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September 12, 2012

HAND DELIVERED

Ms. Ann Cole, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

120234-EI

Re: Tampa Electric Company's Petition to Determine Need for Polk 2-5 Combined Cycle Conversion

Dear Ms. Cole:

Enclosed for filing on behalf of Tampa Electric Company are the original and fifteen (15) copies of each of the following:

1. Tampa Electric Company's Petition to Determine Need for Polk 2-5 Combined Cycle Conversion
2. Tampa Electric Company's Determination of Need for Electrical Power: Polk 2-5 Combined Cycle Conversion
3. Prepared Direct Testimony and Exhibit of Mark J. Hornick
4. Prepared Direct Testimony and Exhibit of Lorraine L. Cifuentes
5. Prepared Direct Testimony and Exhibit of Howard T. Bryant
6. Prepared Direct Testimony and Exhibit of J. Brent Caldwell
7. Prepared Direct Testimony of David M. Lukcic
8. Prepared Direct Testimony and Exhibit of S. Beth Young
9. Prepared Direct Testimony and Exhibit of R. James Rocha
10. Prepared Direct Testimony and Exhibit of Alan S. Taylor

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Also enclosed is one CD containing pdf versions of all of the foregoing.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Office of Public Counsel (w\encls.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Tampa Electric Company's Petition to Determine Need for Polk 2-5 Combined Cycle Conversion.	DOCKET NO. 120234- EI FILED: SEPTEMBER 12, 2012

PETITION

Pursuant to Sections 366.04 and 403.519, Florida Statutes, and Rules 25-22.080, 15-22.081 and 28-106.201, Florida Administrative Code ("F.A.C."), Tampa Electric Company ("Tampa Electric" or "company") petitions the Florida Public Service Commission ("Commission") for an affirmative determination of need for the waste heat recovery conversion of its existing Polk combustion turbines ("CTs") 2 through 5 electrical power plant and associated facilities ("Project" or "Polk 2-5").

In support of this Petition, Tampa Electric States as follows:

1. The Petitioner's name and address are:

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601

2. The names and addresses of Tampa Electric's representatives to receive communications regarding this docket are:

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3. Tampa Electric is a Commission regulated investor-owned utility with its principal offices located at 702 North Franklin Street, Tampa, Florida 33602. Tampa Electric is a utility as defined in Section 366.82(1), Florida Statutes, and is an applicant as defined in Section 403.503(4), for purposes of Section 403.519, Florida Statutes. Tampa Electric is the primarily affected utility within the meaning of Rule 25-22.081, F.A.C.

I. Introduction

4. Tampa Electric proposes to license, construct and operate Polk 2-5, a natural gas combined cycle ("NGCC") power plant at Polk Power Station, a 2,800-acre site located in Polk County, Florida, 40 miles southeast of Tampa. The site currently consists of Polk Unit 1, a 220 MW IGCC plant, and four CTs totaling a net 604 MW in the summer. Polk 2-5 is expected to generate a net 1,195 MW of electricity in winter and 1,063 MW in the summer. Polk 2-5 will result from the conversion of Tampa Electric's four existing CT generating units, Polk 2 through 5, at Polk Power Station into a modern NGCC generating facility, thereby making efficient and economic use of what is otherwise waste heat exhausted from the existing CTs. The energy from this waste heat is captured in four new heat recovery steam generators ("HRSGs"). The steam created in the HRSGs is directed to a single steam turbine generator. With additional supplemental firing of the HRSGs the single steam turbine will generate 459 MW of summer capacity and 463 MW of winter capacity. This generation will allow Tampa Electric to meet a projected need for additional generating resources that begins in 2017 and increases each year thereafter.

5. The Polk Power Station site was originally selected as the result of Tampa Electric's extensive Power Plant Site Selection Assessment Program, which set out in 1989 to

select the most suitable location for meeting the company's future power supply requirements. An integral part of the Polk site selection process was the formation and participation of a Siting Task Force composed of 17 private citizens from environmental groups, businesses and universities in Tampa Electric's service area and throughout Florida. The Polk site was developed to allow for generation expansion in the future.

6. Converting the existing CTs at Polk Power Station to a NGCC facility will enable Tampa Electric to meet its forthcoming electric generating needs through a project that will maximize generation efficiency and cost effectiveness and at the same time minimize impacts on the environment. Through the addition of HRSGs at Polk Power Station the company will be able to harness what otherwise is waste heat and use that essentially free energy source to meet its generating needs beginning in 2017. The addition of heat recovery will provide a 37 percent increase in the generating efficiency of the four CTs incorporated into Polk 2-5, thereby significantly reducing fuel costs. The inherent efficiencies associated with this opportunity will inure to the economic benefit of Tampa Electric's customers, and will do so in a manner that has improved environmental impacts.

7. The Polk 2-5 project, as the company's next unit addition, will provide significant savings to Tampa Electric's customers as compared to the other "self-build" options evaluated by the company. In addition, the project will provide savings over the most cost-effective alternative from among the various responses received in a request for proposal ("RFP") process conducted by the company in advance of filing this petition. Customers will save approximately $132.4 million in cumulative present worth revenue requirements ("CPWRR") in 2012 dollars over the most favorable proposal from the RFP responses the company received.

8. Polk 2-5 will also improve Tampa Electric's environmental profile. The improvement in power generating efficiency from waste heat as an energy source will result in a direct reduction in the emissions rate for all pollutants on a pounds per MW hour basis and reduce CO_2 emission rates by approximately 37 percent. Polk 2-5 will meet, if not exceed, all applicable local, state and federal environmental requirements. These benefits will be achieved using an existing permitted plant site and utilizing reclaimed water to provide the majority of the water needed for the expansion in lieu of further groundwater extraction.

9. Polk 2-5 is needed to provide sufficient generating capacity to maintain electric system reliability at a reasonable cost. As is later explained, that need cannot be satisfied by incremental demand side management ("DSM") measures, conservation or other non-generating alternatives.

10. The Polk 2-5 conversion creates additional dual fuel capacity and improves fuel diversity on Tampa Electric's system. Having dual fuel capability also increases power supply reliability through the added assurance of available fuel. This assurance is particularly valuable during times of potential natural gas disruptions such as those caused by hurricanes. A secondary fuel source also helps reduce the company's reliance on high cost market power during those disruptions, resulting in lower energy costs for customers.

11. Polk 2-5 is the most cost-effective alternative to meet the additional capacity needs of Tampa Electric's system.

12. Tampa Electric requests that the Commission, in its final Order granting a determination of need for Polk 2-5 and its associated facilities, find that the decision to construct the Project is prudent, based on the cost and performance estimates as well as the other relevant assumptions including all applicable statutory and Commission Rule criteria.

II. The Utility Primarily Affected (Rule 25-22.081(1)(a))

13. Tampa Electric is the utility primarily affected by the proposed Project. Tampa Electric is an investor-owned electric utility and the principal subsidiary of TECO Energy, Inc.

14. Tampa Electric is charged with serving its current customer base of over 680,000 customer accounts, as well as new customers that locate in its service territory of approximately 2,000 square miles covering Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The current population in the company's service area is approximately 1.25 million.

15. Tampa Electric is part of the nation's Eastern Interconnection Transmission Network. It has multiple points of interconnection with other utilities that enable power to be exchanged among them. The Tampa Electric bulk transmission system is comprised of 1,322 miles of transmission lines. Integration of the generation, transmission and distribution system is achieved through Tampa Electric's 219 substations.

16. The company has three primary generating stations that include steam, coal fueled and IGCC base load units, NGCC intermediate load units and natural gas and oil fired combustion turbine peaking load units. The total net system generating capacity in the winter of 2011 was 4,684 MW and on an energy basis generated 56 percent solid fuel, 43 percent natural gas and less than 1 percent oil.

17. Polk 2-5 helps contribute to the state's reserve margin criterion and helps alleviate the Florida Reliability Coordinating Council (FRCC) concern regarding the degree to which the peninsular Florida system is becoming increasingly dependent upon demand side management to meet its reserve margin criterion.

III. The Proposed Electrical Power Plant (Rule 25-22.081(1)(b))

18. The proposed Project consists of the construction and operation of Polk 2-5, a NGCC power plant at Polk Power Station, the site of Tampa Electric's existing IGCC facility. The company will utilize its experience with NGCC technology to convert the existing CT Units 2 through 5 at Polk Power Station into a NGCC facility.

19. Polk 2-5 will be a NGCC facility consisting of four CTs, four HRSGs with incremental supplemental firing and a single steam turbine arranged such that each of the four existing CTs will be coupled with a HRSG, with the output of the four HRSGs driving a single steam generator (referred to as a 4x4x1 configuration). The technology is a combination of a combustion turbine (Brayton) cycle and a traditional steam (Rankine) cycle technologies. The combination of these two technologies allows for thermal efficiency of almost 50 percent. This is a proven system for power generation and one with which Tampa Electric has significant experience designing, constructing and operating.

20. Capturing waste heat from the existing Polk CTs 2-5 will generate an incremental net 352 MW of electricity in winter at 32 degrees Fahrenheit and 339 MW in the summer at 92 degrees Fahrenheit. The HRSGs installed at Polk 2-5 will also utilize supplemental firing of natural gas, also known as duct burners, to generate additional steam and provide 120 MW (summer) and 111 MW (winter) of cost-effective peaking capacity that will offset the need for future peaking unit capacity.

21. The Project is being designed with the ability to incorporate approximately 30 MW of solar energy in the form of steam from solar thermal collectors located at the Polk Power Station site. The integration of steam produced via solar collectors into a combined cycle plant is known as a solar hybrid system as it uses the existing combined cycle steam turbine rather

than a separate turbine dedicated to solar use. This is more cost-effective than stand-alone solar and the HRSG supplemental firing creates a back-up and improves reliability.

22. The existing cooling reservoir at the Polk Power Station will be used for cooling the steam from the new steam turbine on Polk 2-5. Use of the existing cooling reservoir infrastructure reduces costs and will allow Polk 2-5 to operate with lower water consumption and lower parasitic load than if a stand-alone cooling tower were used for the steam turbine heat rejection system.

23. A new small cooling tower will be constructed to provide equipment for auxiliary cooling for Polk 2-5 as well as Polk Unit 1. This is needed to optimize the heat loading on the existing cooling reservoir and mitigate operational impacts that could occur due to increased water temperature in the cooling reservoir.

24. The Project is being designed to allow operation of each CT in either simple cycle or combined cycle mode. This will provide considerable operating flexibility and will allow the facility to serve both intermediate and peaking load requirements.

Fuel and Fuel Supply Considerations

25. Polk CTs 2 and 3 have dual fuel capability, meaning that they are able to utilize either natural gas or distillate oil. Polk CTs 4 and 5 will be permitted to have dual fuel capability. Dual fuel capability improves power supply reliability by significantly minimizing, if not eliminating, fuel supply risk.

26. The Project will utilize Tampa Electric's existing natural gas commodity portfolio, storage, pipeline capacity and infrastructure along with backup oil capability and storage. The use of these existing assets reduces costs and increases overall efficiency of fuel supply. Power generated using the waste heat from the existing CTs does not create additional fuel use.

Operation of the new combined cycle at times when the existing CTs would not otherwise be operating also reduces overall system fuel and purchased power costs due to the high efficiency of the new combined cycle unit.

27. Tampa Electric's portfolio of natural gas fuel supply assets and generation units combined with the company's experience and capability in managing its natural gas fuel supply will enhance the reliability and cost-effectiveness of the fuel supply for Polk 2-5.

28. Tampa Electric currently possesses both physical and contractual flexibility for gas delivery in its portfolio. This provides significant flexibility in procuring and allocating natural gas using both the Florida Gas Transmission ("FGT") pipeline system and Gulfstream Pipeline, LLC ("Gulfstream"). Polk Power Station is physically connected to the FGT system as a Primary Delivery Point. Tampa Electric's H. L. Culbreath Bayside Power Station can be supplied from either FGT or Gulfstream and Tampa Electric currently has multiple agreements with both FGT and Gulfstream.

29. Tampa Electric is sponsoring its fuel price forecasts in support of this Petition. Those forecasts are based on sound industry-respected publications, indices, forecasts and escalators. Tampa Electric will demonstrate that its fuel price forecasts are reasonable for planning purposes and for use as a basis for committing to proceed with Polk 2-5.

Fuel Diversity Considerations

30. The addition of Polk 2-5 will maintain Tampa Electric's already well-balanced fuel portfolio. The company will be adding one of the most efficient, economical, and environmental friendly energy sources to its existing well diversified fuel mix of solid fuel and natural gas.

Water Requirements of the Project

31. Polk 2-5's water requirements will be met primarily with reclaimed water from the City of Lakeland. This will minimize the use of ground water.

Transmission Integration and Interconnection Requirements

32. Associated facilities of the Project include new and upgraded transmission facilities with which Polk 2-5 will be interconnected and integrated into Tampa Electric's transmission system. These additions will increase the import and export capability of the Tampa Electric transmission system and provide more source options during planned and unplanned generation outages. Upgrades to the existing 230 KV facilities will also reduce exposure to multi-circuit structure outages, increasing the reliability of the transmission system. The addition of the new transmission facilities will also improve the reliability of the central Florida region for Tampa Electric customers and the entire Florida Reliability Coordinating Council ("FRCC") region.

Project Costs

33. The total in-service costs estimate for Polk 2-5 is $706.6 million, which includes overnight construction costs as well as escalation, transmission costs and AFUDC. Owner's costs include: Project development costs such as technology development and environmental permitting; Project management and operational support and training; legal and other professional services costs; and insurance.

34. Cost estimates are based on a preliminary design completed by the engineering firm of Black and Veatch, which has obtained multiple quotations from major equipment manufacturers and has validated current pricing for commodities and labor in the central Florida area.

35. Tampa Electric plans to competitively bid all the major equipment required for Polk 2-5. The company envisions using multiple prime contractors with contracts containing an appropriate mix of incentives and penalties to align the various contractors with the Project goals.

Environmental Attributes

36. From an environmental perspective, Polk 2-5 will utilize a proven technology that will not only meet, but will likely surpass all applicable environmental regulatory requirements. The selection of NGCC technology over other alternatives will minimize emissions while simultaneously providing cost-effective and reliable energy. By taking advantage of the waste heat from existing Polk CTs 2 through 5, the Project will provide additional generation with minimal additional fuel requirements, thereby reducing air emissions on a pounds per MWH basis. The Project will also take advantage of existing site infrastructure and reclaimed water resources, thereby greatly reducing the need for ground water consumption in the operation of the new facility.

IV. Need for Polk 2-5 (Rule 25-22.081(1)(c))

37. Tampa Electric's need for additional capacity is compelling. After taking into account existing power plant unit capacity, firm purchased power agreements ("PPAs"), and the most recent Ten Year Site Plan load forecast that considers DSM, conservation and renewable energy alternatives, Tampa Electric requires an addition of 294 MW of generating capacity to maintain Tampa Electric's system reliability requirements beginning in 2017. Without any additional capacity to maintain its 20 percent reserve margin reliability criterion, Tampa Electric's 2017 summer reserve margin is projected to decrease to 12.5 percent. Utilizing a

recently updated load, DSM and fuel forecast, and all of the aforementioned considerations, Tampa Electric still requires an additional 205 MW of generating capacity to maintain system reliability requirements beginning in 2017. Polk 2-5 is, therefore, needed to maintain the electric system reliability and integrity for Tampa Electric while addressing the need for reliability and fuel diversity in Florida.

38. Tampa Electric forecasts continued growth of customers in its service territory. The company's recently updated forecast projects approximately 60,000 new customers by 2017 and 103,000 new customers by 2021, with the total number of customers exceeding 735,000 by 2017 and 778,000 by 2021. Peak demand for the summer of 2012 is forecasted to be 3,993 MW, increasing to 4,331 MW in 2021, an average increase of 38 MW per year. Tampa Electric will need to invest in new infrastructure to keep pace with the increasing demand for adequate and reliable power to meet the needs of its growing customer base.

39. Tampa Electric meets its resource needs through generating units, purchased power and DSM. As stated earlier, Tampa Electric's generating resources are located at three primary sites distributed geographically throughout its service territory and as of summer 2012, they along with firm PPAs totaled approximately 4,909 MW (summer) of capacity.

40. Tampa Electric has PPAs with a variety of suppliers totaling 594 MW (summer) for 2012. Tampa Electric also has a contract to purchase firm cogeneration capacity totaling 23 MW in 2012.

41. Tampa Electric requires additional supply resources by 2017 to replace the purchased power contracts as all but one 121 MW contract expire prior to January 2017.

42. Tampa Electric determined in its 2012 integrated resource plan ("IRP") and communicated in its 2012 Ten Year Site Plan that it will need significant additional resources

starting in 2017 to meet its 20 percent reserve margin criterion approved by the Commission in Order No. PSC-99-2507-S-EU. To accomplish this, Tampa Electric will need a minimum of 294 MW of new supply from either power plant installation, purchased power or additional DSM to meet its 2017 reserve margin requirement.

43. New generating capacity, including the associated facilities described herein, built in Tampa Electric's service area is the most cost-effective option to maintain system reliability. After conducting a RFP and considering alternative technologies, Tampa Electric determined that the addition of Polk 2-5 into Tampa Electric's system is the best available option for meeting the company's system reliability needs.

44. Polk 2-5 will add highly efficient and cost-effective generation that, as a utility-owned plant, will be committed to Florida's retail customers and subject to Commission oversight. As shown in the accompanying Need Study, Polk 2-5 will produce adequate electric capacity, improve system efficiency, lower system environmental emissions and maintain system reliability all at a reasonable cost.

V. Tampa Electric's Analysis of Generating Alternatives (Rule 25-22.081(1)(d))

45. Tampa Electric considered a variety of generating options prior to identifying NGCC technology, in the form of Polk 2-5, as the best option for Tampa Electric and its customers. The company's screening process evaluated an array of natural gas, solid fuel and renewable technologies.

46. Strategic considerations in the company's analysis of generating alternatives included fuel price stability, fuel diversity, environmental impacts, technology viability,

construction lead times and site availability. The company's screening analysis narrowed the focus to NGCC or CT technologies for further analysis.

47. Tampa Electric considered simple cycle aero-derivative engines similar to Bayside Unit 3 and simple cycle CTs similar to the existing CTs at Polk Power Station. The company also considered a brownfield 2-on-1 combined cycle unit in addition to converting the existing four Polk CTs into a 4-on-1 combined cycle unit.

48. The company's screening analysis of the various alternatives compared the levelized annual cost of each technology at various capacity factors. Tampa Electric selected NGCC technology as a viable intermediate option and CT technology as a peaking option.

49. Tampa Electric's final integrated resource plan confirmed the need for additional firm purchases in each year from 2012 through 2017 and the addition of Polk 2-5 in 2017. The final plan also demonstrated a CPWRR savings of $65.4 million when Polk 2-5 was compared to the 2011 TYSP with updated fuel forecasts and updated demand and energy and DSM projections.

VI. <u>RFP Process</u>

50. In March 2012, Tampa Electric issued a request for proposal soliciting firm offers for cost-effective alternatives to Polk 2-5. From the initial drafting of the RFP document forward, this process was conducted under the guidance of a very reputable independent third party evaluator, Alan S. Taylor, President of Sedway Consulting, Inc., to keep the process as open and inviting to potential bidders as possible. The RFP process was extensively noticed with pre- and post-RFP release meetings, with website posting of questions from the potential and actual bidders and answers provided to all participants without disclosing the identity of the

participants posing the questions. Tampa Electric's RFP process was open to all potential providers of all or portions of the company's 2017 resource needs, including respondents submitting existing resources, proposing new construction, or offering PPAs.

51. There was robust participation in both the pre-release conference and the post-relief workshop with over 70 questions and answers posted to the company's website. Ultimately, Tampa Electric received four proposals, each of which was opened by the independent third party evaluator and accepted as a qualifying bid for further evaluation.

52. Sedway Consulting was involved in each step of the bid evaluation process including opening the sealed proposals received from each respondent. Sedway Consulting incorporated pricing and operational information from each proposal received into its own analytical model. After cross checking all key modeling assumptions for both the proposals and Tampa Electric's system Sedway Consulting performed and finalized their own initial, independent evaluation.

53. Sedway Consulting later met with Tampa Electric to discuss the evaluation results of the original proposals and agreed that all offers should be short listed. After clarification conference calls in which Sedway Consulting participated, the short listed respondents were provided an opportunity to provide best-and-final offers.

54. Using their own model, Sedway Consulting compared the economics of Tampa Electric's next planned generating unit, Polk 2-5, and each of the proposed resource options (both the original bids and the best-and-final offers). Sedway Consulting's evaluation revealed that Polk 2-5 was $148 million less expensive on a net present value basis than the next cost-effective

RFP compliant proposal.[1] Tampa Electric's internal analysis of the most cost-effective RFP compliant proposal indicated that Polk 2-5 was $132.4 million (NPV) less expensive.

55. After a thorough and detailed evaluation of the available alternatives, Sedway Consulting concluded that Tampa Electric's Polk 2-5 project is the most cost-effective resource for meeting the company's 2017 capacity needs and concurred with Tampa Electric's decision to move forward with that Project. Sedway Consulting's analysis concluded that the solicitation process yielded the best results for Tampa Electric's customers while treating respondents fairly.

VII. Tampa Electric Analysis of Non-Generating and "Self-Build" Generating Alternatives (Rule 25-22.081(1)(e))

56. Tampa Electric has long been a leader in offering its customers cost-effective DSM programs coupled with a comprehensive educational emphasis of the efficient use of energy. Those efforts began in the mid-1970's. Following the 1980 enactment of the Florida Energy Efficiency and Conservation Act, Tampa Electric has filed for and gained Commission approval of numerous DSM programs designed to promote new energy efficient technologies and to change customer behavioral patterns such that energy savings occur with minimal effect on customer comfort.

57. The company has experienced great success with its DSM initiatives. From the inception of its programs in 1980 through the end of 2011, Tampa Electric has achieved 719 MW on winter peak demand reduction, 306 MW of summer peak demand reduction and 770 GWH of annual energy savings. This amount of peak load reduction has eliminated the need for the equivalent of four 180 MW power plants of winter capacity.

[1] The respondent of this RFP compliant proposal also put forth two non-RFP compliant scenarios that Sedway Consulting examined and determined to be $131 million and $69 million (NPV) more expensive than Polk 2-5.

58. The company's DSM program results compare quite favorably to other utilities across the nation, with Tampa Electric's national average ranking for cumulative conservation at the 89th percentile and at the 85th percentile for load management achievement.

59. Tampa Electric reviewed the addition of other generating alternatives as well as potential demand-side programs in determining the most appropriate expansion plans.

60. Tampa Electric's existing DSM programs represent the company's most recently assessed, and most recently Commission approved, collection of available cost-effective DSM alternatives. Tampa Electric included all of these DSM programs in its preliminary demand and energy forecast which effectively reduced system peaks and energy requirements. Since the projected results of those recently approved programs were factored into the assessment for this determination of need, there are no additional cost-effective DSM alternatives or viable renewable options that would defer the need for additional generating capacity in 2017.

61. Similarly, all anticipated cost-effective generating capacity that will be available from renewable resources and qualifying facilities through 2017 has been reflected in Tampa Electric's resource plan. In the future non-firm renewable resources that could cost-effectively provide energy to Tampa Electric would complement the benefits Tampa Electric's customers will receive from Polk 2-5.

62. Taking these benefits into consideration, the interests of Tampa Electric's customers are best served by placing Polk 2-5 in commercial operation in January 2017.

VIII. Adverse Consequences of Delay (Rule 25-22.081(f))

63. In the event Polk 2-5 is delayed by one year or longer, project costs would likely increase and customers would lose the fuel savings benefits for 2017 through the duration of the

delay. In addition to typical factors such as inflation and project management expenses, there is a risk of higher than normal cost increases due to equipment demand. For the past several years there has been somewhat of a lull in generating unit additions due to the broad economic downturn and reduction in energy use. As the economy picks up and energy use increases, it is likely that most utilities will choose gas fired combined cycle technology. The potential rapid increase in demand and the focus on one generating technology by the industry could create a sharp increase in prices for combined cycle equipment and skilled construction labor.

64. The potential for an equipment demand spike would translate to significantly higher costs for customers. Under a scenario where such demand spikes materialize, the result would be higher costs for customers of $100 million on a cumulative present worth revenue requirement basis.

65. In the event of the denial of Tampa Electric's application for a determination of need for Polk 2-5, the company most likely would construct a simple cycle peaking unit in 2017. This would result in higher costs for customers compared to the costs of the proposed Project. Tampa Electric's customers would be denied the efficiencies and economies associated with utilizing waste heat to generate incremental capacity and the environmental attributes associated with Polk 2-5 would not be realized.

IX. Need Study and Prefiled Testimony

66. Tampa Electric submits in support of this Petition and incorporates herein by reference its detailed Need Study and appendices that develop more fully the information required by Rule 25-22.081, Florida Administrative Code. Tampa Electric is also submitting the

testimony of eight witnesses supporting Tampa Electric's request that the Commission grant an affirmative finding of need for Polk 2-5 and its associated facilities.

X. Disputed Issues of Material Fact

67. Tampa Electric presently is unaware of any disputed issues of material fact affecting this proceeding. Tampa Electric will demonstrate during the course of the proceeding that approving a determination of need for Polk 2-5 beginning in 2017 will best serve Tampa Electric's customers by meeting their growing electric supply needs while at the same time providing substantial economic benefits as well as substantial environmental benefits through the efficient use of currently available waste heat as an energy source, an existing generation station site and other existing committed resources. Tampa Electric will demonstrate that there are no reasonably available renewable resources, DSM or other non-generation alternative that would significantly mitigate the need for Polk 2-5.

CONCLUSION

68. Tampa Electric's proposed Polk 2-5 Project is a highly efficient, cost-effective and reliable choice to meet the growing electric needs of Tampa Electric's customers in a very environmentally friendly way. The construction and operation of Polk 2-5 offers Tampa Electric and its customers a number of significant advantages over any other alternative. The Project will deliver major cost savings for the benefit of Tampa Electric's customers, will enable Tampa Electric to reliably meet the electric power needs of its growing customer base and provide Tampa Electric customers and, indeed, all Floridians with key environmental benefits through reduced emissions. Polk 2-5 is consistent with the Peninsular Florida capacity needs and reduces

the dependency on DSM programs to meet reserve criterion. All of this will be achieved using as a base for the Project existing generation plant on an already permitted power plant site.

69. Based upon all of these considerations and the greater level of detail provided in the prepared direct testimony and exhibits of Tampa Electric's witnesses and the need study submitted with this Petition, Tampa Electric respectfully requests that the Commission grant the company an affirmative determination of need for Polk 2-5 and its associated facilities beginning in 2017. Upon approval of this Project Tampa Electric will periodically report to the Commission updated information on the budgeted and actual costs of the Project, compared to the estimated total in-service costs presented in this Petition.

WHEREFORE, Tampa Electric respectfully requests that the Commission grant an affirmative determination of need for Polk 2-5 and its associated facilities beginning in 2017. In so doing, the Commission should:

(a) find that Polk 2-5 is needed to maintain electric system reliability and integrity and to provide adequate electricity at reasonable cost, taking into account the need for fuel diversity and supply reliability;

(b) find that Polk 2-5 is the most cost-effective option for providing efficient fuel diverse generation capacity needed to meet the needs of Tampa Electric's customers beginning in 2017;

(c) find that there is no reasonably available DSM, renewable or other non-generation alternative that would mitigate the need for Polk 2-5;

(d) find that the decision to construct Polk 2-5 is reasonable and prudent, based on the estimated installed costs as well as the other relevant assumptions;

(e) affirm that after Polk 2-5 is placed in service, all prudently incurred non-fuel costs of the Project shall be recoverable through base rates.

Respectfully submitted this 12th day of September 2012.

JAMES D. BEASLEY
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

TECO

TAMPA ELECTRIC

Tampa Electric Company's Determination of Need for Electrical Power: Polk 2-5 Combined Cycle Conversion

Filed: September 12, 2012

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I. EXECUTIVE SUMMARY

Tampa Electric Company ("Tampa Electric" or "company") has determined through its integrated resource planning ("IRP") process a need for the Polk 2-5 combined cycle project ("Polk 2-5"), with a targeted commercial operation date of January 2017. The existing Polk 2 through 5 combustion turbines ("CTs") will be converted to a natural gas combined cycle ("NGCC") facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four Heat Recovery Steam Generators ("HRSGs").

Prospectively, Tampa Electric's firm load is expected to grow approximately 1.2 percent annually winter (1.0 percent summer) or 40-45 MW of firm demand per year. Tampa Electric will continue to meet capacity requirements with the most economical combination of demand-side management ("DSM"), conservation, renewable energy, purchased power, and generating capacity additions. In addition to normal load growth, Tampa Electric requires additional supply resources by 2017 to replace the purchased power contracts of 183 MW expiring on December 31, 2015, 117 MW expiring on December 31, 2016, and an additional 121 MW expiring on December 31, 2018.

Tampa Electric's IRP process incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. By 2017, Tampa Electric's DSM programs will have produced summer and winter customer demand and energy reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW. In order to develop the optimum expansion plan, the company researched current technologies for feasible options. The resulting list of supply resources was screened for technical feasibility, reliability and relative economics. The initial screening resulted in the narrowing of technology alternatives to simple-cycle natural gas and NGCC for further detailed analysis.

Tampa Electric evaluated these technologies utilizing standard IRP techniques. Some of the economic and non-economic factors that were considered included resource reliability, efficiency, range of fuel capability and availability, capital and operating costs, ability to meet current and potential future environmental requirements, water use, and overall site benefits. As a result of this detailed analysis, Tampa Electric determined that NGCC technology is the best option to meet the 2017 need, and conversion of the four existing combustion turbines at Polk Power Station to an NGCC is the most cost-effective alternative.

Once this need was identified, Tampa Electric solicited market alternatives to its next planned generating unit as directed by the resource bid rule. The company issued a Request For Proposals ("RFP"), and considered price and non-price attributes, operational performance, dispatchability, reliability, and environmental compliance, and other issues. After carefully considering and integrating Tampa Electric's DSM load reduction and energy conservation programs and other supply resources, Polk 2-5 was selected as the most cost-effective, reliable means of serving Tampa Electric's customers for the following reasons:

1. It is the most cost-effective next addition to the Tampa Electric system, when compared with all of the "self-build" alternatives.
2. It is the most cost-effective alternative, and the project results in a savings of $132.4 million Cumulative Present Worth Revenue Requirements ("CPWRR") compared to the next best proposal in the RFP process.

3. It achieves significant energy efficiency savings by capturing the waste heat from four existing combustion turbines to generate up to 352 MW of net electrical output with no additional fuel input.
4. It provides up to 120 MW of additional low cost peaking capacity from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for future higher-cost simple cycle CT peaking units.
5. The retention of simple cycle operating capability of the four existing combustion turbines provides operating flexibility and improves system reliability.
6. It achieves dramatic reduction in emission rates from new environmental control equipment and efficiency improvements. The resulting NO_x emission rate is reduced by 86 percent, while the CO_2 emission rate is reduced 37 percent.
7. It conserves fresh water resources by using waste water from the City of Lakeland, and reduces nitrogen loading to Tampa Bay.
8. It enables the potential integration of solar thermal renewable capacity and energy in the future.
9. The existing Polk Power Station site and supporting infrastructure for natural gas is uniquely compatible with Polk 2-5.
10. The transmission upgrade portion of the project will provide much needed infrastructure to reduce transmission congestion, improve grid reliability and reduce losses.

In summary, the selection of Polk 2-5 was supported by subsequent economic analyses of viable supply alternatives, demonstrating that Polk 2-5 is the most cost-effective option compared to other technologies and available supply capacity from the Florida market. After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year deferral of the recommended plan could increase costs to customers by $100 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix. Finally, when considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, Polk 2-5 is needed as a firm resource within the FRCC region.

Polk 2-5 is the best of the "self-build" alternatives and provides significant savings of $132.4 million to Tampa Electric's customers when compared to the second most cost-effective alternative in the RFP while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. The results of these scenarios reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

II. INTRODUCTION AND IRP PROCESS OVERVIEW

A. Introduction

This Need Study supports Tampa Electric's petition to the Florida Public Service Commission ("Commission" or "FPSC") for an affirmative determination of need for the proposed Polk 2-5 NGCC rated at 459 MW summer and 463 MW winter net incremental capacity once the integration with the four existing simple cycle combustion turbines is completed by 2017. As required by Rule 25-22.081, F.A.C., Tampa Electric provides the information that will "allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, the need for fuel diversity and supply reliability, the need to determine whether the proposed plant is the most cost-effective alternative available, and the need to determine whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available." This information supports Tampa Electric's selection of Polk 2-5 as the most cost-effective, reliable, and fuel diverse option to meet its supply resource need in 2017.

The Need Study is composed of twelve major sections. Section I is an "Executive Summary" of Tampa Electric's overall IRP process and the results. Section II "Introduction and IRP Process Overview" provides a more detailed explanation of the company's IRP process and an explanation of the specific process used for this Need Study. Section III entitled "Background and Assumptions" provides a description of Tampa Electric's existing generating system and the assumptions, data, and information utilized. This includes demand and energy forecasts, fuel forecasts, environmental assumptions, financial assumptions and technology assumptions. Section IV "Need for Capacity in 2017" discusses the calculation of Tampa Electric's 2017 need including the impact of DSM load reduction and energy conservation programs. Section V describes the screening of potential supply technologies and results and Section VI includes the detailed economic analysis where the supply alternatives were narrowed based on feasibility and evaluated in greater detail. Section VI also includes qualitative factors that were considered in the selection of Polk 2-5. Section VII describes sensitivity cases and results related to fuel pricing, demand and energy, and construction costs. Section VIII describes the RFP process and results. Section IX describes Polk 2-5 in detail including design, permitting, location, cost and schedule, Section X examines the results with updated assumtions, and Section XI describes the adverse consequences if Polk 2-5 is not approved or is delayed. Finally, Section XII provides the conclusions of the Need Study.

B. Tampa Electric's Integrated Resource Planning Process

Tampa Electric's IRP process, which is the basis of the selection of Polk 2-5, is a planning process that determines the timing, type, and amount of additional demand reduction, energy conservation and supply resources required to maintain system reliability in a cost-effective manner. The process considers the existing customer demand and energy mix, expected growth and changes in the customer demand and energy requirements, existing and future DSM and energy conservation programs, existing Tampa Electric generating units and purchased power, future traditional and renewable supply resources, existing and future bulk transmission system for Tampa Electric and the Florida grid, and potential renewable energy resources appropriate for the Florida energy market. The process used to develop the Polk 2-5 Need Study was conducted as an integral component of Tampa Electric's ongoing IRP process. The primary steps in the process include:

1. Identify additional DSM load reduction alternatives and cost-effective energy conservation alternatives to reduce demand and energy requirements utilizing avoided costs from an initial resource plan;

2. Forecast demand and energy including the impact of existing and potential demand alternatives;
3. Identify the amount and timing of Tampa Electric's incremental resource needs to maintain system reliability criteria;
4. Identify the types of technologies that have the greatest potential for meeting the required resource need and perform an initial economic screen.
5. Conduct detailed economic analysis and consider non-economic factors to decide on the best supply alternatives;
6. Conduct sensitivity analyses to evaluate the impact of potential load forecast and economic variations;
7. Conduct an RFP process and/or business plan development as required based on the recommended resource plan.
8. Incorporate any updated assumptions and confirm the recommended resource plan.
9. Based on the recommended resource plan, determine the avoided costs for deferral of supply resources and implement additional cost-effective DSM resources in the next business planning cycle.

III. BACKGROUND AND ASSUMPTIONS

A. Description of Tampa Electric's System

Tampa Electric, an investor-owned electric utility, is the largest subsidiary of TECO Energy. The service area for Tampa Electric spans approximately 2,000 square miles and consists of Hillsborough County, western Polk County and parts of Pasco and Pinellas counties. Tampa Electric served approximately 676,000 customers in 2011. Tampa Electric has three large generating stations and one peaking station that include fossil steam units, combined cycle units, combustion turbine peaking units, aero-derivative engine units, diesel engine units and an integrated coal gasification combined cycle unit.

Big Bend Power Station: The station contains four pulverized coal-fired steam units equipped with additional environmental controls including selective catalytic reduction, de-sulfurization scrubbers, and electrostatic precipitators. Big Bend Power Station also contains one dual fuel (natural gas or oil), quick-start (full load in less than 15 minutes) aero-derivative peaking unit that could provide black-start capability for the station and the system.

H. L. Culbreath Bayside Power Station: The station contains two natural gas-fired combined cycle units and four quick-start aero-derivative peaking units with black-start capability. Bayside Unit 1 utilizes three combustion turbines, three HRSGs and one steam turbine. Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine. Bayside Units 3 through 6 are natural gas-fired aero-derivative peaking units that are quick-start and provides black-start capability for the station and the system.

Polk Power Station: Polk Power Station includes one base load and four peak load generating units. Polk Unit 1 is a dual fuel integrated gasification combined cycle ("IGCC") unit primarily fired with synthesis gas produced from a blend of low-sulfur coal and petroleum coke ("petcoke"). Distillate oil is a secondary fuel which is used for both start-up and shut-down of the power block, and can be used to operate the combined cycle at times when the gasification system is unavailable. Polk Units 2 through 5 are simple cycle combustion turbines primarily fired by natural gas, and Units 2 and 3 are capable of firing distillate oil as a secondary fuel.

J. H. Phillips Sebring Power Station: Phillips Sebring Power Station includes two diesel oil-fired peaking units located in Sebring, Florida.

These two units were placed on long-term reserve stand-by ("LTRS") status on September 4, 2009 due to the relative higher cost of heavy oil compared to natural gas and coal. These units will remain on LTRS until the operating costs are competitive with other supply resources. These units also have the potential to utilize liquid biofuels and operate as a renewable energy resource in the future.

Other Facilities: Tampa Electric owns two 3 MW diesel engines converted to use natural gas located at the City of Tampa's McKay Bay Refuse to Energy Facility.

The following table lists Tampa Electric's generating assets as of January 1, 2012.

Table 1: Tampa Electric System Installed Capacity

Plant Name	Number of Units	Summer Net MW	Winter Net MW
Big Bend Power Station	5	1608	1643
Bayside Power Station	6	1854	2083
Polk Power Station	5	824	952
Phillips Sebring Power Station[1]	2	36	36
Other Facilities	2	6	6
TOTAL	**20**	**4,292**	**4,684**

1. Transmission and Distribution

Tampa Electric's transmission and distribution system is comprised of 219 substations, 1,322 miles of transmission and 10,998 miles of distribution lines. Tampa Electric's transmission system is interconnected to the Florida

[1] Phillips Sebring Power Station was placed on long-term standby on September 4, 2009 and net capacities are not included in the system total.

transmission grid through ties with Lakeland Electric, Florida Power & Light, Orlando Utilities Commission, Seminole Electric Cooperative, and Progress Energy Florida.

2. Firm Purchased Power Capacity

Tampa Electric currently has a number of firm purchased power agreements ("PPA") with cogeneration facilities, other investor-owned utilities and merchant power providers. Listed below are long term purchase power contracts for capacity and energy ordered by expiration date:

- 441 MW winter and 356 MW summer from the Hardee Power Station through December 2012.
- 23 MW Non-Utility Generator Orange Cogen through December 2015.
- 160 MW from Southern Power from January 2013 through December 2015. Tampa Electric has an option to extend.
- 117 MW from Auburndale Peaking Energy Center through December 2016.
- 121 MW from the Pasco Cogen facility through December 2018.

Tampa Electric expects 499 MW of cogeneration capacity in its service area in 2012. Self-service capacity of 268 MW is used by cogenerators to serve internal load requirements, 23 MW are purchased by Tampa Electric on a firm contract basis, and 19 MW are purchased on a non-firm, as-available basis. The remaining 189 MW of cogeneration capacity is exported out of Tampa Electric's system.

3. Demand-Side Management

DSM is the planning, development, implementation, monitoring and evaluation of energy conservation and load management programs designed to cost-effectively reduce customers' peak demand and overall energy consumption on the company's system. Tampa Electric measures the cost-effectiveness of DSM programs by using the Commission-approved methodology. The methodology consists of three tests: the Rate Impact Measure ("RIM") Test, the Participants' Test and the Total Resource Cost ("TRC") Test.

Tampa Electric has long been a leader in offering its customers cost-effective DSM programs coupled with a comprehensive educational emphasis on the wise use of energy. This effort began in the mid-1970s when Tampa Electric offered its first DSM program, the Energy Answer Home, to curb heating and air-conditioning requirements in new homes by encouraging the use of high-efficiency heat pumps instead of conventional air-conditioning with resistance heating. Within two years, the company introduced a computer-based home energy audit well in advance of the legislation that ultimately required this level of home energy analysis.

In 1980, the Florida Energy Efficiency Conservation Act ("FEECA") was passed by the Florida legislature. In response to that legislation, Tampa Electric filed its DSM plans with the Commission and became the first Florida utility to have its DSM programs for both residential and commercial customers approved. Subsequent to that first DSM plan, Tampa Electric has filed and gained Commission approval of numerous DSM programs designed to promote new energy-efficient technologies to encourage energy savings. Additionally, the company has modified existing DSM programs over time to promote new technologies and maintain program cost-effectiveness.

Through 2011, Tampa Electric's successful DSM initiatives have achieved 719 MW of winter peak demand reduction, 306 MW of summer peak demand reduction and 770 GWH of annual energy savings. Peak load reduction has eliminated the need for the equivalent of four 180 MW power plants.

Furthermore, Tampa Electric's DSM program results compare quite favorably to other utilities across the nation. The Energy Information Administration ("EIA") of the United States Department of Energy ("DOE") reports annually on the effectiveness of utility DSM initiatives. Based on national data reported for the last decade, Tampa Electric ranked as high as the 89th percentile for cumulative conservation and the 85th percentile for load management achievements. Also, of the eight regional entities of NERC, the FRCC ranks third in terms of DSM as a percentage of regional peak.

4. Renewable Energy

Tampa Electric continues to be active in supporting the development of renewable energy resources. The company recognizes renewable energy will advance the utilization of a diverse fuel mix for the production of electricity and the company will demonstrate sound environmental stewardship. Tampa Electric has actively evaluated various renewable energy developers over the years, and continues to investigate ways to structure agreements with consideration of the FPSC avoided cost standard.

Tarnpa Electric's renewable Standard Offer Contract ("SOC") includes the following features: 1) the customer can select any of the fossil fuel generating units in the company's 10-year expansion plan; 2) the renewable SOC is continuously available; 3) there is no subscription limit; 4) the renewable generator can select the term of the contract; and 5) flexibility on capacity and energy payments to the customer.

5. Tampa Electric's Current Energy and Capacity Mix by Fuel Type

The energy and capacity mix for Tampa Electric's generation can significantly affect the cost of electricity. Too much reliance on fuel types with volatile fuel prices can result in significant volatility in the ultimate cost of electricity. Tampa Electric's fuel type mix to meet system demand and energy requirements for 2011 actuals and projections for 2017 are shown below.

Table 2: Tampa Electric's Energy Mix by Fuel Type

Total System	2011 Actual	2017 Forecast
Solid Fuel	56%	59%
Natural Gas	43%	39%
Oil / Other	1%	2%
System Net Energy for Load (GWH)	19,325	20,772

Table 3: Tampa Electric's Capacity Mix by Fuel Type

Total System	2011 Actual	2017 Forecast
Solid Fuel	36.1%	36.3%
Natural Gas	63.9%	63.7%
Oil / Other	0%	0%
System Capacity (MW)	4,909	4,856

B. Assumptions

Demand and Energy Forecasts - The customer demand and energy forecast is the foundation of the integrated resource plan. Tampa Electric utilizes multiple databases and sophisticated analytical tools and methods to develop the forecast. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to develop the most probable demand and energy forecast over a 20-year planning period.

1. Forecast Assumptions

The economic assumptions used in the forecast models are derived from forecasts from Economy.com (Moody's Analytics) and the University of Florida's Bureau of Economic and Business Research ("BEBR"). Numerous assumptions entered into the MetrixND models, an advanced statistics program for analysis and forecasting, of which the more significant ones are listed below.

Population and Households

The population forecast is the starting point for developing the customer and energy projections. BEBR and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and a blend of BEBR and Economy.com in the long term. Through 2021, the average annual population growth rate for Hillsborough County is expected to be 1.4 percent. In addition, Economy.com provides household data as an input to the residential average use model.

Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. Over the next ten years, commercial employment is projected to rise at a 2.3 percent average annual rate and industrial employment is projected to decline slowly at an annual rate of -1.2 percent. Government employment is used in combination with government output to estimate energy sales to public authorities. Economy.com projects government employment to rise at a 0.7 percent average annual rate.

Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy usage by sector. Over the next ten years Economy.com projects output for the entire employment sector to rise at a 3.4 percent average annual rate.

Real Household Income

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2012-2021, real household income for Hillsborough County is expected to increase at a 2.9 percent average annual rate.

Price of Electricity

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Affairs department. The price of electricity is included in each per-customer consumption model. The price variable was primarily used to capture long term impacts of the real price of electricity.

Appliance Efficiency Standards

Another factor influencing energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments.

Also influencing energy consumption is the saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies such as room heating and furnaces are replaced with more efficient technologies such as heat pumps. Similarly, cooling equipment saturation will continue to increase, but is offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather related appliances also helps to lower electricity growth; however, any efficiency gains are offset by the increasing saturation trend of electronic equipment and appliances.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. Monthly profiles used in calculating energy consumption are based on twenty years of historical data. In addition, the temperature profiles used in projecting the winter and summer peak are based on an examination of the minimum and maximum temperatures for the past twenty years and the temperatures on peak days for the past twenty years.

High and Low Economic Sensitivities

The base case sensitivity is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy sensitivities represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high sensitivity and 0.5 percent lower in the low sensitivity. High and Low firm peak demands are shown in Appendix F.

2. Forecast Methodology

MetrixND was used to develop customer, demand and energy forecasts. The software provides a platform for the development of dynamic and fully integrated models. The phosphate demand and energy is forecasted separately and then combined in the total forecast. Likewise, the effect of Tampa Electric's conservation, load management, and cogeneration programs is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

Customer Forecast Models

The customer multi-regression forecasting model is a seven-equation model. The equations forecast the number of customers by seven major categories.

Residential Customer Model

Customer projections are a function of Hillsborough County's population. Since a strong correlation exists between historical changes in customers and historical changes in the county's population, Hillsborough County population estimates for 2012-2021 were used to forecast the future growth patterns in residential customers.

Commercial Customer Model

Total commercial customers include commercial customers and temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers. The commercial customer model is a function of residential customers. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the temporary service model projects the number of customers as a function of construction employment.

Industrial General Service Customer Model

Industrial customers include two rate classes that have been modeled individually: General Service ("GS") and General Service Demand ("GSD"). The GS customer model is a function of Hillsborough County commercial employment.

Industrial GSD Customer Model

The industrial GSD customer model is a function of recent growth trends in the sector.

Public Authority Customer Model

Customer projections are a function of Hillsborough County's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, county level population projections are used to determine future growth in the public authorities sector.

Street & Highway Lighting Customer Model

Recent growth trends in this sector are the basis for the street & highway lighting customer model.

3. Energy Forecast Models

There are a total of seven energy models. All of these models represent average usage per customer (kWh/customer), except for the Temporary Services model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering ("SAE"). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment and incorporating these variables into regression models. This approach allows the models to capture long term structural changes that end-use models are known for, while also performing well in the short term, as do econometric regression models.

Residential Energy Model

The residential forecast model is made up of three major components: (1) the end-use equipment index variables, which capture the long term net effect of equipment saturation and equipment efficiency improvements; (2) the second component serves to capture changes in the economy such as household income, household size, and the price of electricity; and (3) the third component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the year.

Commercial Energy Model

The model framework for the commercial sector is the same as the residential model; it also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

Temporary Service Energy Model

The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth.

Industrial-GS Energy Model

Industrial energy forecasts include two rate classes that have been modeled individually: GS and GSD. The Industrial-GS energy model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

Industrial-GSD Energy Model

The GSD model is based on industrial employment, the price of electricity in the industrial sector, cooling degree-days and the number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

Public Authority Sector Model

Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

Street & Highway Lighting Sector Model

The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street & highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The energy models described above plus an exogenous interruptible and phosphate forecast are added together to arrive at the total retail energy sales forecast.

4. Demand Forecast Models

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long term economic and appliance trend impacts. The volatility of the phosphate load is removed to stabilize the peak demand data series and improve model accuracy. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree days for both the temperature at the time of the peak and the 24-hour average on the day of the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate coincident peak forecast to arrive at the final projected peak demand.

Phosphate Demand and Energy Forecasts

Because Tampa Electric's phosphate customers are relatively few in number, each customer's energy consumption is forecasted individually based on historical usage patterns and detailed information obtained by customer surveys. The Commercial/Industrial Customer Service department's familiarity with industry dynamics, their close working relationship with phosphate company representatives and the surveys are used to determine future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based, and further inputs are provided by trend analysis of historical usage patterns.

Demand-Side Management and Cogeneration Forecasts

Tampa Electric incorporates the impacts of conservation, load management and cogeneration programs into the demand and energy forecasts. This is done by reducing the forecasts by the incremental annual savings associated with conservation and load management programs. In addition, demand and energy projections are adjusted for any projected incremental changes in cogeneration programs that impact the amount of capacity and energy Tampa Electric provides to these customers.

Wholesale Load

Tampa Electric's long-term firm sales are served through contracts with the City of St. Cloud. Future sales for a given year are based on the specific terms of their contracts with Tampa Electric. The City of St. Cloud contract will expire December 31, 2012.

5. Demand and Energy Forecasts

The analysis that resulted in the selection of Polk 2-5 incorporated the June 2011 base demand and energy forecast. In June 2012, an updated demand and energy forecast was completed.

Customer Forecasts

Based on the Demand and Energy forecast, Tampa Electric is projecting an annual average increase of 9,597 new customers over the next ten years from 2012-2021. This average annual increase of 1.3 percent is slightly lower than the average annual growth rate of 1.5 percent during the past ten years from 2002-2011. The number of retail customers by customer class are shown in Appendix C.

Retail Energy Sales Forecasts

The primary driver behind the increase in the energy sales forecast is the average annual increase in customers of 1.3 percent. In addition, average per-customer consumption is expected to decrease at an average annual rate of 0.5 percent. Combining the growth in customers and decline in per-customer consumption, retail energy sales are expected to increase at an average annual rate of 0.8 percent. Excluding the phosphate sector, which has recently been declining, retail energy sales are expected to increase at an average annual rate of 1.0 percent. The amount of retail energy sales by customer class are shown in Appendix D.

Retail Peak Demand Forecasts

Summer and winter retail peak usage per-customer is projected to decrease at an average annual rate of 0.4 percent, which is consistent with historical growth rates as well as per-customer energy consumption. The increase in customers and the decrease in per-customer demand results in an average annual growth rate of 1.0 percent for the winter peak and a 0.9 percent growth rate for the summer peak. Total peak demand for the summer 2012 is forecasted to be 3,993 MW and increase to 4,331 MW in 2021, an average increase of 38 MW per year. The 2012 winter peak was forecasted to be 4,081 MW and increase to 4,453 MW in 2021, an average increase of 41 MW per year. Winter and summer total and firm peak demands are shown in Appendix E. High and low winter and summer firm peak demands are calculated for high and low economic sensitivities and are shown in Appendix F.

June 2012 Customer, Demand and Energy Update

An updated forecast of customers, demand and energy was completed in June of 2012 as part of Tampa Electric's annual planning process. The most current forecast of customers is higher than the forecast presented in the Need Determination Study. However, the current energy sales and peak demand forecasts are lower than the forecasts presented in the Need Study. The primary factor that is driving the changes in the load forecasts is the slower than expected economic recovery and continued reduction in per-customer consumption. The updated retail peak demands are shown in Appendix G.

C. Fuel Forecast

Annual fuel price forecasts developed for the 2012 Fuel and Purchased Power Cost Recovery Clause projection filing and the 2012 Ten Year Site Plan filing were used to analyze supply alternatives for the 2017 need. The coal and natural gas forecasts are provided in Appendix H. These fuel price forecasts were utilized in the detailed economic analysis. Tampa Electric also prepared low and high price forecasts for the sensitivity analyses which are provided in Appendix I and Appendix J, respectively.

Tampa Electric developed a 30-year fuel price forecast utilizing published market pricing indexes and long-term forecasts from independent energy consultants. Refinements were made to the market indexes or consultant prices to align the forecasts to Tampa Electric's physical quality requirements and/or receipt location. For example, most natural gas forecasts are based on the Henry Hub, a recognized market center for trading natural gas. Since much of the natural gas Tampa Electric purchases is delivered into Zone 3 of the Florida Gas

Transmission ("FGT") pipeline, Tampa Electric's natural gas price reflects the typical price difference between Henry Hub and FGT Zone 3.

1. Natural Gas

The foundation for the natural gas price forecast is the 10-year New York Mercantile Exchange ("NYMEX") natural gas futures monthly contract closing prices for the five consecutive business days between July 5, 2011 and July 11, 2011. Since the NYMEX natural gas futures contract is based on physical delivery of natural gas to the Henry Hub in southern Louisiana, Tampa Electric adds a "basis" cost to account for the company receiving its natural gas delivered into FGT Zone 3 instead of into the Henry Hub. This establishes the first 10 years of the forecast. The remaining twenty years of the natural gas forecast are derived by escalating the prior year's price by the projected annual escalation of the Consumer Price Index Less Energy.

2. Solid Fuels

The foundation of the coal price forecast is a combination of various published index prices for like-quality coal for the first two to four years. The publications include Coal Daily and ICAP, an online energy broker and information service. For the subsequent years through 2018, a weighted average price is developed using Argus Coal Daily and index prices, along with the coal prices from an independent, published forecast from Wood Mackenzie Energy Consultants ("Wood Mac"). The company utilizes a weighted average method where Tampa Electric's final coal forecast blends the published market indices with the Wood Mac forecast. The market indices are a high percentage of the blend in the near term and Wood Mac is a low percent. Over time the market indices percentage decreases until the Wood Mac forecast is 100 percent of the forecasted price. Beyond 2018 the coal commodity price is escalated annually consistent with the escalation of the other commodities.

3. Transportation

Tampa Electric has bi-modal transportation to receive fuel for the five solid fuel units, and convey coal to Big Bend Power Station and utilize trucking to deliver blended low sulfur coal and petcoke to the Polk Power Station. Tampa Electric can receive its entire coal supply from either water transportation or rail transportation. These bi-modal transportation services provide reliability and cost-effectiveness.

For natural gas transportation, Tampa Electric has long-term firm pipeline capacity reserved on the FGTpipeline and the Gulfstream Pipeline Company, LLC ("Gulfstream") pipeline. Both the Bayside Power Station and the Polk Power Station are listed as Primary Delivery Points on the FGT Firm Service Agreement which allows for flexible and reliable delivery of natural gas to either station using the same agreement. Also, Bayside Power Station and Big Bend Power Station are connected to both FGT and Gulfstream. Thus, depending on conditions, Tampa Electric can deliver natural gas via different pipelines to different plants.

4. Fuel Price Forecasts

The fuel commodity prices used for the Need Determination Analysis are shown in the following table:

Tampa Electric Fuel Prices Forecast 2013 - 2040			
Year	Natural Gas $/MMBtu	No. 2 Oil $/Gallon	Illinois Basin Coal $/ton
2013	$5.12	$3.33	$55.57
2014	$5.39	$3.51	$56.45
2015	$5.67	$3.69	$58.88
2016	$5.95	$3.88	$55.48
2017	$6.23	$4.06	$55.24
2018	$6.51	$4.24	$52.26
2019	$6.79	$4.42	$55.94
2020	$7.07	$4.60	$59.64
2021	$7.34	$4.78	$63.20
2022	$7.63	$4.97	$66.81
2023	$7.80	$5.08	$69.16
2024	$7.97	$5.19	$71.55
2025	$8.14	$5.30	$73.96
2026	$8.31	$5.41	$76.40
2027	$8.49	$5.53	$78.85
2028	$8.67	$5.64	$81.35
2029	$8.85	$5.76	$83.89
2030	$9.03	$5.88	$86.48
2031	$9.22	$6.00	$89.11
2032	$9.41	$6.13	$91.79
2033	$9.61	$6.26	$94.52
2034	$9.80	$6.38	$97.31
2035	$10.01	$6.52	$100.14
2036	$10.21	$6.65	$103.03
2037	$10.42	$6.79	$105.97
2038	$10.64	$6.93	$108.97
2039	$10.85	$7.07	$112.03
2040	$11.08	$7.21	$115.15

Figure 1: Fuel Forecast for Final Analysis

D. Environmental

Environmental requirements considered in Tampa Electric's analysis of supply alternatives include environmental permitting requirements which are defined by current environmental regulations and planning for future environmental requirements. Environmental permitting requirements are often well established by the permitting of similar units and/or through interpretation of existing regulations. An example is the expected Polk 2-5 environmental permitting requirements discussed in Section VII.C.

Future environmental requirements include currently promulgated rules that have future requirements defined, currently promulgated rules that have future requirements undefined and potential environmental requirements that are currently being considered in federal and/or state legislature. The primary requirements considered by Tampa Electric in this study include future water restrictions in the Southwest Florida Water Management District ("SWFWMD") Southern Water Use Caution Area ("SWUCA"), Mercury Air Toxic and Standards ("MACT"), Clean Air Interstate Rule ("CAIR"), Green House Gas New Source Performance Standards ("GHGNSPS"), New Source Performance Standards ("NSPS"), and 316 (b).

E. General Financial Assumptions

In addition to the fuel, load, environmental and other assumptions described, Tampa Electric utilized certain financial assumptions to conduct its detailed economic analysis. Major financial assumptions used in the Ten Year Site Plan ("TYSP") analysis include:

- Discount rate of 7.95 percent;
- Tax rate of 38.575 percent;
- Property tax of 1.27 percent;
- Escalation rate for capital expenditures of 3.0 percent;
- Escalation rate for fixed and variable O&M of 2.4 percent; and
- AFUDC rate of 8.16 percent.

F. Technology Assumptions

1. Demand Side Programs

Tampa Electric's current DSM plan consists of 30 comprehensive residential, commercial, and industrial programs which provide customers with a variety of program offerings to better manage their energy consumption. Tampa Electric reviews its existing DSM programs for cost-effectiveness and examines the potential for new offerings and program modifications on an annual basis. Appendix A and Appendix B contain a listing of Tampa Electric's current residential and commercial DSM programs, respectively.

2. Supply Technologies

Solid Fuel Technologies

In the screening process, Tampa Electric considered all feasible technologies including IGCC, super-critical pulverized coal ("SCPC"), and circulating fluidized bed combustion ("CFB"). These technologies were evaluated as base load power derived from a blend of bituminous coal that meets current emission standards and limits. Solid fuel technologies typically are characterized as higher construction cost with traditionally lower operating costs when compared to natural gas technologies. The current and near term projections of natural gas prices have reduced operating costs of natural gas technologies compared to solid fuel technologies.

Natural Gas Technologies

Tampa Electric considered a number of natural gas technologies including simple cycle combustion turbine and combined cycle alternatives. The simple cycle combustion turbines ranged from GE 7FA type units to more modern GE LMS100 type units. The combined cycle units considered included 2x1 GE 7FA type units, 2x1 M501G units and the Polk Power Station repower project involving four HRSGs and a single steam turbine or four HRSGs and two steam turbines.

In comparison to other generating technologies, NGCC technologies are typically characterized by relatively lower capital costs, low heat rates and low environmental emissions. The same combustion turbines implemented in simple cycle configurations are characterized by lower capital costs, higher heat rates than combined cycle technologies and typically higher emission rates. The primary reason for the differences between combined cycle and simple cycle efficiencies is the recovery of exhaust heat from the combustion turbine in the combined cycle configuration.

Other Technologies

Renewable technologies tend to have lower or no fuel costs but have significant fixed costs. In addition, technologies such as geothermal and hydroelectric have limited practical application in Florida. Similarly, wind and solar have limited and unpredictable operating hours due to the intermittent nature of their energy source. In the absence of stored energy capability, intermittent renewables are best considered as energy resources and not as firm capacity for planning purposes. However, some renewable energy such as biomass can be considered as a firm resource if sufficient biomass material is stored and available.

IV. NEED FOR CAPACITY IN 2017

A. Reliability Assessment

Tampa Electric utilizes a twenty percent firm reserve margin reliability criteria above the system firm peak, as required by the Florida Public Service Commission ("Commission" or "FPSC") in Order No. PSC-99-2507-S-EU issued on December 22, 1999, and a minimum seven percent supply reserve margin.

The firm reserve margin consists of both supply and non-firm demand resources to maintain an allowance for unexpected variances in system demand, generating unit availability, and purchased power availability and deliverability. The minimum supply reserve margin criterion maintains an important qualitative component of firm reserves for reliability purposes to minimize the impact of the loss of a supply resource at the time of peak. If the firm reserve margin consisted of only non-firm demand reserves (whereby total firm supply equals total load), then the frequency of use of demand resources in a given year would increase significantly. The firm system peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and customer load reduction programs. Customers who continue to participate in these voluntary programs help defer the need for additional supply resources by reducing firm peak demands. These customers may request to become a firm customer or be excluded from a DSM program with appropriate notification.

Utilizing the June 2011 Tampa Electric demand and energy forecast, a reliability analysis determined the amount of any incremental resources needed to maintain a 20 percent margin above the winter and summer system firm peaks. The seasonal system firm peaks include firm retail load and firm wholesale load and exclude all non-firm retail load and as-available wholesale load. The minimum reserve margin for each year is calculated by multiplying the seasonal system firm peak by 20 percent. The net available capacity is determined by combining all installed generating capacity and firm power purchases less the seasonal system firm peak. If the net available capacity is less than the firm reserve margin in any year, incremental capacity is added in that year to achieve the minimum reserve margin requirement. Incremental capacity identified in a given year is included in subsequent years in order to determine the discrete incremental capacity required in each subsequent year.

1. Demand-Side Management

Tampa Electric conducted an extensive evaluation of all conservation measures reasonably available. The company's current 2010-2019 DSM goals were established utilizing a comprehensive set of DSM measures. Through the company's efforts, these goals are being exceeded. Tampa Electric has identified all reasonably achievable DSM demand and energy reductions in its Need Study. There are no DSM alternatives that will cost-effectively defer the need for additional generating capacity in 2017.

B. Tampa Electric's Reliability Assessment Results

The results of the 2012 TYSP final reliability assessment indicate that Tampa Electric will have a summer 2017 need of 294 MW. Table 3 identifies the firm peak demand of 3,940 MW in the summer of 2017 and illustrates the addition of the 20 percent reserve margin requirement to the firm peak to determine the total firm capacity requirement. Tampa Electric's 2017 summer total firm capacity requirement is 4,728 MW. Tampa Electric's net available firm capacity is subtracted from the total firm capacity requirement to determine the summer 2017 incremental capacity need of 294 MW. Details for each year are shown in Appendix K.

Table 4: 2017 Firm Peak Requirements

	Summer 2017 (MW)
Forecasted Firm Retail	3,940
Forecasted Firm Wholesale	0
Total Firm Peak Demand	3,940
Total Firm Capacity Required for 20% Reserve Margin	4,728
Net Available Firm Capacity	4,433
Incremental Capacity Needed[1]	**294**

The reliability analysis was based on existing generating unit operating data and projected system firm peak and energy requirements which were developed in summer 2011. This data supported the development of Tampa Electric's 2012 TYSP filed with the Commission in April 2012. This analysis indicated incremental supply resources are needed in 2017 to meet the 20 percent reserve margin criteria and 7 percent minimum supply criteria. Without additional firm supply resources the summer firm reserve margin is 12.5 percent and the supply component would fall to 6.8 percent in summer 2017.

C. FRCC Reliability Assessment Results

Tampa Electric specific data in conjunction with similar information from other Florida electric utilities is included in the aggregate 2012 FRCC Load and Resource Plan. The FRCC shows that the existing planned demand and supply resource additions by Florida utilities will meet the minimum reliability of 15 percent through 2021, as shown in Appendix M. However, the initial reliability assessment should remove all planned and proposed unit additions and review potential modifications to existing generating capacity.

[1] May not add due to rounding

In addition, the FRCC has analyzed the increasing dependency on DSM programs to provide these reserves. During the 2012 FRCC TYSP workshop on August 13, 2012, it was reported that of the eight NERC reliability regions, the FRCC is among the highest in DSM as a percentage of regional peak. This increased dependency on DSM programs combined with the uncertainty of planned yet uncommitted supply additions as well as existing resources at risk of retirement due to emerging environmental regulations or other factors raise questions regarding future reserve margin calculations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019. This sensitivity analysis is reflected in Appendix N. When considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, firm resources are needed within the FRCC region toward the end of the decade.

V. SCREENING OF POTENTIAL TECHNOLOGIES

Electric utilities have a wide range of potential supply technologies which may be considered for future load requirements. Tampa Electric conducted an initial screening of potential supply technologies (including solid fuel, natural gas fired and renewable resources), based on economic viability and qualitative factors such as technical feasibility, commercial availability, construction timing, and environmental impacts and permitting.

Tampa Electric's supply analysis was conducted first through a qualitative and quantitative screening followed by updated economic analysis.

The screening step is intended to narrow the range of alternatives to focus on the most viable options. Then Tampa Electric conducted a detailed analysis to determine the selection of the most cost-effective option. The objective of the screening was to determine the most viable and applicable technologies for further analysis. The first step in the screening process was a qualitative screening which relied on widely accepted information sources such as the DOE and trade publications, along with engineering judgment, to assess the viability of various technologies. Further screening was conducted using quantitative screening methods by means of a comparison of the levelized total cost ($/kW-yr) for technologies not screened out in the qualitative analysis. This financial parameter considers fuel costs, heat rates, outage rates, and capacity of the generating unit to calculate the nominal cost per unit of capacity for a given operating capacity factor. The primary technology assumptions are shown in Appendix O.

A. Qualitative Screening

Traditional technologies and renewable technologies including wind, solar and biomass were included in the initial screening. Tampa Electric has experience utilizing a diverse range of fuels, including, coal, oil, gas, and biomass, and is always searching for the best option with which to reliably meet our customer need for power.

Renewable technologies, such as wind and solar were looked at as one option to meet our 2017 need. However, the siting difficulty along with inability to meet the requirement for firm capacity eliminated these as viable options for Tampa Electric. It is important to note that Tampa Electric currently employs use of solar power at a number of sites in our service territory and that we continue to evaluate opportunities and proposals on renewable technologies as they fit into our portfolio, while also continuing to maintain our system reliability.

Biomass was also considered as an option. Tampa Electric periodically purchases renewable energy from biomass energy producers in support of its renewable energy program. Tampa Electric secures renewable energy from technologies such as landfill gas generation and energy from the waste of exothermic processes. Tampa Electric also encourages additional renewable energy through its renewable standard offer contract approved by the Commission.

Other technologies such as ocean thermal and tidal are not considered commercially available, and there are no significant geothermal sources in Florida. Finally, there are no fuel cells of sufficient size commercially available to offset the 2017 need.

Qualitatively, solid fuel based units were also considered. Siting for solid fuel based units require more than five years to permit and construct. A solid fuel unit would not be able to be in service by the company's target date in 2017, and could possibly put the reliability of Tampa Electric's system in jeopardy of not meeting customer needs.

B. Quantitative Screening

As part of the initial screening process, Tampa Electric performed a more detailed economic evaluation of the viable technologies available. In this step of Tampa Electric's analysis, the levelized annual cost of each technology was calculated and compared at various capacity factors. The screening curves below illustrate the cost of these technologies over a range of capacity factors.

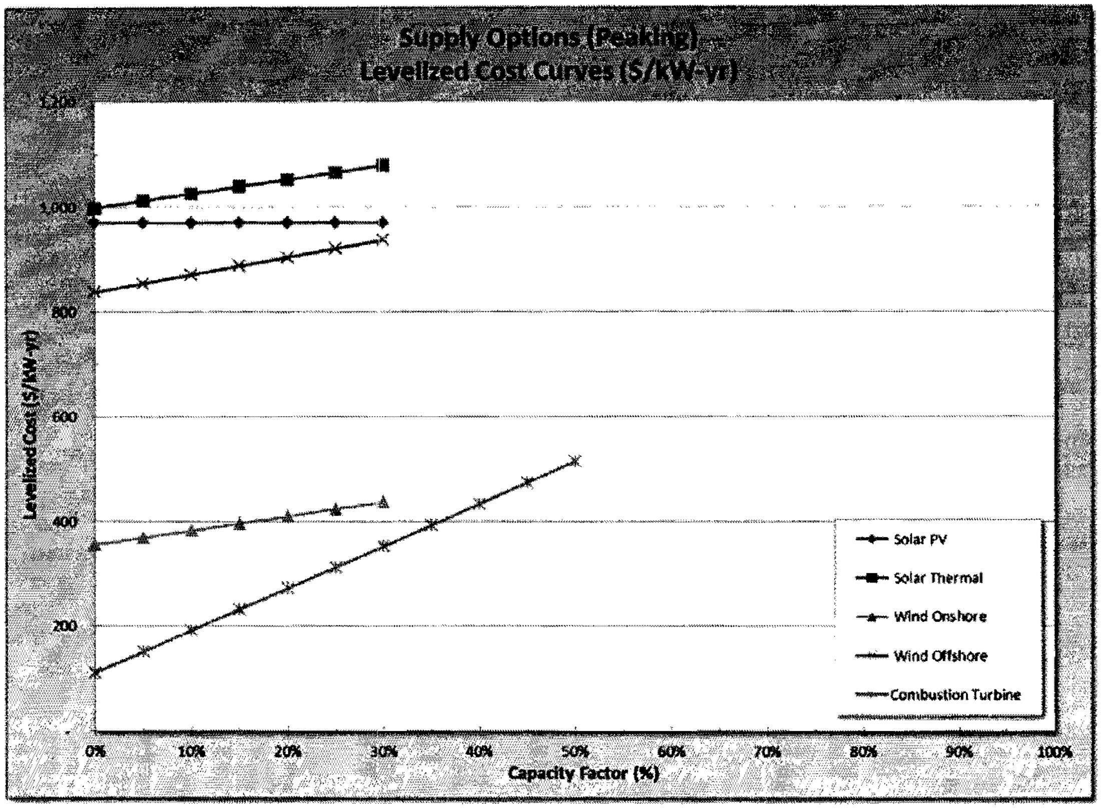


Figure 2: Peaking Technology Screening Curve

Figure 2 shows the low capacity factor technology screen curves. The high cost shown in the curves above further solidifies that wind and solar are not viable options to meet our need in 2017.

In an effort to continue to screen potential technologies and consider a wide range of fuels and capacity factors, Figure 3 includes more traditional technologies over the full range of capacity factors.

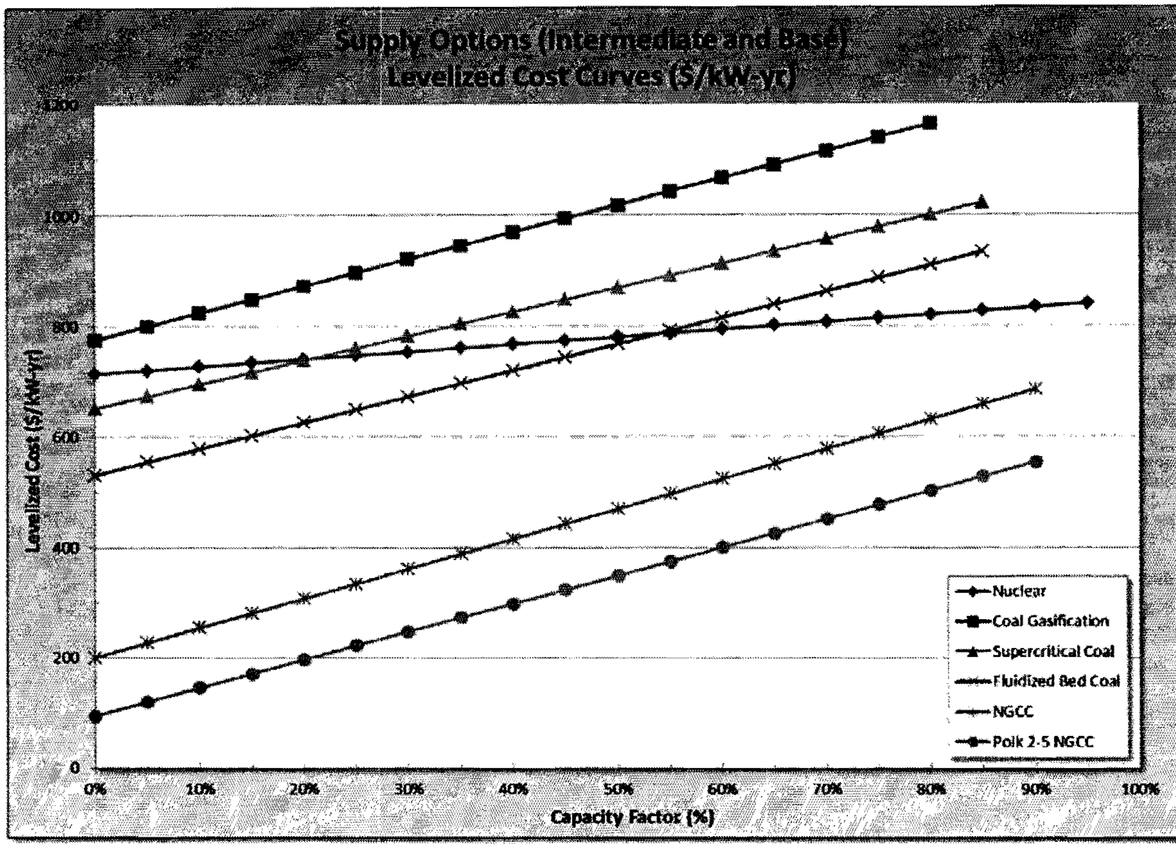


Figure 3: Intermediate and Base Screening Curve

As a result of the screening analysis, Tampa Electric concluded that simple cycle gas-fired CTs and NGCC were the most viable technologies for further consideration of the company's 2017 intermediate need. Because the cost of Aero type CTs and 7FA type CTs are similar on a $/kW-year basis, Tampa Electric determined that due to our experience and our need for power in excess of 60 MWs in 2017, CTs and an NGCC unit were the two alternatives to further consider.

VI. DETAILED ECONOMIC ANALYSIS

A. Description of Analysis

Tampa Electric next conducted detailed economic analysis of the leading supply alternatives. The detailed analysis involved the development of a resource plan for each technology case that was evaluated. In the construction of resource plans for each technology case, new units were added to each case to maintain a 20 percent reserve margin.

There were numerous resource plans that included various in-service dates and various combinations of simple cycle combustion turbines, combined cycle units and the Polk 2-5 conversion. The results of the detailed production costing analyses were combined with the capital revenue requirements to produce results on a CPWRR basis. However, the top eight (lowest cost) plans and fifteen out of the top twenty plans selected the Polk 2-5 conversion in 2017.

Two higher cost plans shown in Table 5 are compared to the Polk 2-5 expansion plan. Alternative 1 is a plan that excludes the Polk 2-5 NGCC conversion and adds only simple cycle natural gas combustion turbines to maintain system reliability. Alternative 2 is a plan that delays the in-service date of the Polk 2-5 NGCC conversion until 2025 and adds simple cycle natural gas combustion turbines to maintain system reliability.

Table 5: Detailed Economic Analysis Resource Plan

Resource Plans

Year	Polk 2-5 Portfolio Additions	Alternative 1 Portfolio Additions	Alternative 2 Portfolio Additions
2012	Peaker PPA 117 MW	Peaker PPA 117 MW	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW	(2) 7FA CT 354/298 MW	(2) 7FA CT 354/298 MW
2018		(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW
2020			
2021			
2022	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW
2023			
2024			
2025	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) Polk 2-5 NGCC 463/459 MW
2026			
2027	–	–	–
2028	–	–	–
2029	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	–
2030	–	–	–
2031	–	–	–
2032	–	–	–

B. Economic Analysis Results

The results of the Tampa Electric's analysis are illustrated in the Table 6. Polk 2-5 provides a CPWRR savings of $284 million and $231 million when compared to the Alternative 1 plan that did not include the Polk 2-5 conversion and the Alternative 2 plan that delayed the Polk 2-5 conversion from 2017 to 2025.

Table 6: Results of Final Economic Analysis

Total System Costs (2012 $ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
CPWRR	18,232	18,516	18,463
Delta		284	231

1. Tampa Electric Selected Alternative

Tampa Electric selected NGCC technology as the best supply alternative to meet its 2017 need based on the results of the levelized cost analysis, detailed economic analysis and consideration of qualitative factors. Important qualitative factors were considered in the selection of NGCC technology including efficiency, dual fuel capability, transmission reliability and voltage support, dispatchability, low environmental emissions, and renewable integration. The levelized cost analysis and initial screening confirmed that the Polk 2-5 conversion was lower cost compared to a stand-alone NGCC. As a result of the lower cost associated with the Polk 2-5 Conversion as well as the factors listed above, the Polk 2-5 Conversion in 2017 was deemed the most cost-effective, reliable, dispatchable, and environmentally beneficial option. The reliability analysis of this recommended expansion plan is reflected in Appendix L.

2. Qualitative Factors and Benefits of the Selected Alternative

The selection of Polk 2-5 provides a number of qualitative benefits to Tampa Electric's customers. The use of natural gas for Polk 2-5 will ensure a diverse energy mix for Tampa Electric and its customers. The existing Polk 2 and 3 CTs have existing dual-fuel capability, thus further improving reliability to our customers. In addition, the resulting availability of these units is expected to be upwards of 96 percent.

Polk 2-5 will be connected directly to Tampa Electric's transmission network. This will provide higher reliability of delivery and the most ancillary benefits to the company's system. The conversion of our existing units also provides additional power with no added fuel consumption (and thereby no increase in emissions) by capturing waste heat from existing CTs which lowers emissions rates. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The conversion also provides the capability for future integration of renewable energy options.

From a qualitative perspective, Polk 2-5 NGCC was favored due to its overall reliability, system emissions rate, and dispatchability.

3. Consistency with Florida Needs

Polk 2-5 does not significantly increase Tampa Electric's reliance on natural gas on a capacity and energy basis and is therefore consistent with state policy actions that encourage fuel diversity. The Polk 2-5 conversion significantly improves the efficiency of the four existing combustion turbines units and the Tampa Electric system overall by lowering the heat rate and dispatching ahead of other less efficient units. It should also be noted that load management and interruptible customer DSM programs are voluntary, so customers have a choice to withdraw from programs at any time with proper notification.

Tampa Electric's need for additional natural gas-fired combined cycle capacity in January 2017 is consistent with the peninsular Florida capacity needs in this same period, as identified by the FRCC and reported in the FRCC 2012 Regional Load and Resource Plan. The FRCC 2012 plan uses Tampa Electric specific data in conjunction with similar information from other

Florida electric utilities. In addition, there are concerns regarding continued operation of existing solid fuel assets due to emerging environmental regulations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019.

VII. SENSITIVITY ANALYSIS

A. Approach

As the final step in our process to select the most cost-effective resource addition as the basis for soliciting requests for power proposals, the company conducted sensitivity analyses comparing uncertainty factors of capital costs, fuel prices, and load growth. To evaluate the sensitivities of these factors, high and low price forecasts were established for capital construction costs and fuel price variations, and in addition, high and low load forecasts were also evaluated for Polk 2-5 and the two selected alternatives.

B. Results of Sensitivity

The results of the capital costs, fuel, and load sensitivities are presented in CPWRR for the Polk 2-5 conversion case in 2017 and the alternative plans described above.

1. Capital Cost Sensitivity

Recognizing that the estimated in-service costs for the Polk 2-5 Conversion are based on preliminary estimates, capital cost sensitivities were analyzed. The high and low cases were established utilizing higher and lower in-service cost for each of the technologies. The results of the capital cost sensitivity analysis are provided in table below:

Table 7: CPWRR Based on Capital Cost Sensitivities ($ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
Low Capital Cost	17,951	18,417	18,229
Delta		466	278
High Capital Cost	18,135	18,592	18,425
Delta		457	290

2. Fuel Price Sensitivity

To evaluate fuel price fluctuations, Tampa Electric prepared high and low price forecasts for coal, natural gas and oil. Appendices G and H include the low and high fuel forecasts, respectively. The high case for natural gas and oil is 35 percent higher than the base case and the low case is 35 percent lower than the base case. Solid fuel commodity pricing is 20 percent higher and lower than the base case, respectively. The results of the fuel sensitivity analysis are provided below:

Table 8: CPWRR Based on Fuel Pricing Sensitivities (2012 $ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
Low Fuel Cost	15,550	15,656	15,716
Delta		106	166
High Fuel Cost	21,972	22,454	22,274
Delta		482	302

3. Load Sensitivity

The base case load sensitivity is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy sensitivities represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high sensitivity and 0.5 percent lower in the low sensitivity. The results of the load sensitivity analysis are provided in the following table:

Table 9: CPWRR Based on Load Sensitivities ($ million)

	Polk 2-5 Conversion	Peaking Only	CC Alt
Low Load Cost	16,857	17,141	17,169
Delta		284	312
High Load Cost	19,792	20,357	19,867
Delta		565	76

These sensitivities demonstrated that Polk 2-5 in 2017 was still the most cost-effective alternative for Tampa Electric's customers.

VIII. RFP for Capacity as per Bid Rule

On March 23, 2012, Tampa Electric issued an RFP to solicit competitive offers to satisfy the company's projected capacity and energy requirements for comparison to Tampa Electric's Polk 2-5. In accordance with the Chapter 25.22.082 Selection of Generating Capacity ("Bid Rule") of the Florida Administrative Code, the RFP provided a detailed description of the Polk 2-5 site, fuel types and costs, estimated costs of the proposed project, and other major financial assumptions. The RFP also detailed the minimum requirements, including but not limited to a minimum 10-year term for purchase power agreements, a maximum of 500 MW and minimum of 50 MW of capacity, and the requirement for firm capacity and energy. The RFP also described the company's objective to maintain a balanced generation mix, while also inviting proposals from renewable generating facilities.

To further ensure the proposals were evaluated on an even and fair basis, Tampa Electric retained the services of Sedway Consulting, Inc. (Sedway Consulting) as an independent evaluator to assist with the development of the RFP and evaluation of the responses. Alan S. Taylor, President of Sedway Consulting, was the primary independent evaluation consultant for the solicitation and has provided testimony in this filing.

On March 16, 2012, the company notified the market of the company's intent to issue an RFP by publishing notices in the Wall Street Journal, the Tampa Tribune, and energy industry publications. An informational meeting was held at Tampa Electric's headquarters on March 21, 2012, prior to the release of the RFP to educate potential bidders on the RFP process and how they could obtain a copy of the RFP. A second meeting was held after the issuance of the RFP, on April 4, 2012, to provide a more in-depth review of the RFP, the Polk 2-5 project, and to answer any questions. Tampa Electric also established a web site that granted access to the RFP documents and allowed potential bidders to submit questions. Both the questions and answers were posted on a "FAQ" page for all to view.

A. Initial Screening

On May 22, 2012, the published due date for proposals, Sedway Consulting facilitated the receipt and opening of all proposals delivered to the company's corporate headquarters. Tampa Electric received a total of four proposals from three bidders, and the table below summarizes these four proposals:

Table 10: RFP Summary of Proposals

Proposal	Type & Term	Technology
A	PPA	Existing CC
B	Sale of Facility	Existing CTs
C	PPA	New CT
D	PPA	New CT

Following the initial screening process described in Section III A.1. of the RFP document, Sedway Consulting, along with Tampa Electric personnel reviewed the proposals to ensure they met the general and specific minimum requirements set forth in the RFP. Tampa Electric, along with Sedway Consulting, contacted bidders whenever there was any missing data, or a need to clarify submitted data.

B. Economic Evaluation of Individual Proposals/Bids

Tampa Electric began the economic evaluation of the above four proposals to determine the relative economic impact on Tampa Electric's system over the study period. The initial rankings of the bid proposals, based on levelized cost curves at the expected capacity factor, indicated A as the most cost effective bid. Bid proposals C and D were initially the least economic for several reasons. Both C and D proposals had higher capacity payments (on a $/kW-month basis) and less efficient heat rates compared to bid proposal A.

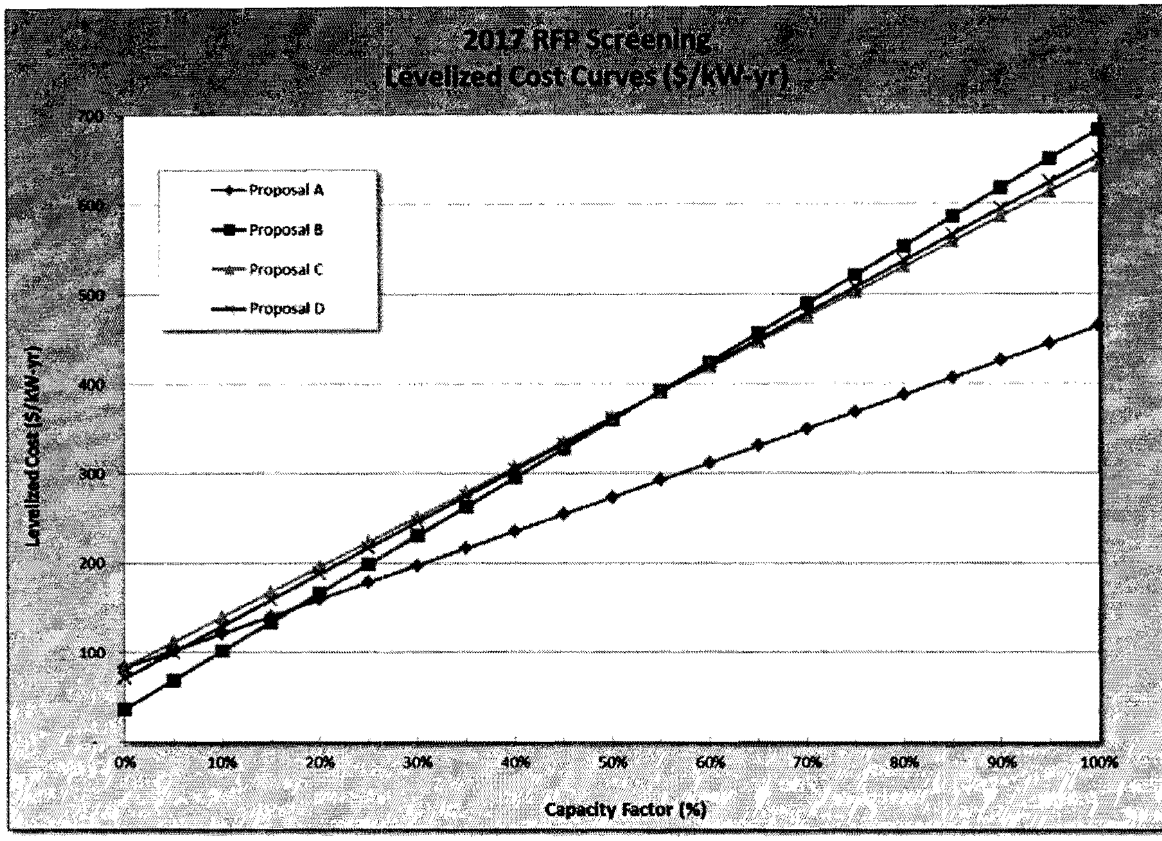


Figure 4: RFP – Initial Screening of Proposals

C. Present Value Economic Screen

Using preliminary system cost assumptions, all four bid proposals were passed to the present value economic ccreen evaluation process where each was evaluated using the CPWRR. This phase of the analysis took into account fixed and variable costs of production for the bid proposals as well as Tampa Electric system impacts. Neither proposal C or D met the 294 MW need in 2017 without the need to add peaking CTs in the 2017 time period.

D. Final Evaluation of Total System Costs

Tampa Electric short-listed all proposals and invited the bidders to submit their best and final offers to the company no later than July 13, 2012. Only the bidder for Proposal B provided modifications to their initial offer. Tampa Electric used the information provided in the best and final offers, as well as transmission integration cost estimates, net equity adjustment for purchase obligations, and fuel infrastructure costs to determine the final total system cost for each proposal.

