirements, and natural gas pipeline flow limits. The production costs from PaR along with any capital and transmission cost increases for network upgrades are loaded into the corporate financial model to develop the annual revenue requirements.

Finally, Seminole’s staff performed risk analysis on both individual alternatives and each of the remaining portfolios. Seminole produced scorecards for each portfolio which not only took into account a weighted risk rating but also a strategic rating, operational flexibility ratings for fuel, real time operational flexibility, and an economic rating for a short-term (10 year) and long-term (30 year) net present value revenue requirement. These portfolio scorecard assessments are reflected in Exhibit No.___ (JD-4).

Q. What were the results of your detailed economic evaluation?

A. Ultimately, the net present value (“NPV”) of the revenue requirements is the basis for comparing different portfolios in the economic evaluation. The CPP/CC Portfolio, which includes the SCCF and the SHCCF along with the removal from service of one of the two existing 664 MW SGS coal units, was the least cost portfolio. The next portfolio in NPV revenue requirement terms was approximately $355 million more expensive over the thirty-three year study period from 2018-2051. Exhibit No.___(JD-3) reflects the differential between the portfolios.

Q. Did Seminole evaluate the cost-effectiveness of taking the second SGS coal unit out of service?

A. No, Seminole believes that continuing operation of one SGS coal unit will enable us to continue the utilization of a valuable, high-performing asset within our portfolio and preserve fuel diversity.

Q. What additional analyses did Seminole perform to evaluate the cost-effectiveness of the various alternatives?

A. Seminole also performed multiple sensitivity analyses outlined below:

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

The results of these analyses are shown in Exhibit__(JD-5) and they support the conclusion that the SCCF and SHCCF together with PPAs (CPP/CC Portfolio) provide the most cost effective solution for Seminole's need.

Q. Did Seminole consider the utilization of additional solar resources?

Seminole also considered the utilization of solar in its sensitivity analysis, Seminole evaluated two different solar alternatives as reflected in Exhibit___(JD-5). Both sensitivity analyses show that the SCCF and SHCCF together with PPA's (CPP/CC Portfolio) is the most cost effective solution. Because Seminole is a winter peaking system, solar is not a viable capacity source to offset our need, but Seminole does acknowledge the energy value of solar and therefore has included 40 MW (summer rating) of new solar in our final recommendation. Seminole does account for the summer capacity benefit in the portfolios.

Q. Did Seminole consider any other factors in its evaluation?

A. In addition to cost-effectiveness and risk impacts, Seminole considered the value of having optionality. One of the new PPAs in this portfolio provides Seminole with the advantage of optionality, giving Seminole the flexibility to modify its commitment up or down with one year's notice. Given the uncertainty of load forecasts, having the ability to modify resource commitments will give Seminole an advantage against economic accelerations/downturns or faster/slower load growth rates.

Q. What was the recommendation of Seminole's Staff to the Board regarding SCCF and SHCCF, and what was the result?

A. At the September 27, 2017 meeting of the Board of Trustees, staff provided an overview of the planning activities and a review of the objectives along with portfolio economics, sensitivity results and risk assessments. Staff also reviewed the components of the portfolio being recommended. Staff then recommended, and the Board unanimously approved, proceeding with the planning, permitting and construction of the SCCF along with the SHCCF tolling agreement with GE and additional PPAs to round out the portfolio.

UPDATED ECONOMIC ANALYSIS

Q. Has Seminole updated its assessment since the September 27, 2017 Board of Trustees approval?

A. Yes. At the October meeting of the Board of Trustees, the 2018 Budget was presented and approved. Staff has updated the economics to incorporate the 2018 Budget assumptions. These assumptions include a new load forecast that was approved by Seminole's Board in September 2017 and a new fuel price forecast updated in June 2017.

Q. Please describe Seminole's updated economic assessment.

A. Seminole conducted a present worth revenue requirements comparison for all four portfolios with the 2018 Budget assumptions. While the total dollar values changed, the rankings between the portfolios did not. The CPP/CC Portfolio, which includes the SCCF and the SHCCF along with the removal from service of one of the two existing 664 MW SGS coal units, remained the least cost portfolio. The next portfolio in NPV revenue requirement terms was approximately $363 million more expensive over the study period. Exhibit No.___(JD-6) reflects the differential between the portfolios.

ADVERSE CONSEQUENCES OF DENIAL

Q. What will be the projected impact on the reliability of service to Seminole's Members and their member/consumers if the SCCF and GE SHCCF projects are not constructed to meet the identified capacity need in 2021 and beyond?

A. In combination, the SCCF and SHCCF projects would provide a total capacity of 1,623 MW and make up approximately 40% of Seminole's generation capacity requirement. If both projects were to be denied, , Seminole would not be able to take an SGS coal unit out of service (664 MW). Moreover, Seminole would still be short by up to 680 MW of capacity, leaving us at the mercy of the market for finding replacement capacity at a higher cost and possibly leaving our Members and their member-consumers at high risk of service interruptions.

If only the SCCF was denied, then again Seminole would utilize the optionality available via our PPAs (350 MW) to offset some of the lost capacity. Here again, however, Seminole would not be able to take an SGS coal unit out of service (664 MW). While these actions would mitigate the capacity need so our Members and their member-consumers would not be at risk of service interruptions, they would increase costs compared to the resource plan with SCCF.

If the SHCCF was denied, then again Seminole could pursue one of two options. One option would be to leave the SGS coal unit in service which would cover our Members and their member-consumers' needs but at a higher cost. The second option would be to utilize the optionality available via our PPAs (350 MW) leaving Seminole with a need for capacity of approximately 220 MW. Seminole would be forced to go to the market to find replacement capacity at a higher cost, possible leaving our Members and their member-consumers at risk of service interruptions.

Q. What will be the projected economic impact on Seminole's Members and their member/consumers if the SCCF and SHCCF projects are not constructed to meet the identified capacity need in 2021 and beyond?

A. The projected economic impact to Seminole's Members and their member-consumers would have the following NPV revenue requirement impacts:

- If both projects were to be denied the adverse impact would not only be the remaining in service of a coal unit but approximately $388 million of additional NPV revenue requirements without consideration of any potential transmission impacts.
- If only the SCCF is denied, the adverse impact would be the continuation of service of the coal unit and approximately $502 million of additional NPV revenue requirements.

- If only the SHCCF is denied, the impact would be approximately $363 million along with the continuation of service of the coal unit.

Q. Does this conclude your testimony?

A. Yes

JULIA A. DIAZGRANADOS

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JDiazgranados@seminole-electric.com • Work 813-739-1538 • cell 813-789-8203

CAREER EXPERIENCE

SEMINOLE ELECTRIC COOPERATIVE INC.
16313 North Dale Mabry Highway, Tampa, Florida 33618
Director of Planning (2017-Present)
Leads budget and financial forecasting processes along with the planning and related analysis of Seminole's long range generating capacity needs including the evaluation of generation alternatives. Provides supervision and work direction to budget, financial forecast and generation planning personnel. Responsible for the application of production costing and corporate financial models in the performance of generation studies budgeting and financial forecasting. Enables integration of Seminole load forecasting into budget, financial and resource planning

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

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

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

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

FUTURE SCOPE, INC.
400 WEST LAKE STREET, SUITE 306, ROSELLE, IL 60172
Principal – Utility Advisory (1999 – 2004)
Provided various utilities in the mid-west and east coast with situational assessments; resolution proposals; application design; project management including budgeting and resource requirements; implementation of systems; and development of user documentation. Created and conducted training courses of developed systems. Oversight of marketing campaigns; sales presentations; and implementation process of company's Capital Management and Cost of Service applications.

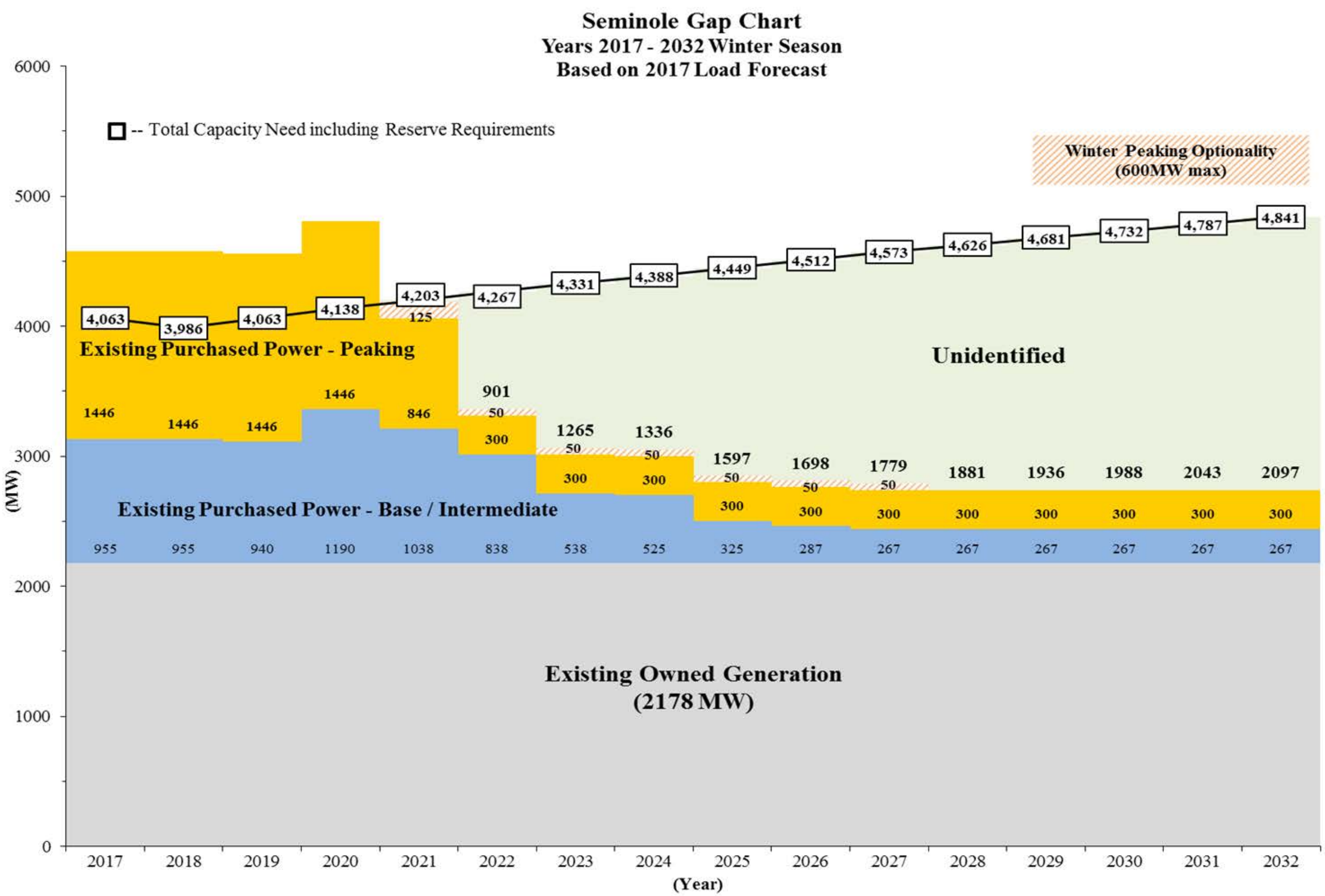
ALLEGHENY ENERGY SERVICE CORPORATION
800 CABIN HILL DRIVE, GREENSBURG, PA 15601
Financial Analyst 1996 -1999
Prepared assumptions and model runs to support operational decision-making, long-term forecasting, budgeting and strategic planning. Performed capital project evaluations/analysis on proposed investments to assist in the prioritizing/allocating of funds. Managed and coordinated the replacement of the Corporate Financial and Capital Management Systems with outside consultants.

Financial Services Analyst 1991 -1996
Maintained and ran Corporate Financial Models. Responsible for the administrative duties of the Local Area Network (LAN) - setup servers, created backup/restore procedures, established user access rights, configured user workstations, and provided technical support for seven departments within Financial Service's area.

EDUCATION

Bachelors of Science Degree, Business Administration
Associate of Science Degree, Electronic Data Processing
FAIRMONT STATE UNIVERSITY
FAIRMONT, WV

- Awarded the Outstanding Electronic Data Processing Student Award



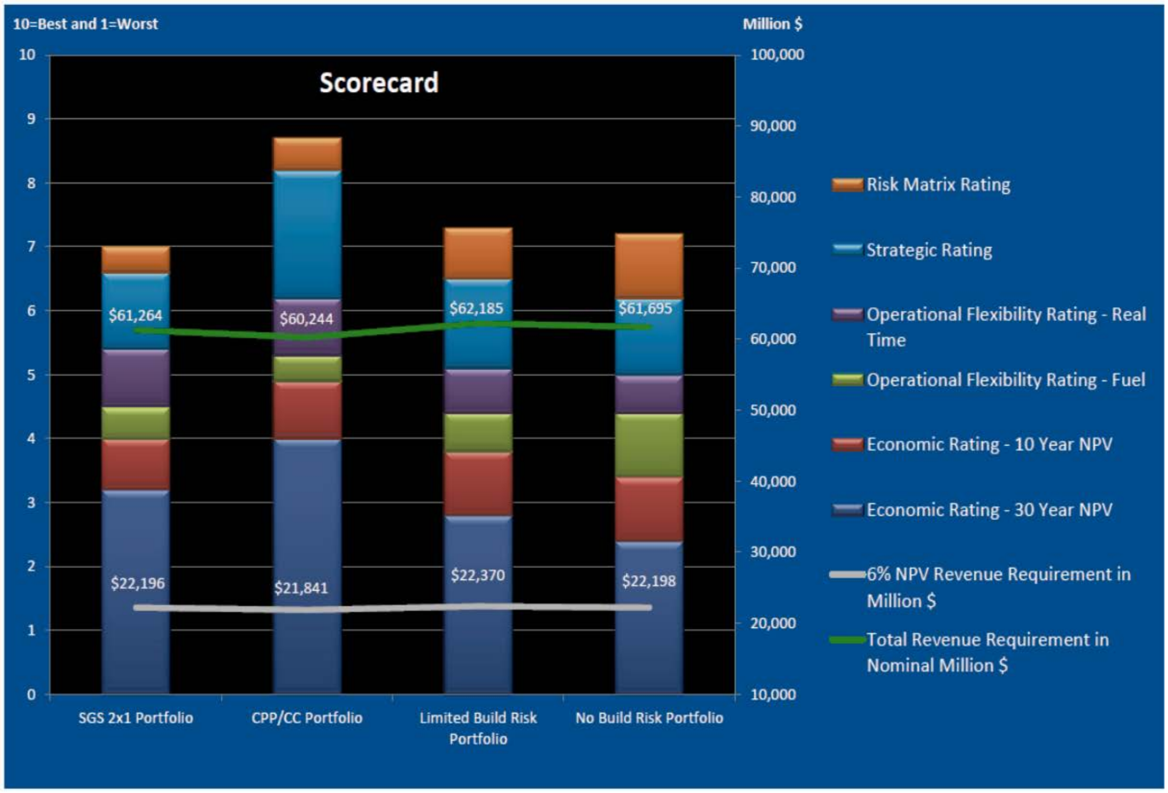
Docket No. 2017_____-EC
Seminole Need Gap Chart
Exhibit No. __ (JAD-2), Page 1 of 1

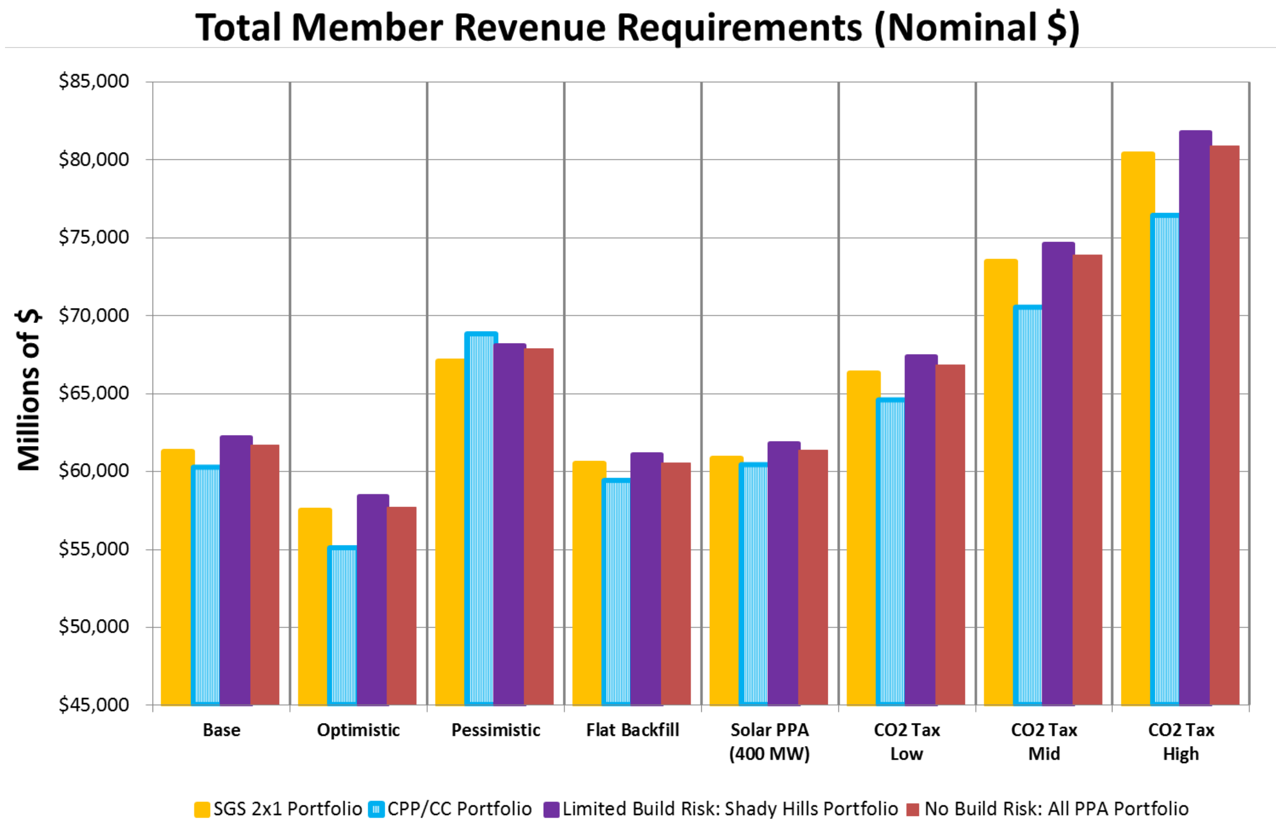
Summary of Initial Economic Analyses

Portfolio Summaries
Initial Economic Analysis Results
(millions of $)

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

Portfolio Scorecard Assessment




Total Member Revenue Requirements (Nominal $)
Millions of $
$85,000
$80,000
$75,000
$70,000
$65,000
$60,000
$55,000
$50,000
$45,000
Base
Optimistic
Pessimistic
Flat Backfill
Solar PPA (400 MW)
CO2 Tax Low
CO2 Tax Mid
CO2 Tax High
SGS 2x1 Portfolio
CPP/CC Portfolio
Limited Build Risk: Shady Hills Portfolio
No Build Risk: All PPA Portfolio

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

KYLE D. WOOD

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF KYLE D. WOOD

DOCKET NO. __________

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Kyle D. Wood. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. By whom are you employed and in what capacity?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Manager of Load Forecasting and Member Analytics.