Table 11: Resource Plans of RFP Portfolios

Year	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
2012					
2013			Proposal B		
2014					
2015					
2016					
2017	Polk 2-5	Proposal A		Proposal C 7FA CT	Proposal D 7FA CT
2018			Polk 2-5		
2019	7FA CT	7FA CT		(2) 7FA CTs	(2) 7FA CTs
2020					
2021					
2022	7FA CT	7FA CT			
2023				Polk 2-5	Polk 2-5
2024					
2025	7FA CT	7FA CT			
2026			7FA CT		
2027		Polk 2-5			
2028					
2029	7FA CT	7FA CT	7FA CT	7FA CT	
2030					
2031					
2032					7FA CT

Analyzing the above resource plans with the revised data provided by the bidders, yielded the following results:

Table 12: RFP CPWRR Results in 2012 ($ million)

	CPWRR ($ million)				
	Polk 2-5	**Proposal A**	**Proposal B**	**Proposal C**	**Proposal D**
Capital	$1,575.2	$1,253.3	$1,400.1	$1,430.9	$1,416.6
O&M	$1,099.7	$1,064.6	$1,068.7	$1,111.2	$1,109.2
Fuel & Purchased Power	$15,566.1	$16,143.0	$15,904.5	$15,909.9	$15,954.9
Total	$18,241.0	$18,460.9	$18,373.4	$18,452.0	$18,480.8
Delta		$219.9	$132.4	$210.9	$239.7

As seen above, Polk 2-5 is the lowest cost option against all proposals. Proposal B, which Tampa electric evaluated as the next best option shows a $132.4 million CPWRR additional cost to Polk 2-5.

E. Non-Economic Evaluation

Tampa Electric understands that while the cost-effectiveness of its selection is important, there are many other qualitative impacts that must be considered. Therefore, thirteen unique, non-economic qualitative factors were developed and evaluated across Polk 2-5 and the proposals.. After review of all of these factors, Polk 2-5 was favored due to its overall reliability, emission rate, and dispatchability. The factors considered and a summary of how each proposal was judged is shown in Appendix P.

F. Final Selection

The results of the RFP analysis indicate that Polk 2-5 is the most economic plan to meet the 2017 capacity needs by $132.4 million CPWRR compared to the next best proposal. Based on these economic results, and consideration of the non-economic impacts relative to the other proposals and technologies considered, Polk 2-5 was selected as the best solution for Tampa Electric's customers in meeting its 2017 need.

IX. TAMPA ELECTRIC'S PROPOSED UNIT

A. Overview

The existing Polk 2 through 5 combustion turbines will be converted to a NGCC facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter, incrementally with a planned in-service date of January 2017. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for two future aero-derivative peaking units due to the expiration of a 121 MW PPA on December 31, 2018. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The NGCC configuration also enables the potential integration of solar thermal renewable capacity and energy in the future.

The total in-service cost of the project (including transmission, but without AFUDC) is expected to be $610.4 million. This includes the direct overnight engineering and procurement costs for the project of $424.4 million. It also includes transmission costs, owner's costs, allowance for indeterminates and escalation.

B. Description

Tampa Electric plans to make use of its experience with NGCC technology to construct Polk 2-5 at Polk Power Station. Polk Power Station occupies over 2,800 acres on State Road 37 in Polk County, Florida, approximately 40 miles southeast of Tampa and about 60 miles southwest of Orlando. The primary fuel for Polk 2-5 will be natural gas and two of the four units will utilize distillate oil for backup.

Polk 2-5 is expected to generate a net 1,195 MW of electricity in winter at 32 degrees Fahrenheit and 1,063 MW in the summer at 92 degrees Fahrenheit. The average annual net heat rate, higher heating value is expected to be about 7,062 Btu/kWh.

The existing units 2-5 are General Electric 7FA combustion turbines installed in a simple cycle configuration. Units 2 and 3 have the ability to use distillate oil for backup and units 4 and 5 are natural gas only. Simple cycle units have a relatively low capital cost and are able to dispatch rapidly to meet peaking needs, but a significant amount of energy is lost in the exhaust.

After conversion, with no additional fuel consumption, Polk 2-5 will generate an incremental net electrical output of 352 MW in the winter at 32 degrees Fahrenheit and 339 MW in the summer at 92 degrees Fahrenheit. In addition, Polk 2-5 will utilize supplemental firing, also known as duct burners, to provide up to 120 MW of additional cost effective peaking capacity that will offset the need for future peaking unit construction.

1. Location

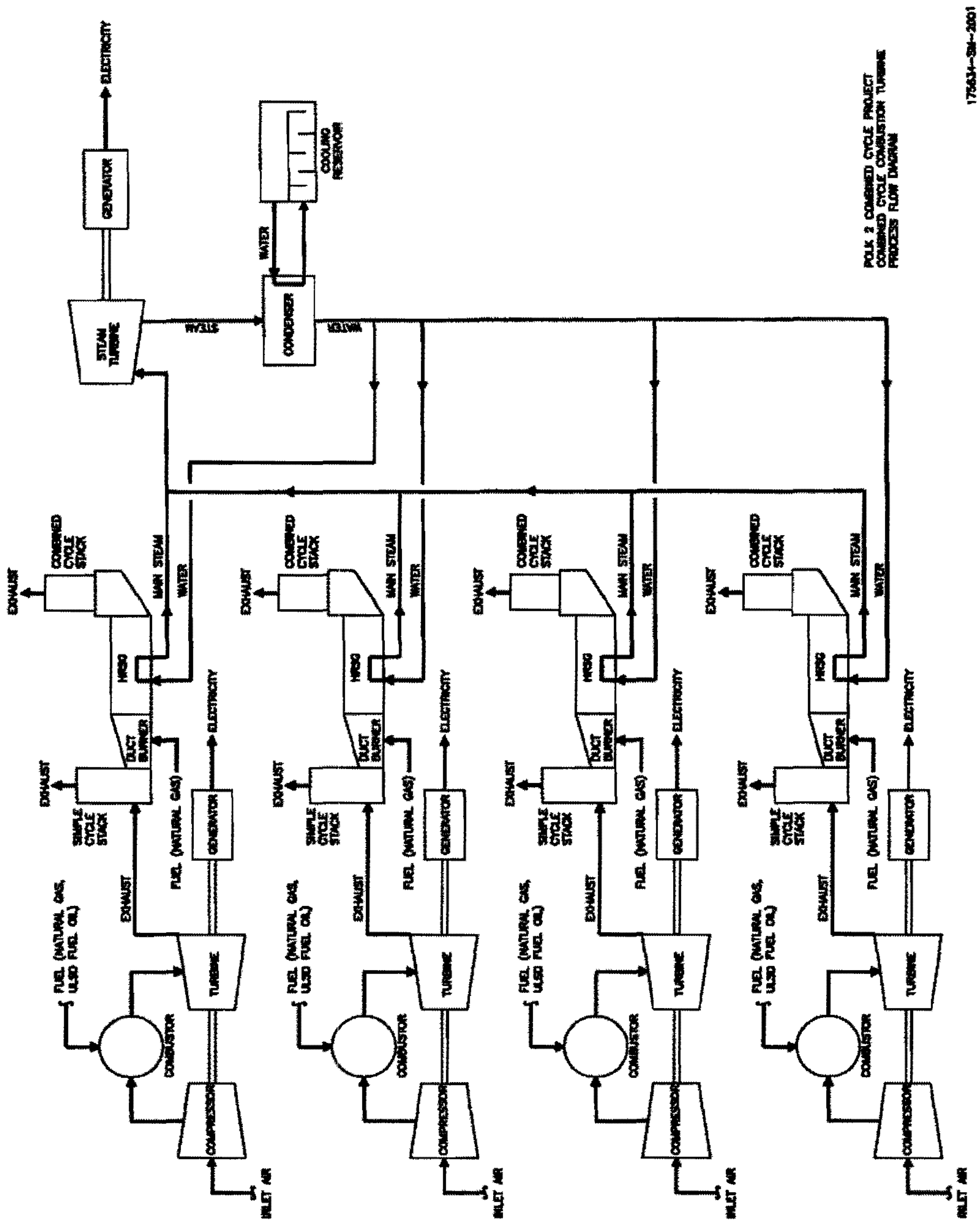
By co-locating Polk 2-5 at Polk Power Station, there are numerous benefits including but not limited to:

- An existing site that has already been developed with future expansion in mind.
- An existing 750 acre cooling reservoir that has adequate capacity to handle a large portion of the cooling needs for Polk 2-5.
- Existing natural gas pipeline infrastructure that already serves the existing units 2-5 and has adequate capacity to serve the incremental need for the supplemental firing system.
- The existing on-site substation can be readily expanded to accommodate the new steam turbine generator interconnection.
- The site has an existing administration building, control room, warehouse, maintenance shop and other facilities that are capable of serving the new unit.
- An existing operations staff experienced in operating this type of generation equipment with minimal training.

2. Design

Tampa Electric is currently in the preliminary engineering stage of design for Polk 2-5. At this stage of the project a preliminary concept of the plant has been developed. This preliminary conceptual design provides sufficient information for estimation of the expected performance, and general arrangement of the plant and high level estimates of the projects schedules and costs. The plant can be broken down into several sections, as described in the following sections. A process diagram is provided in Figure 7 below.

Figure 5: Polk 2-5 Overall Process



3. Systems

a. Natural Gas Delivery

Natural gas will be delivered via an existing FGT pipeline already on the Polk site. The pipeline already serves the existing units 2-5 and has adequate capacity to serve the incremental needs of the supplemental firing system. In addition, the Gulfstream Natural Gas Company's pipeline is close to the Polk site and could be extended in the future for added natural gas delivery diversity.

b. Water Use

The primary consumption of water will be for makeup to the cooling reservoir and cooling tower to replace water lost by evaporation. To a much lesser extent, water will also be used to provide demineralized water for makeup to the HRSGs. The majority of the makeup water needs will be from reclaimed water from the City of Lakeland. In addition, by using the existing cooling reservoir to the maximum extent possible, water use from evaporative losses will be reduced relative to using a cooling tower.

c. Heat Recovery Steam Generators (HRSGs)

Polk 2-5 will utilize triple pressure HRSGs with reheat. This design is the standard for domestic combined cycles and is a very proven and reliable technology. In addition, the HRSGs for Polk 2-5 will include diverter dampers and supplemental firing capability. The diverter dampers provide increased reliability by allowing the combustion turbine to remain in operation in the event the associated HRSG or steam turbine is unavailable. The diverter dampers will also allow Polk 2-5 to retain the current rapid response capability if needed for peaking service. The supplemental firing system will add up to 120 MW (30 MW per HRSG) of relatively low cost and high efficiency peaking capacity when compared to simple cycle combustion turbines.

d. Steam Turbine Generator ("STG")

Polk 2-5 will utilize a modern STG which will be designed with the flexibility to allow cycling, intermediate or base load operation depending on the system's needs and economics. The expected Equivalent Availability Factor for Polk 2-5 is 96.1 percent.

C. Environmental

Tampa Electric is required to obtain federal, state, and regional environmental approvals and permits. The principal environmental approval is certification under Florida's Electrical Power Plant Siting Act ("PPSA") codified in 403.500 Florida Statutes. This is a comprehensive review of all environmental aspects of Polk 2-5, coordinated through the FDEP and involving all state and regional agencies with environmental responsibility and those potentially affected by Polk 2-5.

Polk 2-5 will require federal and federally delegated permits. This includes an approval by the U.S. Army Corp of Engineers ("ACOE") for impacts to wetlands, a Prevention of Significant Deterioration ("PSD")/Air Construction Permit by the FDEP, a National Pollutant Discharge Elimination System ("NPDES") and an Underground Injection Control ("UIC") Permit from FDEP.

The ACOE permit is required under Section 404 of the Clean Water Act and includes a demonstration that impacts to wetlands have been minimized and compensatory wetland mitigation has been provided as needed. Since Polk 2-5 will be located at the existing site of Polk Unit 1, minimal impacts to wetlands will occur. Appendix R contains a detailed list of environmental permitting activities that are currently in process by Tampa Electric for Polk 2-5.

Under the federally authorized PSD program, Polk 2-5 will be required to install Best Available Control Technology ("BACT") and demonstrate that the project will comply with all air quality standards including those applicable to the PSD Class I Areas. FDEP PSD rules are codified in Rule 62-212 F.A.C. An important aspect of PSD review is the determination of BACT.

The Polk 2-5 site was selected at a location that provides the needed infrastructure and minimizes environmental impacts. The Polk Power Station site includes sufficient land area, which has been previously certified to minimize any additional environmental impacts. Water use will be minimized by utilizing reclaimed water for the makeup to the cooling reservoir. Lakeland's Water Treatment Facility currently discharges its reclaimed water into the Alafia River which ends up in Tampa Bay. Polk is taking this water from Lakeland and treating it removing any nutrients before discharging into Little Pane Creek which aids in improving the water quality in Tampa Bay. Using the treated water will minimize additional consumptive use withdrawals to the greatest extent possible and will assist in accelerating the removal of nutrients from Tampa Bay.

Air emissions from Polk Power Station will be minimized by use of Selective Catalytic Reduction ("SCRs") equipment in each HRSG to reduce nitrogen oxide emissions. The SCRs in combination with cycle efficiency improvements will provide an 86 percent reduction in the NO_x emission rate.

D. Transmission Facilities

Polk 2-5 will require the construction of transmission infrastructure as shown in Appendix S. The infrastructure/facilities required are described below:

1. Two new 230 kV transmission lines, three new 230 kV circuit breakers and

a generator step-up transformer are required at Polk to interconnect the Polk 2-5 to the transmission system.

2. A new 230 kV transmission switching station (Aspen Substation) west of Mines Substation.
3. The following new 230 kV transmission lines:
   - Polk Substation to Mines Substation
   - Mines Substation to Aspen Substation
   - Two lines from Aspen Substation to FishHawk Substation
4. Upgrade segments of existing 230 kV transmission lines to create a 230 kV transmission line from Polk Power Substation to Aspen Substation.
5. Interconnect and rerate existing 230 kV transmission line from Big Bend Power Station Substation to Mines Substation into Aspen Substation.
6. Upgrade 16-230 kV circuit breakers at Polk Power Substation, Pebbledale Substation, Mines Substation and Big Bend Power Station Substation.
7. Reroute and upgrade the first Polk Power Substation to Pebbledale Substation 230 kV transmission line.
8. Rerate the second Polk Power Substation to Pebbledale Substation 230 kV transmission line.
9. Install a switched reactor at Davis Substation.
10. Upgrade the bus for the State Road 60 North 230/69 kV Transformer.
11. Upgrade the bus and low side circuit breaker for the Dale Mabry West 230/69 kV Transformer.

The total project costs are approximately $147.2 million. The Polk interconnection/integration work would begin in January 2013 and would be completed by November 2016. The Polk Power Substation to Aspen Substation to FishHawk Substation transmission line construction must begin by October 2014 in order to make an in-service date of November 2016. The remainder of the work will be completed prior to November 2016. This ensures that all transmission facilities are in-service prior to any testing of Polk 2-5 and its equipment prior to its commercial date.

Polk 2-5 will be interconnected with Tampa Electric with 4 transmission lines to the existing Polk Power Substation. The Polk Power Substation is currently connected to the Tampa Electric bulk electric system through four 230 kV lines, two to Pebbledale Substation, one to Mines Substation and one line to the Hardee Power Station. With the new construction, a 230 kV line will be added to the Aspen Substation, eventually running to the FishHawk Substation.

FRCC Transmission Working Group and Stability Working Group have evaluated the proposed interconnection and integration of the Polk 2-5 project and determined it is reliable and does not adversely impact the transmission system in the FRCC region.

E. Cost

The overnight construction cost for Polk 2-5 is $424.4 million. The estimate represents the following pricing components: engineering, equipment procurement, direct and indirect construction, commissioning and owner's costs in 2012 dollars. This estimate was developed by Black & Veatch and reflects current equipment and labor pricing. This project estimate does not include related transmission upgrades or AFUDC. Owner's costs include project development costs such as environmental permitting, project management, operation support and training, legal and other professional services costs. Tampa Electric estimated the owner's costs for Polk 2-5 based on its experience developing and constructing generating units in Florida.

The total in-service cost estimate for Polk 2-5 is $610.4 million, which includes the aforementioned overnight construction costs as well as transmission costs and escalation.

F. Schedule

Conceptual design began in late 2011, and the preliminary engineering package development began in February 2012 and was completed in May 2012. The Site Certification Application will be filed with the FDEP in September 2012. The detailed design and procurement will begin January 2013. Detailed design and procurement activities are expected to continue through November 2014. Construction activities are expected to begin in the first quarter 2014 with general site work. Commissioning of the equipment is expected to begin in February 2016 and the unit is expected to begin commercial operation in January 2017.

The preliminary project schedule is shown in Appendix Q.

X. JUNE 2012 ASSUMPTIONS UPDATE

During the course of this RFP, Tampa Electric, as part of its annual IRP process, developed an updated customer demand & energy forecast, as well as a new fuel pricing forecast. In order to assess the effects of these new forecasts and to ensure it would not alter the selection of the most economical option, another economic evaluation of Polk 2-5 and the most competitive proposal from the RFP process and Alternative 2 was completed utilizing these new forecasts. The results of this analysis is shown in the table below. Even considering newer forecast data developed as part of the on-going IRP process, Tampa Electric determined Polk 2-5 is still the most cost effective alternative compared to the lowest RFP bid proposal.

Table 13: Economic Evaluation with Consideration of June 2012 Updated Assumptions

	CPWRR ($ million)		
	Polk 2-5	**Alternative 2**	**Proposal B**
Capital	$1,557.2	$1,520.4	$1,357.5
O&M	$845.2	$897.5	$815.1
Fuel & Purchased Power	$13,631.7	$13,882.9	$13,623.5
Total	$16,034.1	$16,300.8	$16,131.5
Delta		$266.7	$97.4

As can be seen in the table, Polk 2-5 is still the best option compared to Alternative 2 and Proposal B, which are $266.7 million and $97.4 million more costly with the latest demand and energy and fuel cost forecasts considered.

XI. Adverse Consequences If Polk 2-5 Is Delayed Or Denied

In the event that Polk 2-5 is delayed by two years, project costs would increase, and customer fuel savings for 2017 and 2018 would not be realized. Tampa Electric would construct simple cycle peaking units in 2017 to cover the reserve margin requirement in 2017 and 2018. System energy requirements would be served by peaking capacity resulting in higher fuel costs. This would result in higher costs for customers of $65.4 million on a CPWRR basis. Witness Hornick described the potential for an equipment demand spike scenario if there is a delay. If an equipment demand spike scenario materializes, this could result in higher costs for customers of $100.0 million on a CPWRR basis.

If Tampa Electric's proposed Polk 2-5 is denied, Tampa Electric would not be able to satisfy its minimum 20 percent Reserve Margin and minimum 7 percent supply planning criteria by the summer of 2017 in the most reliable and cost-effective manner. This would expose Tampa Electric's customers to a greater risk of interruption of service in the event of unanticipated forced outages or other contingencies for which Tampa Electric maintains reserves. Even without an interruption in service, without Polk 2-5 the company's customers would be subject to higher fuel costs as the company would have to rely on less efficient simple cycle generation to meet its need.

XII. CONCLUSION

Tampa Electric, through its IRP process, incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW in order to meet the Commission-approved 20 percent reserve margin criteria. Despite Tampa Electric's utilization of all cost-effective DSM programs and the associated increase in load reductions, the company will not be able to defer its need.

Tampa Electric conducted a detailed evaluation of various supply alternatives, including natural gas-fired and solid fuel-fired. After an initial screening process of a variety of viable technologies and fuels, a detailed economic analysis demonstrated that Polk 2-5 is the most cost-effective means of meeting Tampa Electric's 2017 need compared to other technologies and available supply capacity from the Florida market. Tampa Electric's analysis demonstrated Polk 2-5 provides $284 million in savings compared to peaking technology and $231 million in savings compared to peaking then NGCC technology.

After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year deferral of the recommended plan could increase costs to customer by $100 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix.

In conclusion, Polk 2-5 provides significant savings of $132.4 million to Tampa Electric's customers when compared to the next higher cost alternative while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. All these reasons reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

XIII. APPENDICES

Appendix A: Residential DSM Programs

Appendix B: Commercial/Industrial DSM Programs

Appendix C: Retail Customers by Customer Class

Appendix D: Retail Energy Sales by Customer Class

Appendix E: Retail Peak Demand Forecast

Appendix F: High and Low Retail Peak Demand Used in Sensitivity

Appendix G: June 2012 Update Used in Sensitivity

Appendix H: Fuel Forecast

Appendix I: Low Fuel Forecast Used in Sensitivity Analysis

Appendix J: High Fuel Forecast Used in Sensitivity Analysis

Appendix K: Tampa Electric Reliability Analysis

Appendix L: Tampa Final Electric Reliability Analysis

Appendix M: FRCC Reliability Analysis

Appendix N: FRCC Reliability Sensitivity Analysis

Appendix O: Technology Assumptions

Appendix P: RFP Qualitative Factors

Appendix Q: Polk 2-5 Preliminary Project Schedule

Appendix R: Polk 2-5 Environmental Permit Requirements

Appendix S: Transmission Interconnection and Integration Diagrams

Appendix A: Residential DSM Programs

Residential Programs	Measures	Brief Description
Walk-Through Audit	Customer is given eight CFLs	Free audit conducted on-site by trained analyst
On-Line Audit	Customer is given eight CFLs	Free on-line audit available at customer's convenience
Paid Audit	Customer is given eight CFLs	Paid computer assisted audit conducted on-site by trained analyst
Telephone Audit	Customer is given eight CFLs	Free audit conducted by telephone; uses on-line audit tool for evaluation
Heating & Cooling	High-efficiency heat pumps or high-efficiency cooling with natural gas heating	Incentives are $400 for heat pumps replacing strip heat; $275 for heat pumps replacing strip heat; $275 for straight cool with gas heat
Duct Repair	Duct repair	Customer cost to participate is $50 for repairs and sealing of ductwork.
Residential Building Envelope Improvement	Ceiling insulation	Incentive up to $350
	Wall Insulation	Incentive of $0.31 per sq. ft.
	Window Replacement	Incentive of $2.65 per sq. ft.
	Window Film	Incentive of $2.00 per sq. ft.
New Construction Program	Duct Sealing With Mastic	Incentive of $100
	High-efficiency heat pumps or high-efficiency cooling with natural gas heating	Incentive of $275 per unit
	Ceiling insulation	Incentive of $150
	Window upgrades	Incentive of $400
	Water heating	Incentive of $150
	HERs certification	Incentive of $100
Energy Planner	Price responsive load management	Uses programmable thermostat in conjunction with time-of-use pricing tiers to reduce weather sensitive peak loads.
Electronically Commutated Motors	Air hander fan motor upgrade	Incentive of $135
HVAC Re-commissioning	HVAC equipment tune-up and maintenance	Incentive of $75
Energy Education Outreach	CFLs, low-flow items and filter whistles	Program is designed to establish opportunities for energy-efficiency related discussions in an organized setting
Weatherization and Agency Outreach	**Weatherization** - Installation of the following applicable measures: eight CFLs, water heater wrap, water temp cards, low-flow showerheads, wall plate thermometer, refrigeration coil brush, weather-stripping and caulking, R-13 ceiling insulation and duct repair	Low income weatherization through either direct customer request or by the utilization of census data
	Agency Outreach - Customer is given four CFLs, water temp card, low-flow aerators and change air filter whistles	The delivery of energy efficiency kits to educate agency clients on practices that help reduce energy consumption
Prime Time	Direct load control of HVAC equipment, water heating and pool pumps.	This program has been closed to new customers since 2005

Appendix B: Commercial/Industrial DSM Programs

Commercial Programs	Measures	Brief Description
Free Audit	Customer is given eight CFLs	Free audit conducted on-site by trained analyst
Paid Audit	Customer is given eight CFLs	Paid audit conducted by analyst; includes specific data collection
Duct Repair	Duct repair	Incentive of $300
Building Envelope Improvement	Ceiling insulation	Incentive of $0.25 per sq. ft.
	Roof insulation	Incentive of $0.15 per sq. ft.
	Wall insulation	Incentive of $0.40 per sq. ft.
	Window film	Incentive of $1.25 per sq. ft.
Energy Efficient Motors	Motor upgrades	Incentive of $6.00 per HP
Commercial Cooling	High-efficiency cooling equipment	Incentives are $50 per ton for DX units and $37.50 per ton for PTAC units
Chillers	High-efficiency chilled water HVAC	Incentive of $175 per kW reduction
Lighting	High-efficiency lighting in conditioned or unconditioned space	Incentive of $175 per kW reduction
	High-efficiency exit signs	Incentive of $25 per sign
Occupancy Sensors	Installation of occupancy sensors for lighting	Incentive of $25 per sensor
Standby Generator	Load reduction through emergency generation	Incentive of $4.00 per kW reduction
Refrigeration (anti-condensate controls)	Installation of anti-condensate heat controls	Incentive of $0.65 per linear ft.
Water Heating	Water heating upgrades	Incentive of $0.0116 per btu
Conservation Value	Customer specific measures with reductions greater than 5 kW	Incentive of $175 per kW reduction
Commercial Load Management	Direct load control of HVAC equipment, water heating	Incentive for cyclic control (summer only) $3.00 per kW; Incentive for extended control (summer and winter) $3.50 per kW
Demand Response	Price responsive load management	Turn-key program providing price incentives for demand reduction
Industrial Load Management	Load reduction for facilities 500 kW and greater	Approved annual incentive per FPSC cost-effectiveness methodology
Electronically Commutated Motors	Air hander fan and refrigeration motors upgrade	Incentives range from $125 to $180 per HP
HVAC Re-commissioning	HVAC equipment tune-up and maintenance	Incentive of $25 per ton
Cool Roof	Roof systems to reduce cooling demand	Incentive of $0.60 per sq. ft.
Energy Recovery Ventilation	HVAC ventilation systems to reduce cooling demand	Incentives range from $1.32 to $2.26 per cfm of system

Appendix C: Retail Customers by Customer Class

	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2002	518,554	64,665	904	44	5,812	220	590,199
2003	531,257	66,041	1,159	44	6,188	211	604,900
2004	544,313	67,488	1,260	39	6,226	209	619,535
2005	558,601	69,027	1,300	37	6,447	209	635,621
2006	575,111	70,205	1,448	37	6,706	199	653,706
2007	586,776	70,891	1,458	36	6,992	201	666,354
2008	587,602	70,770	1,385	36	7,271	202	667,266
2009	587,396	70,182	1,392	32	7,521	227	666,750
2010	591,554	70,176	1,405	29	7,607	220	670,991
2011	595,914	70,522	1,465	28	7,666	203	675,798
2012	599,454	71,418	1,464	32	7,746	201	680,315
2013	606,320	72,252	1,475	32	7,802	202	688,083
2014	614,152	73,176	1,486	32	7,863	204	696,913
2015	622,637	74,183	1,494	32	7,929	206	706,481
2016	632,012	75,278	1,501	32	8,002	208	717,033
2017	641,161	76,346	1,508	32	8,073	210	727,330
2018	650,099	77,398	1,516	32	8,141	213	737,399
2019	659,014	78,447	1,523	32	8,210	215	747,441
2020	667,793	79,491	1,531	32	8,278	217	757,342
2021	676,073	80,484	1,539	32	8,342	220	766,690
Average Annual Growth Rates							
2002-2011	1.6%	1.0%	5.5%	-4.8%	3.1%	-0.9%	1.5%
2012-2021	1.3%	1.3%	0.6%	0.0%	0.8%	1.0%	1.3%
Average Absolute Growth							
2002-2011	8,596	651	62	-2	206	-2	9,511
2012-2021	8,513	1,007	8	0	66	2	9,597

Appendix D: Retail Energy Sales by Customer Class

Tampa Electric Company
Retail Energy Sales
(GWH)

	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2002	8,046	5,832	1,234	1,378	1,380	55	17,925
2003	8,265	5,843	1,303	1,277	1,481	57	18,225
2004	8,293	5,988	1,327	1,229	1,542	58	18,437
2005	8,558	6,234	1,329	1,149	1,582	60	18,912
2006	8,721	6,357	1,343	936	1,607	61	19,025
2007	8,871	6,542	1,316	1,050	1,692	63	19,533
2008	8,546	6,399	1,236	969	1,776	64	18,990
2009	8,666	6,274	1,088	906	1,771	68	18,774
2010	9,185	6,221	1,058	952	1,724	73	19,213
2011	8,718	6,207	1,072	731	1,761	74	18,564
2012	8,904	6,346	1,121	777	1,822	74	19,044
2013	9,003	6,412	1,131	706	1,833	74	19,158
2014	9,095	6,484	1,135	568	1,844	75	19,201
2015	9,174	6,557	1,133	530	1,856	76	19,326
2016	9,272	6,640	1,128	540	1,871	77	19,528
2017	9,376	6,727	1,122	529	1,887	77	19,719
2018	9,486	6,814	1,117	529	1,903	78	19,927
2019	9,600	6,901	1,112	529	1,919	79	20,141
2020	9,716	6,985	1,107	529	1,935	80	20,352
2021	9,826	7,063	1,102	529	1,949	81	20,550
Average Annual Growth Rates							
2002-2011	0.9%	0.7%	-1.5%	-6.8%	2.7%	3.3%	0.4%
2012-2021	1.1%	1.2%	-0.2%	-4.2%	0.8%	1.0%	0.8%
Average Absolute Growth							
2002-2011	75	42	-18	-72	42	2	71
2012-2021	102	80	-2	-28	14	1	167

Appendix E: Retail Peak Demand Forecast

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3976
2012	4081	3993
2013	4112	4023
2014	4141	4049
2015	4180	4082
2016	4224	4125
2017	4269	4165
2018	4315	4207
2019	4361	4250
2020	4408	4292
2021	4453	4331
Average Annual Growth Rates		
2002-2011	1.2%	1.0%
2012-2021	1.0%	0.9%
Average Absolute Growth		
2002-2011	47	38
2012-2021	41	38

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3777	3748
2013	3819	3784
2014	3864	3823
2015	3910	3859
2016	3955	3900
2017	4003	3940
2018	4050	3980
2019	4097	4022
2020	4146	4064
2021	4194	4103
Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.2%	1.0%
Average Absolute Growth		
2002-2011	53	42
2012-2021	46	39

Appendix F: High and Low Retail Peak Demand Used in Sensitivity

High Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3802	3778
2013	3868	3836
2014	3936	3897
2015	4003	3955
2016	4072	4017
2017	4142	4080
2018	4212	4144
2019	4284	4209
2020	4358	4276
2021	4431	4341
Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.7%	1.6%
Average Absolute Growth		
2002-2011	53	42
2012-2021	70	63

Low Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3758	3725
2013	3779	3740
2014	3802	3758
2015	3825	3773
2016	3849	3791
2017	3874	3810
2018	3898	3827
2019	3922	3847
2020	3947	3866
2021	3972	3882
Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	0.6%	0.5%
Average Absolute Growth		
2002-2011	52	42
2012-2021	24	17

Appendix G: June 2012 Update Used in Sensitivity

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3931
2012	3523	3916
2013	3970	3893
2014	3999	3928
2015	4043	3969
2016	4095	4017
2017	4147	4065
2018	4200	4112
2019	4251	4159
2020	4301	4203
2021	4349	4244
Average Annual Growth Rates		
2002-2011	1.2%	0.9%
2012-2021	1.1%	0.9%
Average Absolute Growth		
2002-2011	47	33
2012-2021	47	36

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3237	3677
2013	3699	3667
2014	3731	3701
2015	3778	3741
2016	3832	3788
2017	3887	3835
2018	3941	3881
2019	3993	3927
2020	4045	3971
2021	4095	4012
Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.3%	1.0%
Average Absolute Growth		
2002-2011	52	42
2012-2021	50	37

Appendix H: Fuel Forecast

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$25.68	$4.92	$2.22
2013	$26.88	$5.30	$2.42
2014	$27.98	$5.58	$2.45
2015	$29.44	$5.86	$2.56
2016	$30.84	$6.12	$2.41
2017	$32.06	$6.39	$2.40
2018	$33.34	$6.67	$2.27
2019	$34.63	$6.93	$2.43
2020	$35.98	$7.19	$2.59
2021	$37.39	$7.44	$2.75
2022	$38.89	$7.70	$2.90
2023	$39.75	$7.87	$3.01
2024	$40.61	$8.04	$3.11
2025	$41.49	$8.21	$3.22
2026	$42.37	$8.39	$3.32
2027	$43.27	$8.56	$3.43
2028	$44.17	$8.74	$3.54
2029	$45.09	$8.93	$3.65
2030	$46.03	$9.11	$3.76
2031	$46.99	$9.30	$3.87
2032	$47.96	$9.49	$3.99
2033	$48.96	$9.69	$4.11
2034	$49.97	$9.89	$4.23
2035	$50.99	$10.09	$4.35
2036	$52.04	$10.30	$4.48
2037	$53.11	$10.51	$4.61
2038	$54.20	$10.72	$4.74
2039	$55.31	$10.94	$4.87
2040	$56.44	$11.16	$5.01

Appendix I: Low Fuel Forecast Used in Sensitivity Analysis

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$14.52	$3.09	$2.22
2013	$15.63	$3.33	$1.93
2014	$16.46	$3.51	$1.96
2015	$17.30	$3.69	$2.05
2016	$18.17	$3.87	$1.93
2017	$19.01	$4.05	$1.92
2018	$19.88	$4.23	$1.82
2019	$20.72	$4.41	$1.97
2020	$21.56	$4.59	$2.14
2021	$22.42	$4.77	$2.30
2022	$23.29	$4.96	$2.46
2023	$23.80	$5.07	$2.55
2024	$24.32	$5.18	$2.65
2025	$24.85	$5.29	$2.75
2026	$25.38	$5.40	$2.84
2027	$25.91	$5.52	$2.94
2028	$26.45	$5.63	$3.04
2029	$27.00	$5.75	$3.14
2030	$27.57	$5.87	$3.25
2031	$28.14	$5.99	$3.35
2032	$28.72	$6.12	$3.46
2033	$29.32	$6.24	$3.57
2034	$29.92	$6.37	$3.68
2035	$30.54	$6.50	$3.80
2036	$31.17	$6.64	$3.91
2037	$31.81	$6.77	$4.03
2038	$32.46	$6.91	$4.15
2039	$33.12	$7.05	$4.28
2040	$33.80	$7.20	$4.40

Appendix J: High Fuel Forecast Used in Sensitivity Analysis

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$30.15	$6.42	$2.22
2013	$32.46	$6.91	$2.90
2014	$34.18	$7.28	$2.95
2015	$35.93	$7.65	$3.07
2016	$37.74	$8.04	$2.89
2017	$39.49	$8.41	$2.88
2018	$41.28	$8.79	$2.73
2019	$43.04	$9.17	$2.91
2020	$44.79	$9.54	$3.10
2021	$46.55	$9.92	$3.29
2022	$48.37	$10.30	$3.48
2023	$49.43	$10.53	$3.59
2024	$50.51	$10.76	$3.70
2025	$51.60	$10.99	$3.81
2026	$52.70	$11.23	$3.93
2027	$53.81	$11.46	$4.04
2028	$54.94	$11.70	$4.16
2029	$56.09	$11.95	$4.28
2030	$57.25	$12.19	$4.40
2031	$58.44	$12.45	$4.52
2032	$59.66	$12.71	$4.65
2033	$60.89	$12.97	$4.78
2034	$62.15	$13.24	$4.91
2035	$63.43	$13.51	$5.04
2036	$64.73	$13.79	$5.18
2037	$66.06	$14.07	$5.32
2038	$67.41	$14.36	$5.46
2039	$68.79	$14.65	$5.60
2040	$70.20	$14.95	$5.75

Forecast of Capacity and Demand at Time of Summer Peak

	Total Installed Capacity	Net Firm Capacity Purchases	Total Capacity Available	System Firm Peak Demand	System Total Peak Demand	Firm Reserve Margin w/o Planned Additions			Supply-Side Reserve Margin w/o Planned Additions		
Year	MW	MW	MW	MW	MW	MW	% of Peak	Shortfall for 20% MW	MW	% of Peak	Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,312	121	4,433	3,940	4,165	493	12.5%	294	268	6.8%	8
2018	4,312	121	4,433	3,980	4,207	453	11.4%	343	226	5.7%	53
2019	4,312	0	4,312	4,022	4,250	290	7.2%	515	62	1.5%	220
2020	4,312	0	4,312	4,064	4,292	248	6.1%	565	20	0.5%	264
2021	4,312	0	4,312	4,103	4,331	209	5.1%	612	(19)	-0.5%	306

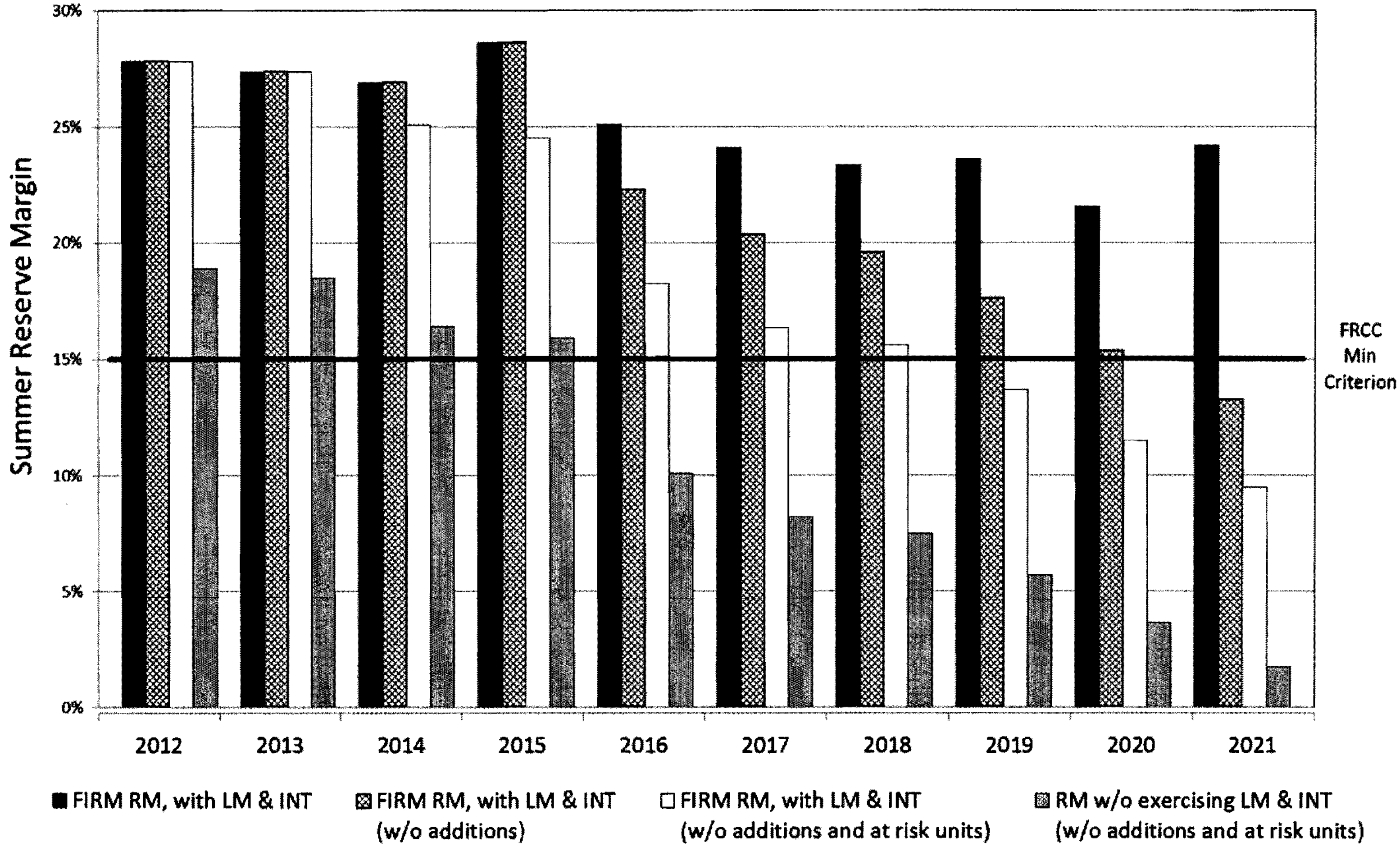
Forecast of Capacity and Demand at Time of Summer Peak

Year	Total Installed Capacity	Net Firm Capacity Purchases	Total Capacity Available	System Firm Peak Demand	System Total Peak Demand	Reserve Margin			Supply-Side Reserve Margin		
	MW	MW	MW	MW	MW	MW	% of Peak	Shortfall for 20% MW	MW	% of Peak	Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,771	121	4,892	3,940	4,165	952	24.2%	N/A	727	18.5%	N/A
2018	4,771	121	4,892	3,980	4,207	912	22.9%	N/A	685	17.2%	N/A
2019	4,920	0	4,920	4,022	4,250	898	22.3%	N/A	670	16.7%	N/A
2020	4,920	0	4,920	4,064	4,292	856	21.1%	N/A	628	15.5%	N/A
2021	4,920	0	4,920	4,103	4,331	817	19.9%	4	589	14.4%	N/A

Forecast of Capacity and Demand at Time of Summer Peak with Planned Additions

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin With Excercising Load Mgmt & Int. MW	Firm Reserve Margin With Excercising Load Mgmt & Int. % of Peak	Reserve Margin w/o Excercising Load Mgmt & Int. MW	Reserve Margin w/o Excercising Load Mgmt & Int. % of Peak
2012	47,747	6,486	54,233	42,430	45,613	11,803	27.8%	8,620	18.9%
2013	48,506	6,316	54,822	43,041	46,270	11,781	27.4%	8,552	18.5%
2014	49,730	5,613	55,343	43,618	46,857	11,725	26.9%	8,486	18.1%
2015	51,567	5,614	57,181	44,459	47,758	12,722	28.6%	9,423	19.7%
2016	52,118	4,473	56,591	45,242	48,594	11,349	25.1%	7,997	16.5%
2017	52,553	4,296	56,849	45,802	49,244	11,047	24.1%	7,605	15.4%
2018	52,539	4,382	56,921	46,152	49,643	10,769	23.3%	7,278	14.7%
2019	53,585	4,263	57,848	46,803	50,356	11,045	23.6%	7,492	14.9%
2020	53,667	4,180	57,847	47,581	51,191	10,266	21.6%	6,656	13.0%
2021	55,968	3,973	59,941	48,273	51,933	11,668	24.2%	8,008	15.4%

Appendix N: FRCC Reliability Sensitivity Analysis



Appendix O: Technology Assumptions

Screening Data

NAME	Solar PV	Solar Thermal	Wind Onshore	Wind Offshore	Aero CT	7FA CT
CAPACITY (MW)	10	100	50	300	61	177
BASE YEAR CAPITAL COST ($000)	62,200	668,200	119,177	1,620,000	40,624	119,498
BASE YEAR CAPITAL RATE ($/kW)	6,220	6,682	2,384	5,400	666	675
BASE YEAR FIXED O&M ($000/Year)	311	0	0	6,900	1,265	1,359
BASE YEAR FIXED O&M ($/kW-yr)	31.09	0.00	0.00	23.00	20.73	7.68
USE FIXED O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR VARIABLE O&M ($/MWh)	0.00	23.32	23.63	29.02	3.87	3.87
USE VARIABLE O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR FUEL RATE ($/MWH)	-	-	-	-	-	-
USE FUEL STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	Y	Y	Y	Y	Y	Y
K-FACTOR	1.5937	1.5937	1.5937	1.5937	1.5937	1.5937
REMAINING LIFE (Years)	25	25	25	25	25	25
Levlized Fixed Charge Rate (FCR)	0.1382	0.1382	0.1382	0.1382	0.1382	0.1382

NAME	Nuclear	IGCC	CFB	SCPC	NGCC	Biomass
CAPACITY (MW)	1,140	623	295	785	530	35
BASE YEAR CAPITAL COST ($000)	5,799,264	3,055,080	1,185,554	2,593,916	680,470	173,195
BASE YEAR CAPITAL RATE ($/kW)	5,087	4,904	4,019	3,304	1,283	4,948
BASE YEAR FIXED O&M ($000/Year)	15,358	20,198	11,411	21,907	3,333	3,990
BASE YEAR FIXED O&M ($/kW-yr)	13.47	32.42	38.68	27.91	6.28	114.00
USE FIXED O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR VARIABLE O&M ($/MWh)	3.86	6.63	1.97	1.55	4.27	15.65
USE VARIABLE O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR FUEL RATE ($/MWH)	-	-	-	-	-	-
USE FUEL STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	Y	Y	Y	Y	Y	Y
K-FACTOR	1.6301	1.5937	1.5937	1.5937	1.5937	1.5937
REMAINING LIFE (Years)	40	25	25	25	25	25
Levlized Fixed Charge Rate (FCR)	0.1265	0.1382	0.1382	0.1382	0.1382	0.1382

Appendix P: RFP Qualitative Factors

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Technology Type	Combined Cycle	Combined Cycle	Peakers	Peaker	Peaker
Transmission Reliability, Voltage Support, Reserves	High High	High High	Medium Low	Medium Low	Medium Low
Water Availability	Municipal Source	Municipal Source	Limited, water use caution area	Unknown	Unknown
Dual Fuel Capability	2 CTs - Yes, 2 CTs - Capable	No	2 CTs - Yes	1 CT - Yes	1 CT - Yes
Project Execution	Low risk	Existing Unit	Existing Unit	Low risk	Low risk
Project Operation	TEC	Owner	ST – contractors LT – TEC employees	Contractor	Contractor
Project Maintenance	CSA	Self-managed, as needed	CSA and CT spares modeled	Self-managed, as needed	Self-managed, as needed
Project Security	Investment Grade	Low – offered lien or step in rights	Investment Grade	Investment Grade	Investment Grade
Environmental Emission Rates	Lower	Lower	Higher	Higher	Higher
Renewable Option	30 MW Solar	None	None	None	None
Simple Cycle Capability	Yes	No	Yes	Yes	Yes
Job Creation and Tax Base	Construction labor	No: existing unit	No: existing unit TEC may increase O&M	Construction, O&M labor	Construction, O&M labor

Appendix Q: Polk 2-5 Preliminary Project Schedule

POLK 2-5 COMBINED CYCLE PROJECT MAJOR MILESTONE SCHEDULE	
Award Contract for Steam Turbine Generator Supply	January 4, 2013
Award Contract for Heat Recovery Steam Generator Supply	April 12, 2013
Award Contract for Preliminary Construction	November 22, 2013
Receive Permits and Modified Site Certification	January 31, 2014
Begin Construction (Plant and Transmission)	February 3, 2014
Award Contract for Construction	March 21, 2014
Begin Tie-in Outages on Existing Units	September 1, 2014
Begin Combined Cycle Startup and Testing	May 2, 2016
Transmission System Upgrades Complete	November 4, 2016
Commercial Operation	January 2, 2017

Appendix R: Polk 2-5 Environmental Permit Requirements

Permit	Review/ Approval Agencies	Status/Comments
• Florida Electrical Power Plant Siting Act (PPSA)	FDEP/Affected Agencies/Siting Board	
o PSD air construction permit	FDEP	
o NPDES industrial wastewater treatment permit	FDEP	
• Ground water discharge permit	FDEP	
• Consumptive water use permit	SWFWMD	
o Section 404 dredge-and-fill permit	USACE/ FDEP	
o Section 10 permit	USACE	
o Endangered/threatened species review	USFWS/ FFWCC	
• Section 401 water quality certification	FDEP	
• Environmental resource permit/storm water management	FDEP	
• Water well construction permit	FDEP	
• Non-transient, non-community water system permit	FDEP	
• Domestic septic system permit	Polk County	
• NPDES storm water permit NOI associated with industrial activity	FDEP	
• Solid waste management facilities permit	FDEP	
Determination of need	FPSC	
o NPDES general permit NOI for storm water for construction sites	EPA	
✦ Phase II Title IV acid rain permit	FDEP/EPA	

Permit	Review/ Approval Agencies	Status/Comments
✦ Title V air emissions operation permit	FDEP	
• Construction dewatering permit	SWFWMD	
✦ Hazardous waste generator registration	EPA/ FDEP	
Notice of construction in navigable aerospace	FAA	
✦ Aboveground storage tank (AST) registration	FDEP	
✦ Spill prevention, control, and countermeasure plan	EPA	
✦ Facility response plan	EPA/FDEP	
• Zoning/local comprehensive plan	Polk County	Already consistent with zoning for Power Plant use.