Q. Please describe your responsibilities in your current position.

A. My primary responsibilities are to develop long-term load forecasts of electric demand and energy for Seminole and its Members. I also provide analytical support for the Energy Efficiency Working Group.

Q. Please state your professional experience and education background

A I have been working as a load forecasting analyst with Seminole since 2012 and have held a supervisory role at the company since 2015. Prior to working at Seminole, I was employed as an economic analyst at Dieter Consulting Group since 2008.

I graduated from the University of South Florida with a Bachelors of Arts in International Business and a Masters of Arts in Economics.

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

A. The purpose of my testimony is to describe Seminole's load forecasting methodology, present and discuss the results of Seminole's most recent long term load forecast, and discuss Seminole’s and our Members’ demand-side management (DSM), energy efficiency and conservation efforts and achievements.

Q. Are you sponsoring any exhibits in the case?

A. Yes. I am sponsoring Exhibit No. ___ (KDW-1), which is a copy my current professional resumé. I also am sponsoring Sections 5.2 and 7 of the Need Study (Exhibit No. __ (MPW-2)), all of which were prepared by me or under my supervision.

LOAD FORECAST

Q. Please describe the existing service territory of Seminole's Members.

The Members' service area is primarily rural and extends into 42 of Florida’s 67 counties. Seminole's Members provide electricity to over 763,000 member-consumers, serving a population of approximately 1.6 million people and businesses. This service territory encompasses a variety of geographic and weather conditions as well as a diverse mix of economic activity and demographic characteristics.

The Member service area in northwestern Florida covers a portion of the panhandle east of the Apalachicola River, parts of the Gulf Coast, and an area below the Florida-Georgia border. Over the past ten-years, average annual residential member-consumer growth in this region is nearly zero. Several factors attribute to the low growth including decreasing natural population, low-performing school systems, lack of employment opportunities, and low occupational wages. A portion of member-consumers also reside in the rural service area where the cost of living is low, but commute to other counties or cities outside the service territory where occupational wages are relatively higher. The Members in this region are Central Florida Electric Cooperative, Inc., Suwannee Valley Electric Cooperative, Inc., Talquin Electric Cooperative, Inc., and Tri-County Electric Cooperative, Inc.

The Member service territory extending from north-central Florida to the northern outskirts of Tampa includes some of the largest electric cooperatives in the Unites States. Growth is strongest in these areas, due to the proximity to expanding metropolitan centers including Jacksonville and Tampa. One expanding development in this region in particular, The Villages, has attracted strong growth over the last ten years despite the economic recession. In 2016, over 75% of Seminole-system load was delivered to this region. The Members in this region are Clay Electric Cooperative, Inc., SECO Energy, and Withlacoochee River Electric Cooperative, Inc.

The southern region of Member service territory includes areas around and east of the Sarasota-Manatee-Bradenton metropolitan area down to Lake Okeechobee and the Everglades. The expanding Sarasota metro area has provided a source of new residential development. Residential member-consumer growth in this area has been above 2% in each of the past four years. The area around Lake Okeechobee and the Everglades has enjoyed far less growth however, adding positive gains to the annual residential member-consumer count for only 5 of the past 10 years. The Members in this region are Glades Electric Cooperative, Inc., and Peace River Electric Cooperative, Inc.

Q. Please describe the existing consumer base of Seminole's Members.

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

Q. What have been Seminole's recent energy sales and peak demands?

A. In 2016, Seminole's net energy for load was approximately 14,471 GWh. From 2014 through 2016, average annual growth in net energy for load was approximately 2.2%. Net firm demand has averaged approximately 3,300 MW in the past three winter seasons and 3,100 MW in the past three summer seasons. Prior to 2014, Seminole Electric Cooperative was a ten-Member system, which included Lee County Electric Cooperative.

Q. How does Seminole's consumer and load growth compare to the State of Florida as a whole.

A. Historically, member-consumer growth rates in Seminole's nine-Member system have exceeded growth rates in the State of Florida as a whole. According to the Florida Office of Economic and Demographic Research ("EDR"), Florida's population grew approximately 1.0% annually on average from 2007 through 2016. During the same ten-year period, the FRCC Load and Resource Plan shows statewide electric-utility residential customer growth averaged approximately 0.6% annually, while residential member-consumer growth in Seminole's nine-Member service area averaged approximately 0.9% annually. In the ten year forecast horizon from 2017 through 2026, Florida's annual population growth is projected to average approximately 1.4%, while residential consumer growth statewide and in the Seminole service area is projected to average approximately 1.4% and 1.5%, respectively.

The Florida Economic Overview published by the EDR on July 28, 2017 provides context for the current pace of economic growth in Florida compared to the Seminole-system. According to the report, employment growth from March 2007 to March 2016 statewide was 2.6%; only 16 of Florida's 67 counties enjoyed growth equal to or greater than 7.1%. Four of these fast-growing counties, Clay, Pasco, Sumter and Lake, contained over half of the residential membership of Seminole's three largest Cooperatives as of March 2017. Employment in Sumter County set the highest rate of growth, topping at 30.3%. Commercial end-use sales in the nine-Member Seminole-system have grown at an average annual rate of approximately 1.5% in the past ten years and approximately 3.1% in the past five years. EDR expects employment and income to continue on a favorable growth path as statewide population growth strengthens. Seminole projects commercial end-use sales to grow at an average rate of approximately 1.7% annually through the ten-year forecast horizon.

Q. Please summarize Seminole's load forecast methodology.

A. Seminole adheres to generally accepted methodology currently employed within the electric utility industry to forecast number of consumers, energy and peak demand. Each Member Cooperative is modeled separately, since each service area exhibits unique growth and geographical characteristics. Seminole produces monthly forecasts for each Member system. If rate classification data is available, class level forecasts are developed and reconciled to match Member-total level forecasts. Seminole's system forecast is the aggregate of Member system forecasts. Model assumptions are collected from Members, government agencies, universities, and other third party providers.

Q. How does Seminole forecast consumer growth?

Seminole forecasts monthly member-consumer growth at Member-total and Member-rate class levels using econometric models. Model training data includes historical number of member-consumers and population estimates for counties served by Members. Future consumer growth projections are based primarily on population forecasts from University of Florida's Bureau of Economic and Business Research (UF BEBR). Population forecasts and other explanatory variables such as number of households, housing stock and employment from Moody's Economic and Consumer Credit Analytics (Moody's) are implemented in consumer models sparingly. Territorial agreements and information provided directly from Member representatives regarding anticipated changes in service territories are incorporated into forecasts, as well.

Q. How does Seminole forecast energy sales?

A. Seminole forecasts monthly energy sales at the Member-total and Member-rate class level with econometric models. Delivery point billing load and Member rate class sales to end-use member-consumers grossed up for distribution losses are trained with a variety of explanatory variables in order to estimate future growth. Explanatory variables include:

- **Weather statistics** for temperature, precipitation and degree days.
- **Economic and demographic indicators** such as population, number of households, housing stock, employment, gross product, income and Seminole's wholesale price.
- **Energy intensity statistics** for heating, cooling and non-weather sensitive (base) end-use appliance saturation and efficiency rates. These data are based on the 2016 Member Residential Appliance Saturation Survey and the Energy Information Administration's Annual Energy Outlook, which Seminole collects from Itron's statistically adjusted end-use spreadsheets.

Historical reductions due to energy efficiency and behind-the meter solar generation are reflected in model training data and are implied in load forecasts. Future expectations of additional behind-the-meter solar adoption are forecasted separately and are netted from energy sales forecasts.

Q. How does Seminole forecast peak demands?

A. Maximum demand by Member by month and by season are modeled using econometric models. Seasonal peak models are designed to predict winter and summer peaks based on a range of months where the highest peaks are expected to occur in each season. Winter seasonal peak models regress the highest peak during November through March of each year against contemporaneous explanatory variables. Summer seasonal peak models regress the highest peak from April through September of each year against contemporaneous explanatory variables. Seasonal peak forecasts replace monthly model forecast results for the month each seasonal peak is most likely to occur. Explanatory variables analyzed in monthly and seasonal demand models include:

- **Weather statistics** for temperature, precipitation, humidity and degree days.
- **Economic and demographic indicators** such as population, number of households, housing stock, employment, income and Seminole's wholesale price.
- **Energy intensity statistics** for heating, cooling and non-weather sensitive (base) end-use appliance saturation and efficiency rates. These

data are based on the 2016 Member Residential Appliance Saturation Survey and the Energy Information Administration's Annual Energy Outlook, which Seminole collects from Itron's statistically adjusted end-use spreadsheets.

- **Load factor** is modeled by month and by season based on temperature statistics.

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

Historical reductions due to demand-side-management and behind-the meter solar generation are reflected in historical load data and are implied in load forecasts. Future expectations of additional behind-the-meter solar adoption are forecasted separately and are netted from peak demand forecasts.

Q. Please summarize the key assumptions used in the load forecast

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

The strongest rates of member-consumer growth in Seminole's forecast horizon are expected to occur within the next five years. Net migration into Florida and economic expansion are expected to drive system growth during this period. Over the next ten years, we expect nearly flat to negative growth in average usage per member-consumer as newer, more efficient technologies saturate the appliance stock.

Q. Please describe Seminole's current consumer, energy, and seasonal peak demand forecast.

A. From 2018 through 2027, Seminole projects the total number of residential and commercial member-consumers served by Members to grow at an average annual rate of approximately 1.4% and 1.3%, respectively.

Residential usage-per-member-consumer has grown approximately 1.1% annually on average from 2012 through 2016, yet this trend is expected to reverse and decline at an average rate of approximately -0.5% annually through 2022 and flatten thereafter. Similarly, commercial use-per-member-consumer has grown at an average annual rate of approximately 1.2% from 2012 through 2016; however this trend is expected to slow to approximately 0.4% through the next ten years.

Overall, net energy for load is projected to grow at an average annual rate of approximately 1.3%, from 14,655 MWh in 2018 to 16,470 MWh in 2027. Similarly, summer net firm demand is projected to grow at an average annual rate of approximately 1.3%, from 3,140 MW in 2018 to 3,516 MW in 2027. Winter net firm demand is projected to grow at an average annual rate of approximately 1.6%, from 3,398 MW in 2018 to 3,909 MW in 2027.

Q. How does Seminole's current load forecast compare to its prior forecasts in recent years?

A. The current load forecast is lower than prior forecasts recently produced in TYSP filings. Updates to the latest load model input data and assumptions are listed below:

- End-use appliance intensities were updated to reflect data from the 2016 Annual Energy Outlook (AEO) from the U.S. Energy Information Administration. The 2016 AEO shows stronger declines in end-use intensities due to higher saturation of newer, more-efficient appliance stock.
- Historical saturation rates of end-use appliances were updated to include results from the 2016 Member Residential Appliance Saturation Survey. The prior survey was conducted in 2012.
- Population and related housing growth data were updated to include the University of Florida's Bureau of Business and Economic Research (BEBR) and Moody's Analytics April 2017 productions. Growth expectations from these sources are generally lower than the forecasts produced a year before.
- Photovoltaic energy output and output at the time of peak demand from new behind-the-meter installations were derived in order to reduce Seminole's expected load requirements in the future. The behind-the-

meter solar forecast is a new component to the load study that has not been included in prior forecasts.

Q. Is Seminole's current load forecast reasonable for planning purposes?

A. Yes. The load forecast is based on generally accepted methodology currently employed within the electric utility industry. Explanatory variable assumptions provided by third parties are reasonable and weather data used to project load is normalized from 30-years of observations. Seminole, its Members, and the Rural Utilities Service (RUS) have consistently relied on Seminole's forecasts as the basis for power supply planning, rate development, and financial planning.

Q. Does the RUS approve Seminole's load forecasts?

A. Yes. Consistent with RUS rules, Seminole is required to submit a load forecast in conjunction with a new RUS loan application within 24 months of the application. Nevertheless, Seminole submits a load forecast annually to the RUS for approval. The most recent load forecast study was approved by RUS in October 2017.

Q. Does Seminole's load forecast reflect the effects of DSM and conservation programs offered by Seminole's Members?

A. Yes. The historical load data utilized in econometric analysis is net of the effects of DSM, energy efficiency and conservation programs, with the exception of behind-the-meter diesel generation.

DEMAND SIDE MANAGEMENT & CONSERVATION

Q. Does Seminole offer any DSM or conservation programs to end-use consumers?

A. No. As a Generation and Transmission cooperative, Seminole provides wholesale power to its Members and does not serve end-use member-consumers.

Q. Does Seminole promote the use of DSM or conservation to its Members in other ways?

A. Yes. Seminole's wholesale rate structure provides Members with price signals that reflect Seminole's cost of supplying power in aggregate. Under this rate structure, Seminole's demand charge to each of its Members is applied to each Member's demand at the time of Seminole's peak. This encourages Members to concentrate their load-management efforts on controlling Seminole's overall system peak rather than their separate peaks. In addition, Seminole's wholesale rate to its Members include time-of-use fuel charges to reflect the differences in fuel costs incurred by Seminole to serve its Members during the peak and off-peak periods. Each Member may use these price signals to evaluate the cost effectiveness of DSM, energy efficiency and conservation measures for its own circumstances. To ensure Members have the opportunity to achieve maximum load-management benefit, Seminole's system operators develop and implement a coordinated load management demand reduction strategy in real time to notify Members when Seminole's monthly billing peak is expected to occur.

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

Q. Do any of Seminole's Members have Commission-approved DSM or conservation programs?

A. No. The provisions of Florida's Energy Efficiency and Conservation Act ("FEECA") related to numeric conservation goals only apply to investor-owned utilities and certain municipal utilities. Thus, neither Seminole nor its Members have Commission approved numeric conservation goals, DSM programs, or DSM plans.

Q. Do Seminole's Members nonetheless offer DSM programs?

A. Yes. Members participate in Seminole’s coordinated load management-demand reduction strategy during peak-demand billing events through distribution system voltage reduction (“VR”) and coincident peak power rate programs. Seminole's Members also offer a variety of programs and services to end-use member-consumers in order to promote energy efficiency, conservation and cost savings. Member DSM, energy efficiency and conservation programs include:

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

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

Q. Have the peak demand and energy savings achieved by Seminole's Members been quantified?

A. Yes. In 2016, Seminole engaged Advanced Energy and Tierra Resource Consultants, LLC (AE/Tierra), an energy and natural resource consulting firm, to help quantify the energy efficiency and DSM savings achieved by Seminole's Members. As discussed in the pre-filed testimony of Tom Hines, AE/Tierra estimated that Seminole's Members achieved approximately 12,353 MWh in annual savings and approximately 85,026 kW (or 85 MW) in winter peak demand savings in year 2015.

Q. Has Seminole evaluated whether there are additional conservation measures that may be reasonably available to Seminole's Members?

A. Yes. In order to help Seminole evaluate potentially available DSM measures to mitigate the projected need, Seminole also engaged AE/Tierra to identify potential new programs and to evaluate their cost-effectiveness. None of the additional measures evaluated by AE/Tierra satisfied the Rate Impact Measure (RIM) test traditionally relied upon by the Commission in evaluating the cost-effectiveness of DSM measures. A copy of AE/Tierra's report is attached to Mr. Hines' pre-filed testimony.

Q. How will Seminole and its Members utilize the results of the DSM potential study?

A. Even though none of the measures analyzed by AE/Tierra passed the RIM Test, Seminole is working with Members to evaluate pilot programs. One of the measures of particular interest to Seminole and its Members are Smart Thermostat Incentives. According to estimates from the 2016 Member Residential Appliance Saturation Survey, there are approximately 24,000

Smart Thermostats already installed in member households. Seminole also is committed to working with its Members to implement recommendations made by AE/Tierra to help improve program tracking and increase future savings by enhancing current efforts and adding new measures to existing programs when appropriate.

Q. In your opinion, are there sufficient DSM or conservation measures reasonably available to Seminole or its Members to mitigate the need for the Seminole Combined Cycle Facility (SCCF)?

A. No. As noted above, none of the potential DSM measures analyzed by AE/Tierra passed the RIM test traditionally utilized by the Commission for analyzing the cost-effectiveness of DSM measures. Despite the demand reductions associated with Seminole's Members' existing DSM programs, which are reflected in Seminole's load forecast, the need for additional capacity still exists and there is not a reasonable scenario in which sufficient DSM or energy efficiency or conservation could be added to avoid the need for additional capacity.

Seminole is projected to require more than 901 MW of additional capacity by 2021 to meet peak demand and maintain the reserve margin. To put this in perspective, in Order No. PSC-14-0696-FOF-EU, the Commission established DSM goals for the utilities subject to FEECA. Based on those goals, the largest electric utility in the State of Florida, Florida Power & Light, is to achieve Commission-approved DSM goals of approximately 526 MW in summer demand reduction and 324 MW in winter demand reduction, over the course of a ten-year period from 2015 through 2024. As an additional point of comparison, TECO, which is comparable in size to Seminole in terms of consumers and annual peak demand, is expected to achieve Commission-approved DSM Goals of approximately 56 MW in summer demand reduction and 78 MW in winter demand reduction, over the course of the same ten-year period. Based on these Commission-approved DSM goals, even large, vertically integrated utilities comparable to and larger than Seminole's size with centralized staff and resources to offer DSM programs directly to their customers cannot cost-effectively achieve 901 MW peak demand reductions through DSM and conservation programs over the course of the next four years.

Q. Does this complete your testimony?

A. Yes.

Kyle D. Wood

Education

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

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

Professional Experience

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

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

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

Academic Awards and Honors

Undergraduate Degree with Distinction

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

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

Study Abroad Student, Osnabrück University, Germany

Professional Association Membership

Utility Advisory Board, SAS

Energy Forecasting Group, Itron

Load Forecasting Working Group, FRCC

Electric Utility Forecasters Forum

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

THOMAS HINES

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF THOMAS HINES

DOCKET NO. __________-EC

DECEMBER 21, 2017

Q. Please state your name and address.

A. My name is Thomas Hines. My business address is 7227 N 16th St Phoenix, Arizona 85020.

Q. By whom are you employed and in what capacity?

A. I am a Principal with Tierra Resource Consultants ("Tierra"), LLC.

Q. What types of company is Tierra?

A. Tierra is a full-service energy and natural resource management consulting firm.

Q. Please state your professional experience.

A I have over 25 years of experience in Demand Side Management ("DSM") program design, implementation, and evaluation. I have successfully designed and managed multiple award-winning energy efficiency programs, including the Arizona Public Service ("APS") ENERGY STAR Homes program and the APS Home Performance with ENERGY STAR program. Throughout my career, I have worked closely with industry stakeholders (including builders, contractors, Realtors, lenders, raters and other trade allies), to drive market transformation. I have testified extensively during public utility commission proceedings and as a public spokesperson for energy efficiency related topics. I also serve as a board member of the Energy and Environmental Building Alliance ("EEBA"), an organization devoted to advancing building science and energy efficient building practices.

I hold a Bachelor of Science degree in Psychology from Rutgers University and a Masters of Environmental Planning degree from Arizona State University.

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

A. The purpose of my testimony is to discuss work that Tierra performed in conjunction with North Carolina Advanced Energy Corporation ("AE") under contract with Seminole Electric Cooperative, Inc. ("Seminole") to help evaluate existing energy efficiency ("EE") and DSM programs offered by Seminole and its Member Cooperatives, as well as potential new offerings. Specifically, the AE/Tierra team assisted Seminole with determining and quantifying the EE/DSM efforts that it and its Member Cooperatives undertook in 2015 to reduce load. Additionally, we recommended ways to enhance the existing EE/DSM programs and offered additional EE/DSM program concepts that Seminole and its Member Cooperatives could consider adding to their portfolio in the future. The analysis of additional EE/DSM program concepts included an evaluation of the cost-effectiveness of the proposed programs.

Q. Are you sponsoring any exhibits in the case?

A. Yes, I am sponsoring the following exhibits, which were prepared by me or under my supervision and are attached to my pre-filed testimony:

- Exhibit No. ___ (TH-1) – Resumé;
- Exhibit No. ___ (TH-2) – a report entitled Energy Efficiency and Demand Management Savings Report; and
- Exhibit No. ___ (TH-3) – a report entitled Energy Efficiency and Demand Management Program Analysis.

Q. Please describe the work that AE/Tierra performed to quantify the savings resulting from the existing EE/DSM offerings of Seminole and its Members.

A. To quantify existing EE/DSM programs, AE/Tierra researched all programs and EE and DSM measures currently offered by Seminole and Member Cooperatives to collect cost and savings information. Seminole and its Members offer many programs and services to educate their members on ways to save energy, including web content, brochures, member outreach events, and on-site energy audits. Although it is expected that these efforts produce significant energy savings and market transformation effects, it is difficult to accurately quantify and attribute specific savings amounts to these educational programs. In addition to these general education programs, the team identified a subset of EE and DSM measures and program activities within the overall portfolio where energy savings could be identified, quantified, and reported. To facilitate accurate and consistent reporting, the team worked with Seminole to standardize the program measures, units, and definitions across all Member Cooperatives. Per-unit energy savings estimates were developed using a combination of sources and custom energy-savings calculations, including regional technical reference manuals, national industry-recognized databases, custom energy modeling work using local weather and building characteristics, and engineering review of Seminole information submitted in response to data requests. Specific references are provided in the following section for each program type. Program participation, such as number of units or meters, and spending on incentives and labor were also collected from all Member Cooperatives and included in benefit/cost calculations for each measure. Finally, a tracking and reporting spreadsheet tool was developed for Seminole and each Member to document all data and summarize results.

Q. What existing energy savings programs did AE/Tierra identify and analyze?

A. Working in conjunction with Seminole, AE/Tierra identified a number of existing energy savings programs and initiatives offered by Seminole and/or Member Cooperatives in 2015, including:

- **Residential Pre-Pay Program**: Residential member-consumers can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- **LED/CFL Efficient Bulb Giveaway**: This program provides participating end-use member consumers with free energy-efficient 10 Watt (W) LED or 13W CFL bulbs to replace their existing 60W incandescent bulbs.

- **Residential Energy Smart Rebate Programs**: A rebate is given to residential member-consumers to upgrade to more efficient equipment and/or improve their home's building envelope. Rebate measures include: air conditioners and heat pumps, heat pump water heaters, solar water heaters, insulation – batt or spray foam – and window film.
- **LED Outdoor and Street Lighting**: This program involves the replacement of utility-owned outdoor and municipal street lighting with lower wattage LEDs. Several types of high efficiency lighting change outs were evaluated including: 100W high pressure sodium (HPS) to 40W, 48W, or 72W LED, 150W HPS to 70W LED, 250W HPS to 107W LED, 1000W metal halide (MH) to 283W or 316W LED.
- **Coincident Peak Power (CPP) Rates**: Coordinated load management-demand reduction program where enrolled commercial and industrial member-consumers are signaled to shed load during critical peak billing periods.
- **Time-of-Use (TOU) Rates**: Residential, commercial, and industrial rates that encourage member-consumers to reduce power use during on-peak hours through price signals. These rates shift energy use, reduce peak demand, and often result in energy savings. Within the scope of the AE/Tierra evaluation, no demand or energy savings were claimed for these rates.
- **Commercial Interruptible Rates:** Direct load control program where Seminole interrupts electrical service to enrolled commercial member-consumers during extreme peak demand, capacity shortage or

emergency conditions. This program was not called as a resource in 2015 but it is available when needed.

- **Commercial Customer Load Generation:** Standby peak-shaving generators which Seminole and its Members may dispatch for purpose of load management and enhanced reliability. Members with standby generators under this program receive a billing credit. This program was not called as a resource in 2015 but it is available when needed.

- **Energy Audits:** On-site energy audit program for residential, commercial and industrial member-consumers.

- **Utility System EE Projects**, including:
    - o Lighting and HVAC upgrades at Seminole generation or administration facilities or Member Cooperative facilities; and
    - o Distribution System Voltage Reduction (VR): Reduction of voltage on certain distribution feeders during peak times.

Q. What were the results of AE/Tierra's quantification analysis?

A. As discussed further in the Energy Efficiency and Demand Management Savings Report attached as Exhibit No. ____ (TH-2), total annual energy savings for Seminole and its Members in 2015 were 12,353 MWh and peak demand savings were 85 MW (at generator including transmission and distribution losses). Lifetime energy savings were 34,479 MWh.

Q. Please describe the work that AE/Tierra performed to evaluate other potential EE/DSM program offerings.

A. AE/Tierra proposed several new program concepts for Seminole and its Members to consider, including:

- Commercial & Industrial Lighting Program;
- Residential Audit Direct Install Kits;
- Direct Load Control or Grid-Enabled Water Heater Program;
- HVAC Quality Install Program; and
- Smart Thermostat Program.

The program concepts were selected based on AE/Tierra experience and feedback from Seminole on current activities in Member Cooperative territories. Our focus was on providing concepts that enhance existing programs or leverage current activities, improve the member experience, provide potential to shift peak demand, promote new technologies, and add value for members.

In order to help evaluate the cost-effectiveness of these programs, Seminole requested information on the impact of implementing EE/DSM programs on rates for all member-consumers, as well as a comparison between the cost of EE/DSM programs and other resources, such as new generation. As such, the AE/Tierra team performed calculations for two cost-effectiveness tests: the Ratepayer Impact Measure (RIM) test and the Utility Cost Test (UCT). These calculations concluded that none of the program concepts that were studied would pass the RIM test as being cost effective at this time. The results of those analyses, as well as other key findings and recommendations, are summarized in a report prepared by AE/Tierra entitled "Energy Efficiency and

Demand Management Program Analysis," which is attached as Exhibit No. ___ (TH-3) to my pre-filed testimony.

Q. Does this conclude your testimony?

A. Yes.

TOM HINES

TOM HINES
Program Design and Regulatory Specialist
Tierra Resource Consultants, LLC
4446 E Camelback Rd, Suite 112
Phoenix, AZ 85018
Office: 602-505-4826 | Mobile: 602-505-4826
Email: Tom.Hines@tierrarc.com
Web: www.TierraRC.com

PROFESSIONAL HISTORY

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

EDUCATION

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

PROFESSIONAL ASSOCIATIONS

- Board of Directors, Energy and Environmental Building Alliance

BIOGRAPHY

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

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

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

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

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

PROFESSIONAL EXPERIENCE

Integrated Distributed Energy Resource Planning and Design

Mr. Hines is currently a leading proponent of Distributed Energy Resource program design to address load shape challenges from high solar DG adoption on the grid, often referred to as the "duck curve." In this role at APS, Tom is tasked with coordinating with a wide range of utility disciplines, including; resource planning, technology assessment, system operations planning, regulatory, smart grid, customer service, and rates to identify new and innovate approaches to distributed energy resource programs that support the continued growth of solar, while minimizing grid impacts. Mr. Hines has begun to expand this effort to other utilities, since 2016.

Energy Efficiency Portfolio Design for Commercial and Residential Programs

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

Policy and Strategic Consulting Support

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

Distributed Storage Technology Evaluations and Pilot Design

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

Program Management and Implementation

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

Distributed Energy Resource Education

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

Energy Efficiency Marketing and Communications.

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

SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT SAVINGS REPORT

Program Year 2015

Original Report issued October 7, 2016
Revised Report December 8, 2017

advanced energy

Primary Investigators/Authors

Tom Hines, Tierra Resource Consultants
Christine Maurer, PE, Advanced Energy
Matt Murray, PE, Advanced Energy
Eric Shum, PE, Tierra Resource Consultants

Organizations

Advanced Energy
Tierra Resource Consultants

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EXECUTIVE SUMMARY

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

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

PROCESS FOR QUANTIFYING ENERGY EFFICIENCY RESULTS

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

AE/Tierra researched all programs and EE measures currently offered by Seminole and Member Co-ops to collect cost and savings information. Seminole and Member Co-ops offer many programs and services to educate their members on ways to save energy, including web content, brochures, member outreach events, and on-site energy audits. Although it is expected that these efforts produce significant energy savings and market transformation effects, it is difficult to accurately quantify and attribute these savings. Within the overall portfolio, the team identified a subset of EE measures and program activities where energy savings could be identified, quantified, and reported. The team also worked to standardize the program measures, units, and definitions across all Member Co-ops, ensuring consistent reporting. Per-unit energy savings estimates were developed using a variety of sources and custom energy-savings calculations, including regional technical reference manuals, national industry-recognized databases, custom energy modeling work using local weather and building characteristics, and engineering review of Seminole information submitted in response to data requests. Specific references are provided in the following section for each program type. Program participation, such as number of units or meters, and spending on incentives and labor were also collected and included in benefit/cost calculations for each measure. Finally, a tracking and reporting spreadsheet tool was developed for Seminole and each Member Co-op to document all data and summarize results.

EE Quantification Process:

Identify Efforts

- Meet with Seminole and Member Co-ops
- Review Seminole survey information and Member Co-op websites
- Define programs, measures, and units; standardize reporting definitions among co-ops
- Determine what efforts can be counted

Data Collection

- Identify data needed for reporting
- Work with Seminole and Member Co-op staff to collect relevant data
- Analyze and QA/QC all data recieved; conduct calls and submit additional data requests to clarify all data collected

Engineering

- Customize savings calculations using local usage profiles, energy modeling tools, weather adjustments, and most relevant regional information
- Document all assumptions and sources of savings calculations

Review & Report

- Develop Total Savings spreadsheet including Seminole and each Member Co-op; each co-op received a spreadsheet with populated EIA-Schedule 6 tables
- Create final report of program EE and demand management savings

PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

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

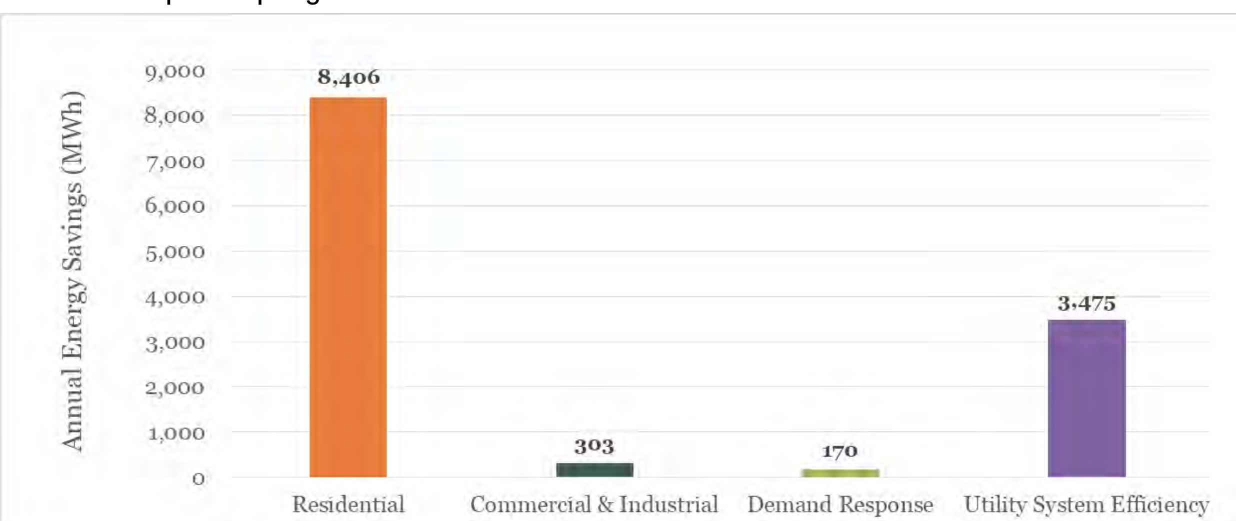
- Residential Pre-Pay Program: Residential members can pre-pay for their electricity and receive enhanced feedback on their energy use and costs. The increased energy awareness that this program provides results in behavioral changes that produce energy savings.
- LED/CFL Efficient Bulb Giveaway Lighting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

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

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

Total Annual Energy Savings by Program Type

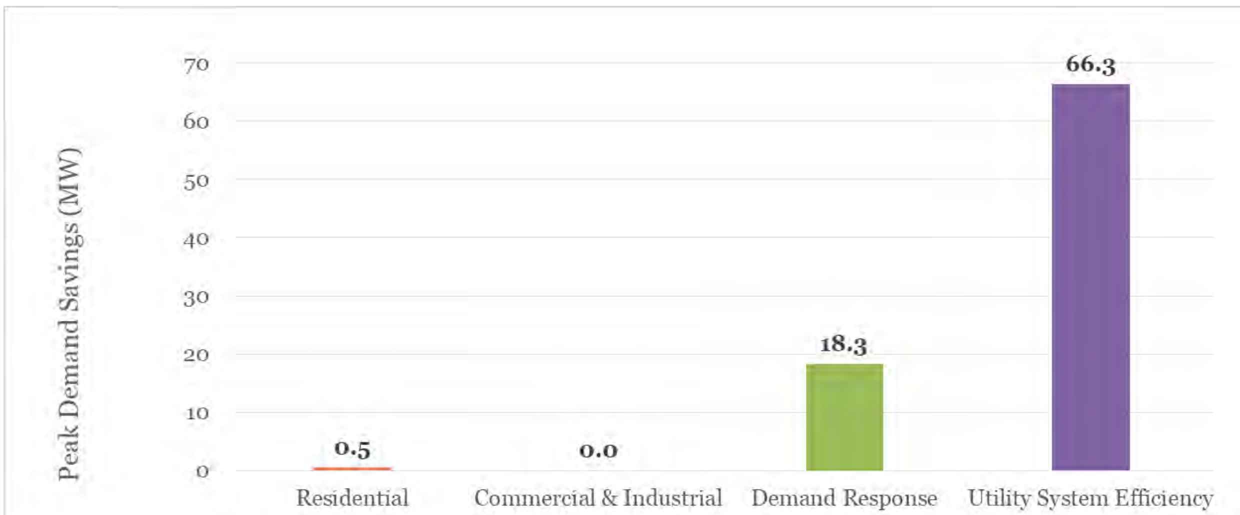
Total annual energy savings for Seminole in 2015 were 12,353 MWh and peak demand savings were 85 MW (at generator including transmission and distribution losses). Lifetime energy savings is 34,479 MWh. The chart below shows all Member Co-op program savings plus utility system savings projects. Residential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