- • Reviewed and approved as part of the PPSA process; required prior to start of construction.
- o Reviewed concurrently with the PPSA process with separate permit issued 30 to 45 days after issuance of certification by Siting Board; required prior to start of construction.
- ✦ Not required prior to start of construction.

Note: EPA = U.S. Environmental Protection Agency.
FAA = Federal Aviation Administration.
FDEP = Florida Department of Environmental Protection.
FFWCC = Florida Fish and Wildlife Conservation Commission.
FPSC = Florida Public Service Commission.
USACE = U.S. Army Corps of Engineers
SWFWMD = Southwest Florida Water Management District.

REDACTED

Appendix S: Transmission Interconnection and Integration Diagrams

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

REDACTED

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

REDACTED

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION TO DETERMINE NEED FOR

POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT

OF

MARK J. HORNICK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK J. HORNICK

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

A. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director of Engineering and Project Management.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1981 from the University of South Florida. I am a registered professional engineer in the state of Florida. I began my career with Tampa Electric in 1981 as an Engineer Associate in the Production Department. I have held a number of engineering and management positions at Tampa Electric's power generating stations. From 1991 to 1998, I was a manager at Big Bend Power Station with various responsibilities including serving as Manager of Operations from 1995 to 1998. In July 1998, I was promoted to Director - Fuels where I was responsible for managing Tampa Electric's fuel procurement and transportation activities.

In March 2000, I transferred to General Manager - Polk and Phillips Power Stations, where I was responsible for the overall operation of these two generating facilities. I have broad experience in the engineering and operation of power generation equipment using oil, natural gas, coal and other solid fuels and technologies including conventional steam cycle, combustion turbine in simple cycle and combined cycle as well as Integrated Gasification Combined Cycle ("IGCC"). I am a past Chairman of the Gasifier Users Association, an international group of users and potential users of gasification technology.

In my current role as Director of Engineering and Project Management I am responsible for centralized engineering support for all operating power stations and for the management of large capital projects including new generating units.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the engineering and construction of the proposed Polk 2-5 Combined Cycle Conversion ("Polk 2-5"). I will describe the proposed facilities and their operating characteristics. Additionally, I will discuss the schedule for completing construction of Polk 2-5 and Tampa Electric's project execution plan. Finally, I will describe the development of the reasonable and prudent project cost estimates.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. ____ (MJH-1) was prepared under my direction and supervision. It consists of the following documents:

Document No. 1	Polk site aerial photograph
Document No. 2	Process Diagram - 4 x 1 Combined Cycle Configuration
Document No. 3	Project Schedule
Document No. 4	Cost Estimate

Q. Are you sponsoring any sections of Tampa Electric's

Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor the section of the Need Study regarding Tampa Electric's Proposed Unit. Specifically, I sponsor sections IX.A "Overview," IX.B "Description," IX.E "Cost" and IX.F "Schedule."

Q. Did you participate in Tampa Electric's evaluation of supply alternatives?

A. Yes. In addition to natural gas combined cycle ("NGCC") technology, Tampa Electric considered other technologies including conventional steam cycle, simple cycle combustion turbines, IGCC, solar and other renewables. My team provided capital costs and construction schedules for these alternatives. Tampa Electric witness R. James Rocha describes the company's evaluation of alternative generating technologies, which demonstrates that the proposed NGCC unit is the most cost-effective, reliable option for Tampa Electric.

Q. What considerations were used in determining that the conversion of the four existing simple cycle combustion turbines ("CTs") at Polk Power Station was the best option for generation expansion?

A. Tampa Electric considered a number of factors in the evaluation of the best technology choice for generation expansion. The primary consideration is the capability to reliably serve the peak demand needs of our customers in the future. Any new generating unit will have to comply with all environmental laws regarding regulated emissions. The overall life cycle cost of the unit, including installed cost and ongoing operation and maintenance expenses should be as low as practicable. In addition to unit reliability and environmental performance, other operating factors such as efficiency, fuel diversity, "dispatchability" (flexibility to start-up, shut-down and rapidly change output) are strong considerations.

PROJECT DESCRIPTION

Q. Please describe the planned project.

A. Tampa Electric plans to make use of its experience with NGCC technology to construct Polk 2-5, an NGCC power plant at Polk Power Station, the site of Tampa Electric's existing IGCC facility. Polk Power Station occupies over 2,800 acres on State Road 37 in Polk

County, Florida, approximately 40 miles southeast of Tampa and about 60 miles southwest of Orlando. An aerial diagram of the Polk site is provided as Document No. 1 of my exhibit.

The existing Units 2-5 were constructed over the past twelve years to meet incremental demand growth in a manner which was very cost effective to our customers. To further reduce the costs to our customers, the company relocated Units 4 and 5 from a cancelled project instead of purchasing new equipment. The units were arranged with the future plan of converting them into a highly efficient combined cycle ("CC") plant.

After conversion, with no additional fuel consumption, Polk 2-5 will generate an incremental net 352 MW of electricity in winter at 32 degrees Fahrenheit and 339 MW in the summer at 92 degrees Fahrenheit. In addition, Polk 2-5 will utilize supplemental firing, also known as duct burners, to provide additional cost effective peaking capacity that will offset the need for future peaking unit construction. With supplement firing, the additional net electrical output of Polk 2-5 will increase to 463 MW in the winter and 459 MW in the summer.

The average annual net heat rate, higher heating value, is expected to be about 7,064 Btu/kWh (48 percent efficiency), and the instantaneous heat rate is expected to be 6,803 (50 percent efficiency) Btu/kWh at an average temperature of 73 degrees Fahrenheit without supplemental firing. Two of the combustion turbines will have the capability of firing distillate oil as a backup fuel.

The supplemental firing will provide peaking capacity at an incremental heat rate of 8,240 Btu/kWh, which compares very favorably to a simple cycle CT with a heat rate of over 10,000 Btu/kWh.

Q. Please briefly describe the power generation technology that Polk 2-5 will utilize.

A. Polk 2-5 will be a NGCC facility consisting of four CTs, four heat recovery steam generators ("HRSGs") and a single steam turbine ("ST") arranged in a 4x4x1 configuration. The technology is a combination of a combustion turbine (Brayton) cycle and a traditional steam (Rankine) cycle. The combination of the two technologies allows for thermal efficiencies of 50 percent and higher.

This is a proven technology with which Tampa Electric and the industry in general have significant experience designing, constructing and operating.

Q. Please describe the various components and systems that will make up Polk 2-5.

The project will utilize the four existing General Electric 7FA combustion turbines on site. We will add triple pressure HRSGs to each of these CTs to capture the waste heat in the exhaust. The HRSGs will also have supplemental firing capability to add approximately 120 MW of peaking capacity.

The steam generated in the four HRSGs will be used in a new ST generator. The ST generator will exhaust into a water cooled condenser which will utilize the existing cooling reservoir at the Polk Power Station for heat rejection. Use of the existing cooling reservoir infrastructure will allow Polk 2-5 to operate with lower water consumption and lower parasitic load than if a cooling tower were used for the ST heat rejection system.

A new cooling tower will also be constructed to provide equipment cooling for Polk 2-5 as well as Polk Unit 1. This is necessary to optimize the heat loading on the existing cooling reservoir and mitigate operational impacts that could occur due to increased water temperature in the cooling reservoir.

KEY PROJECT ATTRIBUTES

Q. Please describe the beneficial aspects of utilizing the "waste heat" from the four existing CTs to produce additional electricity from the Polk site.

A. Polk 2-5 are currently configured as simple cycle combustion turbines with a summer capability of 151 MW each. Simple cycle CTs are relatively low in cost and have the ability to rapidly startup, shutdown and change power output. These machines are good choices for meeting peak power demands.

The exhaust gases leaving CTs are over 1,000 degrees Fahrenheit and contain a substantial amount of energy. By recovering this heat energy, which otherwise would be wasted, up to 352 MW in the winter and 339 MW in the summer of net electric power can be generated without any additional fuel input. Through the addition of heat recovery the efficiency of these generating units will be increased by approximately 37 percent.

Q. How will the Polk 2-5 project impact the environmental profile of the generating units?

A. This project will provide significant environmental benefits. The improvement in power generating efficiency results in a direct reduction in emission rate for all pollutants on a pound per MWH basis. The project will therefore reduce CO_2 emission rates by approximately 37 percent.

The project will also include the installation of Selective Catalytic Reduction equipment ("SCRs") in each HRSG to reduce NO_x emissions. The SCRs in combination with cycle efficiency improvements will provide an approximately 86 percent reduction in the NO_x emission rate.

Q. Does the Polk 2-5 project allow for inclusion of renewable energy in the future?

A. Yes. The project is being designed with the ability to incorporate approximately 30 MW of solar energy in the form of steam from solar thermal collectors located at the Polk site. Integration of steam produced via solar collectors into a CC plant is known as a solar hybrid system as it uses the existing combined cycle steam turbine rather than a separate turbine dedicated to solar use.

Renewable energy from solar thermal hybrid systems is more reliable than other solar technologies because it has the capability to replace solar MWs with capacity from duct firing in the HRSGs. This mitigates the intermittent nature of solar energy due to cloud cover or darkness.

Q. Please discuss the operating flexibility of the proposed project and how system reliability will be impacted.

A. The project is being designed to allow operation of each CT in either simple cycle or CC mode by use of diverter dampers which allow hot exhaust gases to bypass the HRSG. This gives system operators the ability to use the rapid response of CTs when needed for peaking service and the ability to achieve high efficiency in CC mode to serve intermediate and base load needs. In addition, this allows the existing simple cycle capacity to be available for dispatch during times when the steam turbine is unavailable.

Q. What benefit does the inclusion of supplemental firing of the four HRSGs provide?

A. Supplemental firing (or duct firing) provides additional peaking power capability at low cost. The project will incorporate approximately 30 MW of supplemental firing into each HRSG for a total of approximately 120 MW. The steam turbine will be sized to accommodate this additional steam input. Supplemental firing has a very rapid response rate and can be used to supply spinning reserve capacity on the system. The heat rate and installed cost of supplemental firing is lower than other rapid response peaking options such as aero-derivative CTs. In addition, supplemental firing capability must be included in the original design and equipment sizing and will not be able to be added at a later date.

Q. Why is dual fuel capability important and how will this project benefit?

A. The capability to utilize either natural gas or distillate oil as a fuel improves the reliability of the power generating units. In circumstances when the natural gas supply to the facility is curtailed or unavailable, dual fuel units can be operated on distillate oil. This capability is becoming more important as a larger percentage of the generating units in Florida rely on natural gas as a fuel.

Dual fuel capability can also serve to reduce the cost of supplying natural gas to the generating unit(s) via pipeline. Pipeline transportation services can be purchased on a firm basis with known quantities and a fixed price. These are generally "take or pay" agreements. Alternately, pipeline capacity can obtained each day on an "as available" basis. The reliability of supply is greater with firm transportation than with as available transportation, however, the total cost is generally higher with firm agreements. With dual fuel capability, a larger percentage of pipeline capacity can be obtained "as available" since the unit can be operated on distillate oil in the event gas transportation cannot be secured.

Q. Please describe the location of the Polk site and any reliability benefits that may be associated with expanding generating capacity at this location.

A. The Polk Power Station is located approximately 40 miles inland from the Gulf of Mexico at an elevation of approximately 100 feet. This inland location makes it much less likely to suffer damage in the event of a hurricane than coastal facilities.

Q. How will the electric transmission upgrades associated with this project benefit ratepayers?

A. The Polk 2-5 project will provide the interconnection from the new steam turbine generator to the grid and will also include upgrades to the transmission system to allow for the delivery of this energy to customers located west of the facility. These upgrades will relieve transmission congestion in the region and improve both the reliability of the grid and reduce the cost to customers from the ability to economically optimize generating unit operation. This is described in the direct testimony of Tampa Electric witness S. Beth Young.

Q. What source of water will be used to supply the proposed project?

A. The project will utilize reclaimed water from the City of Lakeland to meet the majority of makeup water needs. The use of reclaimed water will be maximized, however ground water can be used to supplement the supply if needed. In addition, by using the existing cooling water reservoir at the site for the majority of the new cooling duty, water use from evaporative losses will be reduced relative to using a cooling tower for this service.

OPERATING PERFORMANCE

Q. What is the expected heat rate for Polk 2-5?

A. Polk 2-5 is expected to have an average annual net heat rate of 7,064 Btu/kWh, and an instantaneous net heat rate of 6,803 Btu/kWh at an average temperature of 73 degrees Fahrenheit without supplemental firing.

Q. Please describe the expected availability for Polk 2-5.

A. The expected Equivalent Availability Factor ("EAF") for Polk 2-5 is 96.2 percent averaged over the life of the unit, based on a Planned Outage Rate of 3.2 percent and a Forced Outage Rate of 0.7 percent.

Q. What is your conclusion regarding the reasonableness of these heat rate and availability expectations?

A. The efficiency and availability estimates for the Polk 2-5 facility have been developed by the engineering firm of Black and Veatch along with Tampa Electric. Black and Veatch has engineered a number of CC units in Florida and around the world. Based on my experience with engineering and operating power plants, I believe the estimated heat rate and availability factors are reasonable.

PROJECT MANAGEMENT AND CONSTRUCTION

Q. What is the expected construction schedule for Polk 2-5?

A. If approved, construction will begin in 2014, and Polk 2-5 is expected to enter commercial operation in January 2017.

Q. Please describe Tampa Electric's efforts to obtain the required certifications and permits to begin construction of Polk 2-5.

A. Tampa Electric began developing design information to support permit application preparation in February 2012. The company entered into a contract with Environmental

Consulting & Technology Inc. The permit activities are described in the direct testimony of Tampa Electric witness David M. Lukcic.

Q. What is the current schedule for the project?

A. Document No. 3 of my exhibit outlines the project schedule. Conceptual design began in late 2011, and the preliminary engineering package development began in February 2012 and was completed in May 2012. The Site Certification Application will be filed with the Florida Department of Environmental Protection in September 2012. The detailed design and procurement will begin in January 2013. Detailed design and procurement activities are expected to continue through November 2014. Construction activities are expected to begin in the first quarter 2014 with general site work. Commissioning of the equipment is expected to begin in February 2016. Finally, the unit is expected to begin commercial operation in January 2017.

Q. What is Tampa Electric doing to mitigate the effects of potential construction schedule uncertainty?

A. The construction effort will be managed by a Tampa

Electric construction management group which is experienced in managing large complex construction projects. In addition, the project schedule is being developed to allow for approximately one month of float per year of construction to provide a schedule contingency for unplanned events.

Q. Does Tampa Electric have experience in building and operating combined cycle power plants similar to the proposed Polk 2-5 facility?

A. Yes. Tampa Electric constructed and has operated since 2003 the H. L. Culbreath Bayside Power Station ("Bayside Power Station") which consists of 4x4x1 and 3x3x1 NGCC units. This $700 million project was constructed on schedule and under budget.

Q. Is NGCC technology used successfully at Tampa Electric's Bayside Power Station?

A. Yes. By a number of measures, NGCC technology has been successfully implemented by Tampa Electric. The company has used NGCC technology to generate more than 66 million MWH of electricity. These units have met efficiency and availability expectations and are a vital part of Tampa Electric's generating unit portfolio.

PROJECT COST

Q. What is Tampa Electric's estimate of the overnight construction costs for Polk 2-5?

A. The overnight construction cost estimate is $424.4 million in 2012 dollars.

Q. Please explain what is included in the cost estimate.

A. Document No. 4 of my exhibit provides the details of the cost estimate. The $424.4 million cost estimate represents overnight construction costs for conversion work on Polk 2-5. This includes all engineering, procurement, construction, commissioning, owner's costs and an allowance for indeterminates. The project estimate does not include related transmission additions or modifications or escalation.

Q. What is Tampa Electric's estimate of the total in-service costs for Polk 2-5?

A. The total in-service cost estimate for Polk 2-5 is $610.4 million, which includes the aforementioned overnight construction costs as well as escalation and transmission upgrades. Owner's costs include project development costs such as technology development and environmental permitting; project management and operational support and training; legal and other professional services costs; and insurance. Tampa Electric estimated the owner's costs for Polk 2-5 based on its experience developing and constructing generating units in Florida.

The $147.2 million costs of required transmission facilities to integrate and interconnect Polk 2-5 with Tampa Electric's system are separately identified and are described in the direct testimony of witness Young.

Q. Did Tampa Electric conduct sensitivity analysis with regards to project construction costs?

A. Yes. The base case is considered the most likely cost based on current equipment market conditions, labor costs and escalation rates. Tampa Electric also applied sensitivities to the base case by utilizing high and low construction cost bands to consider the effect of higher and lower demand for equipment as well as materials and labor costs. Compared to the base case, the low band construction cost is 7 percent lower and the high band construction cost is 6 percent higher.

Q. Will subsequent engineering work result in changes to the installed cost estimate for Polk 2-5?

A. Perhaps. The cost estimate represents the best estimate Tampa Electric has to date for the planned project configuration. The estimate does not include costs for changes in the scope of the project or significant modifications of the planned configuration. During subsequent engineering work, our intent is to optimize the design of the project to minimize the lifetime cost to our customers. Such changes will be evaluated and justified based on the impact to the cost and performance of the project. Approved changes could result in increases or decreases to the cost estimate.

Q. What contracting strategy and competitive pricing options will Tampa Electric pursue to manage the cost and schedule of Polk 2-5?

A. Tampa Electric is planning to competitively bid all the major equipment required for Polk 2-5. The precise contracting strategy has not yet been finalized, but we envision using multiple prime contractors to construct Polk 2-5. These contracts will be fixed price or cost-reimbursable depending on the contract. We plan to use an appropriate mix of incentives and penalties to align the various contractors with the project goals.

Q. What scope of services will Black and Veatch be providing?

A. Currently Black and Veatch has been contracted to perform the preliminary engineering work for both the generating plant and the associated transmission facilities. It is anticipated that, going forward, Black and Veatch will perform the detailed engineering, procurement services and support Tampa Electric's Construction Management team.

Q. What is the current status of Polk 2-5?

A. Tampa Electric is currently engaged in preliminary engineering to develop the project permit applications. Additional engineering efforts are also ongoing to better define the major aspects of the plant design. This information will be used to manage the detailed engineering effort and refine cost estimates and the project schedule.

Q. What is the basis for Tampa Electric's cost estimate for the Polk 2-5 project?

A. Cost estimates are based on a preliminary design completed by Black and Veatch. This design includes the identification and sizing of all major plant components as well as the integration of the unit to existing plant systems. Black and Veatch has obtained multiple quotations for major equipment and has validated current pricing for commodities and labor in the central Florida area.

Q. Please summarize Tampa Electric's efforts to ensure the reasonableness of the Polk 2-5 total estimated installed cost.

A. Tampa Electric has constructed many large capital projects using a similar approach to the Polk 2-5 approach. Tampa Electric employs several strategies to monitor and manage all phases of these projects including: (1) establishing project contracts that will provide the best value; (2) monitoring the work of the engineering company to ensure that work is done in an efficient manner; and (3) assigning full time project controls personnel to manage the costs and the schedule throughout the project execution. Dedicated Tampa Electric personnel lead the project management throughout construction and are integrally involved in each phase of its development. The company's track record using this approach is excellent.

In addition, the overnight construction cost estimate was developed with support from Black & Veatch, which has engineered and constructed numerous similar facilities with a significant amount being in Florida.

Q. Is the total installed cost estimate reasonable?

A. Yes. The total estimated cost represents the best efforts of both Tampa Electric and Black and Veatch. In addition, if the book value of the existing combustion turbines are taken into account, the estimated cost compares favorably to similar projects recently completed.

Q. Are there circumstances that may result in rapidly increasing demand for combined cycle power generating equipment?

A. Yes. There are several factors that are indicating that the demand for natural gas fired generating equipment will significantly increase in the next few years. The economic downturn beginning in 2008 has reduced the growth rate of electricity demand nationwide. A recovery of the economy will reverse this effect and may increase the demand for energy at a rapid rate.

Natural gas prices are at relatively low levels and are forecasted to remain low for several years. This makes gas fired generation a more attractive option versus coal fired units. Natural gas fired technology is typically less expensive to build than other options including nuclear, coal, and renewable generating options such as wind and solar. The combination of low capital cost and forecasted low fuel prices currently make natural gas fired units the most economical choice.

Recent environmental regulations have focused largely on coal fired units. New or tightened regulations on mercury and other metals, small particulates, coal combustion by products and CO_2 have all put pressure on coal fired generation. As a result, many utilities across the nation have announced that they will shut down older, less efficient coal fired units rather than retrofit them with expensive emission controls.

The combination of coal unit retirements (reduced supply) and economic recovery (increased demand) is indication the likelihood of a large number of gas fired units being constructed in the next few years.

In the late 1990's and early 2000's there was a large spike in demand for gas fired units. This resulted in what was termed a "gas bubble" situation where manufacturers had difficulty meeting demand. The lead time for equipment manufacture increased significantly and prices escalated dramatically. The current circumstances indicate that the industry may be on the verge of a similar situation.

Q. How does the timing for the Polk 2-5 CC conversion relate to the potential for an equipment demand spike?

A. The company has surveyed the industry suppliers of major equipment needed for the projects. Currently the lead times and pricing for HRSGs steam turbines, condensers and cooling towers are reasonable. Several manufacturers have indicated that they anticipate lead times will extend and prices will go up in the near future. Tampa Electric is working to issue proposals and lock in prices for major equipment for Polk 2-5 early in 2013. A delay in the project could result in cost increases if there is a market price spike.

Q. Please summarize your direct testimony.

A. If approved, Polk 2-5 will be converted to a highly efficient NGCC facility which will offer numerous benefits to Tampa Electric's customers. With no additional fuel consumption, Polk 2-5 will generate up to an additional 352 MW of electricity resulting in a 37 percent improvement in efficiency over the existing units. The efficiency improvement will also provide an equivalent reduction in air emission rates. Polk 2-5 will also include use of SCR technology, which combined with the efficiency gains, will reduce NO_x emissions by 86 percent.

Polk 2-5 will have additional environmental benefits such as being capable of future renewable integration, use of reclaimed water, no additional land use and permanent deferral of two future peaking units.

In summary, Polk 2-5 will be designed and constructed for $610.4 million in accordance with the project schedule to provide cost effective, clean power for Tampa Electric's customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

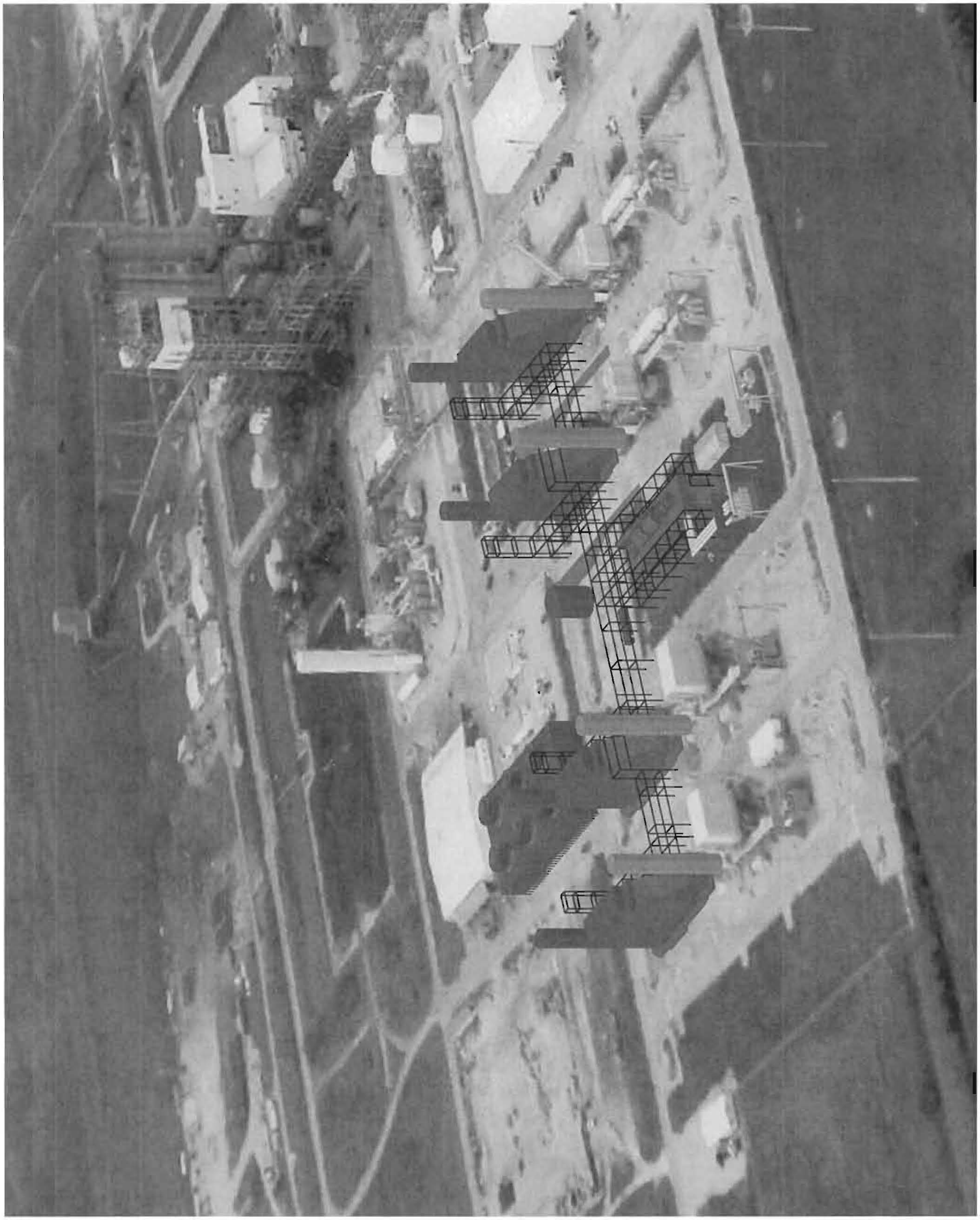
MARK J. HORNICK

Table of Contents

DOCUMENT NO. 1

POLK SITE AERIAL PHOTOGRAPH

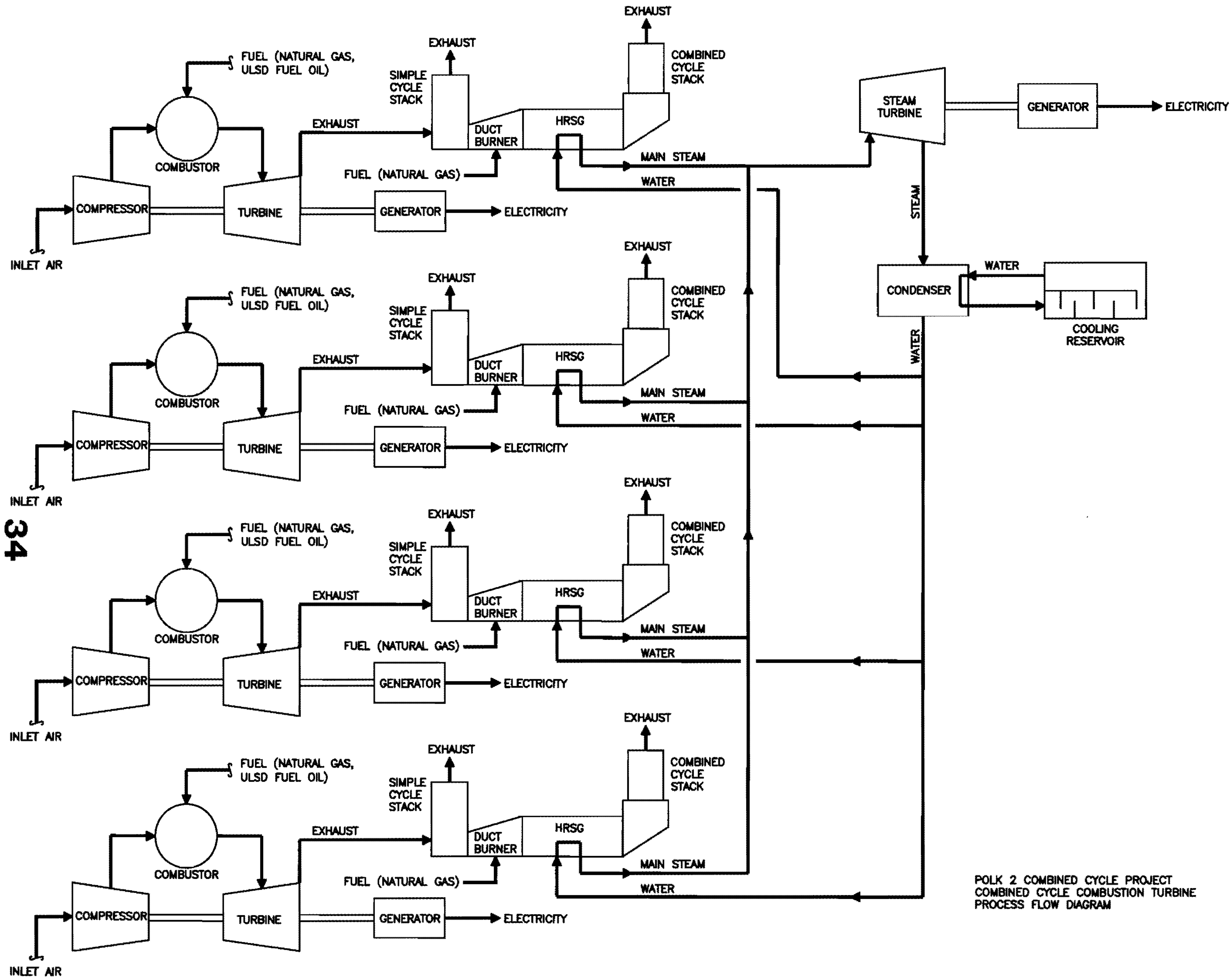
TAMPA ELECTRIC COMPANY
DOCKET NO. 12______-EI
EXHIBIT NO. ____ (MJH-1)
DOCUMENT NO. 1
FILED: 09/12/2012



DOCUMENT NO. 2

PROCESS DIAGRAM - 4 X 1 COMBINED CYCLE

CONFIGURATION



POLK 2 COMBINED CYCLE PROJECT
COMBINED CYCLE COMBUSTION TURBINE
PROCESS FLOW DIAGRAM

175634–SM–2001

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
EXHIBIT NO. ____ (MJH-1)
DOCUMENT NO. 2
FILED: 09/12/2012

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 3
FILED: 09/12/2012

DOCUMENT NO. 3

PROJECT SCHEDULE

POLK 2-5 COMBINED CYCLE PROJECT
MAJOR MILESTONE SCHEDULE

Award Contract for Steam Turbine Generator Supply	January 4, 2013
Award Contract for Heat Recovery Steam Generator Supply	April 12, 2013
Award Contract for Preliminary Construction	November 22, 2013
Receive Permits and Modified Site Certification	January 31, 2014
Begin Construction (Plant and Transmission)	February 3, 2014
Award Contract for Construction	March 21, 2014
Begin Tie-in Outages on Existing Units	September 1, 2014
Begin Combined Cycle Startup and Testing	May 2, 2016
Transmission System Upgrades Complete	November 4, 2016
Commercial Operation	January 2, 2017

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 4
FILED: 09/12/2012

DOCUMENT NO. 4

COST ESTIMATE

POLK 2-5 CONVERSION PROJECT PROJECT COST ESTIMATE	($000)
Direct Construction Costs	352,610
Indirect Construction Costs	71,813
Total Generating Plant Cost	424,422
Transmission Upgrade Cost	147,193
Escalation	38,825
Total Project Before AFUDC	610,440
AFUDC	96,179
Total Expected Project Cost	706,619

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION TO DETERMINE NEED FOR

POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT

OF

LORRAINE L. CIFUENTES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LORRAINE L. CIFUENTES

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

A. My name is Lorraine L. Cifuentes. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Load Research and Forecasting in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. In 1986, I received a Bachelor of Science degree in Management Information Systems from the University of South Florida. In 1992, I received a Masters of Business Administration degree from the University of Tampa. In October 1987, I joined Tampa Electric as a Generation Planning Technician, and I have held various positions within the areas of Generation Planning, Load Forecasting and Load Research. In October 2002, I was promoted to

Manager, Load Research and Forecasting. My present responsibilities include the management of Tampa Electric's customer, peak demand and energy sales forecasts as well as management of Tampa Electric's load research program and other related activities.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe Tampa Electric's load forecasting process, describe the methodologies and assumptions, and present the load forecast used in Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study"). Additionally, I will demonstrate how the forecast is appropriate and reasonable based on the assumptions provided.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I am sponsoring Exhibit No. ____ (LLC-1) consisting of 10 documents, prepared under my direction and supervision. These consist of:

Document No. 1 Economic Assumptions

Document No. 2 Billing Cycle Degree Days

Document No. 3 Customer Forecast

Document No. 4	Per Customer Energy Consumption
Document No. 5	Retail Energy Sales
Document No. 6	Per Customer Peak Demand
Document No. 7	Peak Demand
Document No. 8	Firm Peak Demand
Document No. 9	Firm Peak Load Factor
Document No. 10	Updated Firm Peak Demand

Q. Are you sponsoring any sections of Tampa Electric's Need Study?

A. Yes. I sponsor section III.B. "Demand and Energy Forecasts" of the Need Study.

TAMPA ELECTRIC'S FORECASTING PROCESS

Q. Please describe Tampa Electric's load forecasting process.

A. Tampa Electric uses econometric models and statistically adjusted engineering ("SAE") models, which are integrated to develop projections of customer growth, energy consumption and peak demands. The econometric models measure past relationships between economic variables, such as population, employment and customer growth. The SAE models, which incorporate end-use structure into an econometric model, are used for projecting average per-customer consumption. These models have consistently been used by Tampa Electric for generation planning purposes and the modeling results have been submitted to the Commission for review and approval in past regulatory proceedings.

Q. Which assumptions were used in the base case analysis of customer growth?

A. The primary economic drivers for the customer forecast are Hillsborough County population estimates, service area households and Hillsborough County employment. The population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research ("BEBR") and Moody's Economy.com provide population projections. The population forecast is based upon the projections of BEBR in the short-term and is a blend of BEBR and Economy.com for the long-term forecast. Economy.com provides projections of Hillsborough County households and employment by major sectors. Service area households and Hillsborough County employment assumptions are utilized in estimating non-residential customer growth. For example, an increase in the number of households results in a need for additional services, restaurants, and retail establishments. Additionally, projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Similarly, commercial and industrial employment growth is a good indicator of expected activity in their respective sectors. The ten-year historical and forecasted average annual growth rates for these economic indicators are shown in Document No. 1 of my exhibit.

Q. Which assumptions were used in the base case analysis of energy sales growth?

A. Customer growth and per-customer consumption growth are the primary drivers for growth in energy sales. The average per-customer consumption for each revenue class is based on the SAE modeling approach. The SAE models have three components. The first component includes assumptions of the long-term saturation and efficiency trends in end-use equipment. The second component captures changes in economic conditions, such as increases in real household income, changes in number of persons per household, the price of electricity and how these factors affect a residential customer's consumption level. A complete list of the critical economic assumptions used in developing these forecasts is shown in Document No. 1 of my exhibit. The third component captures the seasonality of energy consumption. Heating and cooling degree day assumptions allocate the appropriate monthly weather impacts and are based on weather patterns over the past 20 years. Historical and projected degree days are shown in Document No. 2 of my exhibit.

Q. Which assumptions were used in the base case analysis of peak demand growth?

A. Peak demand growth is affected by long-term appliance trends, economic conditions and weather conditions. The end-use and economic conditions are integrated into the peak demand model from the energy sales forecast. The weather variables are heating and cooling degree days at the time of the peak and for the 24-hour period of the peak day. Weather variables provide the seasonality to the monthly peaks. By incorporating both temperature variables, the model accounts for cold or heat buildup that contributes to determining the peak day. The temperature assumptions used are based on an analysis of 20 years of peak day temperatures. For the peak demand forecast, the design temperature at the time of winter and summer peak is 31 and 92 degrees Fahrenheit, respectively.

Q. Is 31 degrees Fahrenheit the 20-year average temperature at the time of the winter peak?

A. No. The 20-year average temperature at the time of the winter peak is 35 degrees Fahrenheit. Although 31 degrees is not the 20-year average, it is representative of the average temperature for the top ten coldest peak days in the past 20 years and also the top five coldest peak days in the past ten years. The 31 degrees Fahrenheit assumption has consistently been used by Tampa Electric for generation planning purposes and in peak demand projections submitted to the Commission for review and approval in prior regulatory proceedings.

Q. Is 92 degrees Fahrenheit the 20-year average temperature at the time of the summer peak?

A. Yes, 92 degrees Fahrenheit has consistently been the 20-year average temperature at the time of the peak. It is the summer peak demand projection that has been submitted to the Commission in prior regulatory proceedings.

Q. Does Tampa Electric assess the reasonableness of these base assumptions?

A. Yes. The base case economic assumptions have been evaluated based on a comparison of the data series' historical average annual growth rates to the projected average annual growth rates for the forecast period. In addition, each economic data series is compared to an alternate source and evaluated for consistency. Economy.com's projections for Florida employment by major sectors and Florida real household income are compared to the projections from the Office of Economic and Demographic Research which is part of the Florida Legislature. The projections for Florida employment growth were consistent between the two sources; therefore, it is reasonable to conclude that Economy.com's Hillsborough County employment growth was also reasonable.

Q. Were the forecasts for population growth also evaluated for reasonableness?

A. Yes. Economy.com and BEBR's population forecasts were also compared and evaluated for consistency. A blend of the two sources was used and provides a reasonable population projection.

TAMPA ELECTRIC'S FORECASTED GROWTH

Q. What is Tampa Electric's forecasted customer base?

A. Tampa Electric's current customer base is shown in Document No. 3 of my exhibit. As of December 2011, Tampa Electric's customer base was 675,799 retail accounts.

Q. What is Tampa Electric's projected customer growth?

A. Tampa Electric is projecting an average annual increase of 9,597 new customers over the next ten years (2012-2021). This average annual increase of 1.3 percent is slightly lower than the average annual growth rate of 1.5 percent during the past ten years (2002-2011). Despite the slightly lower customer growth rate, an increase of over 86,000 customers is anticipated over the forecast period as reflected in Document No. 3 of my exhibit.

Q. How does Tampa Electric's projected customer growth rates compare with the growth rates experienced historically?

A. Customer growth rates are lower than those experienced prior to the recent recession; however, customer growth is considerably higher than it was in the recession period between 2007 and 2009. Customer growth was flat to declining during the recession period. Customer growth rates are currently back up to 1.0 percent and are expected to increase over the forecast horizon.

Q. What is Tampa Electric's energy sales forecast?

A. The primary driver behind the increase in the energy sales forecast is customer growth. Additionally, per-customer consumption is expected to decrease at an average annual rate of 0.5 percent, as shown in Document No. 4 of my exhibit. Combining the customer growth and per-customer consumption, retail energy sales are expected to increase at an average annual rate of 0.8 percent. Excluding the phosphate sector which has been declining, retail energy sales are expected to increase at an average annual rate of 1.0 percent. Historical and forecasted energy sales are shown in Document No. 5 of my exhibit.

Q. How does Tampa Electric's projected energy sales compare with the 2011 Ten Year Site Plan ("TYSP")?

A. When compared to the 2011 TYSP (prior year's forecast), both customer growth and per-customer energy consumption were adjusted downward to capture the slower than expected economic recovery. Additionally, energy sales are growing at slower rates in the current TYSP. The result is an average annual increase of 0.8 percent in total retail sales compared to an increase of 1.1 percent in the 2011 TYSP.

Q. What is Tampa Electric's peak demand forecast?

A. Summer and winter peak usage per-customer are both projected to decrease at an average annual rate of 0.4 percent, which is consistent with historical per-customer peak demand. Document No. 6 of my exhibit shows historical and forecasted peak usage per-customer for summer and winter peaks. The increase in customers and the decrease in per-customer demand results in an average annual growth rate of 1.0 percent for the winter peak and a 0.9 percent growth rate for the summer peak. As shown in Document No. 7 of my exhibit, peak demand for the summer of 2012 is forecasted to be 3,993 MW, increasing to 4,331 MW in 2021, an average increase of 38 MW per year. The 2012 winter peak is forecasted to be 4,081 MW, increasing to 4,453 MW in 2021, an average increase of 41 MW per year. Summer and winter firm peak demands, which have been reduced by curtailable load such as load management and interruptible loads, are shown in Document No. 8 of my exhibit.