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

Total Annual Peak Demand Savings by Program Type

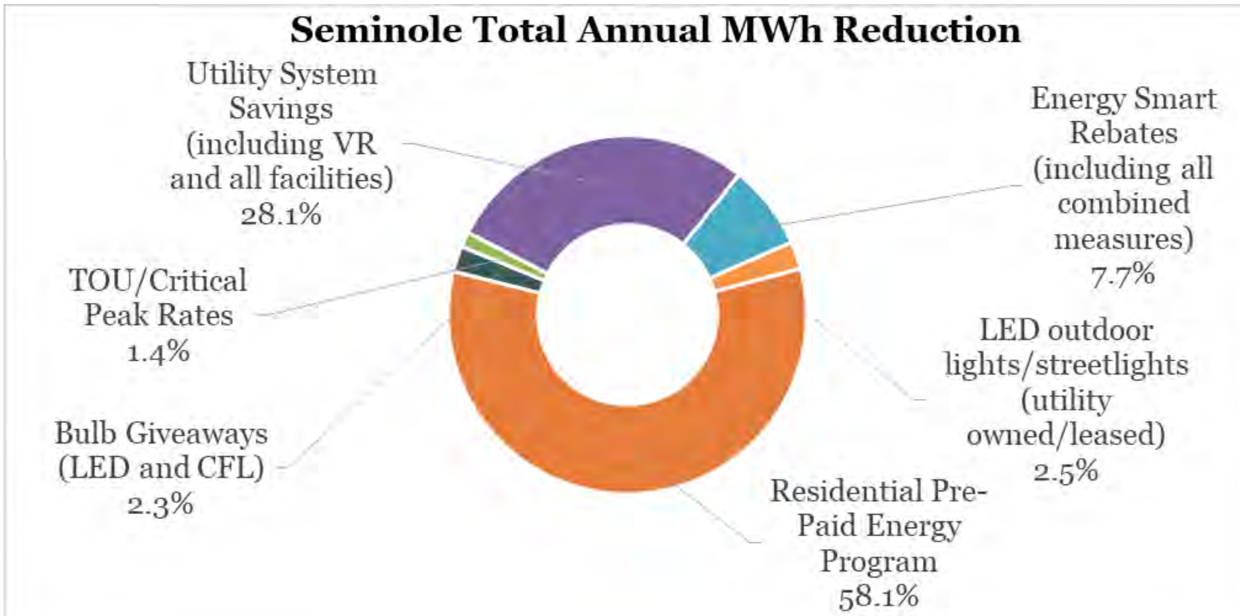
The majority of peak demand savings came from the utility system efficiency programs (78%) and demand response (21.5%). Residential Programs contributed less than 1% of annual demand savings.



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

Percentage of Annual Savings by Program

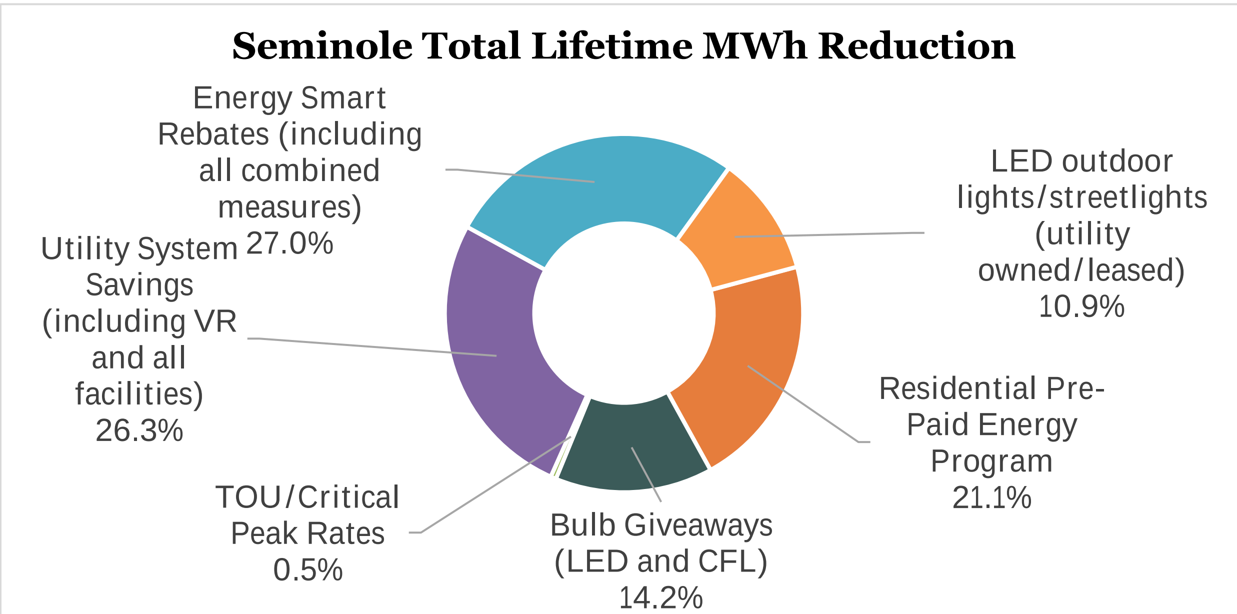
The majority of savings in 2015 came from three programs: pre-pay (58.1%), utility system savings projects (28.1%), and Energy Smart rebates (7.7%). The remaining 6% of savings came from bulb giveaways, TOU or CPP rates, and LED outdoor and street lights.



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

Percentage of Lifetime Savings by Program

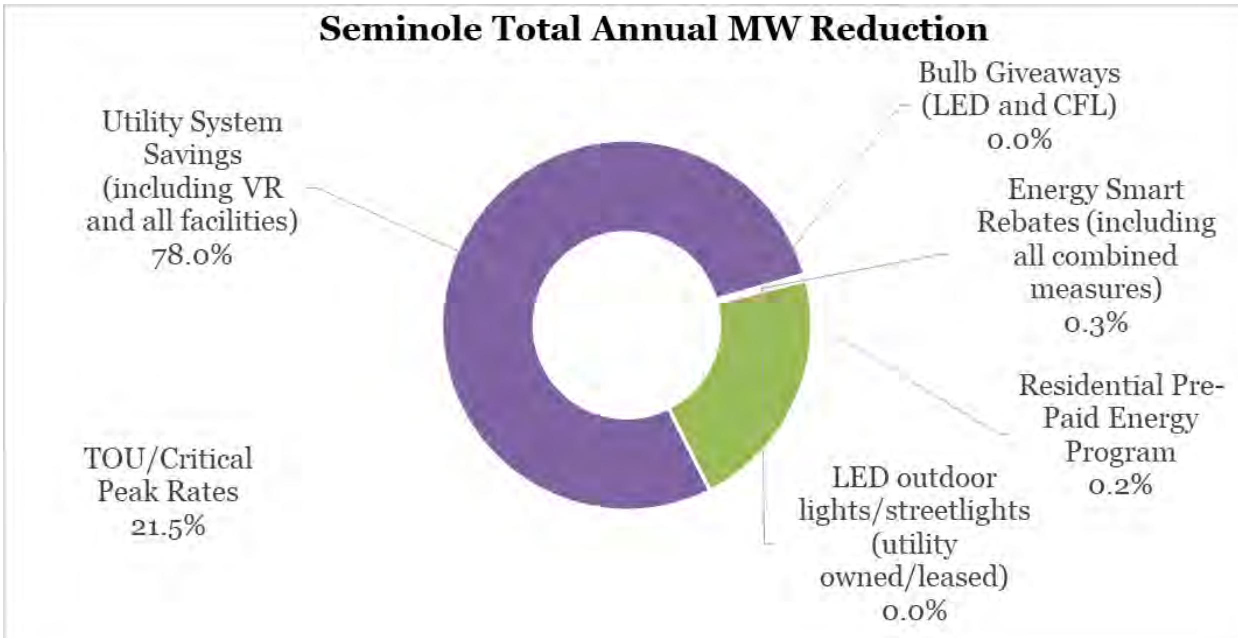
Lifetime savings refer to the cumulative EE savings over the expected lifetime of a measure. Energy Smart rebate measures consist of energy-efficient HVAC equipment and insulation that have much longer lives, so while they only contribute 8% of annual savings, they account for 27.0% of lifetime savings.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



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

Percentage of Annual Peak Demand Savings by Program

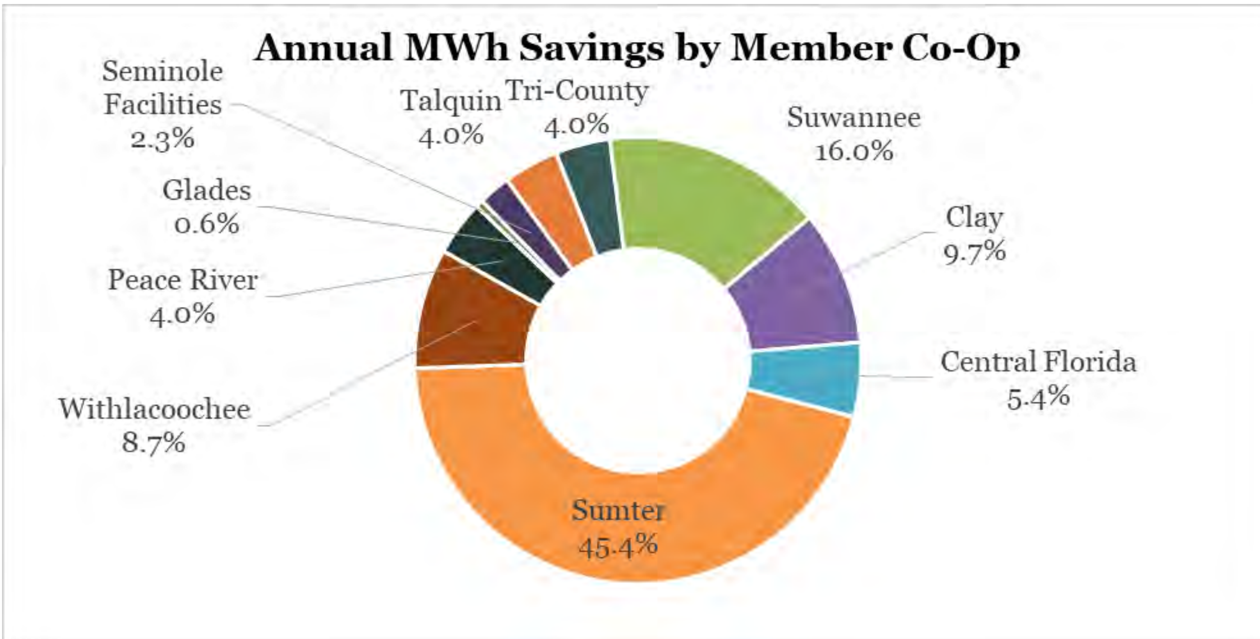
The majority of peak demand savings came from utility system savings projects (71.8%) and TOU/CPP rates (27.5%). Programs that are categorized as traditional customer EE programs contributed less than 1% of annual peak demand savings.



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

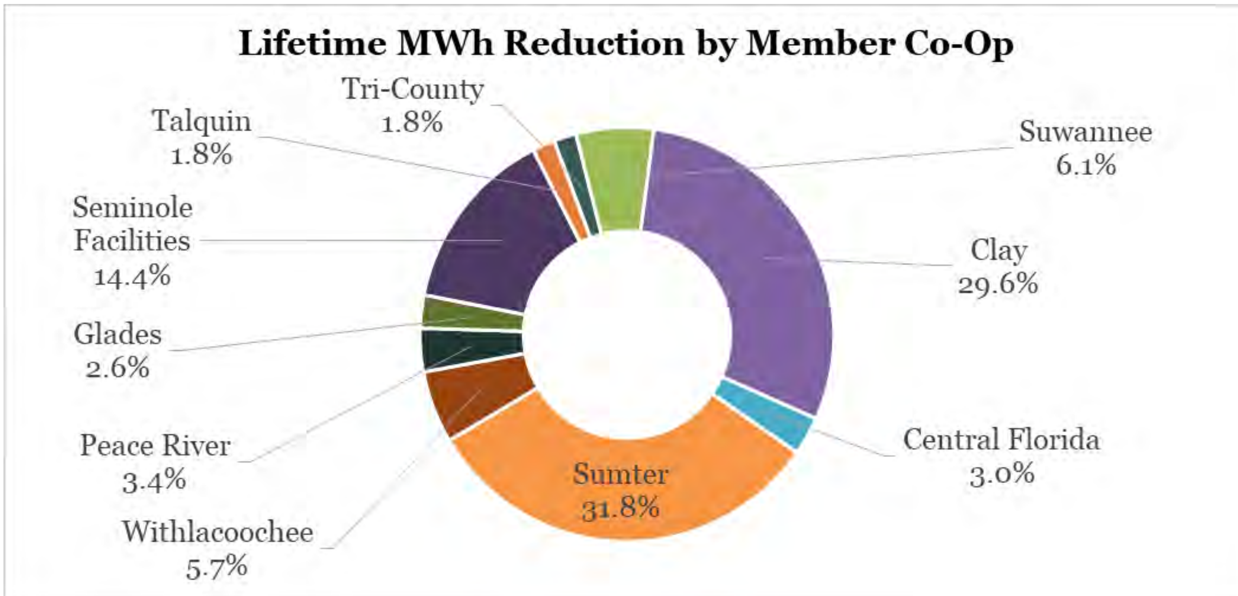
Percentage of Annual Savings by Member Co-op

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



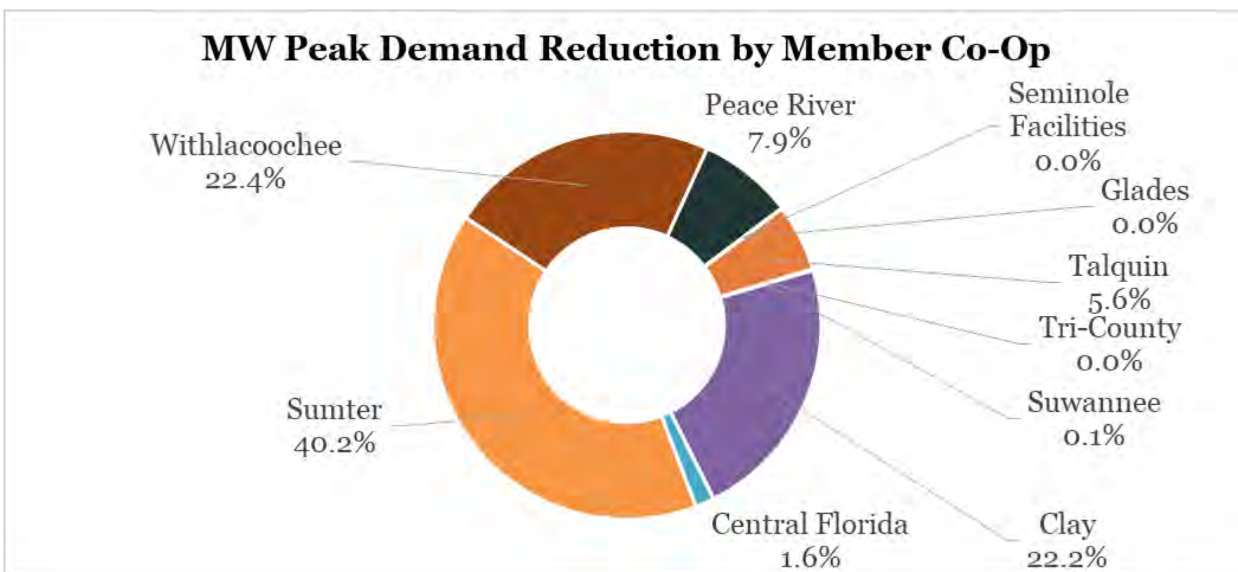
Percentage of Lifetime Savings by Member Co-op

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



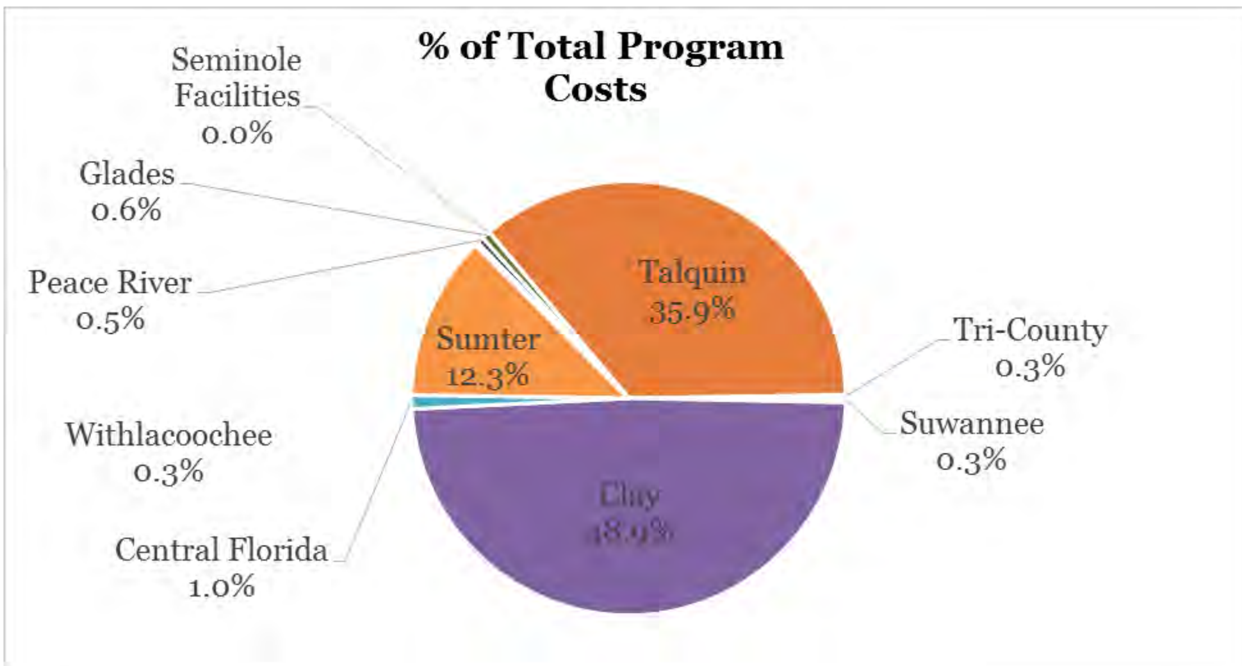
Percentage of Annual Peak Demand Savings by Member Co-op

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



Percentage of Total Energy Efficiency Spending by Member Co-op

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



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

Cost Effectiveness

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

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

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

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

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

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

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

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

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

KEY FINDINGS AND RECOMMENDATIONS

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

Program Enhancement Recommendations

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

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

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

Key Findings and Recommendations by Program Type

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

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

CONCLUSION

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

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SEMINOLE ELECTRIC COOPERATIVE, INC.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT PROGRAM ANALYSIS

October 19, 2017

advanced energy

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INTRODUCTION

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

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

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

EXISTING PROGRAMS DELIVERING ENERGY EFFICIENCY SAVINGS

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

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

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

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

KEY FINDINGS AND RECOMMENDATIONS

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

Program Enhancement Recommendations

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

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

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

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

Key Findings and Recommendations by Program Type

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

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

NEW PROGRAM SUMMARIES

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

Seminole is not subject to the requirements and guidance of the Florida Energy Efficiency and Conservation Act (FEECA); however, it was interested in the cost effectiveness of potential EE/DSM programs. Specifically, Seminole requested information on the impact of implementing EE/DSM programs on rates for all member-consumers, as well as a comparison between the cost of EE/DSM programs and other resources, such as new generation. As such, the AE/Tierra team performed calculations for two cost-effectiveness tests: the Ratepayer Impact Measure (RIM) test and the Utility Cost Test (UCT). (Note that the UCT is also called the Program Administrator Cost [PAC] test.) The team used the definitions of the tests provided in the California Standard Practice Manual. The RIM test was more strongly considered because of the desire for future program offerings to have a minimal impact on rates. It is noted that based on the information and assumptions used to analyze potential program opportunities, none of the future program offerings in this report pass the RIM test and may impact Member rates.