Q. How does Tampa Electric's projected peak demands compare with the 2011 TYSP?

A. Similar to energy consumption, peak demands have been adjusted downward and are growing at slower rates. The result is an average annual increase of 0.9 percent in summer peak demand compared to an increase of 1.3 percent in the 2011 TYSP. Winter peak demands are increasing at an average annual rate of 1.0 percent compared to an increase of 1.3 percent in the 2011 TYSP.

SENSITIVITY ANALYSIS

Q. Has the company performed any sensitivity analyses on its load forecast?

A. Yes. The base case scenario was tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent an alternative to the company's base case outlook. The high scenario represents more optimistic economic conditions in the areas of customers, employment and income. The low band represents less optimistic scenarios in the same areas. Compared to the base case, the expected customer and economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

Q. Were conservation and demand side management ("DSM") impacts accounted for in the energy sales and peak demand forecasts?

A. Yes. Tampa Electric forecasts demand and energy reductions for each conservation and DSM program, which are aggregated to represent the total cumulative savings. The energy sales and peak demand forecasts were adjusted by the total incremental savings each year.

Q. Are the forecasts described in your testimony and filed in the 2012 TYSP the company's most recent customer, demand and energy projections?

A. No. Those forecasts were based on the company's 2011 annual forecast process. The 2012 annual forecast process was completed in June 2012.

Q. How do the more recent 2012 projections of customers, demand and energy consumption compare to the forecasts used in the need study?

A. The most current forecast of customers is higher than the forecast presented in the need study. However, the current energy sales and peak demand forecasts are lower than the forecasts presented in the need study. The primary factor that is driving the changes in the load forecasts is the slower than expected economic recovery and continued reduction in per-customer consumption.

Q. How much lower are the current demand and energy forecasts compared to the forecasts used in the need study?

A. Over the 10-year forecast horizon, the energy sales forecast is an average of 3.5 percent lower than the previous projections. The average firm peak demand reductions in winter and summer are 2.9 percent and 2.7 percent respectively. The most current firm peak projections are shown in Document No. 10 of my exhibit.

Q. Are the most current load forecasts still above the low scenario in the sensitivity analysis?

A. Yes. In 2017, summer firm peak demand projections are above the low scenario by 26 MW.

Q. Does Tampa Electric conclude that the forecasts of customers, energy sales and demand are appropriate and reasonable?

A. Yes. The results have been reviewed by Itron Corporation, a leader in the load forecast consulting industry. The average annual growth rates for per-customer demand and energy usage are compared with each other for consistency and compared to historical growth rates. Summer and winter load factors are reviewed to ensure proper integration of the peak and energy models. The results show that the load factors are reasonable when compared to historical years. Load factors have dropped slightly due to the loss of phosphate load. The load factors are shown in Document No. 9 of my exhibit.

Q. Please summarize your direct testimony.

A. Tampa Electric's service area will continue to grow at a steady pace over the forecast horizon. Based on the most current forecasts, we expect an average increase in customers of 1.5 percent a year which is an increase of almost 60,000 by 2017. As a result, winter and summer firm peak demand is projected to increase by 162 MW and 136 MW, respectively, by 2017. The methods used for developing the customer, demand and energy forecasts presented in my direct testimony, as well as the forecasts updated as part of the company's 2012 annual business plan process, represent best industry practice.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

LORRAINE L. CIFUENTES

Table of Contents

DOCUMENT NO. 1

ECONOMIC ASSUMPTIONS

	Population (Millions)	Residential Price of Electricity ($/MWH)	Real Household Income	Persons Per Household	Per Capita Commercial Real Gross Output (Millions)	Per Capita Government Real Gross Output (Millions)	Construction Employment (Thousands)	Commercial Employment (Thousands)	Industrial Employment (Thousands)
2002	1,060	$64.75	$82,367	2.6	647.5	74.7	35.3	453.6	34.0
2003	1,086	$65.00	$84,255	2.6	653.4	75.7	37.0	448.7	31.7
2004	1,113	$65.95	$86,610	2.6	668.4	77.4	41.0	465.5	32.7
2005	1,139	$65.66	$88,639	2.6	704.9	72.1	45.5	480.8	33.5
2006	1,170	$66.43	$91,584	2.6	714.4	71.9	47.2	490.6	33.8
2007	1,194	$70.16	$91,789	2.6	709.6	76.0	44.9	500.6	32.1
2008	1,200	$69.38	$90,562	2.6	680.0	76.9	39.2	479.9	29.5
2009	1,199	$71.91	$89,183	2.6	666.9	90.2	30.6	453.3	25.7
2010	1,203	$71.55	$88,502	2.6	685.8	77.4	27.0	452.0	24.2
2011	1,211	$66.85	$91,166	2.6	715.0	77.1	29.0	456.7	24.5
2012	1,221	$64.68	$95,661	2.56	748.1	77.7	34.0	472.0	25.2
2013	1,235	$63.21	$99,245	2.56	777.9	77.4	35.5	486.7	25.4
2014	1,252	$61.40	$101,779	2.56	797.8	76.3	36.4	502.0	25.3
2015	1,269	$60.49	$104,180	2.56	814.5	75.6	37.4	514.1	25.1
2016	1,288	$59.65	$106,693	2.56	830.9	75.7	38.1	523.8	24.6
2017	1,307	$58.81	$109,611	2.56	850.9	76.3	38.7	534.0	24.2
2018	1,325	$57.99	$112,938	2.56	871.9	77.1	39.4	544.5	23.8
2019	1,344	$57.19	$116,465	2.56	892.5	78.0	40.3	555.2	23.5
2020	1,361	$56.43	$120,064	2.56	911.8	78.8	41.3	566.1	23.1
2021	1,378	$55.71	$123,867	2.56	929.8	79.7	42.4	576.9	22.7

Average Annual Growth Rates									
2002-2011	1.5%	0.4%	1.1%	0.0%	1.1%	0.4%	-2.2%	0.1%	-3.6%
2012-2021	1.4%	-1.6%	2.9%	0.0%	2.4%	0.3%	2.5%	2.3%	-1.2%

Average Absolute Growth									
2002-2011	17	$0.23	$978	0.00	7.5	0.3	(0.7)	0.3	(1.1)
2012-2021	18	($1.00)	$3,134	0.00	20.2	0.2	0.9	11.7	(0.3)

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
EXHIBIT NO. ____ (LLC-1)
DOCUMENT NO. 1
FILED: 09/12/2012

DOCUMENT NO. 2

BILLING CYCLE DEGREE DAYS

Tampa Electric Company
Billing Cycle Based Degree Days

	Heating Degree Days	Cooling Degree Days
1992	540	3,302
1993	441	3,453
1994	430	3,762
1995	547	3,689
1996	792	3,479
1997	343	3,754
1998	406	4,011
1999	342	3,719
2000	417	3,689
2001	572	3,613
2002	447	3,982
2003	605	3,736
2004	547	3,490
2005	534	3,469
2006	499	3,513
2007	381	3,849
2008	420	3,523
2009	457	3,823
2010	1000	3,642
2011	575	3,844
2012	494	3,661
2013	492	3,665
2014	492	3,665
2015	492	3,665
2016	492	3,665
2017	492	3,665
2018	492	3,665
2019	492	3,665
2020	492	3,665
2021	492	3,665

Average Annual Degree Days		
1992-2011	515	3,667
2012-2021	494	3,661

DOCUMENT NO. 3

CUSTOMER FORECAST

Tampa Electric Company Customer Forecast	
	Number of Customers
2002	590,199
2003	604,900
2004	619,535
2005	635,621
2006	653,706
2007	666,354
2008	667,266
2009	666,750
2010	670,991
2011	675,799
2012	680,316
2013	688,083
2014	696,913
2015	706,481
2016	717,032
2017	727,330
2018	737,398
2019	747,441
2020	757,343
2021	766,690

Average Annual Growth Rates	
2002-2011	1.5%
2012-2021	1.3%

Average Absolute Growth	
2002-2011	9,511
2012-2021	9,597

DOCUMENT NO. 4

PER-CUSTOMER ENERGY CONSUMPTION

(KWH/CUSTOMER)

Tampa Electric Company
Per Customer Energy Consumption
(kWh/Customer)

	Total Retail	Total Excluding Phosphate
2002	30,371	28,039
2003	30,131	28,021
2004	29,759	27,777
2005	29,752	27,954
2006	29,103	27,673
2007	29,313	27,739
2008	28,459	27,008
2009	28,158	26,800
2010	28,634	27,216
2011	27,469	26,388
2012	27,993	26,853
2013	27,843	26,818
2014	27,551	26,737
2015	27,355	26,606
2016	27,234	26,482
2017	27,111	26,385
2018	27,023	26,307
2019	26,946	26,239
2020	26,873	26,175
2021	26,804	26,115

Average Annual Growth Rates		
2002-2011	-1.1%	-0.7%
2012-2021	-0.5%	-0.3%

Average Absolute Growth		
2002-2011	-322	-183
2012-2021	-132	-82

DOCUMENT NO. 5

RETAIL ENERGY SALES

(GWH)

Tampa Electric Company
Retail Energy Sales
(GWH)

	Total Retail	Total Excluding Phosphate
2002	17,925	16,547
2003	18,226	16,948
2004	18,437	17,208
2005	18,911	17,767
2006	19,025	18,089
2007	19,533	18,483
2008	18,990	18,020
2009	18,774	17,868
2010	19,213	18,261
2011	18,564	17,832
2012	19,044	18,268
2013	19,158	18,452
2014	19,201	18,633
2015	19,326	18,796
2016	19,528	18,988
2017	19,719	19,190
2018	19,927	19,398
2019	20,141	19,612
2020	20,352	19,823
2021	20,550	20,021

Average Annual Growth Rates		
2002-2011	0.4%	0.8%
2012-2021	0.8%	1.0%

Average Absolute Growth		
2002-2011	71	143
2012-2021	167	195

DOCUMENT NO. 6

PER-CUSTOMER PEAK DEMAND

(kW/Customer)

Tampa Electric Company
Per Customer Peak Demand
(kW/Customer)

	Winter	Summer
2002	6.12	6.16
2003	6.42	5.99
2004	5.40	6.03
2005	5.80	6.24
2006	5.72	6.13
2007	5.10	6.19
2008	5.56	5.92
2009	6.12	6.02
2010	6.72	5.84
2011	5.97	5.88
2012	6.00	5.87
2013	5.98	5.85
2014	5.94	5.81
2015	5.92	5.78
2016	5.89	5.75
2017	5.87	5.73
2018	5.85	5.71
2019	5.83	5.69
2020	5.82	5.67
2021	5.81	5.65

Average Annual Growth Rates

2002-2011	-0.3%	-0.5%
2012-2021	-0.4%	-0.4%

Average Absolute Growth

2002-2011	-0.02	-0.03
2012-2021	-0.02	-0.02

DOCUMENT NO. 7

PEAK DEMAND

(MW)

Tampa Electric Company
Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3976
2012	4081	3993
2013	4112	4023
2014	4141	4049
2015	4180	4082
2016	4224	4125
2017	4269	4165
2018	4315	4207
2019	4361	4250
2020	4408	4292
2021	4453	4331

Average Annual Growth Rates		
2002-2011	1.2%	1.0%
2012-2021	1.0%	0.9%

Average Absolute Growth		
2002-2011	47	38
2012-2021	41	38

DOCUMENT NO. 8

FIRM PEAK DEMAND

(MW)

Tampa Electric Company
Firm Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3777	3748
2013	3819	3784
2014	3864	3823
2015	3910	3859
2016	3955	3900
2017	4003	3940
2018	4050	3980
2019	4097	4022
2020	4146	4064
2021	4194	4103

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	1.2%	1.0%

Average Absolute Growth

2002-2011	53	42
2012-2021	46	39

DOCUMENT NO. 9

FIRM PEAK LOAD FACTOR

(%)

Tampa Electric Company Firm Peak Load Factor (%)		
	Winter	Summer
2002	62.8%	61.7%
2003	60.2%	62.1%
2004	71.5%	60.9%
2005	65.7%	57.9%
2006	61.6%	57.6%
2007	71.3%	57.5%
2008	62.8%	58.1%
2009	57.1%	56.4%
2010	51.7%	59.1%
2011	56.7%	57.3%
2012	57.4%	57.9%
2013	57.3%	57.8%
2014	56.7%	57.3%
2015	56.4%	57.2%
2016	56.2%	57.0%
2017	56.2%	57.1%
2018	56.2%	57.2%
2019	56.1%	57.2%
2020	55.9%	57.0%
2021	55.9%	57.2%

Average Annual Growth Rates		
2002-2011	-1.1%	-0.8%
2012-2021	-0.3%	-0.1%

DOCUMENT NO. 10

JUNE 2012 UPDATE
FIRM PEAK DEMAND
(MW)

Tampa Electric Company
June 2012 Update
Firm Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3237	3677
2013	3699	3667
2014	3731	3701
2015	3778	3741
2016	3832	3788
2017	3887	3835
2018	3941	3881
2019	3993	3927
2020	4045	3971
2021	4095	4012

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	1.3%	1.0%

Average Absolute Growth

2002-2011	52	42
2012-2021	50	37

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION TO DETERMINE NEED FOR
POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT
OF
HOWARD T. BRYANT

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy

Conservation Cost Recovery ("ECCR") clause, the Environmental Cost Recovery Clause ("ECRC"), and their retail rate designs.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe Tampa Electric's DSM programs and initiatives. I will provide an overview of the company's historical and current DSM programs. I will also discuss the process used by Tampa Electric in setting its DSM goals. Additionally, I will address Tampa Electric's DSM renewable energy initiatives. Finally, I will discuss why the company's comprehensive DSM program offerings cannot be utilized to eliminate the 2017 capacity need.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. _____ (HTB-1) was prepared under my direction and supervision. It consists of the following three documents:

Document No. 1   Tampa Electric DSM Programs
Document No. 2   Tampa Electric DSM Goals
Document No. 3   Tampa Electric 2010-2019 DSM Goals

Accomplishments

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor sections of the Need Study pertaining to DSM. Specifically I sponsor sections III.A.3 "Demand Side Management", III.F.1 "Demand Side Programs", and IV.A.1 "Demand Side Management".

HISTORICAL OVERVIEW OF TAMPA ELECTRIC'S DSM PROGRAMS

Q. Please describe the phrase "demand side management programs" as used by Tampa Electric?

A. Tampa Electric utilizes the term demand side management to describe the planning, development, implementation, monitoring and evaluation of conservation and load management programs designed to cost-effectively reduce weather sensitive peak demand and overall energy consumption on the company's system.

Q. How does Tampa Electric measure the cost-effectiveness of DSM programs?

A. Tampa Electric measures the cost-effectiveness of DSM programs by using the Commission-approved methodology, which consists of three specific tests: the Rate Impact Measure ("RIM") Test, the Participants' Test and the Total Resource Cost ("TRC") Test. Programs that have a cost-benefit-ratio ("CBR") greater than 1.0 under the RIM Test provide benefits to all customers by the deferral or avoidance of new capacity which thereby results in lower rates for all customers than would otherwise occur in the absence of the programs. Similarly, programs that have a CBR greater than 1.0 under the Participants' Test ensure that the programs are economical for customers who choose to participate in the programs. Finally, programs that have a CBR greater than 1.0 under the TRC Test ensure that society, as a whole, is not harmed when comparing specifically defined costs and benefits regardless of who is responsible for those costs and benefits. However, a program with a TRC Test CBR greater than 1.0 in conjunction with its RIM Test CBR of less than 1.0 will result in a cross subsidization occurring between those customers who cannot participate in programs, yet must pay the program costs associated with those who can participate.

Q. When did Tampa Electric begin offering DSM programs to its customers?

A. Tampa Electric has long been a leader in offering its customers cost-effective DSM programs coupled with a comprehensive educational emphasis on the efficient use of energy. This effort began in the mid-1970s when Tampa Electric offered its first DSM program, the Energy Answer Home, to curb heating and air-conditioning requirements in new homes by encouraging the use of high-efficiency heat pumps instead of conventional air-conditioning with resistance heating. Within two years, the company introduced a computer-based home energy audit well in advance of the legislation that ultimately required this level of home energy analysis.

Q. Please describe Tampa Electric's DSM efforts over time.

A. In 1980, the Florida Energy Efficiency and Conservation Act ("FEECA") was passed by the Florida Legislature. In response to that legislation, Tampa Electric filed its DSM plans with the Commission and became the first Florida utility to have its DSM programs for both residential and commercial customers approved. Subsequent to that first DSM plan, Tampa Electric has filed and gained Commission approval for numerous DSM programs designed to promote new energy efficient technologies and to change customer behavioral patterns such that energy savings occur with minimal effect on customer comfort. Additionally, the company has modified existing DSM programs over time to promote evolving technologies and to maintain program cost-effectiveness. Document No. 1 of my exhibit identifies Tampa Electric's current DSM programs.

Q. Has Tampa Electric been successful implementing its DSM initiatives over time?

A. Yes. Tampa Electric has experienced great success with its DSM initiatives. From the inception of its programs in 1980 through the end of 2011, Tampa Electric has achieved 719 MW of winter peak demand reduction, 306 MW of summer peak demand reduction and 770 GWH of annual energy savings.

This amount of peak load reduction has eliminated the need for the equivalent of four 180 MW power plants of winter capacity.

Furthermore, the company's DSM program results compare quite favorably to other utilities across the nation.

The Energy Information Administration of the United States Department of Energy reports annually on the effectiveness of utility DSM initiatives. Based on available data reported for the 2001 through 2010 period, Tampa Electric's national average ranking for cumulative conservation is at the 89^{th} percentile and is at the 85^{th} percentile for load management achievement.

OVERVIEW OF TAMPA ELECTRIC'S DSM PROGRAMS

Q. What are Tampa Electric's current Commission-approved residential DSM programs?

A. Tampa Electric's current DSM plan consists of 11 comprehensive residential programs several of which provide customers with a multitude of program offerings to better manage their energy consumption. A description of these various programs is provided below.

Energy Audit: A comprehensive program offered to all residential customers designed to save demand and energy by increasing customer awareness of energy use in personal residences. The types of audits available include a free walk-through, computer assisted and telephone audits as well as a paid comprehensive audit. Savings are dependent on the customer implementing energy saving recommendations. Recommendations are the same across the four types of audits offered and include an estimated range of savings.

Building Envelope: A conservation incentive program that encourages customers to make cost-effective improvements to existing residences in the areas of ceiling insulation, wall insulation and window improvements. The goal is to offer customer incentives for making these improvements while helping them reduce energy consumption and weather sensitive peak demand.

Energy Planner: A conservation and load management program that relies on a multi-tiered rate structure combined with price signals conveyed to participating customers during the day. This price information is designed to encourage customers to make behavioral or equipment usage changes to their energy consumption thereby achieving the desired high cost period load reduction to assist in meeting system peak. Price information from the utility is used by the customer to program a smart thermostat into preset actions based on the level of pricing. Equipment may be turned on, turned off or changed to a different temperature setting automatically by the smart thermostat or manually by the customer through the smart thermostat in response to either the multi-tiered rates or critical price signals.

Duct Repair: A conservation incentive program designed to reduce demand and energy by decreasing the load on residential air conditioning and heating ("HVAC") equipment. This program eliminates or reduces areas of HVAC air distribution losses by sealing and repairing the air distribution system ("ADS"). The ADS is defined as the air handler, air ducts, return plenums, supply plenums and any connecting structure.

New Construction Program: A conservation program designed to reduce the growth of peak demand and energy consumption in the residential new construction market through the installation of high efficiency equipment and building envelope options. The program utilizes incentives to encourage the construction of new homes that exceed the minimum energy efficiency levels required in the State of Florida Energy Efficiency Code for New Construction.

Heating and Cooling: A conservation program that uses a rebate to encourage the installation of high efficiency heating and cooling systems in existing residential dwellings. The program is aimed at reducing the growth of weather sensitive peak demand and energy through two types of equipment replacement. Both types of equipment replacement have a minimum threshold for qualification of 15.0 Seasonal Energy Efficiency Ratio ("SEER").

Low Income Weatherization/Agency Outreach: A conservation program designed to reduce weather sensitive peak demand and energy. The goal of the program is to establish a package of conservation measures at no cost for the customer. In addition to providing and/or installing the necessary materials for the various conservation measures, a key component will be educating families on energy conservation techniques to promote behavioral changes to help customers control their energy usage. Customer eligibility is determined by utilization of census data to identify eligible customer geographic regions or referral through local community agencies which serve low-income households.

Public Education Outreach: A conservation program designed to save energy and demand by establishing informative presentations to help educate customers on no-cost practices they can implement to reduce energy consumption, low-cost improvements to increase the efficiency of their homes, and incentives available for making larger, long-term investments. This program is designed to establish opportunities for engaging groups of customers and students in energy-efficiency related discussions in an organized setting. In addition, participants will be provided with energy saving devices such as compact fluorescent lamps, low-flow faucet aerators, HVAC filter whistles and energy saving tips and recommendations.

HVAC Maintenance: A conservation incentive program designed to help customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up. This will in turn help participating customers reduce demand and energy usage and help promote positive long-term maintenance habits.

Electronically Commutated Motors: A conservation incentive program designed to reduce demand and energy by decreasing the load on HVAC equipment. Customers will improve the overall efficiency by replacing the existing motor in the air-handler with an electronically commutated motor.

Prime Time: A residential load management program designed to alter Tampa Electric's system load curve by reducing summer and winter demand peaks. Residential loads such as heating, air conditioning, water heaters and pool pumps are controlled from a radio signal initiated by Tampa Electric's Energy Control Center. This signal operates switches located on individual customer homes that are wired directly to the controlled appliances. Customers participating in Prime Time receive monthly credits on their electric bill. Appliances are interrupted on a prescribed schedule unless a system emergency occurs. Currently, Prime Time is closed and not accepting new customers.

Q. What are Tampa Electric's current Commission-approved commercial/industrial DSM programs?

A. Tampa Electric's current DSM plan consists of 19 comprehensive commercial/industrial programs which provide customers with a multitude of offerings to better manage their energy consumption. A description of these various programs is provided below.

Energy Audit: A conservation program designed to reduce demand and energy consumption by increasing customer awareness of energy use in their facilities. The savings are dependent upon customer implementation of audit recommendations. Recommendations are based on the replacement of less efficient equipment and systems or modifications to operations to enhance the customer's overall efficiency. Recommendations are primarily standardized and encourage the customer to implement measures that, if cost-effective, move the customer beyond the efficiency level typically installed in the marketplace.

Cool Roof: A conservation program that uses incentives to encourage the installation of cool roof systems above conditioned spaces. The program is aimed at reducing heat transfer through reflectance which in turn, reduces HVAC loads and improves comfort.

Energy Recovery Ventilation: A conservation program that uses incentives to encourage the installation of ventilation systems that reduce humidity and HVAC loads in buildings. This program is intended to reduce demand and energy while improving comfort in commercial buildings.

Chiller Replacement: A conservation program that uses incentives to encourage the installation of high efficiency electric water-cooled and air-cooled chillers. This program is intended to reduce demand and energy by encouraging customers to replace worn out, inefficient cooling equipment with systems that exceed minimum product standards.

Commercial Lighting: An incentive program for existing commercial facilities to encourage investment in more efficient lighting technologies. Specifically, this program is designed to: 1) affect a significant number of eligible customers; 2) recognize the most probable lighting investment opportunities; and 3) contribute toward weather-sensitive peak demand reduction.

Building Envelope: A conservation program that encourages customers to make cost-effective improvements to existing commercial facilities in the areas of ceiling and roof insulation, wall insulation and window improvements. The goal is to offer customer incentives for making these improvements while helping them reduce energy consumption and weather sensitive peak demand.

Commercial Cooling: A commercial conservation program that uses incentives for the installation of high efficiency cooling systems in commercial buildings. The program is aimed at reducing the growth of peak demand and energy by encouraging customers to replace worn out, inefficient cooling equipment with high efficiency equipment that exceeds minimum product manufacturing standards.

Duct Repair: A conservation incentive program designed to reduce demand and energy by decreasing the load on commercial HVAC equipment. This program eliminates or reduces areas of HVAC air distribution losses by sealing and repairing the ADS. The ADS is defined as the air handler, air ducts, return plenums, supply plenums and any connecting structure.

Energy Efficient Motors: A conservation incentive program designed to reduce demand and energy by encouraging commercial/industrial customers to install premium-efficiency motors in new or existing facilities.

Lighting Occupancy Sensors: A conservation incentive program designed to reduce demand and energy by encouraging commercial/industrial customers to install occupancy sensors to efficiently control lighting systems.

Refrigeration (Anti-Condensate): A conservation incentive program designed to reduce demand and energy by encouraging commercial/industrial customers to install efficient anti-condensate controls on refrigeration equipment.

Water Heating: A conservation incentive program designed to reduce demand and energy by encouraging commercial/industrial customers to install high efficiency water heating systems. Two technologies covered under this program are heat recovery units and heat pump water heaters.

Conservation Value: An incentive program available for all commercial/industrial customers on firm rates to recognize and encourage investments in demand shifting or demand reduction measures. Measures funded in this program are not covered under other Tampa Electric commercial/industrial conservation programs. Candidates are identified through the energy audit, or their engineering consultants can submit proposals for funding which offer energy reduction during weather sensitive peak times.

Commercial Load Management: A load management program intended to help alter the company's system load curve by reducing summer and winter demand peaks. Large loads such as walk-in freezers are interrupted for up to three hours by radio controlled switches similar to those used in the residential load management. Commercial air conditioning equipment is cycled during summer control periods. Monthly incentive credits are paid to customers participating in this program.

Industrial Load Management: A load management program for large industrial customers with interruptible loads of 500 kW or greater. In accordance with the Florida Administrative Code, assessments for customer participation are conducted every six months.

Standby Generator: A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand. Tampa Electric provides participating customers a thirty minute notice that their generation will be required. This allows customers time to start generators and arrange for orderly transfer of load. Tampa Electric meters and issues monthly credits for that portion of the generator's output that could serve normal building load after the notification time. Normal building load is defined as load (type, amount and duration) that would have been served by Tampa Electric if the emergency generator did not operate. Under no circumstances will the generator deliver power to Tampa Electric's grid.

Demand Response: A program intended to alter the company's system load curve by reducing summer and winter demand peaks. The company will contract through a vendor for a turn-key program that will induce commercial/industrial customer to reduce their demand for electricity in response to market signals. Reductions will be achieved through a mix of emergency backup generation, energy management systems, raising cooling set-points and turning off or dimming lights, signage, etc.

HVAC Maintenance: A conservation incentive program designed to help commercial/industrial customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up. This will in turn help participating customers reduce demand and energy usage and help promote positive long-term maintenance habits.

Electronically Commutated Motors: A conservation incentive program designed to reduce demand and energy by decreasing the load on HVAC and refrigeration equipment. Commercial/industrial customers will improve the overall efficiency by replacing the existing motors in air-handlers and refrigeration systems with electronically commutated motors.

Q. Does Tampa Electric engage in other activities closely associated with DSM programs?

A. Tampa Electric has a longstanding practice of engaging in relevant commercial and residential research and development ("R&D") to discover measures that would return DSM savings for customers and the company and therefore become integral to DSM programs. The company's R&D projects have included renewable energy generating technology investigations, renewable energy program development, desiccant technologies for moisture removal from buildings, ventilation designs for fresh air intake on commercial buildings, chiller and motor efficiency testing, anti-condensate controls for refrigerator and freezer doors, thermal energy storage, commercial load management experimentation, heat recovery technology for ice makers and residential and commercial demand response through time specific pricing tiers. From these R&D

efforts, Tampa Electric has developed or enhanced the following programs: Renewable Energy Program, Energy Planner, Conservation Value, Chiller Replacement, Commercial Refrigeration and Commercial Load Management.

TAMPA ELECTRIC'S DSM RENEWABLE ENERGY INITIATIVES

Q. Has Tampa Electric engaged in DSM activities that support renewables?

A. Yes, it has. Some of Tampa Electric's initial work in the area of renewables has included photovoltaic ("PV") arrays. Early work included utilizing PV arrays to charge batteries that would power parking lot lighting. An R&D effort was also undertaken to evaluate the use of PV arrays to provide emergency lighting at a strategic storm shelter.

Tampa Electric's commitment to a more formalized renewable energy program began in 2001. The company implemented a pilot renewable energy program with the following goals: 1) determine the level of program interest among customers and their willingness to pay a higher cost for renewable energy; 2) examine marketing methods to identify the most cost-effective manner to secure residential and commercial program participants;

3) determine the longevity of customer participation; 4) determine the functionality of certain renewable generation; and 5) determine the sustainability of renewable fuel resources.

Due to the R&D effort put forth on the pilot program, Tampa Electric offers a permanent renewable energy program for both residential and commercial customers. The program continues to offer incremental renewable energy that is produced locally and within the State and as such, the environmental benefits accrue to the citizens of Florida.

Q. What are Tampa Electric's other Commission-approved renewable DSM programs?

A. Tampa Electric's current DSM plan consists of the aforementioned permanent program and four pilot renewable program offerings. A description of these various programs is provided below.

Renewable Energy Program: A program designed to allow residential and commercial/industrial customers the option of paying an additional charge for incremental renewable energy delivered to the company's grid system.

The customer can elect to pay $5.00 for a 200 kWh block of renewable energy generated from renewable resources on an on-going monthly or one-time basis.

Solar Photovoltaics (Pilot): A conservation incentive program designed to reduce demand and energy by encouraging residential and commercial/industrial customers to install PV systems. Participants must agree to have the system interconnected to the grid with an interconnection agreement in place once installation has occurred.

Residential Solar Water Heating (Pilot): A conservation incentive program designed to reduce demand and energy by encouraging residential customers to install solar water heating ("SWH") technologies on residential premises.

School PV (Pilot): A conservation program designed to reduce demand and energy by providing schools designated as emergency shelters with PV systems. In addition, Tampa Electric has partnered with the Florida Solar Energy Center to provide educational components for teachers and students to evaluate and understand the performance and benefits of PV.

Low-income Solar Water Heating (Pilot): A conservation program designed to reduce demand and energy by providing the installation of SWH systems on low-income housing done in partnership with local non-profit building organizations.

DSM GOALS SETTING PROCESS

Q. Why are DSM goals established for Tampa Electric?

A. Investor-owned utilities like Tampa Electric have DSM goals established by the Commission as a requirement of FEECA and the Florida Administrative Code. Furthermore, DSM goals are established and utilized in the cost-effective planning to meet future generating needs.

Q. How frequently are Tampa Electric's DSM goals established?

A. Tampa Electric's DSM goals are established by the Commission every five years for a 10-year period. Every five years, the existing goals are re-examined for appropriateness and often adjusted to reflect levels of accomplishment as well as the changing potential of customer participation based on DSM technology development and customer willingness to participate.

Tampa Electric's current Commission-approved DSM goals are shown in Document No. 2 of my exhibit.

Q. How has Tampa Electric performed relative to its DSM goals?

A. Since 1980, Tampa Electric has met or exceeded its DSM demand and energy goals in every period but one. Document No. 3 of my exhibit clearly demonstrates that Tampa Electric is exceeding its DSM goals for the current period.

Q. How were Tampa Electric's current Commission-approved DSM goals developed?

A. Tampa Electric's process to develop its DSM goals used multiple steps. The first step was to identify the measures to be evaluated for cost-effectiveness. Tampa Electric identified 270 measures for evaluation. The next step was to perform the cost-effectiveness evaluation on each measure across the various market segments where potential acceptance could occur. This resulted in almost 2,300 individual measure cost-effectiveness evaluations being performed. Next, Tampa Electric examined those measures that were cost-effective to determine their potential for program development. Once the results from this step were identified, the cost-effective measures were separated into residential and commercial/industrial categories and became the foundation for DSM goals proposed to the Commission. The Commission approved the company's DSM goals in Docket No. 080409-EG, Order No. PSC-09-0855-FOF-EG, issued December 30, 2009.

ABILITY TO SATISFY 2017 CAPACITY NEED THROUGH DSM

Q. Has Tampa Electric identified all of the cost-effective DSM program potential for the 2010 through 2019 period?

A. Yes. Through the exhaustive DSM goals setting process that culminated in the demand and energy goals for the 2010 through 2019 period, Tampa Electric has identified all the cost-effective DSM program potential for the period.

Q. In 2007, a modification was made to subsection (4) of Section 403.519, Florida Statutes, that requires the Commission, in making its determination of need for a requesting utility, to consider "…whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available." Has Tampa Electric met this requirement?

A. Yes. Tampa Electric has conducted an extensive evaluation of all demand-side conservation and renewable energy measures reasonably available. The company's current 2010-2019 DSM goals were established utilizing a comprehensive set of DSM measures. Through the company's efforts, these goals are being exceeded.

Q. Will Tampa Electric's DSM efforts provide sufficient potential such that the capacity identified in this determination of need can be deferred?

A. No. Tampa Electric has identified all reasonably achievable DSM demand and energy reductions and utilized that potential in the assessment of this determination of need. The company will not be able to meet the capacity identified in this determination of need. Therefore, Tampa Electric's evaluation of future generating capacity has already captured all the cost-effective DSM potential available on the company's system, and there are no DSM alternatives that could defer the need for additional generating capacity in 2017.

Q. Please summarize your direct testimony.

A. Tampa Electric has been successfully implementing cost-effective DSM programs since the 1970s. During the last decade, the company's average national ranking is at the 89th percentile for cumulative conservation and the 85th percentile for load management achievements. Through 2011, Tampa Electric has implemented 719 MW of winter DSM and 306 MW of summer DSM which equates to four 180 MW power plants.

Tampa Electric has been very consistent at meeting or exceeding its DSM goals set by the Commission. Furthermore, Tampa Electric assesses its DSM potential on an annual basis and seeks Commission approval of those programs that will cost-effectively help the company reach its DSM goals while providing customers with opportunities to better manage their energy usage.

In spite of Tampa Electric's efforts and significant accomplishments in the areas of DSM and renewables, the company is not able to meet the 2017 capacity need through additional conservation measures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

HOWARD T. BRYANT

Table of Contents

DOCUMENT NO. 1

TAMPA ELECTRIC DSM PROGRAMS

Tampa Electric DSM Programs

Residential

Energy Audits:
- Walk-Through
- Computer Assisted
- Phone
- Paid

Building Envelope:
- Ceiling Insulation
- Wall Insulation
- Window Replacement
- Window film

Energy Planner
Duct Repair
New Construction
Heating and Cooling
Low Income Weatherization/Agency Outreach
Public Education Outreach
HVAC Maintenance
Electronically Commutated Motors (HVAC)
Prime Time

Commercial/Industrial
Energy Audits:
Free
Paid
Cool Roof
Energy Recovery Ventilation
Chiller Replacement
Lighting:
Indoor
Outdoor
Exit Signs
Air Conditioning Replacement
Duct Repair
Building Envelope:
Ceiling Insulation
Roof Insulation
Wall Insulation
Window Film
Energy Efficient Motors
Lighting Occupancy Sensors
Refrigeration (Anti-Condensate)
Water Heating
Conservation Value
Industrial Load Management
Standby Generator
Demand Response
Cogeneration
HVAC Maintenance
Electronically Commutated Motors (HVAC, Refrigeration)
Commercial Load Management
Renewable Energy
Renewable Energy Subscription
Solar PV Incentives
Solar Water Heating Incentives
Solar for Schools
Low-Income Solar Water Heating

DOCUMENT NO. 2

TAMPA ELECTRIC DSM GOALS

(2010 - 2019)

Tampa Electric DSM Goals
2010-2019

Residential

Year	Tampa Electric Projected Summer Demand Savings (MW) Incr.	Cum.	Commission Approved Summer Goal (MW) Incr.	Cum.	Tampa Electric Projected Winter Demand Savings (MW) Incr.	Cum.	Commission Approved Winter Goal (MW) Incr.	Cum.	Tampa Electric Projected Annual Energy Savings (GWH) Incr.	Cum.	Commission Approved Annual Energy Goal (GWH) Incr.	Cum.
2010	7.0	7.0	4.6	4.6	9.2	9.2	6.4	6.4	14.9	14.9	9.8	9.8
2011	8.8	15.9	6.6	11.2	11.1	20.3	8.5	14.9	19.9	34.8	14	23.8
2012	10.0	25.9	8.4	19.6	12.3	32.6	10.2	25.1	23.1	57.9	17.7	41.5
2013	11.5	37.4	9.9	29.5	13.8	46.4	11.5	36.6	20.6	78.5	20.6	62.1
2014	12.7	50.1	10.8	40.3	15.1	61.5	12.2	48.8	22.6	101.1	22.6	84.7
2015	13.3	63.5	10.9	51.2	16.0	77.6	11.6	60.4	23.0	124.1	23.0	107.7
2016	12.7	76.2	9.8	61.0	15.4	92.9	10.1	70.5	21.5	145.6	21.3	129.0
2017	11.7	87.9	9.0	70.0	14.1	107.0	8.8	79.3	20.2	165.7	19.4	148.4
2018	11.4	99.3	8.3	78.3	13.6	120.6	8.0	87.3	19.8	185.5	18.3	166.7
2019	11.0	110.3	7.8	86.1	12.9	133.6	7.4	94.7	19.2	204.7	17.3	184.0

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Commercial / Industrial

Year	Tampa Electric Projected Summer Demand Savings (MW) Incr.	Cum.	Commission Approved Summer Goal (MW) Incr.	Cum.	Tampa Electric Projected Winter Demand Savings (MW) Incr.	Cum.	Commission Approved Winter Goal (MW) Incr.	Cum.	Tampa Electric Projected Annual Energy Savings (GWH) Incr.	Cum.	Commission Approved Annual Energy Goal (GWH) Incr.	Cum.
2010	3.7	3.7	2.5	2.5	2.1	2.1	0.9	0.9	12.2	12.2	6.5	6.5
2011	4.9	8.6	3.6	6.1	2.5	4.6	1.1	2.0	17.3	29.5	10.6	17.1
2012	5.7	14.3	4.3	10.4	3.0	7.6	1.4	3.4	18.4	48.0	15.4	32.5
2013	6.0	20.3	5.1	15.5	3.2	10.7	1.3	4.7	19.2	67.1	16.2	48.7
2014	6.8	27.0	5.4	20.9	3.7	14.4	1.5	6.2	20.4	87.5	19.5	68.2
2015	7.1	34.1	6.0	26.9	4.0	18.4	1.7	7.9	21.6	109.1	20.9	89.1
2016	7.4	41.5	6.2	33.1	4.1	22.5	1.6	9.5	22.7	131.8	21.6	110.7
2017	8.2	49.7	6.3	39.4	4.6	27.1	1.6	11.1	22.9	154.7	21.8	132.5
2018	7.6	57.2	6.4	45.8	4.2	31.2	1.7	12.8	22.1	176.8	22.1	154.6
2019	7.0	64.2	6.3	52.1	3.7	34.9	1.7	14.5	21.7	198.5	21.7	176.3

DOCUMENT NO. 3

Tampa Electric

2010-2019 DSM Goals Accomplishments

Tampa Electric Incremental 2010-2019 DSM Goals Accomplishments

Total Residential and Commercial/Industrial

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2010	18.5	7.3	253.4%	19.2	7.1	270.4%	35.6	16.3	218.4%
2011	22.0	9.6	229.2%	23.9	10.2	234.3%	52.2	24.6	212.2%

Residential

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	10.2	8.5	120.0%	8.6	6.6	130.3%	19.2	14.0	137.1%

Commercial/Industrial

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2010	7.2	0.9	800.0%	11.1	2.5	444.0%	18.3	6.5	281.5%
2011	11.8	1.1	1072.7%	15.3	3.6	425.0%	33.0	10.6	311.3%

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
EXHIBIT NO. ____ (HTB-1)
DOCUMENT NO. 3
FILED: 09/12/2012

Tampa Electric Cumulative 2010-2019 DSM Goals Accomplishments

Total Residential and Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	18.5	7.3	253.4%	19.2	7.1	270.4%	35.6	16.3	218.4%
2011	40.5	16.9	239.6%	43.1	17.3	249.1%	87.8	40.9	214.7%

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	21.5	14.9	144.3%	16.7	11.2	149.1%	36.5	23.8	153.4%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	7.2	0.9	800.0%	11.1	2.5	444.0%	18.3	6.5	281.5%
2011	19.0	2.0	950.0%	26.4	6.1	432.8%	51.3	17.1	300.0%

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. _____ (HTB-1)
DOCUMENT NO. 3
FILED: 09/12/2012

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION TO DETERMINE NEED FOR
POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT
OF
J. BRENT CALDWELL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering from the University of South Florida in 1988. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed my current position where a portion of my responsibilities include the long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe Tampa Electric's fuel procurement and delivery strategy for Polk 2-5 Combined Cycle Conversion ("Polk 2-5"). I describe the pipeline infrastructure, contractual portfolio, and company capabilities that will be used to ensure reliable and cost-effective fuel supply for Polk 2-5.

I also sponsor the fuel price forecast that was used in the Polk 2-5 analyses. I describe the development of the fuel price forecast, including the sources of projected future prices, the value of sensitivity around those price projections, and the reasonableness of the forecast for use in the Polk 2-5 analyses.

Finally, I briefly describe Tampa Electric's market solicitation for reliable and cost-effective purchased power alternatives in lieu of building Polk 2-5. This description includes Tampa Electric's Request for

Proposals ("RFP") issued March 23, 2012 and the bids received in response to the RFP.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. _____ (JBC-1) was prepared under my direction and supervision. It consists of the following documents:

Document No. 1 Fuel Price Forecast

Document No. 2 Fuel Price Forecast Range Compared to Independent Forecasts

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor sections of the Need Study regarding the fuel price forecasts. Specifically, I sponsor sections III.C. "Fuel Forecast," IV.A.1., "Firm Purchased Power Agreements," and VIII.B.1. "Fuel Sensitivity".

FUEL SUPPLY FOR POLK UNITS 2-5 CC CONVERSION

Q. Please describe the fuel supply needs for Polk 2-5?

A. When the conversion is complete, Polk 2-5 will be an approximately 1,100 (1,063 summer, 1,195 winter) MW natural gas fueled combined-cycle ("CC") unit. The incremental capacity of the project, over and above the current stand-alone combustion turbine ("CT") capacity of Polk Units 2 through 5, will be approximately 459 MW of summer capacity and 463 MW of winter capacity. With an overall heat rate of approximately 7 MMBtu/MWH, Polk 2-5 requires approximately 7 MMBtu/MWH times 1,100 MW which equals 7,700 MMBtus of natural gas fuel per hour of generation at maximum generation. When the unit runs for 16 hours, its total natural gas consumption will be approximately 7,700 MMBtu/hour times 16 hours which equals 123,200 mmBtu of total natural gas consumption. These figures provide a sense of the amount of gas that will need to be procured to run the plant.

In addition to the primary fuel of natural gas, half of Polk 2-5 will be able to run on distillate oil. When oil is used to fuel two of the four CTs in Polk 2-5, the natural gas fuel requirements will be essentially reduced by half. While natural gas supply disruptions are rare, this dual fuel capability will provide for added reliability from a fuel supply perspective.

Q. How does Polk 2-5 fit into Tampa Electric's overall fuel supply strategy?

A. The Tampa Electric generation fleet consists of a balanced portfolio of coal and natural gas fueled generation assets. Because Polk 2-5 will utilize heat recovery technology on existing units, the conversion fits into the company's fuel supply strategy in many ways. Polk 2-5 maintains the balance of coal and natural gas fueled generation in the company's portfolio while improving total system fuel efficiency. This improved efficiency results in lower energy costs for customers and maintains the price stability afforded by a balance of coal and natural gas fueled generation.

Q. How will the fuel supply needs of Polk 2-5 be met?

A. The existing flexible and reliable natural gas and oil supply infrastructure will continue to be used to supply fuel to Polk 2-5. Polk 2-5 will utilize the existing natural gas commodity portfolio, storage, pipeline capacity and infrastructure along with backup oil capability and storage in a more efficient manner. The four existing CTs, Polk Units 2 through 5, are currently in operation at Polk Power Station and are already using those fuel supply assets. The steam turbine added to convert the four CTs to a combined-cycle unit uses the waste heat from the existing CTs to generate the additional MW, without the need for additional fuel. The four existing CTs generate approximately 160 MW each and require approximately 11.0 MMBtu/MWh of natural gas at maximum generation. Therefore, the four existing CTs require four times 160 MW times 11.0 MMBtu/MWh, which equals 7,000 MMBtus/hour, nearly the same amount of fuel per hour for 640 MW as required by Polk 2-5 that will deliver approximately 1,100 MW. Also, Polk CT Units 2 and 3 have distillate oil backup, including storage. Those units will have the same oil backup capability and utilize the same distillate oil supply and storage when they become part of Polk 2-5.

Q. What other considerations make fuel supply for Polk 2-5 reliable and cost-effective?

A. Tampa Electric's portfolio of natural gas fuel supply assets and generation units combined with Tampa Electric's experience and capability in natural gas fuel supply enhance the reliability and cost-effectiveness of the fuel supply for Polk 2-5.

Q. Does Tampa Electric have experience supplying fuel for natural gas fueled units?

A. Yes, Tampa Electric has been supplying natural gas to Polk Units 2-5 since 2000, to the H. L. Culbreath Bayside Power Station ("Bayside Power Station") since 2003, and to five aero-derivative peaking units located at Bayside Power Station and Big Bend Power Station since 2009.

Specifically, the company's Fuels Management department provides procurement and fuel management services for support of the Tampa Electric generation portfolio as well as the Peoples Gas System distribution system. Fuels Management has developed and manages a diverse portfolio of natural gas supply assets that includes commodity supply source from several regions, salt cavern storage capacity, upstream pipeline capacity, and market area delivery pipeline capacity on three different interstate pipelines.

Q. Please describe Tampa Electric's current natural gas delivery capability and flexibility to the Polk site and the rest of its system?

A. Tampa Electric maintains a commodity supply portfolio which includes base load, intermediate and daily swing supply. This supply portfolio is coupled with a significant portfolio of natural gas pipeline assets to serve the company's fleet of natural gas fueled generators. Bayside, Polk and Big Bend Power Stations are physically connected to the Florida Gas Transmission ("FGT") pipeline system. Bayside and Big Bend Power Stations are physically connected to the Gulfstream Pipeline, LLC ("Gulfstream") system. Thus, Tampa Electric has redundant physical natural gas delivery to two of its three natural gas fueled stations. In addition to physical natural gas pipeline delivery flexibility, Tampa Electric also has interstate pipeline contractual delivery flexibility. The company has multiple long-term firm pipeline capacity agreements with FGT and Gulfstream. Tampa Electric's primary service agreement with FGT lists Bayside and Polk Power Stations as Primary Delivery Points allowing Tampa Electric to deliver natural gas to either plant as a Primary Delivery Point. Natural gas scheduled timely to either station as a primary delivery point will have the highest priority for delivery in the event of a pipeline constraint.

With its physical delivery flexibility and contractual delivery flexibility, the company's natural gas portfolio contains significant reliability and flexibility to direct gas supply deliveries to different power plants using either FGT or Gulfstream. Each day, Tampa Electric assesses the economic benefits and operational reliability of its natural gas delivery assets. The company chooses the most economic and reliable dispatch of its pipeline portfolio for serving Tampa Electric's natural gas generation needs, depending on the current circumstances. Polk CT Units 2-5 already benefit from this reliable and flexible portfolio, and that benefit will continue for Polk 2-5 after the conversion.

Q. Are there opportunities to further enhance the long-term reliability and flexibility of the natural gas delivery portfolio?

A. Yes. In addition to its access to FGT, the Gulfstream pipeline is located relatively close to the Polk Power Station property. While the connection is not needed currently, Tampa Electric expects that when economics and market operational issues indicate that it is beneficial, the company will eventually connect Polk

Power Station to Gulfstream to further enhance the reliability and optionality of natural gas supply and delivery to Polk Power Station.

Q. Please describe the backup fuel source that could be used for Polk 2-5 in the event of a natural gas supply disruption?

A. Polk CTs 2 through 3 already have distillate oil backup fuel capability and onsite storage. The existing distillate tank provides enough storage to operate those CT units for at least 72 hours of continuous operation. Tampa Electric also has existing liquid fuel supply contracts to replenish the diesel fuel as necessary.

Q. Do you believe sufficient fuel supply will be available to support Polk 2-5 during the unit's expected life?

A. Yes. Natural gas supplies have surged in the U.S. due to recent developments in the extraction of natural gas trapped in shale formations. The Energy Information Administration indicates natural gas supplies are growing and there are enough proven reserves in the U.S. to meet the country's natural gas supply needs for many decades.

FUEL PRICE FORECAST

Q. Are you sponsoring fuel price forecasts that were used in the Polk 2-5 analyses?

A. Yes. I am sponsoring fuel price forecasts prepared under my direction and that were provided to the company's Resource Planning group for use in the Polk 2-5 economic analyses.

Q. Please describe the process of developing and applying fuel forecasts at Tampa Electric?

A. Tampa Electric prepares an official, 30-year fuel price forecast each summer, and this official forecast is used by the Resource Planning group for long-term planning analyses conducted during the subsequent twelve months. This official forecast is prepared during the summer to coincide with preparation of the Fuel and Purchased Power Cost Recovery Clause filing typically filed with the Florida Public Service Commission at the beginning of August, for the actual/re-projection of the current year, and the beginning of September, for the projected year. This same official long-term forecast is also used for the Ten Year Site Plan ("TYSP") filed the following April. Consistent with Tampa Electric's typical processes, the fuel price forecast used in the Polk 2-5 economic analyses was the same official long-term forecast prepared in the summer of 2011 for the 2012 Fuel and Purchased Power Cost Recovery Clause Projection filing and the 2012 TYSP.

Q. Please describe how the fuel forecast was prepared for each commodity.

A. The fuel price forecast contains projected pricing for the commodity and delivery of the commodity for natural gas, distillate oil (*i.e.*, No. 2 oil), residual oil (*i.e.*, No. 6 oil), coal, and propane. The forecast is produced annually and spans a projected 30-year time period. The projected fuel commodity prices are derived from a combination of published market indices, independent fuel price forecasts, and escalators. Tampa Electric utilizes the escalators to extend the forecasts beyond the period of published values.

The foundation for the natural gas price forecast is the 10-year New York Mercantile Exchange ("NYMEX") natural gas futures monthly contract closing prices for the five consecutive business days between July 5, 2011 and July 11, 2011. Since the NYMEX natural gas futures contract is based on physical delivery of natural gas to the Henry Hub in southern Louisiana, Tampa Electric adds a "basis" cost to account for the company receiving its natural gas delivered into FGT Zone 3 instead of into the Henry Hub. This establishes the first 10 years of the forecast. To generate the full 30 year forecast (*i.e.*, the remaining 20 years), Tampa Electric escalates the natural gas price by the projected escalation of the Consumer Price Index Less Energy.

The foundation for the distillate oil forecast is the NYMEX No. 2 Heating Oil futures contract monthly closing prices for the five consecutive business days between June 1, 2011 and June 7, 2011. At that time, the NYMEX only published the No. 2 oil futures contracts through December, 2012. To generate the full 30-year forecast, Tampa Electric escalated the distillate oil price consistent with the escalation used for natural gas.

The foundation for the residual oil forecast is the distillate oil forecast. To produce the residual oil forecast, Tampa Electric first calculated the relationship between distillate and residual oil, *i.e.*, the cost ratio of No. 6 to No. 2 oil. The company applied this relationship to its distillate oil forecast to derive the residual oil price. The result is a 30-year forecast for residual oil.

When forecasting coal prices, Tampa Electric uses published forecasts for "like-quality" coals (*i.e.*, coals that are comparable to those burned in its generating units). If necessary, the company makes price adjustments to the published indices or published forecast prices to account for quality and locational differences. These price adjustments align the published coal's heat content and sulfur content with the coals burned at Tampa Electric's coal generating stations.

The foundation of the coal forecast is a combination of various published index prices for like-quality coal for the first two to four years. The publications include *Coal Daily* and ICAP, an online energy broker and information service. For the subsequent years through 2018, a weighted average price is developed using *Argus Coal Daily* and index prices, along with the coal prices from an independent, published forecast from Wood Mackenzie Energy Consultants ("Wood Mac"). The company utilizes a weighted average method where Tampa Electric's final coal forecast blends the published market indices with the Wood Mac forecast. The market indices are a high percentage of the blend in the near term and Wood Mac is a low percent. Over time the market indices percentage decreases until the Wood Mac forecast is 100 percent of the forecasted price. Beyond 2018, the coal commodity price is escalated annually consistent with the escalation of the other commodities.

Q. Are Tampa Electric's fuel price forecasts reasonable for planning purposes and as a basis for committing to proceed with Polk 2-5?

A. Yes. As previously described, Tampa Electric's fuel price forecasts are based on sound, industry-respected publications, indices, forecasts and escalators. Tampa Electric's approach of using NYMEX as the basis of its fuel price forecasts is a reasonable approach. The NYMEX represents the balance point between buyers and sellers and is a sound indicator of the market for a fuel commodity, including fuels such as natural gas and oil.

Q. Did Tampa Electric consider fuel price uncertainty in its fuel price forecasts?

A. Yes. While Tampa Electric believes its base forecast is appropriate for planning purposes, the company also recognizes that uncertainty exists in any fuel price forecast. To evaluate fuel price fluctuations, Tampa Electric prepared high and low price forecasts for natural gas, oil, and coal. For both oil and natural gas, these alternative scenario price forecasts are increased or decreased by 35 percent. For coal, the commodity price is increased or decreased by 20 percent. Document No. 2 of my exhibit shows a graphical representation of the range of natural gas prices used by Tampa Electric for analysis. Natural gas price forecasts from the Energy Information Administration and Wood Mac are also included on the graph. As shown on the graph, Tampa Electric's base forecast is consistent with other independent forecasts available at the time and the sensitivity range is reasonable.

Q. Has Tampa Electric updated its annual fuel price forecast?

A. Yes. Tampa Electric recently updated its fuel price forecast for the 2013 fuel and purchased power cost recovery clause projection filing. This forecast was developed similarly to the 2012 fuel projection forecast and fuel costs are generally lower in the 2013 projection than the 2012 projection. The 2013 fuel projection fuel price was also used as a sensitivity in the Polk 2-5 analysis.

REQUEST FOR PROPOSALS

Q. Did Tampa Electric test the power market for purchase power opportunities that could substitute for Polk 2-5?

A. Yes. Tampa Electric published an RFP on March 23, 2012, soliciting proposals for power to purchase. The company also consulted with Mr. Alan S. Taylor of Sedway Consulting to assist with drafting the RFP document and evaluating subsequent proposals. Mr. Taylor's direct testimony, filed on behalf of Tampa Electric in this docket, describes his role in the RFP process. As detailed in his direct testimony, Mr. Taylor has a vast amount of experience with conducting power RFP and need determinations in the U.S., including Florida. Mr. Taylor provided guidance to Tampa Electric so that the RFP was open and inviting to potential bidders.

Q. What information did the RFP include?

A. The RFP provided a detailed description of the Polk 2-5 project, fuel types and costs, estimated costs of the proposed project and other major financial assumptions. The RFP also contained minimum proposal requirements, such as the requirement for firm capacity and firm access to fuel, and a timeline of key RFP activities, such as dates for the RFP Bid Workshop and the proposal submission deadline. Lastly, the RFP contained a draft proposed purchase power agreement, allowing potential respondents to submit proposals based upon known and consistent terms and conditions.

Q. How did Tampa Electric solicit responses to the RFP?

A. In order to alert the market to this RFP, the company published notices in the *Wall Street Journal*, the *Tampa Tribune* and other energy industry publications. Two informational meetings were held at the company's headquarters in Tampa to describe the RFP process and to encourage offers and proposals in response to the RFP. The first meeting was a pre-release meeting held on March 21, 2012. This meeting was noticed to the public on March 16, 2012 and was held prior to the official release of the RFP. The purpose of the pre-release meeting was to discuss the RFP process, including how to obtain a copy of the RFP and its attachments and how to formally submit questions to Tampa Electric. The second meeting was the RFP Bid Workshop held on April 4, 2012. The workshop provided a more in-depth review of the RFP and provided participants the opportunity to ask in depth questions after having reviewed the RFP. Both meetings allowed potential bidders to participate either in person or via telephone conference call. Lastly, Tampa Electric established a publicly available web site (www.tampaelectric.com/2017powerrfp) that granted access to the RFP documents and contained a form whereby potential respondents could submit RFP questions to Tampa Electric. The company posted the questions anonymously and the corresponding answers on the web site for the benefit of all potential respondents.

Q. Was there robust participation in the RFP?

A. Yes. Both the pre-release conference and the post-release workshop were attended by numerous individuals representing several segments of the energy industry and no objections to the process were expressed by the participants. Also, over 70 questions were posted to the website and answered by the company. Ultimately, the company received four proposals. Each proposal was opened by Mr. Taylor, the third party evaluator, and accepted as a qualifying bid for evaluation. The evaluation process is described in the direct testimonies of Mr. Taylor and Tampa Electric witness R. James Rocha.

Q. Please summarize your direct testimony.

A. Tampa Electric seeks to maintain a balance of fuel types with flexible supply and delivery options for the generating sources on its system as a way to provide lower cost, to manage fuel price stability and maintain fuel supply reliability. The company determined that additional natural gas fueled generation is needed and will accomplish these goals. Tampa Electric's proposed Polk 2-5 project will convert four existing natural gas fueled CTs into a more efficient combined cycle operating unit. Since the steam turbine is powered by waste heat from the existing CTs, the pipeline infrastructure, including primary firm delivery point designation, already exist at the site. Thus, Polk 2-5 will benefit from using the existing expertise and flexible and reliable fuel supply infrastructure already being utilized to fuel all of the company's generation fleet.

The company has utilized independent, industry-recognized fuel price forecasts and market information as the basis of the fuel price forecast used in the Polk 2-5 need determination analyses. The forecasted fuel prices are based on NYMEX futures markets, published market indices, and independent energy consultant forecasts. The forecast used for the need determination is the same forecast Tampa Electric produced for its 2012 Fuel and Purchased Power Cost Recovery Clause filings and its 2012 Ten Year Site Plan, and the issuance and analysis of the RFP responses. Additionally, the company utilized fuel price sensitivities to evaluate price uncertainty with respect to forecasted natural gas, oil, and coal commodity prices. Polk 2-5 will allow Tampa Electric to maintain system fuel diversity that results in reliability and cost advantages that benefit customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

J. BRENT CALDWELL

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DOCUMENT NO. 1

FUEL PRICE FORECAST

Table of Forecasted Fuel Prices

Tampa Electric Fuel Prices Forecast 2013 - 2040

Year	Natural Gas $/MMBtu	No. 2 Oil $/Gallon	Illinois Basin Coal $/ton
2013	$5.12	$3.33	$55.57
2014	$5.39	$3.51	$56.45
2015	$5.67	$3.69	$58.88
2016	$5.95	$3.88	$55.48
2017	$6.23	$4.06	$55.24
2018	$6.51	$4.24	$52.26
2019	$6.79	$4.42	$55.94
2020	$7.07	$4.60	$59.64
2021	$7.34	$4.78	$63.20
2022	$7.63	$4.97	$66.81
2023	$7.80	$5.08	$69.16
2024	$7.97	$5.19	$71.55
2025	$8.14	$5.30	$73.96
2026	$8.31	$5.41	$76.40
2027	$8.49	$5.53	$78.85
2028	$8.67	$5.64	$81.35
2029	$8.85	$5.76	$83.89
2030	$9.03	$5.88	$86.48
2031	$9.22	$6.00	$89.11
2032	$9.41	$6.13	$91.79
2033	$9.61	$6.26	$94.52
2034	$9.80	$6.38	$97.31
2035	$10.01	$6.52	$100.14
2036	$10.21	$6.65	$103.03
2037	$10.42	$6.79	$105.97
2038	$10.64	$6.93	$108.97
2039	$10.85	$7.07	$112.03
2040	$11.08	$7.21	$115.15

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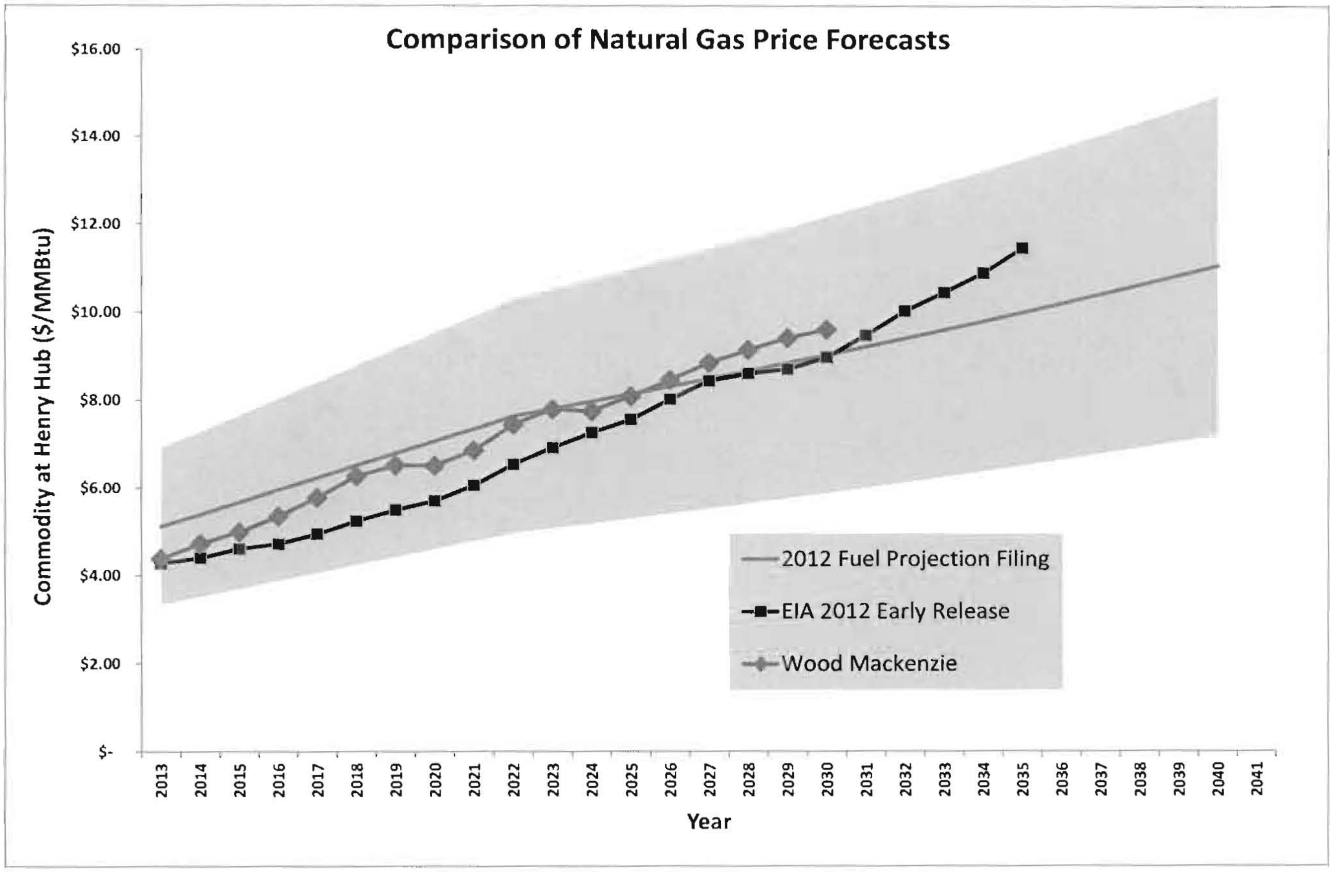
DOCUMENT NO. 2

FUEL PRICE FORECAST RANGE
COMPARED TO INDEPENDENT FORECASTS

Graph of Natural Gas Price Forecast with Range and Compared to Independent Forecasts



TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION TO DETERMINE NEED FOR
POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY
OF
DAVID M. LUKCIC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID M. LUKCIC

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

A. My name is David M. Lukcic. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager Environmental Capital Projects in the Environmental Health and Safety Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor's of Science degree in Electrical Engineering from University of South Florida, and a Masters of Business Administration from University of South Florida. I am also a registered Professional Engineer in the State of Florida. I worked in Energy Delivery in Distribution Engineering and Standards for two years overseeing the design and implementation of our company's distribution design standards. In 2000, I was promoted to Manager of Land and Water Programs in Environmental Affairs. In 2003, I became Manager Environmental Capital Projects in Environmental Health and Safety. I have overseen the development, submittal, and permitting of Transmission Line Siting Act ("TSLA") and Power Plan Siting Act ("PPSA") projects over the last 12 years. This includes the Willow Oak - Wheeler - Davis and the Lake Angus - Gifford transmission siting's as well as the development and submittal of both integrated coal gasification combined cycle ("IGCC") and natural gas combined cycle ("NGCC") units.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to demonstrate, from an environmental perspective, the benefits of the proposed Polk 2-5 Combined Cycle Conversion over other alternatives Tampa Electric considered. I will describe the environmental requirements and permits necessary to comply with existing regulation. Finally, I will explain why the selection of NGCC technology is the best alternative to ensure the company meets or surpasses environmental requirements on emissions over other technologies.

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor sections of the Need Study entitled "Environmental". Specifically, I sponsor sections III.D "Environmental" and IX.C. "Environmental."

ENVIRONMENTAL BENEFITS OF POLK 2-5

Q. What are the environmental benefits of NGCC generation versus simple cycle combustion turbine ("CT") generation?

A. The conversion of the existing CTs to an NGCC unit is designed to take advantage of the waste heat from operation of the CTs that would otherwise be vented into the atmosphere. This waste heat is a valuable resource that can be used to generate up to 352 MW of electric power without any additional fuel input. The addition of heat recovery will make the efficiency of these generating units to increase by approximately 37 percent. The improvement in power generating efficiency results in a direct reduction in the emission rate for all pollutants on a pound per MWH basis and will also reduce CO_2, NO_x, and SO_x emission rates by approximately 37 percent.

The project will also include the installation of Selective Catalytic Reduction ("SCRs") equipment in each heat recovery steam generator ("HRSG") to reduce NO_x emissions. The SCRs in combination with cycle efficiency improvements will provide an 86 percent reduction in the NO_x emission rate.

Q. Are there any other environmental benefits specific to the Polk 2-5 conversion project?

A. Yes, the Polk Power Station site is already sited and zoned for power generation. This project takes advantage of significant existing infrastructure. The Polk Power Station site will also take advantage of an existing Reclaimed Water Supply Agreement with the City of Lakeland and Polk County that will provide for a majority of the water needed for the expansion. The project will utilize reclaimed water for the makeup to the cooling reservoir. Lakeland's Water Treatment Facility currently discharges its reclaimed water into the Alafia River which flows into Tampa Bay. Polk Power Station is taking this water from Lakeland and treating it removing any nutrients before discharging into Little Pane Creek which aids in improving the water quality in Tampa Bay. Using the treated water will minimize additional consumptive use withdrawals to the greatest extent possible and will assist in lessening the amount of nutrients flowing into Tampa Bay.

ENVIRONMENTAL APPROVALS AND REQUIREMENTS

Q. What type of permits will be required for Polk 2-5?

A. Polk 2-5 will require federal, state, and regional environmental approvals and permits. The principal approval is Certification under Florida's Electrical PPSA. This will include a comprehensive review of all environmental aspects of Polk 2-5, coordinated through the Florida Department of Environmental Protection ("FDEP") and will involve all state and regional agencies with environmental responsibility and those potentially affected by Polk 2-5.

Q. Please summarize the major requirements for the environmental approvals for Polk 2-5.

A. The environmental approvals required for the Polk 2-5 conversion will require the assembly of technical information on the physical equipment and operational parameters in addition to the environmental aspects of the future operations. The environmental regulatory agencies will evaluate the environmental impacts and/or improvements of the project against historical operations of the plant and alternate generation technologies. Based on this evaluation they will make a determination whether any operational restrictions are needed or if any additional pollution control equipment is needed for the Polk 2-5 conversion.

Q. What is the schedule for filing the required environmental permits?

A. We expect to file the Site Certification Application with the FDEP in September 2012.

Q. What general features of the Polk Power Station site serve to meet existing or potential environmental requirements?

A. The Polk Power Station site was selected because of the advantages of using the existing site and infrastructure which helps minimize environmental impacts. The Polk Power Station site includes sufficient land area, which has been previously certified in accordance with the PPSA. In addition, Polk Power Station has secured additional consumptive water from Reclaimed Water Use

Agreements with both the City of Lakeland and Polk County. These agreements will not only minimize additional groundwater withdrawals but will also remove nutrients from the reclaimed water before it is used for cooling water purposes and then returned to the environment.

Q. Will the proposed project comply with all local, state and federal environmental standards and requirements?

A. Yes, it will.

COMPLIANCE STRATEGY

Q. Will the emission rates of mercury from Polk 2-5 meet or be lower than regulatory standards?

A. The recently promulgated Mercury and Air Toxics Standards for mercury and other hazardous air pollutants do not apply to natural gas-fired units and there are no other mercury emission rate standards applicable to Polk 2-5. Mercury emissions from natural gas units are de minimis.

Q. What are the Mercury and Air Toxics ("MACT") standards for Electric Generating Units and how will they influence or impact Polk 2-5?

A. The MACT standards for Electric Generating Units are not applicable to natural gas units including Polk 2-5.

Q. How do the emissions of Polk 2-5 compare to those from units using coal generation technologies?

A. The emissions from Polk 2-5 are substantially lower than units using coal generation technologies. In fact, compared to super critical coal technology, NO_x SO_2, CO_2, emissions are lower by 90, 99, and 42 percent respectively, and Mercury levels are 99.9 percent lower utilizing the proposed combined cycle technology.

Q. How do the air emission rates for Polk 2-5 compare with recently proposed NGCC generation projects such as Florida Power & Light's ("FP&L") modernization of Port Everglades Plant?

A. Polk 2-5 will have similar emission rates to recently proposed NGCC projects such as FP&L's modernization of Port Everglades. This is demonstrated by a comparison of the most recently proposed projects in the state of Florida based on permit applications and proposed data.

Q. How will the emission rates proposed for Polk 2-5 affect air quality?

A. The emission rates will only minimally affect Florida's air quality. This owes largely to the fact that the bulk of the incremental generation will come from waste heat from natural gas combustion that is already occurring. Polk County and the entire air shed or geographical area associated with Polk 2-5 are classified as in attainment with all National Ambient Air Quality Standards. The emissions as a result of Polk 2-5 are not expected to change the attainment status of the area.

OTHER ENVIRONMENTAL CONSIDERATIONS

Q. Are there any environmental or permitting requirements associated with the proposed transmission line required for the Polk 2-5 project?

A. Yes. The associated transmission facilities will be permitted through the FDEP Site Certification process. The company does not anticipate any problems obtaining the necessary permitting as a majority of the route will be in either Tampa Electric owned land/easements or in road right-of-way. The preferred route also minimizes any environmental impact and is further described in the direct testimony of Tampa Electric witness S. Beth Young.

Q. Please summarize your direct testimony.

A. Polk 2-5 will utilize a proven technology that will not only meet, but will likely surpass existing environmental regulatory requirements. The selection of NGCC technology over other alternatives will minimize emissions while simultaneously providing cost-effective and reliable energy. This project takes advantage of the waste heat which will result in additional generation with minimal fuel addition therefore reducing emissions on a pound per MWH basis. The project will also take advantage of the existing site infrastructure and the water resources that exist at the current facility.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION TO DETERMINE NEED FOR

POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT

OF

S. BETH YOUNG

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

S. BETH YOUNG

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

A. My name is S. Beth Young. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Energy Control Center.

Q. Please provide a brief outline of your educational background and business experience.

A. I received my Bachelor's of Science in Electrical Engineering degree from the University of South Florida in 1983. I am a registered professional engineer in the state of Florida. I joined Tampa Electric as a co-operative education student in 1980 and became a full time employee as an associate engineer in 1983. From 1983 through 2007, I held various positions in Tampa Electric's Electric Delivery Department including System Operations, Substation Engineering, Lighting and

Standards. In 2007, I was promoted to Director, Substation Services and Project Management. In this position, I was responsible for the construction and maintenance of the substation facilities of Tampa Electric and the management of large Transmission and Distribution ("T&D") projects within Tampa Electric. In August 2009, I added Meter Services responsibilities which included meter specifications, testing, meter reading, and field credit. In February 2010, I was named Director, Energy Control Center. My present responsibilities include the areas of long-term transmission and distribution infrastructure planning day-to-day distribution outage restoration, transmission and distribution system operations, system dispatch operations, wholesale energy accounting and billing, transmission billing, system reliability tracking and reporting, construction and maintenance of Tampa Electric's lighting facilities and Energy Delivery emergency response and planning.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe how Tampa Electric determined the most cost-effective transmission plan for the interconnection and integration of Tampa Electric's proposed Polk 2-5 Combined Cycle ("Polk 2-5") Conversion project that meets both North American Electric Reliability Council ("NERC") and Florida Reliability Coordinating Council ("FRCC") reliability standards. I will discuss the overall transmission evaluation process Tampa Electric conducted including the stability and steady state power flow study results used in determining the most cost-effective manner to interconnect and integrate Polk 2-5 into the transmission system. Finally, I will discuss the estimated costs and construction schedule of the transmission system facilities required to interconnect and integrate Polk 2-5 into Tampa Electric's system.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. I sponsor Exhibit No. ___ (SBY-1) that consists of four documents:

Document No. 1	Polk 2-5 CC Interconnection Diagram
Document No. 2	Polk 2-5 Integration Diagram
Document No. 3	Summary of Required Facilities, Ratings and Cost

Document No. 4 FRCC letter confirming the reliability of the interconnection and integration plan

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor section III.A.1. entitled "Transmission and Distribution" and section IX.D. entitled "Transmission Facilities".

Q. Please describe Tampa Electric's transmission system.

A. Tampa Electric's transmission system consists of approximately 1,300 miles of transmission lines and is operated at 3 different voltage levels; 69 kV, 138 kV, and 230 kV. Tampa Electric is interconnected to four other balancing areas through twenty-seven tie lines.

Q. Please describe Tampa Electric's evaluation process that results in determining the most cost-effective transmission system requirements for new generation resources.

A. Tampa Electric's process begins with evaluating the proposed generating plant site location to determine its proximity to existing transmission facilities. To the extent there are existing transmission facilities nearby, the site is then assessed to determine its capability for reliably interconnecting and integrating the proposed new generation into the transmission system as a firm Tampa Electric network resource.

Q. What factors are considered when integrating the proposed new generation into the transmission system?

A. There are numerous factors that are considered prior to integration of a new generating unit into the bulk electric system ("BES"). They include:

- The megawatt ("MW") amount of generation being added at the generation site and various dispatch profiles of the new generation resource relative to existing generation resources serving Tampa Electric and others utilities' load in the region;
- Compliance with NERC and FRCC reliability standards;
- Stability and system protection impacts;
- Impact on existing Tampa Electric or third party facilities;

- Capability to upgrade existing substation or transmission facilities;
- Ability to site new substation or transmission line facilities including right-of-way requirements, existing right-of-way capabilities, permitting requirements, and expected time frame to acquire right-of-way and necessary permits;
- Ability to construct the required transmission facilities without having to take outages on existing operating facilities during periods that would result in an adverse reliability impact;
- Operating considerations such as maintenance requirements of the proposed interconnection and integration facilities and impacts to the ongoing operation of the system;
- The timing and amount of power needed for testing equipment such as pumps and motors;
- Expected in-service testing and commercial operation dates for new generation, which determines the date transmission interconnection and integration facilities must be completed for the unit's testing; and
- The initial and ongoing costs of facilities and operations.

Q. How did Tampa Electric evaluate the impact of the Polk 2-5 generation addition on the Bulk Electric System?

A. A Network Resource Interconnect Study ("NRIS") was used to evaluate the impact of the generation addition on Florida's BES. The NRIS included a review of stability requirements, short circuit impacts and steady state requirements in compliance with NERC and FRCC reliability standards. These power flow studies were used to evaluate the performance of the transmission system and to determine various project alternatives that would be needed to interconnect and integrate the new generation into the BES.

Q. How were project alternatives for adding or upgrading transmission facilities developed?

A. A Tampa Electric core team developed and reviewed potential alternatives and estimated costs. This core team was comprised of engineers from System Planning, Environmental, Health and Safety, Substation Engineering, Transmission Engineering, Telecommunications, System Security and staff from Line Clearance, Real Estate, Project Management, and Community Relations. As part of their analysis, this team considered the issues outlined

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previously, including ability to construct, potential upgrade of existing facilities, right-of-way requirements, in-service dates and operating considerations. When the core team was satisfied that they had developed the most cost-effective transmission interconnection and integration plan that complied with NERC and FRCC reliability standards, the process was deemed complete.

Q. How is the Polk Power Station connected to the BES?

A. The Polk Power Station is interconnected to the BES through the Polk Power Substation. [redacted]

Q. What were the results of the stability, short circuit and power flow studies that Tampa Electric performed?

A. The stability studies did not show any adverse impacts to the BES by the addition of the Polk 2-5. The Short circuit study showed that 16-230 kV circuit breakers located at Polk Power, Pebbledale, Mines and Big Bend Power Substations did not meet the interrupting capability required due to the addition of Polk 2-5.

The results of the power flow studies determined under certain dispatches an overload might occur on the following facilities:

1. The 230 kV transmission line from Polk Power Substation to Mines Substation,
2. The 230 kV transmission line from Pebbledale Substation to FishHawk Substation,
3. The two 230 kV transmission lines from Polk Power Substation to Pebbledale Substation,
4. Some additional 3rd parties' transmission facilities.

These results indicated that, under extreme conditions, there might not be enough transmission capability out of Polk Power Substation to transmit the entire plant's capacity. After considering these potential impacts, the core team set about to consider various alternatives to insure continuing BES reliability.

Q. What projects did the core team recommend after reviewing the power flow study results?

A. The core team recommended the following projects in order to maintain the BES reliability:

1. Build a new 230 kV transmission switching station (Aspen Substation) west of Mines Substation.
2. Build the following 230 kV transmission lines
   - Polk Power Substation to Mines Substation,
   - Mines Substation to Aspen Substation,
   - Two lines from Aspen Substation to FishHawk Substation.
3. Upgrade segments of existing 230 kV transmission lines to create a 230 kV transmission line from Polk Power Substation to Aspen Substation.
4. Interconnect and rerate existing 230 kV transmission line from Big Bend Power Substation to Mines Substation into Aspen Substation.
5. Upgrade 16-230 kV circuit breakers at Polk Power Substation, Pebbledale Substation, Mines Substation and Big Bend Power Substation.
6. Reroute and upgrade the first Polk Power Substation to Pebbledale Substation 230 kV transmission line.
7. Rerate the second Polk Power Substation to Pebbledale Substation 230 kV transmission line.
8. Install a switched reactor at Davis Substation.
9. Upgrade the bus for the State Road 60 North 230/69 kV Transformer.

10. Upgrade the bus and low side circuit breaker for the Dale Mabry West 230/69 kV Transformer.

DESCRIPTION OF PLANNED PROJECT

Q. Please provide a general description of the existing transmission facilities at Polk Power Station.

A. As I previously stated, the Polk Power Substation is connected to the BES by four 230 kV transmission lines. Two of these lines run from Polk Power Substation to the Tampa Electric Pebbledale Substation. The third line runs from Polk Power Substation to Tampa Electric's Mines Substation and the fourth from Polk Power Substation to Invenergy's Hardee Station.

Q. Please provide a general description of the transmission facilities required for interconnection and integration of Polk 2-5 to Tampa Electric's system.

A. Two new 230 kV transmission circuits, three new 230 kV circuit breakers and a generator step-up transformer will be required to interconnect the new generation to the Polk Power Substation. As previously stated, one new switching substation, four new 230 kV transmission lines and upgrades to four other 230 kV transmission lines will be required to integrate Polk 2-5 into the BES. In addition, sixteen circuit breakers will need to be upgraded, some buswork and a 69 kV circuit breaker upgraded and a switched reactor added.

Q. Has the route for the four new 230 kV transmission lines been selected?

A. Yes. A route study was initiated in December 2011 and completed on July 27 2012. The route study identified the most cost-effective corridor Tampa Electric should utilize for the four new 230 kV transmission lines necessary as part of the Polk 2-5 project. Tampa Electric expects approval from the Florida Department of Environmental Protection of the corridor in the fourth quarter of 2013.

Q. How did Tampa Electric evaluate the transmission related costs associated with the planned Polk 2-5?

A. An estimating team made up of members from Substation Engineering, Transmission Engineering, Real Estate, System Security, Telecommunications, Line Clearance, Community Relations, Project Management, and Environmental Health and Safety reviewed the transmission interconnection and integration requirements to develop a scope of work. This included the review of existing drawings and site visits. Each member, along with an engineering consulting firm, then estimated the costs to complete their scope of work. As stated previously, the final corridor for the four new 230 kV transmission lines was not selected until July 27, 2012; therefore, the transmission line costs were based on one of the potential routes. The potential route used in the evaluation was approximately 4 miles longer than the route determined to be the most cost-effective in the completed route study.

Q. What is the total cost of the transmission interconnection and integration costs for Polk 2-5?

A. The total estimated project cost is approximately $147.2 million. A summary of the facilities required and associated costs is provided in Document No. 3 of my exhibit. Utilizing the updated information from the aforementioned route study completed on July 27, 2012, project costs would decrease as compared to those used in the project estimate, but these costs have not been finalized.

Q. What is the schedule for construction of the transmission facilities needed for the interconnection and integration of Polk 2-5?

A. The Polk 2-5 interconnection/integration work is scheduled to begin January 2013 and is estimated to be completed by November 2016. This will allow time for testing of the unit and associated NGCC equipment prior to its commercial in-service date. The Polk Power Substation to Aspen Substation to FishHawk Substation transmission line construction will begin by October 2014 with an in-service date of November 2016. The remainder of the work will be completed prior to November 2016. This ensures that all transmission facilities will be in-service prior to any full power testing of Polk 2-5.

Q. Has this assessment, along with the Polk 2-5 interconnection and integration requirements discussed above, been reviewed by the FRCC?

A. Yes. According to the FRCC's Regional Transmission Planning Process, Tampa Electric's interconnection and integration plan for Polk 2-5 as discussed above was provided to the FRCC for review and affirmation was given that no reliability issues exist. A letter from the

FRCC confirming the reliability of Tampa Electric's interconnection and integration plan is provided in Document No. 4 of my exhibit.

Q. What were the FRCC conclusions about Tampa Electric's Polk 2-5 transmission plan?

A. Based on the review and analysis conducted by the Transmission Working Group, the FRCC Planning Committee has determined that the proposed interconnection and integration plan will be reliable and will not adversely impact the reliability of the FRCC transmission system.

TRANSMISSION RELIABILITY BENEFITS OF POLK 2-5

Q. How will Polk 2-5 and its associated transmission facilities improve Tampa Electric's transmission reliability to Tampa Electric customers?

A. In addition to integrating the Polk 2-5 generation reliably into the BES, the new transmission facilities will also increase the import and export capability of the Tampa Electric transmission system. This provides more source options during planned and unplanned generation outages. The upgrades of the existing 230 kV facilities will also reduce the existing exposure to multi-circuit structure outages, increasing the reliability of the transmission system.

The addition of the new transmission facilities in the Central Florida region of the BES will also improve the reliability of that region for Tampa Electric customers as well as for those in the FRCC region.

Q. Please summarize your direct testimony.

A. Tampa Electric has completed stability, short circuit and power flow studies to determine the impact of the interconnection and integration of Polk 2-5 to the BES. The studies indicate two new 230 kV transmission circuits, three new 230 kV circuit breakers and a generator step-up transformer will be required to interconnect the new generation to the Polk Power Substation. In addition one new switching substation, four new 230 kV transmission lines and upgrades to other 230 kV transmission lines will be required to integrate Polk 2-5 into the BES. Sixteen circuit breakers, some buswork and a 69 kV circuit breaker will also need to be upgraded as well as the addition of a switched reactor.

These additions will reliably interconnect and integrate the Polk 2-5 into the BES. In addition, Tampa Electric customers will benefit by the increased import and export capability, reduced exposure to multi-circuit structure outages and improved reliability for the Central Florida region.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

S. BETH YOUNG

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DOCKET NO. 12_____-EI
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DOCUMENT NO. 1

POLK 2-5 CC INTERCONNECTION DIAGRAM

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The content of this page has been redacted and filed separately with a request for confidential classification.

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DOCUMENT NO. 2

POLK 2-5 INTEGRATION DIAGRAM

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (SBY-1)
DOCUMENT NO. 2
FILED: 09/12/2012

The content of this page has been redacted and filed separately with a request for confidential classification.

DOCUMENT NO. 3

SUMMARY OF REQUIRED FACILITIES, RATINGS AND COST

Summary of Required Facilities, Ratings and Cost

Circuit #	Point of Origin and Termination	Project Description	Revised Rating (MVA)	Anticipated Capital Investment ($ million)
230007	Big Bend to Aspen 230 kV	This circuit will be rerated to a rating of 729.4 MVA.	729.4	
230401	Polk to Aspen 230 kV	The existing circuits from Polk to Mines East and from Mines West to Big Bend will be disconnected from Mines substation and tied together to create the modified circuit 230401. This circuit will be rerated to a rating of 729.4 MVA.	729.4	
230402	Mines West to Aspen 230 kV	This is a new consctruction of approximately 15 miles circuit with a rating of 1,118.6 MVA.	1,118.6	
230426	Aspen to FishHawk 230 kV	This is a new consctruction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	$125
230427	Aspen to FishHawk 230 kV	This is a new consctruction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	
230606	Polk to Pebbledale Ckt 1 230 kV	This circuit will be rerouted for approximately 9.8 miles to eliminate a double circuit line with the existing Polk to Mines East line with a rerate of 729.4 MVA.	729.4	
230635	Polk to Mines East 230 kV	This is a new consctruction of approximately 12 miles circuit with a rating of 1,118.6 MVA.	1,118.6	
-	Aspen Switching Station	This is a new contruction of the Aspen 230 kV Switching Station along the existing circuits between Mines West and Big Bend.	-	$8
-	Davis Substation Switched Reactor	A new switchable series reactor will be installed on the Davis to Chapman circuit (230601).	-	$2
-	FishHawk 230 kV Substation Upgrade	The FishHawk 230 kV Substation will be upgraded as a result of the addional capacity.	-	$1
-	Mines 230 kV Substation Upgrade	The Mines 230 kV Substation will be upgraded as a result of the addional capacity.	-	$2
-	Polk Steam Turbine Interconnect & Upgrade	The Polk 2-5 Steam Turbine will be interconnected to the existing station and required upgrades.	-	$5

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
EXHIBIT NO. ____ (SBY-1)
DOCUMENT NO. 3
FILED: 09/12/2012

DOCUMENT NO. 4

FRCC LETTER CONFIRMING THE RELIABILITY OF THE INTERCONNECTION AND INTEGRATION PLAN

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
1408 N. WESTSHORE BLVD., SUITE 1002
TAMPA, FLORIDA 33607-4512
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

June 7, 2012

Beth Young
Director of Energy Control Center
Tampa Electric
P.O. Box 111
Tampa, Fl 33601-0111

Re: FRCC Review of the Polk Power Station Combined Cycle Conversion interconnection

Dear Beth,

Florida Reliability Coordinating Council's (FRCC) Transmission Working Group (TWG) and Stability Working Group (SWG) have evaluated the proposed interconnection and integration of the Polk Power Station Units 2-5 Combined Cycle Conversion Project (PK CC Conv Project) to interconnect to the Tampa Electric (TEC) transmission system. Based upon the information provided by TEC to the FRCC, the TWG has determined that the proposed interconnection and integration of the PK CC Conv Project with the identified projects, protection upgrades and remedies, is reliable and does not adversely impact the transmission system within the FRCC Region.

The PK CC Conv Project will encompass converting the existing Polk Power Station simple cycle combustion turbines (Polk Units 2-5) into a natural gas fired, four-on-one, combined cycle unit with the addition of a new steam turbine. The new steam turbine will result in an incremental 500 MW net increase (summer and winter) to the existing capacity of the four simple cycle combustion turbines located in Polk County, Florida. The proposed total capability of the PK CC Conv Project will have a summer net output of 1,195 MW and a winter net output of 1,232 MW. The scheduled in-service date is January 1, 2017.