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

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

Seminole also provided certain primary data based on the best available information at the time of analysis. This data included avoided energy, capacity, and transmission costs for the years 2017 to 2043, current average residential and commercial retail rates, and an escalation schedule for retail rates. For the avoided cost assumptions, we considered two scenarios. The first scenario (listed as (1) on all tables) included the total annual value of avoided capacity cost for a new generic unit coming online in May 2021. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest contingency during four summer months only per year. The second scenario (listed as (2) on a tables) included the total value of avoided capacity cost based upon responses received in Seminole's March 1, 2016 Request for Firm Capacity for the period from June 2021 through December 2025. The total annual cost of a new generic unit coming online in year 2026 is reflected thereafter. Years 2017 through 2020 include the cost of reliability purchases for Seminole's single largest contingency during four summer months only per year. Where the scenarios produced different values, we have noted them in the tables below with (1) and (2).

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

Commercial & Industrial Lighting Program

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

Program Description

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

Target

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

Energy Efficiency Savings Measures

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

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

Incentive Design

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

Implementation Plan

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

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

Marketing and Member Education

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

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

Potential Results

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

Units & Savings		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
366	2190	0.472
Costs		
Incentive Costs	**Implementation Costs**	**Total Costs**
$250,157	$83,386	$333,543

Cost Test Results	
Cost Test	**Estimated Result**
Utility Cost Test (UCT)	1.44 (1), 1.36 (2)
Ratepayer Impact Measure (RIM) Test	0.38

Residential Audit Direct Install Kits

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

Program Description

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

Target Audience

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

Energy Efficiency Savings Measures

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

Incentive Design

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

Implementation Plan

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

Marketing and Member Education

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

Potential Results

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

Potential Results

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

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

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

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

Direct Load Control or Grid-Enabled Water Heater Program

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

Program Description

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

Target Audience

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

Energy Efficiency Savings Measures (Either/Or)

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

Incentive Design

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

Implementation Plan

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

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

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

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

Marketing and Member Education

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

Potential Results

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

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

HVAC Quality Install Program

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

Program Description

This program will incentivize quality installations of replacement heating and cooling equipment in existing single-family homes, which will result in a better performing system. The Quality Install Program will follow the ACCA Quality Installation 5 Manual to ensure that the system is sized correctly, the total airflow of the system is set to the manufacturer's specifications, the duct system is well sealed, the refrigerant is correctly charged, and the total static is within the manufacturer's specifications. These five steps are often overlooked during equipment change out, which results in underperforming equipment. Program delivery will include rebates to contractors that will reduce or cover the cost of the extra work associated with quality installations, a robust quality control/quality assurance protocol, and training to ensure contractors are capable of participating. A complementary program can be rolled out simultaneously that will retro-commission existing equipment to address duct tightness and refrigerant charge. The AE/Tierra team concentrated on a replacement program in this report but included cost-effectiveness calculations for a retro-commissioning program as well. The HVAC Quality Install and HVAC Quality Retrofit Programs are projected to result in average annual energy savings of 451 kWh and 305 kWh, respectively, per household per year. Neither program passed the RIM test and may result in rate impacts to Member Cooperatives.

Target Audience

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

Energy Efficiency Savings Measures

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

Incentive Design

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

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

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

Implementation Plan

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

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

Marketing and Member Education

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

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

Potential Results

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

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
550	**248**	**0.076**
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$110,000	**$86,260**	**$196,260**

COST TESTS	
Cost Test	**Estimated Result**
Utility Cost Test (UCT)	**0.38(1), 0.36(2)**
Ratepayer Impact Measure (RIM) Test	**0.22(1), 0.21(2)**

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

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,282	**391**	**0.217**
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$192,300	**$69,167**	**$261,467**

COST TESTS	
Cost Test	**Estimated Result**
Utility Cost Test (UCT)	**0.48(1), 0.43(2)**
Ratepayer Impact Measure (RIM) Test	**0.26(1), 0.23(2)**

Smart Thermostat Program

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

Program Description

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

Target Audience

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

Energy Efficiency Savings Measures

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

Incentive Design

Incentives will be paid directly to the member because installation may be done by the member or a contractor. A one-time equipment incentive will be paid to the member for installing up to two smart thermostats in a single home. If demand response is activated, the member will receive a set incentive rate per year. There will be a limit to the number of demand events that can happen annually. The cost effectiveness results presented here are not based on the use of the demand response features. Utilizing demand response will significantly increase demand savings and program costs, and will require additional planning to maximize benefits.

Implementation Plan

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

Marketing and Member Education

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

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

Potential Results

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

UNITS + SAVINGS		
Estimated Annual Projects	**Annual MWhs Saved**	**Coincident MW Saved**
1,517	555	0.212
COSTS		
Incentive Costs	**Implementation Costs**	**Total Costs**
$75,850	$158,250	$234,100

COST TESTS	
Cost Test	**Estimated Result**
Utility Cost Test (UCT)	**1.04 (1), 0.96(2)**
Ratepayer Impact Measure (RIM) Test	**0.37(1), 0.36(2)**

CONCLUSION

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

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

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

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2017__________-EC

IN RE: PETITION OF SEMINOLE ELECTRIC COOPERATIVE, INC., FOR DETERMINATION OF NEED FOR SEMINOLE COMBINED CYCLE FACILITY

DIRECT TESTIMONY & EXHIBITS OF:

ALAN S. TAYLOR

BEFORE THE PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF ALAN S. TAYLOR

DOCKET NO. __________

DECEMBER 21, 2017

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Alan Taylor. My business address is 821 15th Street, Boulder, Colorado 80302.

Q. By whom are you employed and in what capacity?

A. I am President of Sedway Consulting, Inc. ("Sedway Consulting").

Q. Please describe your duties and responsibilities in that position.

A. I perform consulting engagements in which I assist utilities, regulators, and customers with the challenges that they may face in today's dynamic electricity marketplace. My area of specialization is in the provision of independent evaluation services in power supply solicitations and in the associated economic and financial analysis of power supply options.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Science Degree in energy engineering from the Massachusetts Institute of Technology and a Masters of Business Administration from the Haas School of Business at the University of California, Berkeley, where I specialized in finance.

I have worked in the utility planning and power procurement consulting area for 30 years, predominantly specializing in integrated resource planning, competitive bidding analysis, utility industry restructuring, market price forecasting, and asset valuation. I have testified before state commissions in proceedings involving resource solicitations, environmental surcharges, and fuel adjustment clauses.

I began my career at Baltimore Gas & Electric Company (BG&E), where I performed efficiency and environmental compliance testing on the utility system's power plants. I subsequently worked for five years as a senior consultant at Energy Management Associates ("EMA", a firm that was later acquired by ABB), training and assisting over two dozen utilities in their use of EMA's operational and strategic planning models, PROMOD III and PROSCREEN II. During my graduate studies, I was employed by Pacific Gas & Electric Company ("PG&E"), where I analyzed the utility's proposed demand side management ("DSM") incentive ratemaking mechanism, and by Lawrence Berkeley Laboratory ("LBL"), where I evaluated utility regulatory policies surrounding the development of brownfield generation sites.

Subsequently, I worked at PHB Hagler Bailly (and its predecessor firms) for ten years, serving as a vice president in the firm's Global Economic Business Services practice and as a senior member of the Wholesale Energy Markets practice of PA Consulting Group, when that firm acquired PHB Hagler Bailly in 2000. In 2001, I founded Sedway Consulting, Inc. and have continued to specialize in economic analyses associated with electricity wholesale markets. Since the founding of Sedway Consulting, I have provided independent evaluation services in over four dozen electric utility conventional and renewable resource solicitations, several of them in Florida where I have testified before the Florida Public Service Commission ("FPSC") on a number of occasions.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. Sedway Consulting was retained by Seminole Electric Cooperative, Inc. ("Seminole" or the "Company") to provide independent monitoring and evaluation services in the utility's 2016 solicitations for competitive power supplies to meet the Company's 2021 (and beyond) capacity needs. Sedway Consulting oversaw both the self-build and market alternative solicitation efforts. In the first instance, Sedway Consulting was involved with the monitoring and evaluation of proposals for power island equipment ("PIE"), long-term service agreements ("LTSA"), and engineering, procurement, and construction ("EPC") services that might be selected – if cost-competitive – in developing a resource that Seminole would own and operate. In the second instance, Sedway Consulting monitored Seminole's solicitation of market alternatives (i.e., resources that would be owned and operated by others, with capacity and energy being sold to Seminole under power purchase agreements ["PPAs"]). As the principal consultant on the project, I reviewed Seminole's solicitation processes, performed a parallel and independent economic evaluation of both sets of proposals – those PIE, LTSA, and EPC proposals associated with the self-build solicitation and those PPA proposals submitted in response to the utility's market alternative solicitation. Ultimately, I concluded that Seminole's best option for meeting its long-term capacity needs was a combination of resources from both solicitations:

1. a self-build new natural-gas-fired 1,122 MW (winter capacity) combined-cycle ("CC") facility at Seminole's existing Seminole Generating Station ("SGS") site with an expected in-service date of December 1, 2022 – hereafter referred to as the Seminole CC facility ("SCCF"),
2. a 30-year PPA for power supplies from a new natural-gas-fired 573 MW (winter capacity) CC facility to be developed, owned, and operated by Shady Hills Energy Center, LLC (a subsidiary of GE Energy Financial Services, Inc.) at a site in Spring Hill, Florida with an expected in-service date of December 1, 2021 – hereafter referred to as the Shady Hills CC facility ("SHCCF"),
3. a 15-year PPA for power supplies from two existing natural-gas-fired peaking combustion turbines ("CT") for 346 MW of winter capacity owned by Shady Hills Power Company LLC at essentially the same site where the new 573 MW CC facility will be developed, with a delivery start date of June 1, 2024,
4. a 20-year PPA for power supplies from a new solar photovoltaic ("PV") 40 MW (nameplate) facility to be developed, owned, and operated by Tillman

Solar Center LLC (a subsidiary of Coronal Energy) in High Springs, Florida with an expected in-service date of June 1, 2021,

5. a 15-year PPA for a firm system sale from existing peaking and intermediate resources of Duke Energy Florida ("DEF") for up to 450 MW each year through 2030 and up to 300 MW each year thereafter, with a delivery start date of January 1, 2021,
6. a 5-year PPA for a firm system sale from existing resources of Southern Company Services, Inc. ("SCS") for up to 350 MW each year through May 31, 2024 and up to 100 MW for each year thereafter, with a delivery start date of June 1, 2021,
7. an amendment to an existing PPA with Oleander Power Project Limited Partnership (a subsidiary of Southern Power Company) to extend deliveries of peaking capacity through the end of 2021, and
8. a decision to remove from service one of the two existing coal-fired units at Seminole's Seminole Generating Station facility (with a reduction in winter capacity of 664 MW) at the end of 2022.

Only the first two resources in the above list (SCCF and SHCCF) require FPSC approval and are the primary focus of my Determination of Need testimony. However, the complete portfolio is provided and discussed in my testimony as the entire package of resources, agreements, and decisions were components of the least-cost portfolio and therefore provide necessary context for the selection of the two resources that require approval.

The purpose of my testimony is to describe my role as an independent monitor/evaluator and present my findings. I will discuss the process and tools that I used to conduct Sedway Consulting's independent economic evaluation. Based on the results of my independent evaluation, I concluded that Seminole's new self-build SCCF and the new SHCCF behind the 30-year Shady Hills Energy Center PPA are essential components of the least-cost portfolio in meeting Seminole's long-term capacity needs.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit No. __ (AST-1) consisting of two documents, which are attached to my direct testimony:

Document No. 1	Resume of Alan S. Taylor
Document No. 2	Sedway Consulting's Independent Evaluation Report

III. INDEPENDENT MONITOR/EVALUATOR ACTIVITIES.

Q. Please describe the role you performed as an independent monitor/evaluator in Seminole's 2021 RFPs.

A. As the independent monitor/evaluator in Seminole's 2021 RFPs, I reviewed Seminole's RFPs and associated materials and discussed with the utility the modeling tools and processes that it intended to use in its evaluation of proposals. I attended the bid opening processes in Tampa for both the self-build PIE/LTSA and EPC RFPs and was directly copied on the email submissions of proposals by bidders in the market alternative/PPA RFP. Throughout the process, I monitored all email exchanges and virtually all conference calls between Seminole and the bidders (for all three RFPs:

PIE/LTSA, EPC, and market alternatives). Before receiving the market alternative proposals, I requested that Seminole run its detailed production cost model, ABB's Planning and Risk ("PaR") model, and provide production cost results that I could use to calibrate Sedway Consulting's resource evaluation model. I received emailed electronic copies of all market alternative proposals directly from the bidders on or about the Proposal Due Date (May 9, 2016) and evaluated the economic, operational, and pricing information from each proposal. Seminole conferred with me on a number of issues relating to proposal RFP-noncompliance decisions, interpretation of proposal information, clarification requests, and economic evaluation assumptions. Regarding RFP-noncompliance decisions, there were some proposals that did not meet all of the RFP's threshold requirements and were thus disqualified. I concurred with these disqualification decisions. In addition, Seminole provided estimates of self-build project costs and characteristics after the initial PIE/LTSA proposals (which were received on April 18, 2016) were evaluated. These estimates were updated periodically as the selection of the PIE/LTSA counterparty and contract were finalized/negotiated and as the EPC RFP was conducted (with initial proposals received on November 30, 2016, best-and-final-offers on June 22, 2017, and the negotiation of a final EPC contract through the summer and fall of 2017). As the evaluation progressed, Seminole and I discussed appropriate courses of action and modeling assumptions. Using Sedway Consulting's Response Surface Model ("RSM") and Revenue Requirements Model ("RRM"), I evaluated Seminole's evolving self-build resource and all qualified market alternative proposals and assessed their overall costs and benefits. I compared Sedway Consulting's ranking and results with those of

Seminole to confirm consistency of assumptions and concurrence of conclusions. In addition, I was copied on all email communications between Seminole and the bidders in all three solicitations, monitored virtually all negotiation calls with shortlisted bidders to ensure consistent communication and fair treatment, and participated in Seminole internal discussions regarding qualitative issues and risk factors associated with specific proposals or portfolio combinations of proposals. I made presentations to Seminole's executive team and Board of Trustees regarding Sedway Consulting's independent evaluation process and conclusions, and I documented the evaluation process and results in an independent evaluation report that is attached to my testimony as Exhibit No. __ (AST-1), Document No. 2.

Q. Were you were involved in the development of the RFPs?

A. No. Sedway Consulting was retained after the RFPs had been released. However, I reviewed the RFP documents, suggested some minor process revisions (which were adopted by Seminole and communicated to the bidding community), and concluded that the RFPs were reasonable documents for soliciting proposals.

Q. Do you believe that Seminole's evaluation process was conducted fairly?

A. Yes. The market alternative proposals and Seminole's self-build resource were evaluated on an equal footing, with consistent assumptions applied to all resource options.

IV. DESCRIPTION OF SEDWAY CONSULTING MODELS.

Q. Please describe Sedway Consulting's RSM model and its use in Seminole's resource solicitation.

A. The RSM was the primary model used in Sedway Consulting's independent evaluation of Seminole's resource options and transactions. It is a spreadsheet model that I have used in dozens of solicitations around the country. It is a relatively straightforward tool that allows one to independently assess the cost impacts of different generating or purchase resources for a utility's supply portfolio. Most of the evaluation analytics in the RSM involve calculations that are based entirely on my input of proposal costs and characteristics. A small part of the model examines system production cost impacts and needs to be calibrated to simulate a specific utility's system. In the case of the Seminole market alternatives solicitation, in the weeks prior to the proposal opening, I requested that Seminole execute specific sets of runs with its detailed production cost model. With the results of these runs, I was able to calibrate the RSM to approximate the production cost results that Seminole's PaR detailed production cost model would produce in a subsequent evaluation of any proposals or self-build options that Seminole might receive. Thus, I would not have to rely on Seminole's modeling of a proposal or self-build option; instead, I would be able to insert my own inputs into Sedway Consulting's own model and independently evaluate the economic impact of any particular resource. In short, the RSM provides an independent assessment to help ensure against the inadvertent introduction of significant mistakes that could cause the evaluation team to reach the wrong conclusions.