The TWG reviewed the results of the steady state single and multiple contingency analyses. The results did not identify any contingency event that caused limitations in the FRCC Region with PK CC Conv Project facility at maximum queued output. In addition to the steady state analysis, the SWG reviewed the dynamic simulations showing a stable response at peak load and light load levels for normally cleared and delayed cleared three-phase faults in the vicinity of PK CC Conv Project. The results indicate that there are no grid stability concerns with the addition of the PK CC Conv Project.

A review of the short circuit analysis has shown that there are no short circuit concerns with the addition of the PK CC Conv Project.

Based upon the above review and analysis conducted by the TWG, the FRCC Planning Committee has determined that the proposed interconnection and integration of the PK CC Conv Project to interconnect to the TEC system, does not adversely impact the reliability of FRCC transmission system.

Sincerely, Vicente Ordax

Vicente Ordax, Jr., P.E.
Manager of Planning

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120234-EI

IN RE: TAMPA ELECTRIC COMPANY'S PETITION TO DETERMINE NEED FOR POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT

OF

R. JAMES ROCHA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

R. JAMES ROCHA

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

A. My name is R. James Rocha. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Planning, Strategy & Compliance. I direct the resource planning group where my responsibilities include identifying the need for future resource additions as well as analyzing the economic and other operational impacts to Tampa Electric's system associated with the addition of resource options.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the Georgia Institute of Technology with a Bachelor of Nuclear Engineering degree in 1982 and a Master of Science Degree in Nuclear Engineering in 1983. I earned a Master's degree in Business Administration from the

University of Tampa in 1993 and I am a registered Professional Engineer in the State of Florida. In 1984, I was employed by Commonwealth Edison Company as a nuclear fuel engineer, modeling unit operation. In 1987, I joined Florida Power, and became a resource planning engineer in the Generation Planning department. In 2000, I became Manager of Financial Analysis at TECO Energy, responsible for business development and asset management. Since 2006, I have held several positions at Tampa Electric responsible for budgeting, business strategies and North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") and non-CIP NERC compliance. I have 28 years of accumulated electric utility experience working in the areas of resource planning, business and financial analysis, and engineering. In December 2011, I was appointed to my current position.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe Tampa Electric's integrated resource planning ("IRP") process and the resulting resource plan which supports the 2017 need for the Polk 2-5 combined cycle conversion project ("Polk 2-5"), a natural gas combined cycle ("NGCC") unit rated at 459 MW summer and 463 MW winter net incremental capacity, respectively. My direct testimony will (1) describe Tampa Electric's existing system and resource mix, (2) describe Tampa Electric's IRP process for selection of future demand and supply resource alternatives, (3) demonstrate that Polk 2-5 is the most cost-effective alternative to reliably meet Tampa Electric's customer needs, (4) describe the need for additional resources for the Florida Reliability Coordinating Council ("FRCC") region, (5) describe the results of the RFP analysis, and (6) explain the adverse consequences if Polk 2-5 is deferred or denied.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. _____ (RJR-1) was prepared under my direction and supervision. It consists of the following thirteen documents:

Document No. 1 Energy Mix by Fuel Type
Document No. 2 Capacity Mix by Fuel Type
Document No. 3 Levelized Cost Screening Curves
Document No. 4 Tampa Electric Reliability Analysis
Document No. 5 FRCC Reliability Analysis
Document No. 6 FRCC Reliability Sensitivity Analysis
Document No. 7 Preliminary Resource Plans & Analysis
Document No. 8 IRP Resource Plans & Analysis

Document No. 9 IRP Sensitivity Analysis
Document No. 10 RFP Summary of Proposals
Document No. 11 RFP Resource Plans & Analysis
Document No. 12 RFP Qualitative Factors
Document No. 13 June 2012 Assumptions Update

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I am sponsoring the following sections of the Need Study: I. "Executive Summary", II. "Introduction and Overview", III.A. "Description of Tampa Electric's System", III.F.2. "Supply Technologies", IV. "Need for Capacity in 2017" (with the exception of IV.A.1.), V. "Screening of Potential Technologies", VI. "Detailed Economic Analysis", VII. "Sensitivity Analysis", X. "June 2012 Assumptions Update", XI. "Adverse Consequences if Polk 2-5 is Delayed or Denied" and XII. "Conclusion".

DESCRIPTION OF EXISTING SYSTEM AND RESOURCE MIX

Q. Please describe Tampa Electric's service area.

A. Tampa Electric, an investor-owned electric utility, is the principal subsidiary of TECO Energy, Inc. The service area for Tampa Electric spans approximately 2,000 square miles and consists of Hillsborough County, western Polk County and parts of Pasco and Pinellas counties. Tampa Electric served approximately 676,000 customers in 2011.

Q. What types of units make up Tampa Electric's existing generating system?

A. Tampa Electric has three large generating stations and one peaking station including an integrated gasification combined cycle ("IGCC") and steam coal base load units, NGCC intermediate load units, natural gas and oil fueled combustion turbine units, aero-derivative engine peaking units, and oil fueled internal combustion peaking units. The total net system generating capacity in winter 2011 was 4,684 MW and 4,292 MW in summer 2012. Tampa Electric operates 670 MW of winter net generating capacity that has dual fuel capability which improves overall system reliability.

Big Bend Power Station includes four pulverized coal-fired steam units and one aero-derivative peaking unit. Big Bend Units 1 through 4 are coal units that were retrofitted between 2007 and 2010 with additional environmental control systems including selective catalytic reduction ("SCR") to reduce nitrogen oxides ("NO_X") emissions to complete the station's comprehensive air emissions reduction program. Big Bend Combustion Turbine ("CT") 4 is a dual fuel (natural gas or oil) unit that is quick-start (full load in less than 15 minutes) and could provide black-start capability (a generating unit capable of starting from a shutdown condition without assistance from the electric system) for the station and the system.

H. L. Culbreath Bayside Power Station ("Bayside Power Station") includes two NGCC units and four aero-derivative peaking units. Bayside Unit 1 utilizes three combustion turbines, three heat recovery steam generators ("HRSG") and one steam turbine. Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine. Bayside Units 3 through 6 are natural gas-fired aero-derivative peaking units that are quick-start and provide black start capability for the station and the system.

Polk Power Station includes one base load and four peak load generating units. Polk Unit 1 is a dual fuel IGCC unit primarily fired with synthesis gas produced from a blend of low-sulfur coal and petroleum coke ("petcoke"). Distillate oil is a secondary fuel which is used for both start-up and shut-down of the power block, and can be used to operate the combined cycle at times when the gasification system is unavailable. Polk Units 2 through 5 are simple cycle CTs primarily fired by natural gas, and Units 2 and 3 are capable of firing distillate oil as a secondary fuel.

J. H. Phillips Sebring Power Station includes two diesel oil-fired peaking units located in Sebring, Florida. These two units were placed on long-term reserve stand-by ("LTRS") status on September 4, 2009 due to the relative higher cost of heavy oil compared to natural gas and coal. These units will remain on LTRS until the operating costs are competitive with other supply resources. These units also have the potential to utilize liquid biofuels and operate as a renewable energy resource in the future.

Q. Does Tampa Electric include any purchased power in its total supply resource mix?

A. Yes. Tampa Electric purchases power, both firm and non-firm, from other utilities and independent power producers operating in the Florida market. In 2011, Tampa Electric solicited the market for firm peaking power through the end of 2016 to replace the 20-year Hardee Power station purchase power agreement ("PPA") expiring December 31, 2012. Two PPAs were executed in fall 2011 for peaking capacity from the Florida market. These agreements are described in more detail in section III.A.2. of the Need Study. Only firm purchased power capacity is included in the reliability assessment process to determine the timing and minimum amount of new resources required to maintain the firm reserve planning criteria. However, both firm and non-firm purchased power energy is included in the production cost analyses to determine the most cost-effective mix of resources needed.

Q. What is the expected energy and capacity mix by fuel type for Tampa Electric's total supply resources including purchases in 2017?

A. The energy mix by fuel type for 2011 was 56 percent solid fuel, 43 percent natural gas, a slight amount of oil and 1 percent net interchange purchases on an energy (MWH) basis. In 2017, the energy mix is expected to be 59 percent solid fuel, 39 percent natural gas, a slight amount of oil and 2 percent net interchange purchases on the same basis. This is reflected in Document No. 1 of my exhibit. The capacity mix by fuel type for 2011 was 36 percent solid fuel and 64 percent natural gas on a capacity (MW) basis. In 2017, the capacity mix is expected to be 36 percent solid fuel and 64 percent natural gas on a capacity (MW) basis. This is reflected in Document No. 2 of my exhibit.

Q. Has Tampa Electric developed and implemented demand and energy reduction programs in its existing resource mix?

A. Yes. As described in Section III.A.3. of the Need Study, Tampa Electric has successfully developed and implemented numerous demand reduction and energy conservation programs for over 30 years. The cumulative effect of these programs as of the end of 2011 has eliminated the need for 719 MW in the winter and 306 MW in the summer of net generating capacity by slowing growth in both the company's peak demand and energy requirements. This reduction is roughly equivalent to the combined winter net capacity of Big Bend Units 1 and 2, and by 2017 the cumulative effect of these programs will eliminate the need for more than 376 MW of net summer generating capacity. As a percentage of the Tampa Electric total peak demand, this represents 9.0 percent of the planned total summer peak of 4,165 MW in 2017, higher than any NERC region average for demand reduction. Tampa Electric witness Howard T. Bryant describes the company's demand-side management ("DSM") achievements in his direct testimony.

INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

Q. What are the objectives of Tampa Electric's IRP process?

A. Tampa Electric's IRP process determines the timing, amount and type of additional demand reduction, energy conservation, and supply resources required to maintain system reliability in a cost-effective manner. The process considers the existing customer demand and energy mix, expected growth and changes in the customer demand and energy requirements, existing and future DSM and energy conservation programs, supply resources comprised of the Tampa Electric generating units and purchased power, existing and future bulk transmission system for Tampa Electric and the Florida grid, and potential renewable energy resources appropriate for the Florida energy market.

Q. Please describe Tampa Electric's IRP process.

A. The IRP process balances existing and future demand and supply resources in a reliable and cost-effective manner while considering strategic factors. Since cost-effectiveness is a requirement for both demand and supply resources, the process is an iterative cycle to capture the value of deferring new generating units or PPAs resulting from additional DSM programs. A reference resource plan that includes both demand and supply resources is developed which then becomes the basis for determining the new avoided costs for deferral of supply resources. The additional cost-effective DSM resources are then implemented to establish the system demand and energy requirement, which is the new basis for consideration of supply resource additions. The cycle is repeated annually each business planning cycle, as all of the operating and financial assumptions are updated.

The supply resources are initially screened on a levelized cost basis with several criteria: construction costs, operating and maintenance costs, technology viability or applicability to the operating region, commercial availability, and construction lead times. Multiple resource plans are developed that consist of various combinations of technologies and in-service dates to maintain system reliability. The relative impacts of each resource expansion plan are evaluated for total system annual operating and maintenance costs and incremental capital costs. This includes fuel, fixed and variable O&M, purchased power capacity, energy and transmission wheeling and/or transmission construction costs, and the incremental costs to build all new generating units and associated transmission capacity in each expansion plan. The plans are then initially ranked based on the lowest cumulative present worth revenue requirements ("CPWRR") of the system over a 30-year operating period.

The highest ranked resource plan incorporates an initial demand and energy forecast including DSM and supply resources. The supply resources in the reference resource plan are then used to determine the avoided cost for an economic analysis of additional viable DSM and conservation programs.

Next, the cost-effective DSM programs are included in a revised demand and energy forecast which effectively reduces system peaks and energy requirements. The revised system demand and energy forecast is used in a final reliability analysis to determine the new timing and magnitude of additional supply resources needed to meet system reliability criteria.

Final economic evaluations and sensitivities are performed to determine the recommended resource plan. The highest ranked plans are evaluated under various sensitivities to test key planning assumptions and compare the relative cost impact on a CPWRR basis. Strategic factors such as system and FRCC region reliability, resource dispatchability, system and FRCC deliverability, constructability (lead time, available technology, etc.), fuel diversity and environmental impacts are considered in determining the most cost-effective and viable resource mix for both Tampa Electric's customers and

Florida. In addition, the existing generating system is reviewed and includes planned unit retirements, expected modifications to operating performance, capital, fixed O&M, and variable O&M since the integration of new resources has the potential to impact the utilization of existing generating assets.

SYSTEM RELIABILITY PROCESS

Q. Please describe the criteria that Tampa Electric utilizes in its IRP process to determine both the minimum amount and timing of additional resources required to maintain system reliability.

A. Tampa Electric utilizes a 20 percent firm reserve margin reliability criteria above the system firm peak, as required by the Florida Public Service Commission ("Commission") in Order No. PSC-99-2507-S-EU issued on December 22, 1999, and a minimum 7 percent supply reserve margin. The firm reserve margin consists of both supply and non-firm demand resources to maintain an allowance for unexpected variances in system demand, generating unit availability, and purchased power availability and deliverability. The minimum supply reserve margin criterion maintains an important qualitative component of firm reserves for reliability purposes to minimize the impact of the loss of a supply resource at the time of peak.

If the firm reserve margin consisted of only non-firm demand reserves (whereby total firm supply equals total load), then the frequency of use of demand resources in a given year would increase significantly. The firm system peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and customer load reduction programs. Customers who continue to participate in these voluntary programs help defer the need for additional supply resources by reducing firm peak demands. These customers may request to become a firm customer or be excluded from a DSM program with appropriate notification.

As reflected in its 2011 Ten Year Site Plan ("TYSP") and then updated in its 2012 TYSP analyses, Tampa Electric is expecting to incrementally reduce demand through 2017 by 70.4 MW and 33.1 MW in summer and winter, respectively, and reduce the system energy requirement by 230.7 GWH, but will still require 294 MW of capacity additions in 2017 to its existing supply resource mix to meet the 20 percent reserve margin criteria.

Q. Please describe the FRCC Minimum Reserve Margin Planning criterion.

A. The FRCC has established a minimum firm reserve margin planning criterion of 15 percent, taking into account the three investor owned utilities' requirement of twenty percent. The 15 percent margin is calculated using the aggregate planned firm peaks of all FRCC member utilities in addition to the aggregate generating units and firm PPAs; it also includes all net firm interchange via the bulk transmission ties to the SERC region. This margin assumes that all available capacity is deliverable to all load centers. During the FRCC presentation to the Commission at the TYSP workshop on August 13, 2012 ("TYSP workshop"), the FRCC presented analysis of the degree to which the peninsular Florida system is becoming increasingly dependent upon demand side management to meet its reserve margin criterion. In order to ensure the peninsular Florida system remains reliable in the future, the FRCC has developed and will monitor a metric for DSM as a percentage of regional peak.

SUPPLY RESOURCE ANALYSIS

Q. What supply alternatives were considered in the analysis that resulted in the selection of converting Polk 2-5 from simple cycle to CC as the company's next planned generating unit addition?

A. Tampa Electric considered a variety of options prior to identifying NGCC technology as the best option for Tampa Electric and its customers. Tampa Electric's screening process included natural gas, solid fuel and renewable technologies. General characteristics of natural gas technologies include lower emissions, lower heat rate, configured as either simple cycle or CC, wide range of capacity sizes, and competitive cost per unit output. Characteristics of solid fuel technologies include lower variable fuel costs and higher fixed costs, such as capital construction and fixed operating and maintenance costs, and somewhat higher emissions depending on environmental control technologies. Solid fuel technologies are typically better suited for large capacity and high utilization applications because these assets will dispatch for longer continuous periods of time. Their lower variable operating costs, longer ramp rates, and longer minimum down times make cycling off the units more difficult than natural gas based technology.

Renewable technologies tend to have lower or no fuel costs but have significant fixed costs. In addition, technologies such as geothermal and hydroelectric have limited practical application in Florida. Similarly, wind and solar have limited and unpredictable operating hours due to the intermittent nature of their energy source. In the absence of stored energy capability, intermittent renewables are best considered as energy resources and not as firm capacity for planning purposes. However, some renewable energy such as biomass can be considered as a firm resource if sufficient biomass material is stored and available.

Q. Which options were determined to be appropriate for Tampa Electric's needs and system characteristics and analyzed in greater detail?

A. The TYSP process included strategic considerations such as fuel price stability, fuel diversity, environmental impacts, technology viability, construction lead times, site availability, and FRCC regional supply needs in the 2012-2021 period. Tampa Electric's screening analysis narrowed the focus to natural gas-fired combined cycle or simple cycle technologies for further analysis in the IRP process.

Q. Please describe the natural gas-fired generation alternatives considered.

A. Tampa Electric considered in its screening simple cycle aero-derivative engines similar to Bayside Unit 3 and simple cycle combustion turbines similar to Polk Unit 5. The company also screened a stand-alone 2x1 combined cycle unit in addition to the integration of the existing Polk Units 2 through 5 peaking units into a combined cycle unit.

Q. Please describe the results of Tampa Electric's screening analysis used to select the best supply alternatives for the detailed economic analyses.

A. Tampa Electric's screening analysis of the various alternatives compared the levelized annual cost ($/kW-yr) of each technology at various capacity factors. The levelized cost includes the cost to construct, operate and maintain each technology. The slope of each cost curve is a function of the heat rate and variable O&M which increases linearly with the increasing capacity factor. For all technologies, the cost at zero capacity factor is simply the levelized construction cost and fixed O&M. Tampa Electric selected the following viable options: natural gas combined cycle technology as intermediate options and simple cycle combustion turbines as peaking options. The graphical results of the levelized cost screening curves are presented in Document No. 3 of my exhibit.

DEMAND RESOURCE ANALYSIS

Q. How were demand resources factored into the IRP process?

A. Tampa Electric included all DSM programs described by witness Bryant in its preliminary demand and energy forecast, which effectively reduced system peaks and energy requirements. By 2017, Tampa Electric's existing and incremental DSM programs are projected to contribute summer and winter demand reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH is expected and is reflected in the projected firm peak and system energy requirements.

Q. Is it possible for Tampa Electric to meet its expected resource needs through additional DSM and renewable energy resources?

A. No. As previously stated, Tampa Electric identified all cost-effective DSM reductions and utilized that potential in the assessment of this determination of need. There are no additional cost-effective DSM alternatives (above the currently forecasted demand reductions and energy conservation) or viable cost-effective renewable energy resources that would defer the need for additional generating capacity in 2017.

RELIABILITY ANALYSIS AND RESOURCE PLAN

Q. Please describe the results of the reliability analysis.

A. The reliability analysis was based on existing generating unit operating data and projected system firm peak and energy requirements which were developed in summer 2011. This data supported the development of Tampa Electric's 2012 TYSP filed with the Commission in April 2012. This analysis indicated incremental supply resources are needed in 2017 to meet the 20 percent reserve margin criteria and 7 percent minimum supply criteria, as shown on Document No. 4 of my exhibit. Without additional firm supply resources the summer firm reserve margin is 12.5 percent and the supply component would fall to 6.8 percent in summer 2017.

Q. Please describe the results of the FRCC region reliability analysis.

A. Tampa Electric's 2012 TYSP data was included in the aggregate 2012 FRCC TYSP workshop presentation to the Commission on August 13, 2012. The FRCC reserve margin table in Document No. 5 of my exhibit shows that the existing planned demand and supply resource additions by Florida utilities will meet the minimum reliability of 15 percent through 2021. However, the initial reliability assessment should remove all planned and proposed unit additions and review potential modifications to existing generating capacity.

In addition, the FRCC has analyzed the increasing dependency on DSM programs to provide these reserves. Beginning with the 2012 Load & Resource Plan, the FRCC developed a metric for DSM as a percentage of regional peak. During the FRCC workshop, it was reported that of the eight NERC reliability regions, the FRCC is among the highest in DSM as a percentage of regional peak.

This increased dependency on DSM programs combined with the uncertainty of planned yet uncommitted supply additions as well as existing resources at risk of retirement due to emerging environmental regulations or other factors raise questions regarding future reserve margin calculations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019. This sensitivity analysis is reflected in Document No. 6 of my exhibit.

Q. Please describe the results of the preliminary IRP analysis.

A. The IRP included an additional 70.4 MW and 33.1 MW of summer and winter demand reductions and incremental energy conservation of 230.7 GWH compared to the cumulative reductions to date. The IRP also confirmed the need for firm purchases through 2016, and confirmed the need for the conversion of the existing Polk 2-5 peaking units to combined cycle in 2017 together with an additional simple cycle combustion turbine in 2019. The preliminary resource plan is shown in Document No. 7 of my exhibit. This shows that accelerating the Polk 2-5 in-service date from 2019 as shown in the 2011 TYSP to 2017 resulted in $65.4 million in savings.

The IRP screening process identified numerous resource plans and two alternate plans were selected for further comparative analysis to the Polk 2-5 plan. The first alternate plan utilized only simple-cycle peaking unit additions throughout the planning horizon, and the second alternate plan utilized simple-cycle peaking units in the near term with the conversion of the Polk CTs to a NGCC in 2025. The final IRP resource plans that Tampa Electric considered are shown in Document No. 8 of my exhibit.

Q. Please describe the results of the final IRP analysis.

A. Tampa Electric's economic evaluation process and consideration of qualitative factors determined that constructing NGCC technology at Polk Power Station represented the most cost-effective option for Tampa Electric and its customers. The expansion plan was then used to develop avoided cost parameters to evaluate new and modified DSM programs. The final Polk 2-5 plan demonstrated a CPWRR savings of $231.1 million when compared to the next best alternative. The two alternate plans are higher total cost utilizing the base assumptions due to higher operating costs. This base economic analysis is shown in Document No. 8 of my exhibit.

Q. Did Tampa Electric conduct sensitivity analyses related to the selection of Polk 2-5 in the IRP process?

A. Yes. Tampa Electric conducted sensitivity analyses to compare the Polk 2-5 plan with the two alternate expansion plans. The analyses tested the sensitivity of the recommended plan to independent variances in fuel prices, customer demand and energy forecasts, and expansion plan construction costs. High and low fuel forecast bands are discussed in the direct testimony of Tampa Electric witness J. Brent Caldwell. High and low customer demand forecast bands are discussed in the direct testimony of Tampa Electric witness Lorraine L. Cifuentes. High and low construction cost bands are discussed in the direct testimony of Tampa Electric witness Mark J. Hornick. The analysis held all other factors constant while applying the targeted sensitivities to the recommended plan and alternate plans to determine the total systems costs and compare the 30-year CPWRR.

Q. Please describe the results of the IRP sensitivity analyses.

A. After completion of the six sensitivity cases mentioned above, Polk 2-5 was found to be the most economical choice in all cases. When comparing Polk 2-5 to the two alternate plans in the capital cost sensitivities, Polk 2-5 showed savings of $278.4 million (low cost) and $289.9 million (high cost) in CPWRR compared to the next most cost-effective option. When comparing Polk 2-5 to the two alternate plans in the customer demand and energy sensitivities, Polk 2-5 showed savings of $283.9 million (low demand) and $75.6 million (high demand) in CPWRR compared to the next most cost-effective option. When comparing Polk 2-5 to the two alternate plans in the fuel price sensitivities, Polk 2-5 showed savings of $106.2 million (low fuel cost) and $302.1 million (high fuel cost) in CPWRR compared to the next most cost-effective option. A summary of the economic sensitivity analysis is shown in Document No. 9 of my exhibit.

RESOURCE REQUEST FOR PROPOSALS

Q. Did Tampa Electric conduct an RFP to solicit proposals to meet its peaking needs from 2013 through 2016 to replace the expiration of the 20-year Hardee Power agreement that expires on December 31, 2012?

A. Yes. In 2011, Tampa Electric issued a Request for Proposals ("RFP") to solicit market proposals for capacity needs from known participants in the market and conducted bilateral negotiations with the top proposals. This resulted in selecting two competitive agreements to purchase 117 MW peaking power through the end of 2016 and 160 MW peaking power through the end of 2015.

Q. Did Tampa Electric conduct an RFP to solicit alternatives to meet its need for intermediate power beginning in 2017?

A. Yes. Tampa Electric conducted an RFP which solicited proposals from all market participants. In March 2012, Tampa Electric issued an RFP soliciting firm offers for cost-effective alternatives to Polk 2-5. The RFP development and evaluation process are discussed here and in the direct testimony of witness Alan S. Taylor on behalf of Tampa Electric.

Q. Please describe the development process of the RFP.

A. Various subject matter experts from across the company, along with witness Taylor as the independent evaluator, crafted, reviewed and edited the RFP document. It incorporated sufficient schedule, scope and basis detail for all respondents in the preparation of their bid, specifying how their bid would be evaluated. As an attachment to the RFP, Tampa Electric included a draft PPA that provided respondents with a clear understanding of the general terms and conditions.

Q. Please describe the evaluation process of the RFP?

A. The evaluation process included: initial screening for minimum requirements, high level economic evaluation of individual proposals, present value economic screen of proposals, and a final evaluation of total system costs and non-economic factors. Short-listed bidders were invited to make a best and final offer. The final present value evaluation included a relative evaluation of non-economic factors.

In addition to evaluating individual proposals, Tampa Electric evaluated combinations of proposals into portfolios of generating alternatives in order to solicit a robust range of individual proposals. Eligible proposals that passed initial screening and individual economic ranking, but did not individually meet the capacity requirement for a given year, were evaluated in portfolios that matched them with other resources to meet the capacity need and the sequence of annual need identified in the solicitation.

Q. What was the result of the RFP for 2017 capacity?

A. Document No. 10 of my exhibit contains a summary of the short-listed bidders. After comparing the results of Tampa Electric's analysis and those performed by the independent evaluator, Polk 2-5 NGCC was selected as the most cost-effective alternative. This resulted in a CPWRR savings of $132.4 million relative to the next higher cost bidder. A summary of the RFP resource plans and economic analysis is shown in Document No. 11 of my exhibit.

Q. Please describe Tampa Electric's proposed Polk 2-5 NGCC unit.

A. The existing Polk 2 through 5 combustion turbines will be converted to a NGCC facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter, incrementally. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for two future aero-derivative peaking units due to the expiration of a 121 MW PPA on December 31, 2018. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The NGCC configuration also enables the potential integration of solar thermal renewable capacity and energy in the future.

Q. Does Polk 2-5 have dual fuel capability?

A. The existing Polk Units 2 and 3 have dual fuel capability; the existing Polk Units 4 and 5 are currently natural gas fuel only, but will be permitted for future dual fuel capability. The cost for converting Units 4 and 5 are not included in the construction and operating plan.

Q. Please describe the consideration of the qualitative factors in the selection of Polk 2-5.

A. Tampa Electric considered 13 unique non-economic, qualitative factors in its selection. The proposals were evaluated individually and in the relative context of the other proposals. Document No. 12 of my exhibit contains a summary of the evaluation of the relative qualitative factors. Polk 2-5 NGCC was favored due to its overall reliability, system emissions rate, and dispatchability.

FINAL RECOMMENDED RESOURCE PLAN

Q. Were any resource plan assumptions updated prior to developing the final recommended resource plan and after the implementation of the RFP?

A. Yes. As part of the business planning cycle for Tampa Electric, the fuel forecast, the customer demand forecast, and other operating and financial forecasts are updated in June 2012 of each year. These updated forecasts are the basis for the next business planning cycle and activities, including: studies which support all of the cost recovery clause filings in August for reforecasting end of current year and following year projections. These updated assumptions are also used to develop the company's following year TYSP filed in April. As a result, Tampa Electric updated its fuel price and customer demand forecast in June 2012 as part of its normal business cycle and in preparation for the 2013 fuel adjustment filed in August 2012 and the

2013 TYSP filing due in April 2013. This analysis included the impacts of new and modified DSM programs. An assessment of the June 2012 updated fuel price forecast and customer demand and energy forecast confirm the forecasts are within the bands of the sensitivities used in the original IRP process. The updated fuel price forecast reflects lower natural gas prices overall; the updated solid fuel price forecast are somewhat lower as well.

The updated demand and energy forecast reflects lower growth in customer demand and energy requirements which reduces the amount of capacity needed in 2017 from 294 MW to 205 MW; this affirms Tampa Electric’s stated need for additional resources in 2017. The updated forecasts were used to test the IRP and RFP recommended plan to construct Polk 2-5 NGCC as the most cost-effective alternative. For the IRP alternate expansion plan cases using updated forecasts, the Polk 2-5 plan resulted in CPWRR savings of $266.7 million relative to the closest IRP alternate expansion plan. For the RFP proposals using updated forecasts, the resulting CPWRR savings is $97.4 million relative to the most competitive bidder. Both of these updated forecast results support Tampa Electric’s final recommended resource plan. Document No. 13 of my exhibit contains a summary of the analysis utilizing updated assumptions. Finally, considering the comprehensive analyses, the qualitative factors, and the benefit to state-wide reliability Polk 2-5 is the most cost effective alternative for customers.

Q. What is the expected relative average retail customer cost impact of Polk 2-5 compared to the reference case alternative?

A. The relative retail customer cost impact was calculated on an energy (MWH) basis. In 2017, the projected average retail customer cost impact for the Polk 2-5 NGCC plan is $6.09 per MWH; however, the customer cost recovery clause impact for Polk 2-5 NGCC is projected to be lower by $1.32 per MWH due to lower fuel and purchased power and capacity costs for a net customer cost impact of $4.76 per MWH compared to projected costs in 2016. The incremental supplemental duct-firing capacity of Polk 2-5 replaces the purchased power capacity that retires at end of 2018. This cost-effective incremental capacity eliminates the need for additional supply resources and the associated costs to construct and operate those avoided units. Finally, the PPA expiration incrementally lowers the customer cost recovery clause impact by an additional $0.50 per MWH that would otherwise occur in 2019.

BASIS FOR DETERMINATION OF NEED

Q. Has Tampa Electric adequately established that there is a need for Polk 2-5?

A. Yes. Tampa Electric will require an additional 294 MW of firm supply resources in 2017 based upon the reliability analysis. The most recent June 2012 forecast update for customer demand described in the testimony of witness Cifuentes reaffirms this need; based on this update, there is a need for 205 MW of firm supply resources in 2017.

Q. Is the addition of Polk 2-5 consistent with the needs of peninsular Florida?

A. Yes. Polk 2-5 does not significantly increase Tampa Electric's reliance on natural gas on an energy basis and is therefore consistent with state policy actions that encourage fuel diversity. The Polk 2-5 conversion significantly improves the efficiency of the four existing combustion turbines units and Tampa Electric's system overall by lowering the heat rate and dispatching ahead of other less efficient units. It should also be noted that load management and interruptible customer DSM programs are voluntary, so customers have a choice to withdraw from programs at any time with proper notification. During the

2012 TYSP Workshop on August 13, the FRCC presented a chart to the FPSC which showed the summer reserve margin without exercising load management or interruptibles would only be about 15 percent, which includes all planned additions, including Polk 2-5 in 2017.

Tampa Electric's need for additional natural gas-fired combined cycle capacity in January 2017 is consistent with the Peninsular Florida capacity needs in this same period, as identified by the FRCC and reported in the FRCC 2012 Regional Load and Resource Plan. The FRCC 2012 plan uses Tampa Electric specific data in conjunction with similar information from other Florida electric utilities. In addition, there are concerns regarding continued operation of existing solid fuel assets due to emerging environmental regulations and the costs to comply. Tampa Electric has completed all the required environmental controls for all of its solid fuel units. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019.

ADVERSE CONSEQUENCES

Q. What would be the adverse consequences if the Polk 2-5 in-service date were delayed from 2017 to 2019?

A. In the event that Polk 2-5 is delayed by two years, project costs would increase, and customer fuel savings for 2017 and 2018 would not be realized. Tampa Electric would construct simple cycle peaking units in 2017 to cover the reserve margin requirement in 2017 and 2018. System energy requirements would be served by peaking capacity resulting in higher fuel costs. This would result in higher costs for customers of $65.4 million on a CPWRR basis. Witness Hornick describes the potential for an equipment demand spike scenario if there is a delay. If this equipment demand spike scenario materializes, this would result in higher costs for customers of $100.0 million on a CPWRR basis.

Q. What would be the adverse consequences if the proposed Polk 2-5 is denied?

A. If Polk 2-5 is denied, Tampa Electric would not be able to satisfy its minimum 20 percent Reserve Margin and minimum 7 percent supply planning criteria by the summer of 2017 in the most reliable and cost-effective manner. This would expose Tampa Electric's customers to a greater risk of interruption of service in the event of unanticipated forced outages or other contingencies for which Tampa Electric maintains reserves. Even without an interruption in service, without Polk 2-5 the company's customers would be subject to higher fuel costs as the company would have to rely on less efficient simple cycle generation to meet its need.

Q. Should Tampa Electric's petition for determination of need for Polk 2-5 be approved?

A. Yes. For the reasons I have described, Polk 2-5 is the most cost effective option for Tampa Electric's customers to maintain system reliability, environmental emission rates and fuel diversity. Tampa Electric requests that the Commission issue an affirmative determination of need for Polk 2-5 in this proceeding.

Q. Please summarize your direct testimony.

A. Tampa Electric's IRP process incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. By 2017, Tampa Electric's DSM programs will have produced summer and winter customer demand and energy reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW. Alternate plans, technologies, sensitivities, timing, and a market solicitation were evaluated and the selection of Polk 2-5 was supported by subsequent economic analyses of viable supply alternatives, demonstrating that Polk 2-5 is the most cost-effective option compared to other technologies and available supply capacity from the Florida market.

After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year deferral of the recommended plan could increase costs to customers by $100.0 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix. When considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, Polk 2-5 is needed as a firm resource within the FRCC region.

Polk 2-5 provides significant savings of $132.4 million to Tampa Electric's customers when compared to the most cost-effective alternative while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. The results of these scenarios reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

R. JAMES ROCHA

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
WITNESS: ROCHA

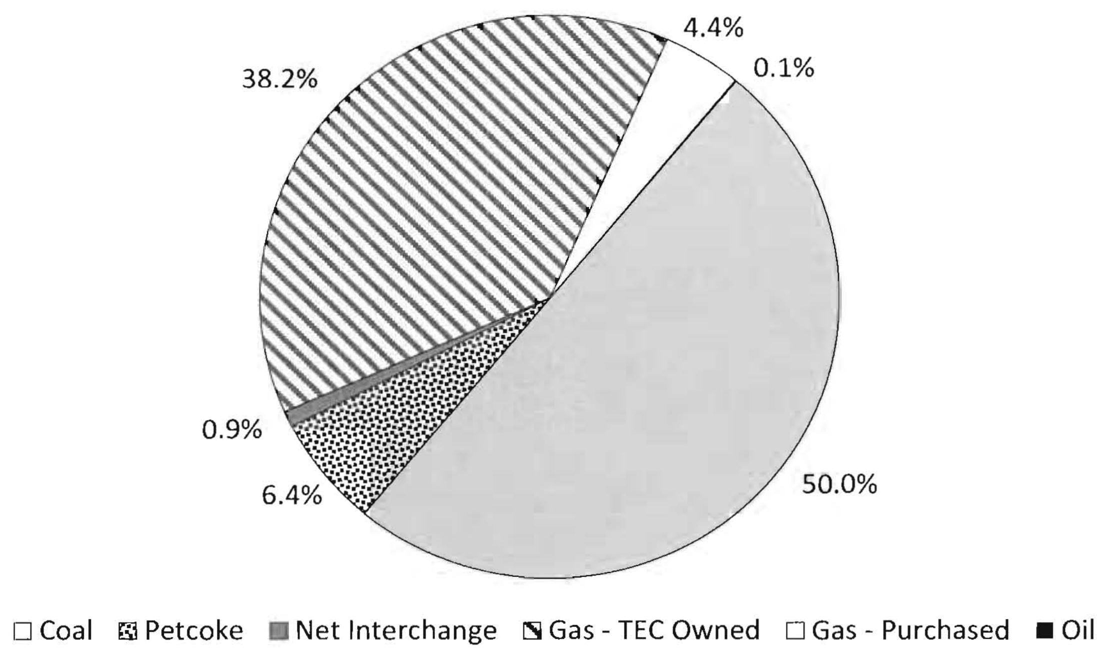
Table of Contents

DOCUMENT NO. 1

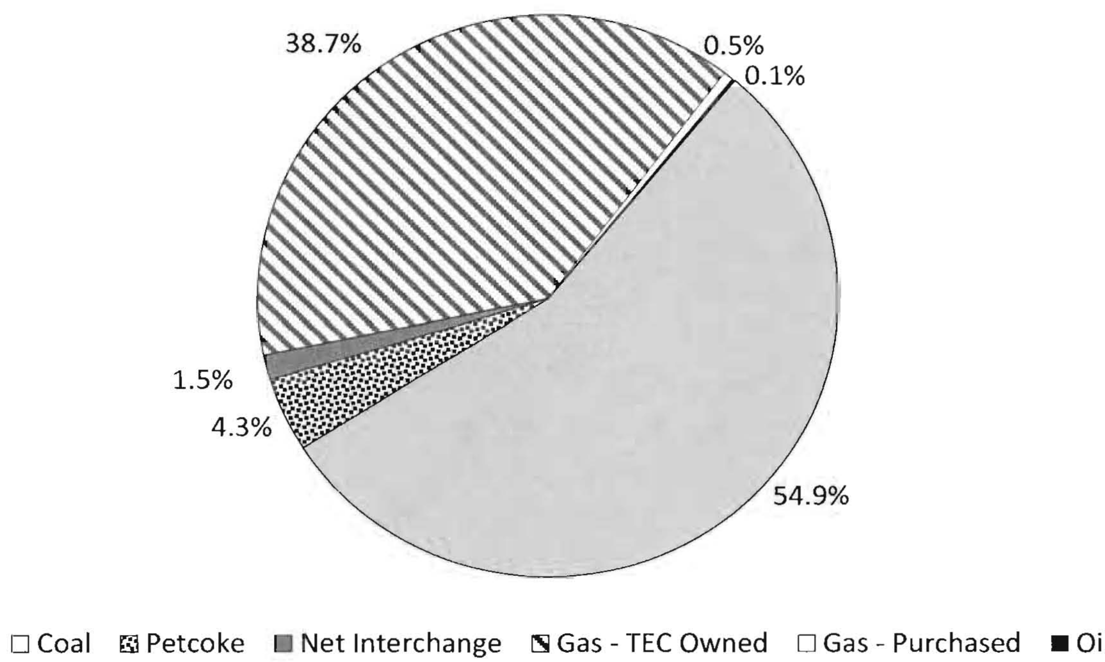
ENERGY MIX BY FUEL TYPE

Energy Mix By Fuel Type

2011 Actual Energy Percentage By Fuel Type
Total Energy - 19,325 GWh



2017 Projected Energy Percentage By Fuel Type
Total Energy - 20,773 GWh

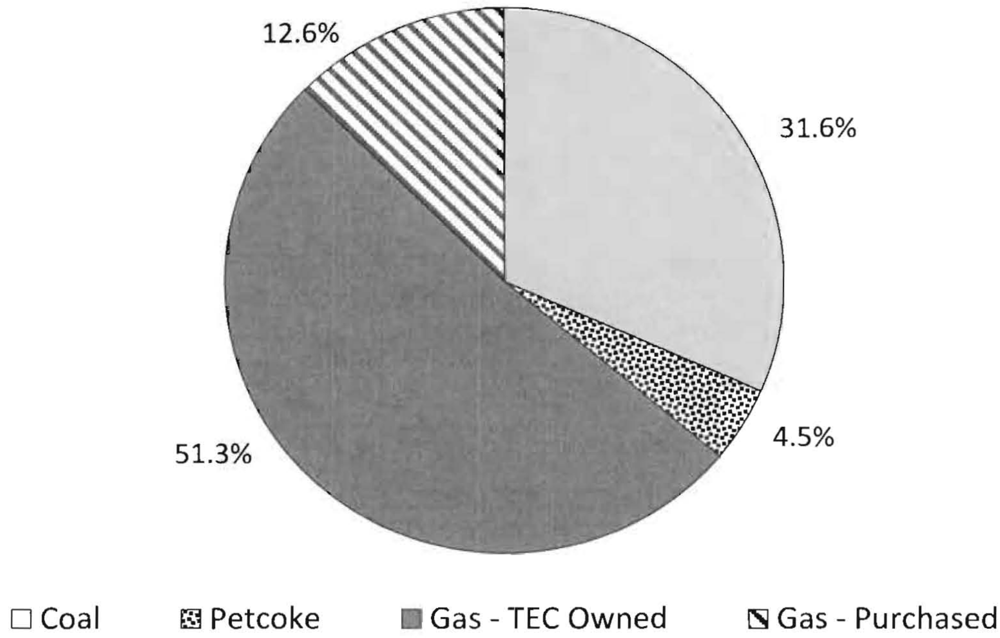


DOCUMENT NO. 2

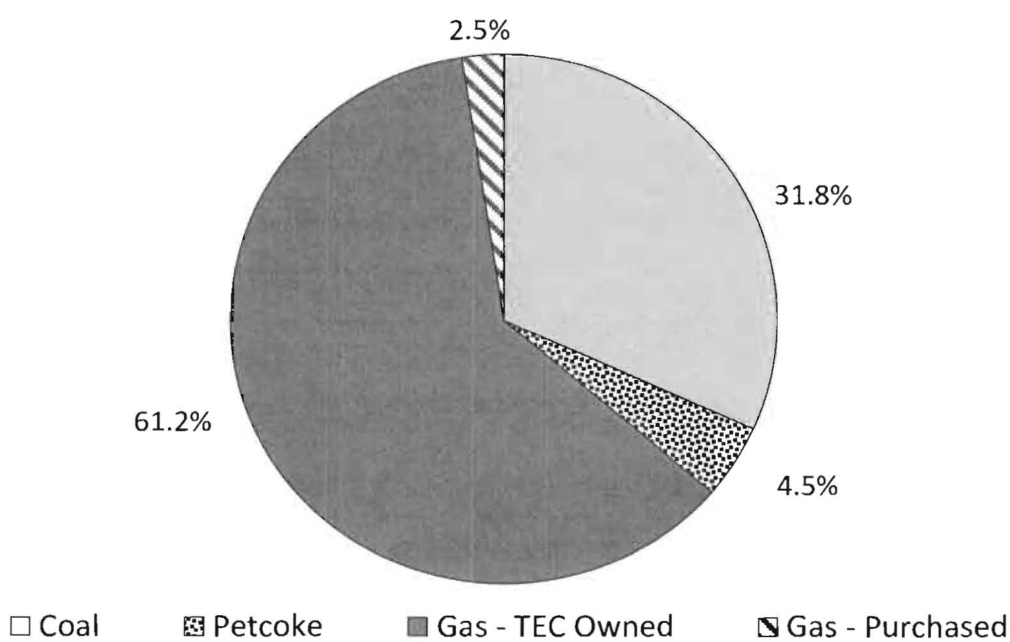
CAPACITY MIX BY FUEL TYPE

Capacity Mix By Fuel Type

2011 Actual Capacity Percentage By Fuel Type
Total Capacity - 4,909 MW



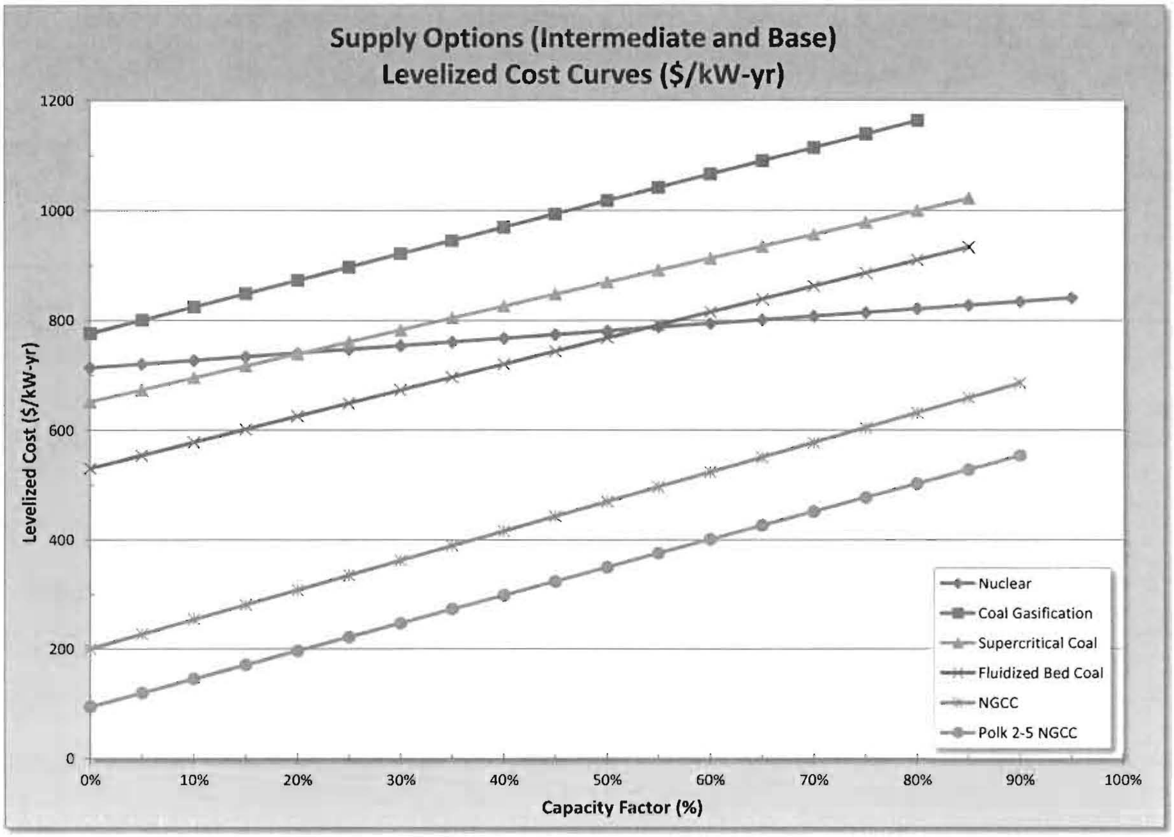
2017 Projected Capacity Percentage By Fuel Type
Total Capacity - 4,856 MW