Q. How is the RSM an independent analytical tool if it is based on initial PaR results?

A. As I noted above, most of the calculations performed by the RSM are not based on PaR results in any way. There are two main categories of costs that are evaluated in a resource solicitation: fixed costs and variable costs. The costs in the first category – the fixed costs of a proposal – are calculated entirely separately in the RSM, with no reliance on the PaR model for these calculations. The second category – variable costs – has two parts: (1) the calculation of a resource's variable dispatch rates and, (2) the impact that a resource with such variable rates is likely to have on Seminole's total system production costs. As with the fixed costs, a proposal's variable dispatch rates are calculated entirely separately in the RSM, with no basis or reliance on the PaR model. It is only in the final subcategory – the impact that a resource is likely to have on system production costs – that the RSM has any reliance on calibrated results from PaR.

Q. Please elaborate on that area of calculations where the RSM is affected by the PaR calibration runs.

A. This is the area of system production costs. These costs represent the total fuel, variable operation and maintenance ("O&M"), emission, and purchased power energy costs that Seminole incurs in serving its members' loads. Given Seminole's load forecast, the existing Seminole supply portfolio (i.e., all current generating facilities and purchase power contracts), and many specific assumptions about future resources and fuel costs, PaR simulates the dispatch of Seminole's system and forecasts total production costs for each month of each year of the study period. At the outset of the solicitation project, the RSM was populated with monthly system production cost results that were created by the PaR calibration runs.

Q. What did the RSM do with this production cost information?

A. Once incorporated into the RSM, the production cost information allowed the RSM to answer the question: How much money (in monthly total production costs) is Seminole likely to save if it acquires a proposed resource, relative to a reference resource? The use of a reference resource simply allowed a consistent point of comparison for evaluating all proposals and Seminole's self-build options. As a reference resource, I used a hypothetical gas-fired resource with a very high variable dispatch rate associated with a heat rate of 13,000 Btu/kWh. In fact, I could have picked any variable dispatch or heat rate for the reference resource and obtained the same relative ranking of proposals out of the RSM. The cost of the reference resource has no impact on the relative results – it is merely a consistent reference point.

Q. Can you provide a numerical example that shows how the RSM works?

A. Certainly. Assume that a utility has a one-year resource need of 500 MW and must select one of the two following proposals:

	Proposal A	**Proposal B**
Capacity:	500 MW	500 MW
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Price:	$30/MWh	$40/MWh

For both proposals, the RSM has already calculated the fixed costs (and represented them in the capacity price) and the variable costs (and represented them in the energy price). Proposal A is more expensive in terms of fixed costs, but Proposal B is more expensive on an energy cost basis. The RSM calculates the final piece of the economic analysis – the different impacts on system production costs – to determine which proposal is less expensive in a total sense for the utility system as a whole.

Assume that the 13,000 Btu/kWh reference unit has a variable cost of $50/MWh and that the RSM has been calibrated and populated with the following production cost information:

For a 500 MW proxy resource, the utility's one-year total system production costs are:

$900 million for a $50/MWh energy price reference resource
$894 million for a $40/MWh energy price resource (Proposal B)
$876 million for a $30/MWh energy price resource (Proposal A)

Thus, the energy savings (relative to the selection of a $50/MWh reference resource) are $24 million for Proposal A with its $30/MWh energy price and $6 million for Proposal B with its $40/MWh energy price. In its proposal ranking process, the RSM converts all production cost savings into a $/kW-month equivalent value so that the savings can be deducted from the capacity price to yield a final net cost (in $/kW-month) for each proposal. Converting the energy savings in this numerical example into $/kW-month equivalent values yields the following:

$24 million / (500 MW * 12 months) = $4.00/kW-month
$6 million / (500 MW * 12 months) = $1.00/kW-month

The RSM calculates the net cost of both proposals by subtracting the energy cost savings from the fixed costs:

	Proposal A	**Proposal B**
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Cost Savings:	$4.00/kW-month	$1.00/kW-month
Net Cost:	$5.00/kW-month	$4.50/kW-month

Proposal B is less expensive. This can be confirmed through a total cost analysis as well:

Proposal A will require total capacity payments of $54 million (= 500 MW x $9.00/kW-month x 12 months), and Proposal B will require $33 million (= 500 MW x $5.50/kW-month x 12 months). Thus, Proposal A has fixed costs that are $21 million more than Proposal B.

Proposal A will provide $18 million more in energy cost savings (= $24 million - $6 million); however, this is not enough to warrant paying $21 million more in fixed costs. Therefore, Proposal B is the less expensive alternative.

Note that the RSM is described in more detail in the independent evaluation report that is attached to my testimony as Document No. 2 of my Exhibit No. ___(AST-1).

Q. With that understanding of the RSM process, what did you do to calibrate the RSM to PaR?

A. I reviewed the production cost information that Seminole provided at the start of the project and confirmed that the production costs were, for the most part, exhibiting smooth, correct trends (i.e., they were increasing where they should be increasing and declining where they should be declining). Having verified that the RSM production cost values were "smooth," I was confident that inputting variable cost parameters into the models for similar proposals would yield similar production cost results. Although the RSM is not a detailed model and could not simulate Seminole's production costs with PaR's accuracy, in the end (after accounting for future portfolio composition and future unit revenue requirement methodology differences), the independent RSM evaluation results tracked PaR's results reasonably well.

Q. Once the RSM was calibrated, what was the next step?

A. I was ready to receive and evaluate proposals. Market alternative bidders had been instructed to cc me on the email submissions of their proposals that they were sending to Seminole, and indeed all participants in the RFP did. I read each proposal and participated in discussions with Seminole about interpreting the proposals, identifying areas requiring clarification, and assessing each proposal's compliance with the RFP's Minimum Requirements. Seminole communicated with proposers to seek clarification and corrections to uncertain areas of the proposals, copying me on all email correspondence and encouraging bidders to do the same.

I incorporated pricing and operational information from each proposal into the RSM. Such information included contract commencement and expiration dates, summer and winter capacity, capacity pricing, heat rates, fuel supply assumptions, variable O&M charges, start-up costs, start-up fuel requirements, expected forced outage hours, and expected planned outage hours. Most of this information was directly inputted into the RSM. After the initial part of the evaluation, Seminole provided Sedway Consulting with its own modeling results so that Sedway Consulting could cross-check all key modeling assumptions and outputs and ensure consistency with the information in the RSM.

Q. Were there any costs that were considered in Sedway Consulting's analysis that were not predefined through the PaR/RSM calibration process described above or were not part of the actual proposals' pricing?

A. Yes, as described in the attached Independent Evaluation Report, there were two categories of costs that could not be predicted prior to the receipt of proposals or appropriately characterized in the pricing structure of proposals – 1) cost estimates for transmission network upgrades that might be required to accommodate a proposed resource or combination of resources, and 2) cost estimates for firm gas transportation requirements for gas-fired resources. Both of these cost categories were highly dependent on the location of projects, their point of electrical interconnection, and their natural gas pipeline supply considerations.

Q. How were these cost estimates developed?

A. In both cases, Seminole's subject area experts provided these cost estimates after being provided pertinent details about the proposed resources.

Q. Were you in a position to independently verify these estimates?

A. No. Sedway Consulting does not have the transmission models or in-depth knowledge of Florida's current or future electric or natural gas infrastructure to develop or verify the estimates of Seminole's subject area experts. However, I found them to be fairly balanced and consistent from a $/kW standpoint and do not believe that any bidder was inappropriately advantaged or disadvantaged by these estimates. I studied the estimates to see if anything was out of line and concluded that they did not appear to be biased. In addition, I was free to use or modify the estimated costs in any way I deemed appropriate – and indeed did so, in line with evaluation processes that Sedway Consulting has employed in other resource solicitations.

Q. Were there any other Seminole estimates that were used in your analysis that were not locked down prior to the receipt of proposals?

A. Yes, in a sense. Sedway Consulting and Seminole had discussed and locked down assumptions about generic resources that Seminole would model as filler resources that would be added to its modeling simulations to address future capacity needs associated with load growth, project retirements, or the expiration of PPAs. Similarly, Sedway Consulting uses filler resource assumptions in the RSM. However, the costs and benefits for these resources were developed by blending the costs and benefits for the top three long-term resources that were received in the solicitations. This process is described more fully in Exhibit No.__(AST-1), Document No. 2, the Independent Evaluation Report.

Q. Please describe the RRM and how it was used.

A. Sedway Consulting's Revenue Requirements Model, or RRM, is another spreadsheet model that I have used in numerous solicitations across the country to calculate annual revenue requirements associate with project-related capital expenditures. It is a much simpler model than the RSM. In the case of Seminole's solicitations, I used the RRM to calculate my independent estimates of annual revenue requirements associated with Seminole's self-build construction costs and of levelized annual transmission costs associated with any resources that were likely to trigger transmission network upgrades (e.g., new resources such as the SCCF, SHCCF, and other new build market alternatives).

V. SEDWAY CONSULTING'S FINDINGS AND RESULTS.

Q. What were the results of Sedway Consulting's RSM and RRM analyses?

A. Using the RSM and RRM, Sedway Consulting was able to compare the economics of Seminole's self-build resource and each of the proposed resource options. That comparison entailed a calculation of the net present value of each option from 2021 through 2051 and accounted for 1) filler resources that would need to "fill in" behind options that expired before 2051 and 2) the cost or revenue valuation of small additional generic seasonal purchases or sales that would align all portfolios with the same projected capacity need. In the near-final results that I presented to Seminole's Board of Trustees on July 12, 2017, the final selected portfolio was found to be $282 million (cumulative present value of revenue requirements – "CPVRR") less expensive than the next best portfolio of alternatives. The Board of Trustees approved the plan to finish negotiations with the counterparties of the resources included in the final selected portfolio. The results and the ranking of resources and portfolios are described in Sedway Consulting's independent evaluation report that is attached as Document No. 2 of Exhibit No. __ (AST-1).

Q. What do you conclude about Seminole's solicitations?

A. I conclude that the resources depicted earlier in my testimony as components of the final selected portfolio represent the best, least-cost resources for meeting Seminole's 2021-and-beyond capacity needs and concur with Seminole's decision to move forward with those projects and PPAs. The solicitation process yielded the best results for Seminole's Members while treating bidders fairly. The RFP was sufficiently detailed to provide necessary information to bidders. The economic evaluation methodology and assumptions were appropriate and unbiased, and the independent evaluation procedures provided a cross-check of Seminole's proposal representation in PaR and confirmed Seminole's conclusions. I participated in Seminole's internal discussions about project and portfolio risks and believe that the final selected portfolio is well balanced from a risk perspective. I monitored the negotiation and communication process with the PIE/LTSA, EPC, and market alterative bidders and can confirm that Seminole conducted a fair and unbiased process. Finally, I conclude that Seminole's selected portfolio – which includes both the SCCF and SHCCF resources as essential components – is at least $282 million CPVRR less expensive than the next best portfolio of alternatives.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DOCUMENT 1 OF EXHIBIT AST-1

RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

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

EMPLOYMENT HISTORY

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

EDUCATION

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

PROFESSIONAL EXPERIENCE

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

SELECTED PROJECTS

2015- **Minnesota Solicitation for New Resources**
2017 Client: Minnesota Power Company

Provided independent evaluation services in five solicitations for new resources: up to 400 MW of gas-fired generation and up to 300 MW each of wind, solar, demand response, and customer cogeneration resources. Mr. Taylor reviewed the request for proposals (RFP), managed the Sedway Consulting team in performing a quantitative and qualitative evaluation of all proposals, monitored communications and negotiations with shortlisted bidders, and provided reports for filing with the Minnesota Public Utilities Commission regarding the results of the solicitations.

2014- **California Evaluation/Negotiation of Non-Conventional Resource Solicitation**
2017 Client: Southern California Edison

Provided independent evaluation services in several solicitations for new resources: two for up to 36 MW new energy storage resources, one for over 1,000 MW of near-term resource adequacy capacity, and one for a broad array of non-conventional resources to address over 100 MW of reliability needs in a local area. In that last project, solicited resource types included energy efficiency, demand response, in-front-of-meter and behind-the-meter energy storage, renewable resources, and hybrid transactions. For all four solicitations, Mr. Taylor managed the Sedway Consulting team in performing a parallel evaluation of offers and monitoring negotiations with shortlisted bidders.

2013- **Florida Solicitation for New Capacity**
2014 Client: Duke Energy Florida

Served as an independent evaluator in a solicitation for over 1,600 MW of new capacity in Florida. Resources had to be on-line by 2018. Proposals were compared to the utility's next planned generating unit – a natural-gas-fired combined-cycle generating facility. Mr. Taylor assisted with the development of the RFP, performed a parallel evaluation of all proposals, monitored communications and negotiations with contracting counterparties, and testified before the Florida Public Service Commission regarding the solicitation's results.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REDACTED VERSION

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR SEMINOLE ELECTRIC'S POWER SUPPLY SOLICITATIONS FOR 2021 CAPACITY NEEDS

Submitted by:

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

December 21, 2017

Introduction and Background

In early 2016, Seminole Electric Cooperative, Inc. (Seminole) launched three solicitations to seek resources or transactions that would help the cooperative meet its forecasted capacity needs in 2021 and beyond. Two of those solicitations were associated with Seminole's efforts to explore the development of a self-build resource at its Seminole Generating Station (SGS) site; they involved Requests for Proposals (RFP) for 1) power island equipment (PIE) and an associated long-term service agreement (LTSA), and 2) engineering, procurement and construction (EPC) services to install the selected power island equipment and construct the balance of the facility. The third solicitation was for market alternatives (i.e., new build facilities that would be owned and operated by others, sales of power from existing facilities, and system sales from a portfolio of resources). Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent monitoring and evaluation services over all of these RFPs and provide a parallel economic evaluation of responses that might address Seminole's capacity needs. The primary focus of this report is the market alternative RFP, with the results of the PIE/LTSA and EPC solicitations incorporated in the form of finalized self-build alternatives that competed with the market alternatives.

This independent evaluation report documents Sedway Consulting's evaluation process and presents the results of Sedway Consulting's economic analysis. It describes:

- the proposals that were received in response to Seminole's market alternatives 2021 RFP and the Seminole finalized self-build options,
- Sedway Consulting's proprietary Response Surface Model (RSM) and Revenue Requirements Model (RRM) which were used to conduct the parallel economic evaluation,
- fundamental assumptions that were applied,
- additional economic factors that affected the final cost of each resource, and
- the development and comparison of complete portfolios of resources that would meet Seminole's capacity needs.

Receipt of Market Alternative Proposals

In Seminole's market alternatives RFP, bidders were instructed to email their submission to Seminole (and cc Sedway Consulting) by May 9, 2016. On or before that date, Sedway Consulting received 265 proposals from 40 power suppliers. For organizational and ease of comparison purposes, Seminole segregated the submitted proposals into four categories (with offer count totals next to each label):

- solar photovoltaic (PV) – 127 offers,
- baseload – 16 offers,
- intermediate – 75 offers, and
- peaking – 47 offers.

These offer totals represent the overall numbers of proposals received, prior to any disqualification decisions or qualitative review that ultimately reduced the number of proposals that moved through the evaluation process. Sedway Consulting and Seminole reviewed their respective proposal counts and confirmed that any differences are due to some disqualifications and minor interpretation issues.

One rationale for segregating solar PV proposals into a separate category was the fact that Seminole is a winter-peaking entity, with its peak loads occurring during hours that solar resources provide little or no generation. Therefore, while these resources may provide some energy and fuel-diversity benefits throughout the year, they could not appreciably meet the need that Seminole was hoping to address with its RFPs.

Virtually all of the proposals in the last three categories could be modeled and evaluated on a side-by-side basis in Sedway Consulting's Response Surface Model (RSM). Therefore, the differentiation of proposals into baseload, intermediate, and peaking was less important from Sedway Consulting's perspective than another critical factor in the evaluation process – namely, the regional location of resources or power supplies. Essentially, Seminole's Member loads are electrically connected or located in either Duke Energy Florida's (DEF) balancing authority area (BAA) or Florida Power & Light's (FPL) BAA, with a third BAA as Seminole's north system (SSN). That third area has relatively little load; the majority of Seminole's load is in DEF's BAA. It was important to procure resources or transactions that would support Seminole's Members' needs in those areas and minimize the costs and reliance of inter-regional transfers. With its market alternatives RFP, Seminole provided historical load information for both of these load areas to provide bidders with important locational information. The FPL BAA has a long-term projected peak load of approximately 600 MW and an average load of approximately 400 MW. It was recognized that procuring more than those quantities in the FPL BAA would result in additional transmission wheeling/transfer costs to bring the power into the DEF BAA to serve Seminole's predominant needs there. Similarly, it was recognized that resources outside of Florida (e.g., in the Southeast Electric Reliability Council, SERC) would incur transmission-related costs – and potential reliability concerns, if Seminole relied too heavily on such resources. Thus, this report depicts and segregates much of the offer statistics into five different categories: solar PV, DEF BAA, FPL BAA, SSN BAA (which can reasonably provide capacity to either the FPL or DEF BAAs), and SERC.

Table A-1 depicts the number of non-solar offers by resource type and locations.

Table A-2 provides a summary of the solar PV proposals that Sedway Consulting received from each bidder. As has been Sedway Consulting's reporting approach in all solicitations, the identities of bidders and projects who were not selected for final contracts has been redacted as confidential. Thus, the actual bidder and project names in Tables A-2 through A-6 for these non-selected bidders and projects are redacted and the tables include a "Code" column that provides a counterparty letter and project number reference that is used throughout the remainder of the report.

Table A-1
Offer Count and Location of Summary of Non-Solar PV Proposals

	DEF BAA	FPL BAA	SSN BAA	SERC/Other	Total
Baseload	3	4	0	9	16
Intermediate	39	2	18	16	75
Peaking	21	7	12	7	47
Total	63	13	30	32	138

Note: One of the baseload offers in the DEF BAA column was actually a combination of small existing resources in both the DEF and FPL BAAs.

The tables include the number of proposals provided by each bidder. In many instances, bidders provided multiple mutually-exclusive proposals for the same resource (e.g., with flat or escalating pricing, different delivery period durations). Thus, the total number of offers was considerably more than the total number of projects.

The final column in Table A-2 provides the levelized solar PV energy price (in $/MWh) as calculated by Sedway Consulting for each project's best offer. Obviously, for offers with a flat, non-escalating price, the levelized price is that proposed price; but for offers with escalating prices, the levelized price is that flat, non-escalating price that would result in the same net present value over the term of the proposed agreement as the escalating price – and provides for a comparable metric for ranking the offers. In cases where there were multiple, mutually-exclusive offers for a project, the value in the final column represents the lowest levelized price among those offers. The ranking of the bidders in the table is based on each bidder's best project levelized price.

Table A-3 provides the number of proposals from each bidder for baseload, intermediate, and peaking resources that would provide power deliveries in the DEF BAA. Some of the proposals were for resources that would be connected to Tampa Electric Company's (TECO) system, where power could be transferred (with a wheeling cost) into the DEF system. Tables A-4 through A-6 provide similar summaries for the proposals offered in the FPL BAA, SSN BAA, and SERC regions, respectively. The tables include a "Type" column that identifies the proposed technology (CC=combined cycle, CT=combustion turbine, System=system sale, MSW=municipal solid waste). Similar to Table A-2, the identities of bidders and projects that were not selected for final contracts are confidential and hence redacted. The rankings of the bidders in the tables are roughly based on the economics of their best proposal in the initial evaluation phase.

Disqualification Decisions

Of the bidders/ proposals listed in Table A-2, bidders SolarU-1 and SolarV-1 were disqualified for lack of specificity (e.g., failure to provide specific prices).

Table A-2
Summary of Solar PV Proposals

	Bidder	Project	Code	Nameplate Capacity (MW)	Number of Proposals	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	1	[redacted]
2	[redacted]	[redacted]	SolarB-1	75	6	[redacted]
3		[redacted]	SolarB-2	50	6	[redacted]
4		[redacted]	SolarB-3	50	6	[redacted]
5		[redacted]	SolarB-4	75	6	[redacted]
6	[redacted]		SolarC-1	375	3	[redacted]
7	Coronal	[redacted]	SolarD-1	25	1	[redacted]
8		Tillman	SolarD-2	50	1	[redacted]
9		[redacted]	SolarD-3	50	1	[redacted]
10		[redacted]	SolarD-4	50	1	[redacted]
11		[redacted]	SolarD-5	75	1	[redacted]
12		[redacted]	SolarD-6	75	1	[redacted]
13	[redacted]	[redacted]	SolarE-1	75	2	[redacted]
14		[redacted]	SolarE-2	65	2	[redacted]
15	[redacted]	[redacted]	SolarF-1	75	2	[redacted]
16		[redacted]	SolarF-2	75	2	[redacted]
17		[redacted]	SolarF-3	53	2	[redacted]
18	[redacted]	[redacted]	SolarG-1	65	12	[redacted]
19	[redacted]	[redacted]	SolarH-1	75	12	[redacted]
20		[redacted]	SolarH-2	75	12	[redacted]
21	[redacted]		SolarI-1	75	12	[redacted]
22	[redacted]	[redacted]	SolarJ-1	465	2	[redacted]
23		[redacted]	SolarJ-2	75	2	[redacted]
24		[redacted]	SolarJ-3	125	2	[redacted]
25	[redacted]		SolarK-1	75	4	[redacted]
26	[redacted]		SolarL-1	50	1	[redacted]
27	[redacted]	[redacted]	SolarM-1	65	4	[redacted]
28	[redacted]		SolarN-1	125	6	[redacted]
29	[redacted]		SolarO-1	65	2	[redacted]
30	[redacted]	[redacted]	SolarP-1	225	4	[redacted]
31	[redacted]		SolarQ-1	50	1	[redacted]
32	[redacted]		SolarR-1	80	3	[redacted]
33	[redacted]		SolarS-1	75	1	[redacted]
34	[redacted]		SolarT-1	75	1	[redacted]
35	[redacted]		SolarU-1	75	1	[redacted]
36	[redacted]		SolarV-1	25	1	[redacted]

Table A-3
Summary of DEF BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-1	1,064	6
2			CC	A-2	863	6
3			CC	A-3	599	6
4			CT	A-4	482	12
5	GE Shady Hills	Project 2	CC	B-1	573	4
6		[redacted]	CC	B-2	463	4
7			CT	B-3	519	2
8	[redacted]	[redacted]	CT	C-1	117	1
9	[redacted]		CT	D-1	484	2
10			CC	D-2	538	2
11	DEF	Peaking	System	E-3	50-300	1
12		Intermediate	System	E-4	50-300	1
13	[redacted]	[redacted]	CC	F-1	121	5
14			CC	G-1	557	4
15			Biomass	H-1	70	2
16			ES	I-1	75-225	3
17			Biogas	J-1	34	1
18			CC	K-1	N/A	1

Of the bidders/proposals in Table A-3, ten offers from Bidder A (two each associated with Projects A-1, A-2, and A-3 and four associated with A-4) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP. Also, Bidder K-1 was disqualified for lack of specificity.

Table A-4
Summary of FPL BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CT	L-1	515	5
2			System	A-5	100-1000	2
3	[redacted]		System	A-6	100-1000	2
4			System	A-7	All	1
5	[redacted]		MSW	M-1	25	1
6			MSW	N-1	40	2

No proposals were disqualified from the set that is depicted in Table A-4.

Table A-5
Summary of SSN BAA Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	A-8	1,058	6
2		[redacted]	CC	A-9	859	6
3		[redacted]	CC	A-10	641	6
4		[redacted]	CT	A-11	480	12

Of the bidders/proposals in Table A-5, ten offers from Bidder A (two each associated with Projects A-8, A-9, and A-10 and four associated with A-11) were disqualified because they exceeded the maximum term length of 30 years that was specified in the market alternatives RFP.

Table A-6
Summary of SERC Proposals

	Bidder	Project	Type	Code	Winter Capacity (MW)	Number of Proposals
1	[redacted]	[redacted]	CC	L-2	500	4
2			CC	L-3	350	4
3			CC	L-4	200	4
4		[redacted]	System	L-5	138	4
5	[redacted]	[redacted]	CC	O-1	225	2
6	[redacted]	[redacted]	CC	P-1	350	1
7	[redacted]		System	Q-1	50-440	3
8	[redacted]	[redacted]	CT	R-1	280	4
9		[redacted]	CC	R-2	533	1
10	[redacted]		Call Option	S-1	200	3
11	[redacted]		System	T-1	50	1
12	[redacted]	[redacted]	Wind	C-2	200	1

No proposals were disqualified from the set that is depicted in Table A-6.

Evaluation and Selection Process

As noted earlier, Seminole is winter peaking cooperative and solar PV projects are not in a position to address this need. At the times that the winter peak might occur, there is little or no sunshine. Thus, the evaluation process was bifurcated into a review of the solar PV proposals for potential selection for environmental and diversification benefits and a full analysis of the non-solar PV proposals that offered firm capacity that could meet Seminole's capacity needs.

Solar PV Proposal Analysis

In the case of the solar PV analysis, Seminole and Sedway reviewed the proposals (especially pricing and qualifications) and decided to shortlist five of the top six bidders (i.e., SolarA, SolarB, SolarC, SolarD [Coronal, the firm that was ultimately awarded a final contract], and SolarF). The SolarE and SolarF bidders were very close in pricing and thus on the cusp of either being included or excluded from the short list. Seminole opted to shortlist SolarF because of slightly better qualitative considerations. Seminole held meetings and calls with the shortlisted bidders in which Sedway Consulting participated. After learning more about the qualifications of these bidders and the status of their projects, Seminole asked all shortlisted bidders to review their proposed pricing and provide "best-and-final-offers" (BAFO) by September 9, 2016; also, Seminole let each bidder know which of each bidder's projects were of greatest interest to Seminole. These were the following: SolarA-1, SolarB-1, SolarB-2, SolarB-3, SolarC-1 (with guidance that Seminole was not interested in procuring more than 75 MW), SolarD-1, SolarD-2 (the Coronal Tillman project that was ultimately selected), SolarD-4, SolarF-1 and SolarF-2. In several cases, bidders provided multiple options for each project (e.g., different terms, fixed or escalating prices). Table A-7 shows the lowest levelized BAFO price for each project. Seminole reviewed the BAFOs and decided to select bidders SolarB and SolarD with whom to commence negotiations and perform further due diligence. Although bidder SolarA had the lowest pricing, the bidder did not yet have a site or any interconnection information. The two final shortlisted bidders were much further along with the development of their projects. Sedway Consulting concurred with the selection of the two bidders for negotiations.

Solar PV Proposal Final Selection

Negotiations and due diligence discussions continued into 2017 with both bidders. In late May 2017, given the passage of time and the recognition that solar PV panel prices had continued to decline, Seminole encouraged both bidders to sharpen their pencils and provide final lower pricing, if they so chose. Both did, with a range of sizes and terms. Bidder SolarD (Coronal) came in with the lowest prices, as depicted in Table A-8 as levelized prices for those bids that were in the same size range and term.

Table A-7
September 2016 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	[redacted]		SolarA-1	75	20	[redacted]
2	[redacted]	[redacted]	SolarB-2	50	30	[redacted]
3		[redacted]	SolarB-1	75	30	[redacted]
4		[redacted]	SolarB-3	75	30	[redacted]
5	Coronal	[redacted]	SolarD-1	75	20	[redacted]
6		Tillman	SolarD-2	75	20	[redacted]
7		[redacted]	SolarD-4	75	20	[redacted]
8	[redacted]		SolarC-1	75	25	[redacted]
9	[redacted]	[redacted]	SolarF-1	75	28	[redacted]
10			SolarF-2	75	28	[redacted]

The Coronal Tillman project had the lowest price and was selected for final negotiations. On October 16, 2017, Seminole and Tillman Solar Center, LLC (a subsidiary of Coronal Energy) executed a 20-year PPA for solar PV generation from a new facility to be built in Alachua County, Florida with an expected commercial operation date of June 1, 2021.

Table A-8
June 2017 Revised Prices for Shortlisted Solar PV Proposals

	Bidder		Project	Nameplate Capacity (MW)	Term of Proposals (years)	Best Levelized Price ($/MWh)
1	Coronal	Tillman	SolarD-2	40	20	[redacted]
2		[redacted]	SolarD-4	40	20	[redacted]
3	[redacted]	[redacted]	SolarB-2	50	20	[redacted]
4		[redacted]	SolarB-3	50	20	[redacted]
5		[redacted]	SolarB-1	50	20	[redacted]

Non-Solar PV Proposal Analysis

As noted earlier, solar PV capacity provides little or no contribution to meeting Seminole's winter peak. Thus, the cooperative's 2021 RFP was essentially soliciting proposals for other types of generation. The analysis of proposals for this other generation was the primary focus for Sedway Consulting's independent evaluation efforts. In this report, all references to proposals and proposal evaluation tasks from this point forward are entirely associated with Sedway Consulting's and Seminole's non-solar PV proposal analyses.

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

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

The remainder of this report section addresses the following topics:

- a description of the RSM and its evaluation process,
- the use of a "back-fill" resource in evaluating proposed transactions that expire before the end of the study period,
- proposal/resource cost computation (and costs that were developed outside of the RSM),
- the use of surplus/deficit capacity assumptions to adjust for the slightly different annual or seasonal sizes of competing portfolios, and
- the process of developing final cost estimates for competing portfolios.

RSM Evaluation Process

The economic information for all outside proposals and Seminole's self-build option(s) was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each resource on Seminole's system production costs. The RSM calculated each proposal's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each proposal, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period.

A proposal's net cost was a combination of fixed and variable cost factors. On the fixed side, the RSM calculated annual fixed costs associated with capacity payments (or generation-related revenue requirements), fixed O&M costs, firm gas transportation costs, third-party transmission wheeling charges (where applicable), and transmission revenue requirements. These annual total fixed costs were discounted to mid-2017 dollars.

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

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

For the same capacity as the proposal under consideration, the RSM also estimated Seminole's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 13,000 Btu/kWh. Thus, for each proposal, the RSM yielded estimates of the annual production cost savings that Seminole would be projected to experience if the utility selected the resource option, relative to acquiring the same sized transaction but at the high reference resource dispatch rate. The lower an proposal's variable dispatch charge, the greater the production cost savings.

Back-Fill Resource

As was mentioned earlier, the RSM accounted for the costs of replacing capacity for all proposed contracts that expired before the end of the study period (2051). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a consistent and appropriate comparison of the value of proposals that had varying contract durations. In effect, by supplementing each short-term proposal with a back-fill resource for the later years, the RSM was simulating what Seminole would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity that was roughly equal to that expired resource.

As the basis for cost assumptions for the back-fill resource, Sedway Consulting use a blend of the cost and benefit streams associated with the three top-ranked individual proposals for long-term power supplies. By doing so, Sedway Consulting was using direct market information as guidance for what future capacity might cost. All capacity-related costs were escalated by a modest rate of 1.0%/year (which was assumed to be a reasonable assumption for the rate of inflation minus future potential for technology cost reductions). In addition, Sedway Consulting employed a methodological variation, whereby the RSM scaled the replacement capacity to exactly equal the size of the expiring proposal resource. Thus, all PPA proposals enjoyed the benefit of being replaced at the end of their terms with a resource that exhibited the operating efficiencies and economy-of-scale benefits of these three top-ranked offers (which were fairly large in capacity). In other words, if a 200 MW proposal ended in 2031, the RSM assumed that a 200 MW CC facility replaced it in 2032; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW plant, but rather, they were a prorated portion of the construction costs of a larger facilities.

It is worth noting that this development of a smoothly escalating cost and benefit stream and the scaling process differed from the future generation expansion assumptions and methodologies employed by Seminole. In the end, however, the approaches probably did not significantly alter either evaluation team's results, as they accomplish the same general goal of continuing to meet Seminole's future capacity needs with generic replacement capacity. However, this is one of several reasons that Seminole's and Sedway Consulting's final portfolio cost differential are different. Sedway Consulting retains the right to evaluate utility solicitations with its own methodologies and believes that using two different approaches reinforces a solicitation's evaluation process when both approaches yield results that support the same conclusion(s).

As noted above, depending on the "in-service date" for the back-fill resource, the back-filler's capital costs were escalated from a 2021 base-year value by 1.0%/year. This escalation assumption represented Sedway Consulting's estimate of how construction costs were likely to increase for generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using Seminole's declining revenue requirements profile for the recovery of capacity costs of future generic resources, Sedway Consulting used an escalating pattern that yielded the same long-term present value of revenue requirements. A traditional revenue requirements profile results in the highest capital charges in a project's early years. Thereafter, the capital-related charges decline. This is the opposite from what is usually seen in most power purchase proposals in power supply solicitations. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore restructured the filler's profile of capacity costs to match what is generally seen in the marketplace. This meant that the filler's first year's capacity costs were the lowest, with each year thereafter escalating at 1.0%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the component top-ranked project cost streams, which include the Seminole's 2x1H self-build resource and its traditional declining revenue requirements profile.

Over the full 30 years, the restructuring of the back-fill resource's capacity costs made no difference to the present value of the blended top-ranked proposals' cost streams. However, in the evaluation of outside proposals that did not extend through the end of the study period, it provided a more favorable basis for such proposals' evaluation. In effect, it assumed that, following the expiration of an outside proposal's term, Seminole would procure replacement power supplies at a trended price based on the best market resources. In reality, if a utility-build resource was determined to be most cost-effective at this future decision point, the declining revenue requirements profile would represent the actual annual costs that Seminole's customers would likely pay.

Figure A-1

[redacted]

Proposal/Resource Cost Computation

Sedway Consulting used its own proprietary Revenue Requirements Model (RRM) to develop estimates of the annual revenue requirements for Seminole' self-build option(s) and cross-checked them with those provided by Seminole. Both sets of values compared quite closely, and Sedway Consulting relied on its RRM results for use in the RSM.

Most of the input assumptions for the proposals and other cost and operational parameters for Seminole's self-build option(s) were directly input into the RSM in a straightforward fashion from the proposal submissions. However, the following were some key additional external cost estimates that were developed outside of each proposal and input into the RSM:

- Firm gas transportation
- Third-party transmission costs
- Network upgrade-related transmission costs.

Firm gas transportation. Seminole's RFP required that bidders of gas-fired projects ensure that firm gas transportation would be available for their facilities. In the RFP bid forms/spreadsheets, bidders were asked to provide information that would allow Seminole to estimate the expected annual firm gas transportation (i.e., pipeline reservation) charges for each project. Sedway Consulting reviewed Seminole's calculations, compared Seminole's values to some of its own calculations and ultimately adopted the same or close approximations to Seminole's values for each applicable proposal.

In addition to the annual firm gas pipeline reservation charges, bidders provided and/or Seminole estimated fuel price adders for each project's natural gas supply, where applicable. These adders accounted for locational basis differentials and, in some cases, additional firm gas transportation variable charges.

Third-party transmission costs. As noted above, Seminole members have load in three balancing areas in Florida, and the cooperative sought to procure power supplies in locations that would minimize excessive transfers between those areas (or from out-of-state). That said, proposals that entailed such transfers were allowed; they simply needed to include the necessary third-party transmission wheeling costs associated with such transfers. In fact, bidders had to identify in their proposals any firm transmission wheeling charges (e.g., for point-to-point transmission service) that would be incurred and passed on to Seminole for such transfers or for wheeling across third-party transmission systems.

Network-update-related transmission costs. With the addition of new generation to a utility system (and sometimes even for redirected sales of power from existing resources), portions of the utility's transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. For proposals for new resources that would be located in the relevant balancing area authorities, bidders were responsible for recognizing that their resource might trigger the need for network upgrades on the DEF or FPL transmission systems. It was each bidder's responsibility to initiate, when appropriate, an interconnection request to study what those costs would be. Seminole, in turn, calculated what the effect would be on the DEF and FPL transmission rate tariffs and the costs that its members would need to pay on any on-going basis for its portion of such network upgrades. Where appropriate, estimates of such network upgrade investments were sought from bidders and/or calculated by Seminole's transmission subject matter experts for specific proposals. Sedway Consulting reviewed and adopted these annual cost estimates. However, Sedway Consulting employed a different methodology than Seminole for attributing these network-upgrade-related costs to projects. Sedway Consulting calculated Seminole's portion of the levelized annual transmission revenue requirements[1] for the applicable investment and applied those annual costs only during the term of the PPA (or economic life of the asset in the case of owned generation options). Seminole developed revenue requirements from the transmission investment estimates and applied them for all years of the study period for all bids. Neither approach was right or wrong;

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

each was based on slightly different but defensible end-effects assumptions. In any case, as noted earlier, Sedway Consulting was free to employ its own evaluation methodologies that may differ from Seminole's; and although that contributed to somewhat different final quantitative results, the fact that different approaches supported the same final conclusions reinforces provides greater assurance in the results of the solicitation.

Surplus/Deficit Capacity Benefit/Cost – Portfolio Cost Computation

In Sedway Consulting's analysis, projects were initially evaluated on a stand-alone basis rather than in the context of a long-term generation expansion plan, as was the case with Seminole's detailed model. In its final analysis, Sedway Consulting accounted for the different capacity of each resource by developing portfolios of resources that relatively closely met Seminole's project seasonal (i.e., summer and winter) capacity needs in 2021-2025. In instances where there was a small surplus or deficit of capacity in a season, Sedway Consulting used short-term capacity valuation assumptions that Seminole provided at the start of the RFP project and periodically updated with the latest market information for small short-term capacity transactions. For long-term portfolio capacity differences (i.e., past 2025), Sedway Consulting used its filler resource assumptions to determine the benefits of surplus capacity or the costs of being slightly short.

The inclusion of these costs or benefits of marginal capacity in the RSM results placed those results on a more comparable footing with the Seminole detailed production costing and generation expansion results.

RSM Evaluation Results

The evaluation process for the non-solar PV resources went through a series of "shortlistings" over the course of the RFP process, with uncompetitive projects being set aside and released from further consideration at various stages. For the first cut, Sedway Consulting and Seminole identified proposals that had high risks and/or high prices that made them outliers and undesirable candidates for selection. The following Tables A-8 through A-11 depict the RSM levelized $/kW-month net cost results for the initial review of the qualified offers, segmented into the same delivery zones as was depicted in Tables A-3 through A-6. The proposal ranking in each table is based on the levelized net cost, from lowest to highest.

In Table A-8 (for the DEF BAA proposals), it was decided that the bottom five proposals (H-1, G-1, D-2, I-1, and J-1) had net costs that were too high to warrant continued evaluation. Also, as far as competing peaking CT resources, the least cost-effective CT proposal (D-1) was seen as unnecessary for continued evaluation, given that there were better CT/peaking proposals in the BAA to consider.

Table A-8
Initial RSM Results – DEF BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	C-1	117	[redacted]
2	[redacted]	CT	A-4	482	
3	GE Shady Hills CT	CT	B-3	519	
4	DEF Peaking	System	E-3	50-300	
5	[redacted]	CT	D-1	484	
6	DEF Intermediate	System	E-4	50-300	
7	GE Shady Hills CC2	CC	B-1	573	
8	[redacted]	CC	B-2	463	
9		CC	A-1	1,064	
10		CC	A-2	863	
11		CC	A-3	599	
12		CC	F-1	121	
13		Biomass	H-1	70	
14		CC	G-1	557	
15		CC	D-2	538	
16		ES	I-1	75-225	
17		Biogas	J-1	34	

Later in the evaluation process, discussions with the bidder behind the Proposals A-1, A-2, A-3, and A-4 – all of which were associated with the same site – yielded the conclusion that the development efforts were in a rather early stage. Given that this translated into greater risks and uncertainty, these offers were removed from the later stages of the evaluation.

Proposal C-1 was for the purchase of an existing CT facility, with the proposed transfer to occur well before Seminole's 2021 need. More importantly, the CT's generation technology was an old non-standard, one-of-a-kind technology in the southeast U.S. that Seminole concluded would be hard to maintain and find spare parts. Sedway Consulting participated in several discussions with Seminole about the possible options if the cooperative were to buy this facility. However, both concluded that the technology risks were too high and the proposal was set aside.

Lastly, the Proposal B-2 was at the same site and mutually exclusive with a higher-ranked more attractive GE Shady Hills CC2 project, so that proposal was set aside. The remaining proposals continued to be included in the portfolio evaluation process, including Proposal F-1, which was sold by [redacted] to [redacted] during Seminole RFP process and is labeled as such in later tables.

For the Table A-9 proposals associated with resources in the FPL BAA, the last one in the table (Proposal A-7) was set aside because selecting it would cause Seminole to lose it ability to tap any other future power supply opportunities in the FPL BAA (e.g., short-term economic purchases). The bidder had two other proposals (A-5 and A-6) that did not have this drawback and included valuable optionality in the amount of capacity that Seminole could procure. That optionality value is not reflected in the RSM net cost metrics but was captured later in the portfolio development process. Thus, Seminole and Sedway Consulting agreed that those proposals should continue to be evaluated. The small Proposals M-1 and N-1 had net costs that were too high to warrant continued inclusion in the evaluation process and were set aside.

Table A-9
Initial RSM Results – FPL BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	[redacted]	CT	L-1	515	2.25
2	[redacted]	System	A-5	100-1000	3.76
3	[redacted]	MSW	M-1	25	4.38
4	[redacted]	System	A-6	100-1000	5.70
5	[redacted]	MSW	N-1	40	9.09
6	[redacted]	System	A-7	All	N/A

Table A-10 depicts the four SSN market alternative proposals as well as Seminole's two self-build options at the cooperative's SGS site in the SSN BAA – the 2x1H CC (SCF) and a smaller 1x1H CC. Seminole and Sedway Consulting had several calls/meetings with the bidder of the four market alternative proposals (which were all at the same proposed site) and concluded that gas supply constraints (and the associated costs of remedying those constraints) made the larger Proposals A-8 and A-9 too risky and expensive; thus, the self-build options and the smaller Proposals A-11 and A-10 continued to be evaluated.

Table A-10
Initial RSM Results – SSN BAA Proposals

	Project	Type	Code	Winter Capacity (MW)	Net Cost ($/kW-mo)
1	Seminole 2x1H (SCCF)	CC		1,122	[redacted]
2	[redacted]	CT	A-11	479	[redacted]
3	[redacted]	CC	A-8	1,058	[redacted]
4	Seminole Self-Build 1x1H	CC		595	[redacted]
5	[redacted]	CC	A-9	859	[redacted]
6	[redacted]	CC	A-10	641	[redacted]

Table A-11 depicts the proposals associated with resources in SERC. Because of transmission constraints and the potential for curtailments of power deliveries from SERC into peninsular Florida, Seminole recognized that it would be unwise to rely too heavily on resources in SERC to meet the cooperative's firm capacity needs. Thus, early in the evaluation process, it reviewed the supply portfolios of other peninsular Florida utilities to assess what percentage of their total capacity needs those utilities procured from SERC resources. Based on that review, Seminole concluded that it should set a maximum of 350 MW as the limit for SERC-based supplies.

Table A-11
Initial RSM Results – SERC Proposals

	Project	**Type**	**Code**	**Winter Capacity (MW)**	**Net Cost ($/kW-mo)**
1	[redacted]	CC	L-2	500	3.16
2	[redacted]	CC	L-3	350	3.16
3	[redacted]	CC	L-4	200	3.22
4	[redacted]	CC	O-1	225	3.48
5	[redacted]	CC	P-1	350	3.49
6	Southern Company	System	Q-1	50-440	3.55
7	[redacted]	Call Option	S-1	200	3.67
8	[redacted]	System	L-5	138	3.81
9	[redacted]	CT	R-1	280	3.98
10	[redacted]	System	T-1	50	7.22
11	[redacted]	CC	R-2	533	8.67
12	[redacted]	Wind	C-2	200	N/A

Given the 350 MW limit, two proposals were eliminated (L-2 and R-2) and one (Q-1), after discussions with Southern Company regarding its system sale proposal, was revised to have a maximum capacity of 350 MW.

One proposal (C-2) was for long-term energy deliveries from a wind facility in Kansas via point-to-point transmission service across a yet-to-be-developed transmission line to the Tennessee Valley Authority (TVA), then across the Southern Company system into Florida. The expected transmission costs resulted in a rather high $/MWh price for a non-firm, non-dispatchable product that would consume a majority of Seminole's 350 MW SERC limit. Thus, the proposal was set aside.

Low-ranked Proposals S-1, L-5, R-1, T-1, and R-2 were removed from further evaluation because of their poor quantitative metrics. The remaining proposals had net costs that were in a fairly tight range. Of the Projects L, O, and P, only Proposal O-1 was for deliveries from a full facility. The Proposals L-3, L-4, and P-1 were partial plant proposals and had the scheduling and settlement complications of dealing with other offtakers. Proposals O-1 and Q-1 (the Southern Company system sale) were seen as the best SERC proposals. Ultimately, the optionality associated with the Southern Company transaction (which could be set as low as 50 MW in a delivery year) made it the best fitting SERC resource in the final portfolio.

Final Proposal and Portfolio Analysis

Table A-12 depicts the final set of all of the resources that were modeled for the final selection decision in mid-2017. These were the results that Sedway Consulting presented to Seminole's Board of Trustees on July 12, 2017. The ranking is based on each resource's levelized and normalized $/kW-month net cost.

There are several important things to note in reviewing the RSM ranking. First, the results are based on a stand-alone analysis, are normalized for the size of each resource, and therefore, on an individual basis, do not necessary meet the capacity need. Total portfolio considerations and cost comparisons are addressed later.

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

Third, as noted earlier, Sedway Consulting calibrated the RSM with proxy run information from Seminole's detailed production cost model prior to the receipt of proposals. Because Seminole was procuring resources to replace a rather significant percentage of its overall supply portfolio and because it received so many qualified proposals, the evaluation process took longer than expected. By the spring of 2017, Seminole had developed new load, fuel price, and other planning-related forecasts and incorporated this new information into its modeling systems. Sedway Consulting reviewed the new forecasts and believed them to be better than the previous 2016 forecasts. Thus, Seminole and Sedway Consulting coordinated on a new set of proxy runs to recalibrate Sedway Consulting's RSM for the 2017 forecasts. Given that this occurred well after Seminole had received and reviewed the proposals in its RFP process, Sedway Consulting reviewed the final rankings under both RSM vintages. Thus, in Table A-12, levelized net costs are shown for each final proposal under "Old" and "New" forecast assumptions, and the table is ranked on the "Old" metric. The rankings were essentially unchanged, with some minor flipping of some proposals in the ranking as indicated with italicized values in the "New" column.

It is important to note that both of the DEF System Sales and the Southern Company Services (SCS) System had significant optionality (with annual delivered capacities as low as 50 MW); this optionality is not reflected in the net cost statistics and rankings.

Table A-12
Ranking of Final Proposals

	Proposal/Resource	Code	Type	Status	Start Date	Capacity (MW)	Term (years)	Levelized Net Cost ($/kW-month)	
								Old	New
1	Self-Build 2x1		CC	New	12/1/2022	1,122	30	[redacted]	[redacted]
2	[redacted]	L-1	CT	Existing	6/1/2021	172-515	5	[redacted]	[redacted]
3	Shady Hills	B-3	CT	Existing	6/1/2024	173-519	23*	[redacted]	[redacted]
4	DEF Peaking	E-3	System	Existing	6/1/2021	50-300	9	[redacted]	[redacted]
5	[redacted]	O-1	CC	Existing	6/1/2021	235	10	[redacted]	[redacted]
6	SCS System	Q-1	System	Existing	6/1/2021	50-350	3	[redacted]	[redacted]
7	[redacted]	A-5	System	Existing	6/1/2021	100-1000	10	[redacted]	[redacted]
8	DEF Intermediate	E-4	System	Existing	6/1/2021	50-300	5	[redacted]	[redacted]
9	Self-Build 1x1		CC	New	6/1/2021	595	30	[redacted]	[redacted]
10	Shady Hills 1x1	B-1	CC	New	12/1/2021	573	30	[redacted]	[redacted]
11	[redacted]	A-10	CC	New	5/1/2021	641	20	[redacted]	[redacted]
12	[redacted]	A-6	System	Existing	6/1/2021	100-1000	10	[redacted]	[redacted]
13	[redacted]	F-1	CC	Existing	6/1/2021	121	20	[redacted]	[redacted]

* This was the contemplated term of the Shady Hills CT contract at the time of the July 12, 2017 Board of Trustees meeting; during the subsequent negotiation process, the term was reduced to 15 years.

Portfolio Analysis

Seminole and Sedway Consulting reviewed their respective evaluation results and developed portfolios of proposals that would meet the cooperative's capacity needs. As this process was underway in early 2017, two important considerations came to light. First, Seminole began to explore potential savings that might be achieved by removing one of its SGS coal units from service and replacing that capacity with cost-effective resources and transactions that were available from its 2021 RFP. In the spring of 2017, Seminole retained an engineering firm to develop detailed estimates of the costs of the service removal process and the difference in the costs of continuing to operate one instead of two of its coal units. Second, it was recognized that each portfolio had certain expected portfolio transmission impacts that needed to be taken into consideration.

With these issues in mind, three specific optimal portfolios (i.e., optimal within the context of their purpose and constraints) rose to the top in terms of economic and strategic value and were labeled the following:

1. Clean Power Plan (CPP)
2. SGS 2x1
3. Limited Build

Tables A-13 through A-15 provide the component resources and additional economic factors of the three portfolios. Sedway Consulting found that the CPP portfolio was the least-cost option, yielding estimated total portfolio net costs that were $282 million less than the next best portfolio (which was the SGS 2x1 portfolio).

The first portfolio is depicted in Table A-13 and reflects the least-cost portfolio that entailed removing an SGS coal unit from service, achieving the cost savings associated with that removal, and replacing the coal unit's capacity with the most cost-effective resources that were available from Seminole's 2021 RFP.

Table A-13
Portfolio Net Cost - CPP

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	GE Shady Hills CC2	B-1	573	12/1/2021	30	[redacted]
3	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	[redacted]
4	Southern Company	Q-1	350	6/1/2021	5	[redacted]
5	DEF-intermediate	E-4	300	6/1/2021	9.5	[redacted]
6	DEF-peaking	E-3	300	6/1/2021	9.5	[redacted]
7	[redacted]	L-1	172	6/1/2021	5	[redacted]
8	DEF-Winter Extension					[redacted]
9	Surplus Capacity Impacts					[redacted]
10	Remove SGS 1 from service					[redacted]
11	Portfolio Transmission Impacts					[redacted]
12	TOTAL					**130**

Table A-14 depicts the SGS 2x1 portfolio which was the least-cost portfolio that did not entail removing an SGS coal unit from service.

Table A-14
Portfolio Net Cost - SGS 2x1

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	Self-Build GE 2x1		1122	12/1/2022	30	[redacted]
2	Southern Company-5yr	Q-1	350	6/1/2021	5	[redacted]
3	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	[redacted]
4	DEF-peaking	E-3	300	6/1/2021	9.5	[redacted]
5	[redacted]	L-1	172	6/1/2021	5	[redacted]
6	DEF-Winter Extension					[redacted]
7	Surplus Capacity Impacts					[redacted]
8	Portfolio Transmission Impacts					[redacted]
9	TOTAL					**412**

Table A-15 depicts the least-cost portfolio that does not entail Seminole's development of any new self-build resources (nor the removal from service of any coal unit). Only one new build resource would be constructed if Seminole pursued this Limited Build portfolio – Shady Hill's CC (SHCCF).

Table A-15
Portfolio Net Cost – Limited Build

	Bidder/Project	Code	Winter Capacity (MW)	COD	Term (years)	Net Cost ($M)
1	GE Shady Hills CC2	B-1	573	12/1/2021	30	[redacted]
2	GE Shady Hills 2CTs	B-3	346	6/1/2024	23	
3	Southern Company-5yr	Q-1	350	6/1/2021	5	
4	DEF-intermediate 9.5yr	E-4	300	6/1/2021	9.5	
5	DEF-peaking	E-3	300	6/1/2021	9.5	
6	[redacted]	L-1	172	6/1/2021	10	
7	DEF-Winter Extension					
8	Surplus Capacity Impacts					
9	Portfolio Transmission Impacts					
10	TOTAL					**621**

Thus, on a CPVRR basis, the CPP Portfolio that Seminole selected was found to be $282 million less expensive than the next lowest-cost portfolio of alternatives. Sedway Consulting believes that this is a conservative cost differential because it is likely that the RSM results did not fully capture the production cost benefits associated with replacing coal generation with gas-fired generation.

Conclusions

Sedway Consulting performed an independent evaluation of Seminole's self-build option(s) and the market alternatives that were submitted in response to Seminole's 2021 RFP and concluded that the CPP portfolio represented the lowest-cost portfolio for meeting Seminole's 2021 resource need. That portfolio was found to be $282 million less expensive on a CPVRR basis than the next cheapest portfolio of alternatives.