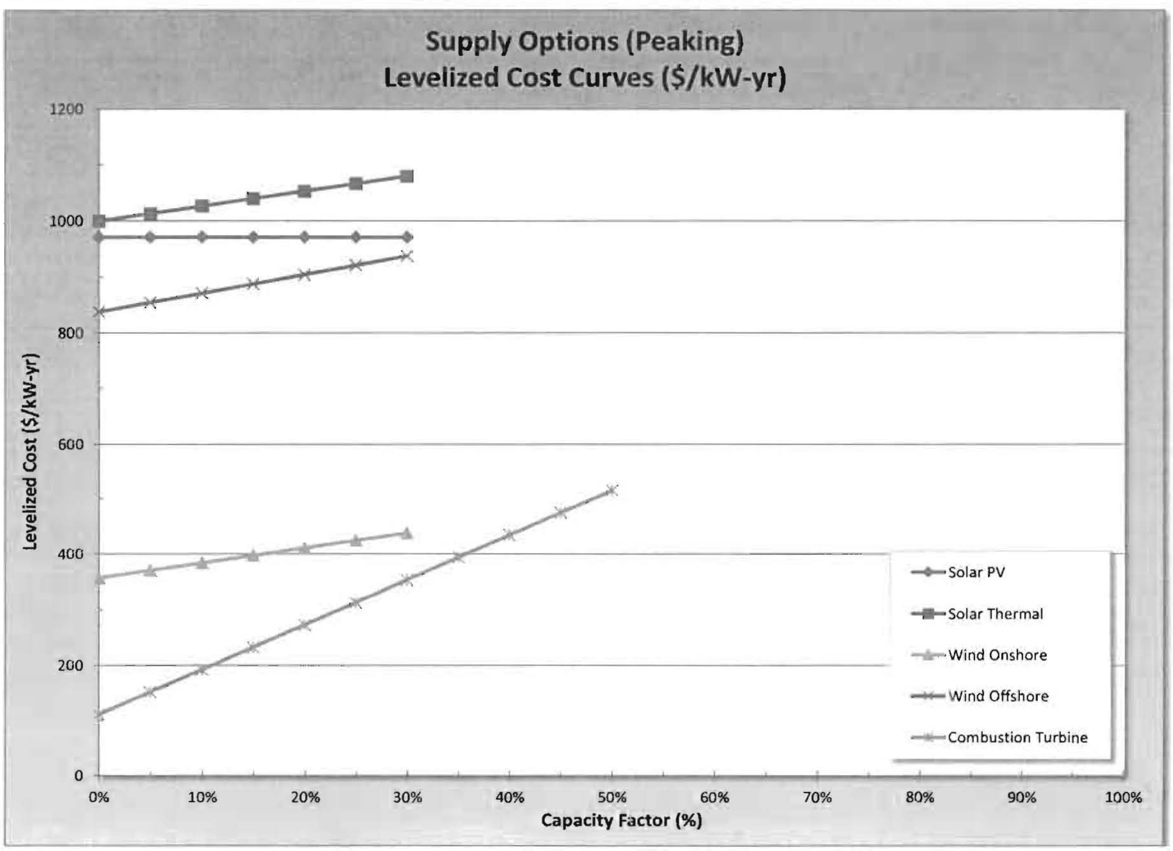


DOCUMENT NO. 3

LEVELIZED COST SCREENING CURVES

Levelized Cost Screening Curves





DOCUMENT NO. 4

TAMPA ELECTRIC RELIABILITY ANALYSIS

Tampa Electric Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak

Year	Total Installed Capacity	Net Firm Capacity Purchases	Total Capacity Available	System Firm Peak Demand	System Total Peak Demand	Firm Reserve Margin w/o Planned Additions			Supply-Side Reserve Margin w/o Planned Additions		
	MW	MW	MW	MW	MW	MW	% of Peak	Shortfall for 20% MW	MW	% of Peak	Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,312	121	4,433	3,940	4,165	493	12.5%	294	268	6.8%	8
2018	4,312	121	4,433	3,980	4,207	453	11.4%	343	226	5.7%	53
2019	4,312	0	4,312	4,022	4,250	290	7.2%	515	62	1.5%	220
2020	4,312	0	4,312	4,064	4,292	248	6.1%	565	20	0.5%	264
2021	4,312	0	4,312	4,103	4,331	209	5.1%	612	(19)	-0.5%	306

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FRCC RELIABILITY ANALYSIS

FRCC Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak with Planned Additions

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin With Excercising Load Mgmt & Int. MW	Firm Reserve Margin With Excercising Load Mgmt & Int. % of Peak	Reserve Margin w/o Excercising Load Mgmt & Int. MW	Reserve Margin w/o Excercising Load Mgmt & Int. % of Peak
2012	47,747	6,486	54,233	42,430	45,613	11,803	27.8%	8,620	18.9%
2013	48,506	6,316	54,822	43,041	46,270	11,781	27.4%	8,552	18.5%
2014	49,730	5,613	55,343	43,618	46,857	11,725	26.9%	8,486	18.1%
2015	51,567	5,614	57,181	44,459	47,758	12,722	28.6%	9,423	19.7%
2016	52,118	4,473	56,591	45,242	48,594	11,349	25.1%	7,997	16.5%
2017	52,553	4,296	56,849	45,802	49,244	11,047	24.1%	7,605	15.4%
2018	52,539	4,382	56,921	46,152	49,643	10,769	23.3%	7,278	14.7%
2019	53,585	4,263	57,848	46,803	50,356	11,045	23.6%	7,492	14.9%
2020	53,667	4,180	57,847	47,581	51,191	10,266	21.6%	6,656	13.0%
2021	55,968	3,973	59,941	48,273	51,933	11,668	24.2%	8,008	15.4%

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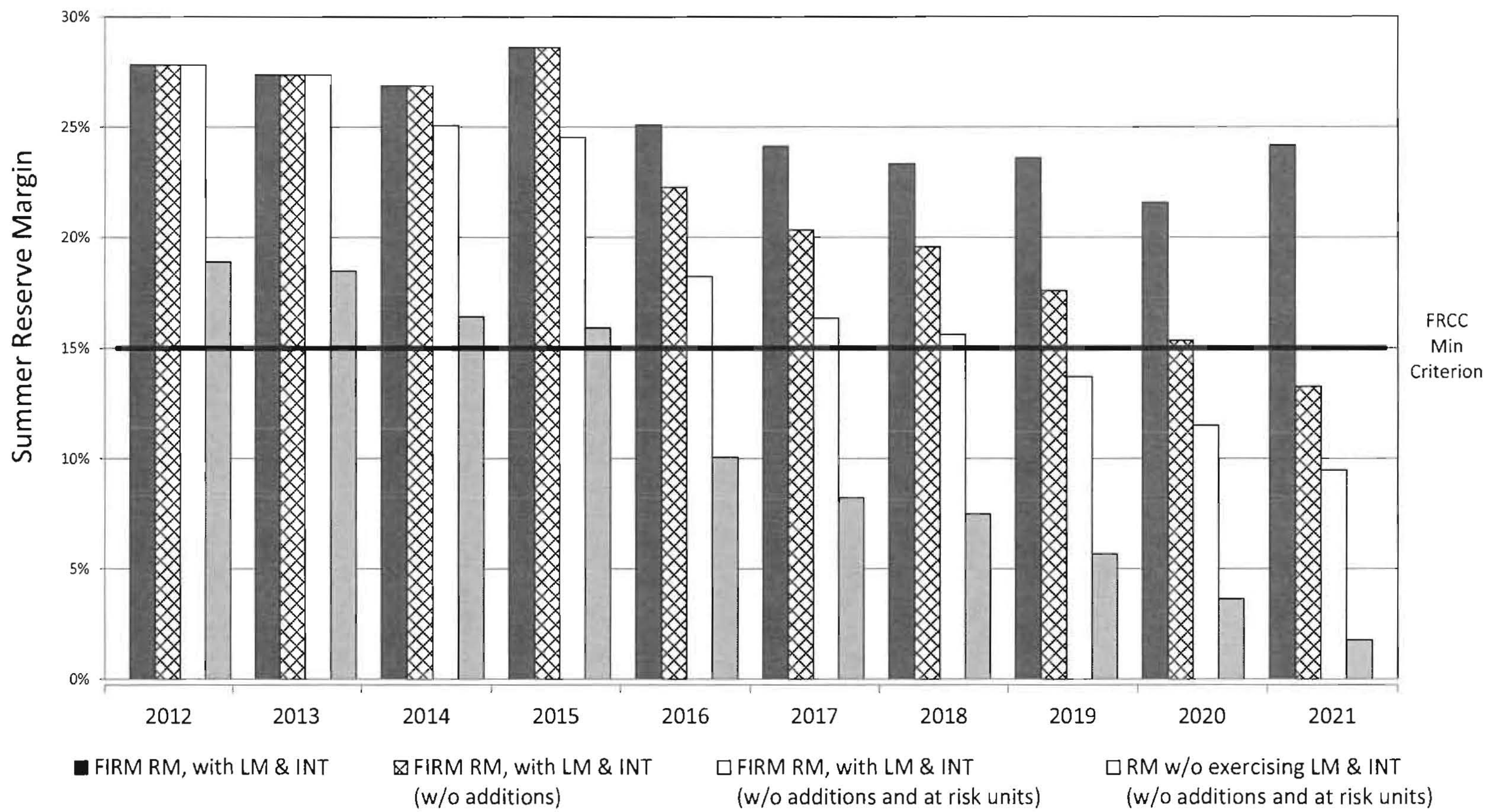
FRCC RELIABILITY SENSITIVITY ANALYSIS

FRCC Reliability Sensitivity Analysis



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DOCUMENT NO. 7

PRELIMINARY RESOURCE PLANS & ANALYSIS

Preliminary Resource Plans & Analysis

Resource Plans

2019 Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) Polk 2-5 NGCC 463/459 MW
2020	
2021	

2017 Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	
2021	

CPWRR ($M)

	2019 Polk 2-5	2017 Polk 2-5
Capital	$1,584.2	$1,566.4
O&M	$1,113.6	$1,099.7
Fuel & Purchased Power	$15,599.8	$15,566.1
Total	$18,300.3	$18,232.2
Delta		$65.4

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IRP RESOURCE PLANS & ANALYSIS

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IRP Resource Plans & Analysis

Resource Plans

Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	_
2028	_
2029	(1) 7FA CT 177/149 MW
2030	_
2031	_
2032	_

Alternative 1

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	_
2028	_
2029	(1) 7FA CT 177/149 MW
2030	_
2031	_
2032	_

Alternative 2

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) Polk 2-5 NGCC 463/459 MW
2026	
2027	_
2028	_
2029	_
2030	_
2031	_
2032	_

CPWRR ($M)

	Polk 2-5	Alternative 1	Alternative 2
Capital	$1,566.4	$1,281.1	$1,576.9
O&M	$1,099.7	$1,172.5	$1,139.5
Fuel & Purchased Power	$15,566.1	$16,062.6	$15,746.9
Total	$18,232.2	$18,516.2	$18,463.3
Delta		$284.0	$231.1

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IRP SENSITIVITY ANALYSIS

IRP Sensitivity Analysis

CPWRR ($M)

	Polk 2-5	Alternative 1	Alternative 2
Capital Costs Sensitivities:			
Low	$17,950.5	$18,416.9	$18,228.9
Delta		$466.4	$278.4
High	$18,135.3	$18,592.1	$18,425.2
Delta		$456.8	$289.9
Customer Demand Sensitivities			
Low	$16,857.1	$17,141.0	$17,168.7
Delta		$283.9	$311.6
High	$19,791.6	$20,356.6	$19,867.2
Delta		$565.0	$75.6
Fuel Costs Sensitivities			
Low	$15,549.6	$15,655.8	$15,715.5
Delta		$106.2	$165.8
High	$21,971.5	$22,453.5	$22,273.5
Delta		$482.1	$302.1

DOCUMENT NO. 10

RFP SUMMARY OF PROPOSALS

REDACTED

RFP Summary of Proposals

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Company	TEC	[redacted]			
Type	Intermediate	Intermediate PPA	Sale of peaking facility	Peaking PPA	Peaking PPA
Technology	4x1 CC Conversion	2x1 CC	(2) 7FA CTs	New Build 7FA.05 CT	New Build 7FA.05 CT
Plant Name	Polk Power Station	[redacted]			
Capacity (MW)	459(S)/463(W)				
Start Year	2017	2017	2013	2017	2017
Term (years)	N/A	10	N/A	10	15
HR (Btu/kWh)	7,062	[redacted]			

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RFP RESOURCE PLANS & ANALYSIS

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RFP Resource Plans & Analysis

Resource Plans

Year	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
2012					
2013			Proposal B		
2014					
2015					
2016					
2017	(1) Polk 2-5 NGCC 463/459 MW	Proposal A		Proposal C (1) 7FA CT 177/149 MW	Proposal D (1) 7FA CT 177/149 MW
2018			(1) Polk 2-5 NGCC 463/459 MW		
2019	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW		(2) 7FA CT 354/298 MW	(2) 7FA CT 354/298 MW
2020					
2021					
2022	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW			
2023				(1) Polk 2-5 NGCC 463/459 MW	(1) Polk 2-5 NGCC 463/459 MW
2024					
2025	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW			
2026			(1) 7FA CT 177/149 MW		
2027		(1) Polk 2-5 NGCC 463/459 MW			
2028					
2029	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	
2030					
2031					
2032					(1) 7FA CT 177/149 MW

CPWRR ($ million)

	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Capital	$1,575.2	$1,253.3	$1,400.1	$1,430.9	$1,416.6
O&M	$1,099.7	$1,064.6	$1,068.7	$1,111.2	$1,109.2
Fuel & Purchased Power	$15,566.1	$16,143.0	$15,904.5	$15,909.9	$15,954.9
Total	$18,241.0	$18,460.9	$18,373.4	$18,452.0	$18,480.8
Delta		$219.9	$132.4	$210.9	$239.7

DOCUMENT NO.12

RFP QUALITATIVE FACTORS

RFP Qualitative Factors

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Technology Type	Combined Cycle	Combined Cycle	Peakers	Peaker	Peaker
Transmission Reliability, Voltage Support, Reserves	High High	High High	Medium Low	Medium Low	Medium Low
Water Availability	Municipal Source	Municipal Source	Limited, water use caution area	Unknown	Unknown
Dual Fuel Capability	2 CTs - Yes, 2 CTs - Capable	No	2 CTs - Yes	1 CT - Yes	1 CT - Yes
Project Execution	Low risk	Existing Unit	Existing Unit	Low risk	Low risk
Project Operation	TEC	Owner	ST – contractors LT – TEC employees	Contractor	Contractor
Project Maintenance	CSA	Self-managed, as needed	CSA and CT spares modeled	Self-managed, as needed	Self-managed, as needed
Project Security	Investment Grade	Low – offered lien or step in rights	Investment Grade	Investment Grade	Investment Grade
Environmental Emission Rates	Lower	Lower	Higher	Higher	Higher
Renewable Option	30 MW Solar	None	None	None	None
Simple Cycle Capability	Yes	No	Yes	Yes	Yes
Job Creation and Tax Base	Construction labor	No: existing unit	No: existing unit TEC may increase O&M	Construction, O&M labor	Construction, O&M labor

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DOCUMENT NO. 13

JUNE 2012 ASSUMPTIONS UPDATE

June 2012 Assumptions Update

Resource Plans

Portfolio Additions

Year	Polk 2-5	Alternative 2	Proposal B
2012			
2013			Proposal B
2014			
2015			
2016			
2017	(1) Polk 2-5 NGCC 463/459 MW	(2) 7FA CT 354/298 MW	
2018			
2019		(1) 7FA CT 177/149 MW	(1) Polk 2-5 NGCC 463/459 MW
2020	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	
2021			
2022			
2023	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	
2024			
2025			
2026	(1) 7FA CT 177/149 MW	(1) Polk 2-5 NGCC 463/459 MW	
2027			(1) 7FA CT 177/149 MW
2028			
2029	(1) 7FA CT 177/149 MW		(1) 7FA CT 177/149 MW
2030			
2031			
2032			

CPWRR ($ million)

	Polk 2-5	Alternative 2	Proposal B
Capital	$1,557.2	$1,520.4	$1,357.5
O&M	$845.2	$897.5	$815.1
Fuel & Purchased Power	$13,631.7	$13,882.9	$13,623.5
Total	$16,034.1	$16,300.8	$16,131.5
Delta		$266.7	$97.4

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 12 0234 -EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION TO DETERMINE NEED FOR

POLK 2-5 COMBINED CYCLE CONVERSION

DIRECT TESTIMONY AND EXHIBIT

OF

ALAN S. TAYLOR

ON BEHALF OF TAMPA ELECTRIC COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ALAN S. TAYLOR

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Alan S. Taylor, and my business address is 821 15th Street, Boulder, Colorado, 80302.

Q. By whom are you employed and what position do you hold?

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 and graduated valedictorian.

I have worked in the utility planning and operations area for 25 years, predominantly as a consultant 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", now New Energy Associates), 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 two dozen electric utility conventional and renewable resource solicitations.

Q. What is the purpose of your direct testimony?

A. Sedway Consulting was retained by Tampa Electric Company (Tampa Electric) to provide independent evaluation services in the utility's 2012 solicitation for competitive power supplies. As the principal consultant on the project, I helped with the development of the Request for Proposals ("RFP"), reviewed Tampa Electric's solicitation process, and performed a parallel and independent economic evaluation of both Tampa Electric's Next Planned Generating Unit ("NPGU") and the proposals that were received by Tampa Electric in response to the utility's solicitation. Ultimately, I concluded that Tampa Electric's Repowering of Polk 2-5 into a combined-cycle ("CC") facility described in Tampa Electric's RFP, with an in-service date of January, 2017, represented the most cost-effective resource for meeting Tampa Electric's resource needs for 2017.

The purpose of my direct testimony is to describe my role as an independent 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 Tampa Electric's Polk Power Station

Repowering option is more cost-effective than the proposed power purchase agreement ("PPA") and asset sale alternatives that were submitted in Tampa Electric's resource solicitation.

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

Q. Please describe the role you performed as an independent evaluator in Tampa Electric's 2012 RFP project.

A. As the independent evaluator in Tampa Electric's 2012 power supply solicitation, I reviewed Tampa Electric's 2012 Ten-Year Site Plan and the utility's modeling processes pertaining to its use of Planning and Risk, Tampa Electric's detailed production costing model. I participated in the March 21, 2012 Pre-Issuance Conference Call and attended the April 4, 2012 Bidders Conference in Tampa. Before receiving the proposals, I requested that Tampa Electric run its Planning and Risk model and provide production costing results that I could use to calibrate Sedway Consulting's resource evaluation model. I participated in the opening of proposal packages in Tampa on the Proposal Due Date (May 22, 2012), retained an electronic copy of each submitted proposal, and evaluated the economic/pricing information from each proposal. Tampa Electric conferred with me on a number of issues relating to proposal RFP-noncompliance decisions, interpretation of proposal information, clarification requests, and economic evaluation assumptions. As the evaluation progressed, Tampa Electric and I discussed appropriate courses of action and modeling assumptions. Using Sedway Consulting's Response Surface Model ("RSM"), I evaluated Tampa Electric's NPGU and each submitted proposal and assessed their overall costs. I compared Sedway Consulting's ranking and results with those of Tampa Electric to confirm consistency of assumptions and concurrence of conclusions, and I documented the entire process in an independent evaluation report.

Q. You stated that you were involved in the development of the RFP. What did your involvement entail?

A. As the independent evaluator, I reviewed draft versions of the RFP document, participated in several discussions by phone, and was given the opportunity to provide my input and suggestions for improving the RFP.

Q. Do you believe that Tampa Electric's RFP was a reasonable document for soliciting proposals?

A. Yes. As one who has developed over a dozen such utility resource RFPs, I believe that Tampa Electric's RFP struck a good balance between being sufficiently detailed without being burdensome on the respondent. With its RFP, Tampa Electric released a draft PPA that provided bidders with a clear understanding of the general business arrangement that Tampa Electric contemplated.

Q. Do you believe that Tampa Electric's evaluation process was conducted fairly?

A. Yes. The proposals and Tampa Electric's NPGU were evaluated on an equal footing, with consistent assumptions applied to all resource options.

Q. Please describe Sedway Consulting's RSM model and its use in Tampa Electric's resource solicitation.

A. The RSM 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 Tampa Electric solicitation, in the weeks prior to the proposal opening, I requested that Tampa Electric 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 Tampa Electric's Planning and Risk model would produce in a subsequent evaluation of any proposals or self-build options that Tampa Electric might receive. Thus, I would not have to rely on Tampa Electric's modeling of a proposal or self-build option; instead, I would be able to insert my own inputs into my 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 Planning and Risk results?

A. As I noted above, most of the calculations performed by the RSM are not based on Planning and Risk 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 Planning and Risk 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 Tampa Electric'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 Planning and Risk 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 Planning and Risk.

Q. Please elaborate on that area of calculations where the RSM is affected by the Planning and Risk 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 Tampa Electric incurs in serving its customers' load. Given Tampa Electric's load forecast, the existing Tampa Electric supply portfolio (i.e., all current generating facilities and purchase power contracts), and many specific assumptions about future resources and fuel costs, Planning and Risk simulates the dispatch of Tampa Electric'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 Planning and Risk 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 Tampa Electric 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 Tampa Electric'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 25,000 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:	\$40/MWh	\$60/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 25,000 Btu/kWh reference unit has a variable cost of $150/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 $150/MWh energy price reference resource

$894 million for a $60/MWh energy price resource (Proposal B)

$876 million for a $40/MWh energy price resource (Proposal A)

Thus, the energy savings (relative to the selection of a $150/MWh reference resource) are $24 million for Proposal A with its $40/MWh energy price and $6 million for Proposal B with its $60/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 direct testimony as Document No. 2 of my exhibit.

Q. With that understanding of the RSM process, what did you do to calibrate the RSM to Planning and Risk?

A. I reviewed the production cost information that Tampa Electric 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 Tampa Electric's production costs with Planning and Risk's accuracy, in the end (after accounting for future portfolio composition and future unit revenue requirement methodology differences), the independent RSM evaluation results tracked Planning and Risk's results reasonably well.

Q. Once the RSM was calibrated, what was the next step?

A. I flew to Tampa for the Proposal Due Date, opened all proposal packages, and retained an electronic copy of each proposal. I read each proposal and participated in discussions with Tampa Electric about interpreting the proposals, identifying areas requiring clarification, and assessing each proposal's compliance with the RFP's Minimum Requirements. Tampa Electric 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, 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, Tampa Electric 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.

On June 21, 2012, Tampa Electric and Sedway Consulting discussed the evaluation results of the original proposals and agreed that several offers should be shortlisted. The bidders of these offers were engaged in conference calls (which Sedway Consulting monitored) to discuss their bids and respond to questions. These bidders were provided an opportunity to provide best-and-final offers on July 13, 2012.

Q. What were the results of Sedway Consulting's RSM analysis?

A. Using the RSM, Sedway Consulting was able to compare the economics of Tampa Electric's NPGU and each of the proposed resource options (both the original bids and the best-and-final offers). That comparison entailed a calculation of the net present value of each option from 2013 through 2046 and accounted for 1) resources that would need to "fill in" behind options that expired before 2046 and 2) differences in the capacity of each option proposed. The evaluation was performed for a base case set of fuel price and load forecast assumptions, as well as a low fuel price/low load scenario and a high fuel price/high load scenario. Tampa Electric's NPGU was found to be $69 million (cumulative present value of revenue requirements - "CPVRR") less expensive than the next best resource's best-and-final offer under base case assumptions. The results, ranking of resources and additional scenarios are described in detail in Sedway Consulting's independent evaluation report that is attached as Document No. 2 of my exhibit.

Q. What do you conclude about Tampa Electric's solicitation?

A. I conclude that Tampa Electric's NPGU is the most cost-effective resource for meeting Tampa Electric's 2017 capacity needs and concur with Tampa Electric's decision to move forward with that project. The solicitation process yielded the best results for Tampa Electric's customers while treating proposers fairly. The RFP was sufficiently detailed to provide necessary information to proposers. The economic evaluation methodology and assumptions were appropriate and unbiased, and the independent evaluation procedures provided a cross-check of Tampa Electric's proposal representation in Planning and Risk and confirmed Tampa Electric's conclusions. Finally, I conclude that Tampa Electric's NPGU is $69 million CPVRR less expensive than the next best offered resource under base case assumptions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

ALAN S. TAYLOR

ON BEHALF OF TAMPA ELECTRIC COMPANY

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DOCUMENT NO. 1

RESUME OF ALAN S. TAYLOR

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

- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases; analyzed thousands of power supply proposals.
- 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

2006- **California Solicitations for Conventional and Renewable Resources**
2012 Client: Southern California Edison

Currently serving or has served as the Independent Evaluator (IE) in 18 solicitations for power or gas supplies in southern California – one for over 2,500 MW of new conventional resources, four for renewable energy purchases to help Southern California Edison meet its state Renewables Portfolio Standard (RPS) requirements, five for near-term capacity resources, four for reverse energy auctions of the dispatch rights to facilities under new power purchase agreements, and four for gas financial hedging products. Mr. Taylor managed or is managing a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who are/were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1993 **Competitive Bidding Design**
Client: Northern States Power

Assisted NSP in the utility's effort to design a generic competitive bidding RFP that could be issued for a variety of generation resources. Two dozen RFPs from other utilities were reviewed to determine the appropriate weights and mechanisms that should be used to score various project attributes.

1993 **Evaluation of 500 MW Supply-Side Solicitation**
Client: San Diego Gas & Electric

Assisted in the evaluation of 15 bids that were received from a 500 MW solicitation for power by SDG&E. The utility wanted to determine whether or not there were less expensive alternatives to the implementation of its plan to repower one of its own units. The 15 projects represented over 4,000 MW. The bids were evaluated using extensive production costing modeling, in which over 1,000 model runs were performed to evaluate each bid under a variety of scenarios.

DOCUMENT NO. 2

SEDWAY CONSULTING'S INDEPENDENT EVALUATION REPORT

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR TAMPA ELECTRIC COMPANY'S 2012 POWER SUPPLY SOLICITATION

Submitted by:

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Boulder, Colorado

September 10, 2012

Introduction and Background

On March 23, 2012, Tampa Electric Company (Tampa Electric) issued a Request for Proposals (RFP) for capacity and energy to satisfy the utility's projected incremental resource need for 2017. In April, 2012, Tampa Electric released its 2012 Ten-Year Site Plan with three load forecasts (a low-load scenario, a base case, and a high-load scenario) that translated into the cumulative 2017-2019 capacity needs depicted in Table A-1.

Table A-1
Tampa Electric Cumulative Capacity Needs
(All Values in MWs)

Year	Low Load Forecast	Base Case Forecast	High Load Forecast
2017	139	295	463
2018	159	343	540
2019	304	515	739

Tampa Electric's RFP indicated that power supply proposals would be competing against a utility self-build option – namely, a conversion of four existing simple-cycle combustion turbines (CTs) at Tampa Electric's Polk power plant[1] into a 4-on-1 combined-cycle (CC) facility. The addition of the CC steam cycle is projected to provide Tampa Electric with incremental summer capacity of 459 MW by January, 2017; this conversion project was referred to as the Next Planned Generating Unit (NPGU).

Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent evaluation services to Tampa Electric and provide a parallel economic evaluation of responses to the RFP. This independent evaluation report documents Sedway Consulting's evaluation process and presents the results of Sedway Consulting's economic analysis. It describes Sedway Consulting's proprietary Response Surface Model (RSM) which was used to conduct the parallel economic evaluation, fundamental assumptions that were applied, and additional economic factors that affected the final cost of each resource.

Receipt of Proposals

On May 22, 2012, Tampa Electric received five proposals from four power suppliers. One proposal – from [redacted] – was a follow-up offer regarding a biomass retrofit project of some of TECO's existing Bayside units. Because the proposal involved a developer's use of a Tampa Electric-owned power plant, it did not comply with the RFP. Indeed, the bidder confirmed that the proposal was never meant to be considered as part of the 2012 RFP and was merely a continuation of negotiations that had been underway with Tampa Electric for several years. Thus, the [redacted] proposal was set aside, and four

[1] Specifically Polk Units 2-5.

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remaining proposals that involved three power projects from three bidders were ultimately compared with Tampa Electric's NPGU. All of these projects were natural gas-fired technologies. The four proposals/three projects entailed the following:

1. [redacted] a [redacted] power purchase agreement (PPA) for capacity and energy deliveries commencing January 1, 2017 [redacted] Hereafter, this proposal will be referred to as Proposal A in the unredacted portions of this report.

2. [redacted] a sale [redacted] proposed that the asset sale and transfer conclude on June 1, 2013. Hereafter, this proposal will be referred to as Proposal B in the unredacted portions of this report.

3. [redacted] PPA for capacity and energy deliveries commencing January 1, 2017 [redacted] The bidder provided alternative proposals for two PPAs of different durations – one of approximately [redacted] with an expiration date of [redacted] and a second of approximately [redacted] with an expiration date of [redacted].[2] Hereafter, these two proposals will be referred to as Proposal C (for the shorter PPA) and Proposal D (for the longer PPA) in the unredacted portions of this report.

Table A-2 depicts key information for Tampa Electric's NPGU and each of the proposals. Specifically, the table includes each resource's summer capacity, type (combined cycle or combustion turbine), the year that the PPA or asset transaction is expected to commence deliveries, the PPA term (or economic life in the case of asset transaction), levelized capacity price or capital-related revenue requirement (over the PPA term or asset life), full load heat rate, and variable operation and maintenance (O&M) charge.

Table A-2
Summary of Tampa Electric's NPGU and Initial Proposals

Resource	Sum. Cap. (MW)	Type	Start Year	Term/ Econ. Life (yrs)	Cap. Price ($/kW-mo)	Full Load Heat Rate (Btu/kWh)	Var. O&M ($/MWh)
Proposal A	[redacted]	[redacted]	2017	[redacted]	[redacted]	[redacted]	[redacted]
Proposal B	[redacted]	[redacted]	2013	[redacted]	[redacted]	[redacted]	[redacted]
Proposal C	[redacted]	[redacted]	2017	[redacted]	[redacted]	[redacted]	[redacted]
Proposal D	[redacted]	[redacted]	2017	[redacted]	[redacted]	[redacted]	[redacted]
Polk NPGU	459	CC	2017	30	16.94	7,062	2.98

[2] For ease of reference, these PPA alternatives will simply be referred to as [redacted]-year and [redacted]-year proposals in the remainder of this report.

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It is important to note that the statistics for Tampa Electric's NPGU in Table A-2 are based on the conversion project's *incremental* capacity. On a total capacity basis, the project will entail adding 459 MW of summer capacity to four existing CTs that have a combined summer capacity of 604 MW. Thus, the complete combined cycle plant will have a summer capacity of 1,063 MW. The levelized capacity price includes all capital costs (for generation and transmission investments) and fixed O&M costs and is converted into an equivalent levelized capacity price by dividing these costs by the incremental 459 MW. The Proposal B levelized capacity price also includes an estimate for fixed O&M costs. Unlike the NPGU, none of the bid information in Table A-2 includes transmission costs or firm gas transportation costs – all of which were calculated as described later in this report and subsequently added to the bid costs. In some cases (specifically, Proposal B), such additional costs amounted to more than $[redacted]/kW-month in levelized terms.

[redacted]

Although Sedway Consulting's (and Tampa Electric's) base case evaluation results of the initial proposals yielded total costs that were higher than the costs of Tampa Electric's NPGU, the results were deemed to be close enough[3] to warrant shortlisting all four proposals on June 22, 2012. Conference calls were scheduled with each of the bidders on July 2-3, 2012 to allow for further clarification of each bid. Sedway Consulting monitored all of those conference calls. Each bidder was offered the opportunity to provide a best-and-final offer by July 13, 2012.

[redacted]

[3] Also, sufficient uncertainty existed in key evaluation areas to warrant further review of each bid.

[redacted] All subsequent information and results in this report pertain to the best-and-final offers.

Evaluation Process

Through its review of the proposals that Sedway Consulting retrieved at the bid opening (and the subsequent submission of best-and-final offers), Sedway Consulting extracted the following economic information for each proposal:

- 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 operation and maintenance (O&M) charges (where applicable)
- Firm fuel transportation assumptions
- Fuel pricing or indexing
- Heat rate (base and duct-fired, where applicable)
- Variable O&M pricing
- Start-up costs and fuel requirements
- Expected forced outage and planned outage hours
- Tampa Electric and third-party transmission costs.

The same or analogous information was received for Tampa Electric's NPGU.

The remainder of this report section addresses the following topics:

- a description of the RSM,
- the use of a "filler" resource in evaluating proposed transactions that expired before the end of the study period, and
- the process of developing final cost estimates for all resources.

RSM Evaluation Process

The economic information for all outside proposals and Tampa Electric's NPGU was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each proposal on Tampa Electric's system production costs. The RSM calculated each option's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each option, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period. In addition, Sedway Consulting's analysis accounted for the different sizes of resources by calculating additional costs or benefits associated with meeting Tampa

Electric's resource needs from 2017-2019. For those resources and scenarios where a resource would not fully meet Tampa Electric's resource needs through 2019, a per-MW cost of a new generic CT was added to the resource's costs to cover the deficiency. In instances where a resource provided more than the required capacity, a credit was calculated – thereby recognizing the value of surplus capacity in deferring the need for Tampa Electric to develop or procure future generating capacity in 2019 and beyond.

An option's net cost was a combination of fixed and variable cost factors. On the fixed side, the RSM calculated annual fixed costs associated with capacity payments (or generation and transmission revenue requirements), fixed O&M costs, incremental capital charges, and firm gas transportation costs. These annual total fixed costs were discounted to mid-2012 dollars.

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

The RSM then estimated Tampa Electric's system production costs for each month and each option by interpolating between production costs estimates that were extracted from a set of Planning and Risk runs. 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 Tampa Electric system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated Tampa Electric's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 25,000 Btu/kWh. Thus, for each option, the RSM yielded estimates of the annual production cost savings that Tampa Electric would be projected to experience if the utility selected the resource option, relative to acquiring the same sized transaction but at the high reference resource dispatch rate. The lower an option's variable dispatch charge, the greater the production cost savings.

Filler 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 (2046). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a side-by-side comparison of the value of proposals that had varying contract durations. Also, the RSM had been calibrated with Planning and Risk runs that assumed that a proxy proposed resource would provide its capacity for the entire duration of the study period. Thus, it was necessary to continue a proposal's capacity throughout the entire period so as to maintain consistent and sufficient reserve margins. In effect, by supplementing each short-term proposal with a filler resource for the later years, the RSM was simulating what Tampa Electric would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity equal to that expired resource.

As the basis for cost assumptions for the filler resource, Sedway Consulting (and Tampa Electric) used the Polk NPGU CC resource. The same $/kW fixed cost assumptions (e.g., capital-related revenue requirements, fixed O&M costs) and variable cost assumptions (e.g., heat rates, variable O&M costs, fuel supply issues) were used, although all capital-related costs were escalated by 3%/year and variable O&M costs were escalated by 2.4%/year to account for later in-service dates than the NPGU's 2017 expected commercial operation date. The only difference involved 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 the NPGU combined-cycle plant. In other words, if a 200 MW proposal ended in 2027, the RSM assumed that a 200 MW combined-cycle facility replaced it in 2028; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW combined-cycle plant, but rather, they were a prorated portion of the construction costs of the larger NPGU combined-cycle facility.

As noted above, depending on the "in-service date" for the filler resource, the filler's capital costs were escalated from a 2012 base-year value by 3%/year. This escalation assumption represented Tampa Electric's estimate of how construction costs were likely to increase for its generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using Tampa Electric's declining revenue requirements profile for the recovery of capacity costs, Sedway Consulting used an escalating pattern that yielded the same long-term present value of revenue requirements. A traditional revenue requirements profile results in the highest capital charges in a project's early years. Thereafter, the capital-related charges decline. This is the opposite from what is usually seen in most power purchase proposals in power supply solicitations. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore restructured the filler's profile of capacity costs to match what is generally seen in the marketplace. This meant that the filler's first year's capacity costs were the lowest, with each year thereafter escalating at 3%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the traditional declining revenue requirements profile. Both profiles have the same present value.

Over the full 30 years, the restructuring of the filler's capacity costs made no difference to the present value of the facility's revenue requirements. However, in the evaluation of outside proposals that did not extend through 2046 (the end of the study period), it provided the most favorable basis for such proposals' evaluation. In effect, it assumed that, following the expiration of an outside proposal's term, Tampa Electric would procure replacement power supplies at a trended price based its NPGU. In reality, if the NPGU was determined to be most cost-effective at this future decision point, the declining revenue requirements profile would present the actual annual costs that Tampa Electric's customers would likely pay.

Figure A-1
Comparison of Capacity Price Profiles

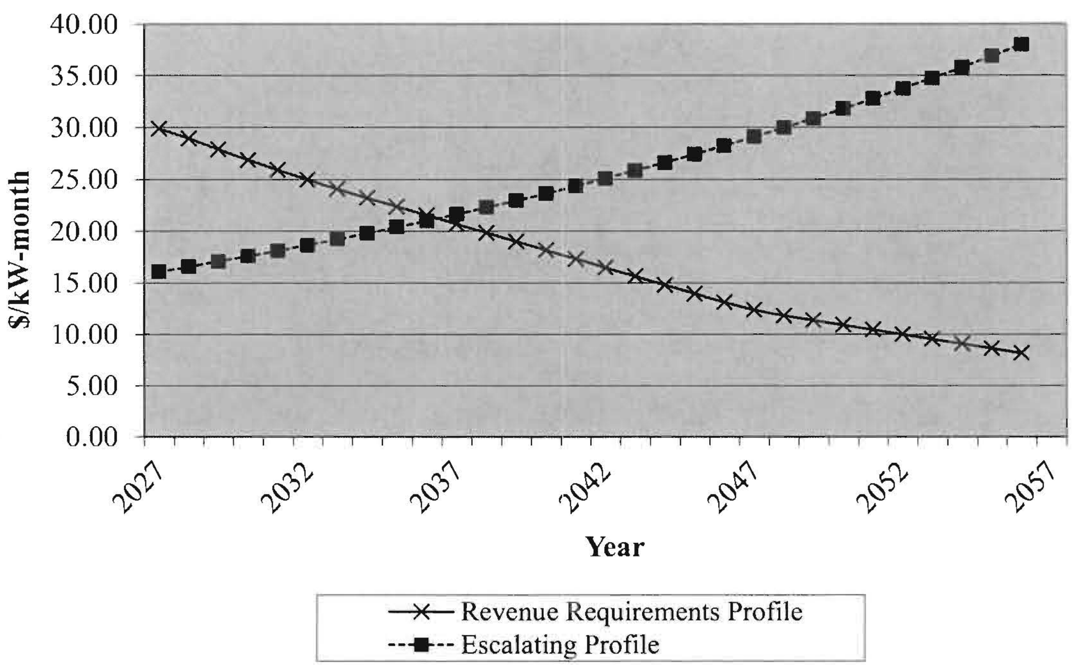
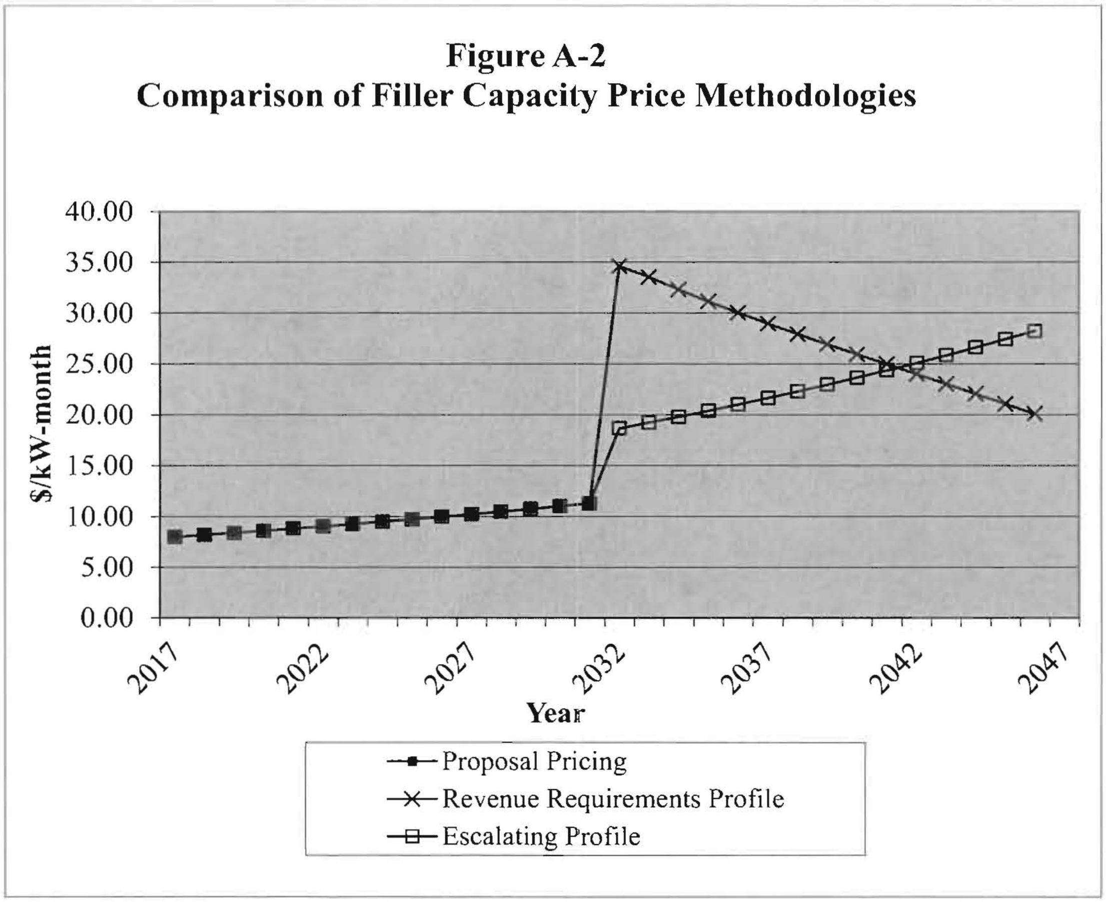


Figure A-2 depicts a comparison of the two approaches for replacing a hypothetical 15-year proposed power supply contract. The proposed contract is assumed to have a capacity charge that begins at $8/kW-month and escalates at 2.5%/year.

Relative to the declining revenue requirements methodology, the escalating filler capacity price methodology favors the 10-year proposed power supply because it defers the most expensive years of capacity costs until beyond the end of the study period. Thus, the present value of total study-period capacity costs (i.e., power supply proposal plus filler resource) is lower under the escalating filler methodology than under the declining revenue requirements methodology. Ultimately, the use of different filler methodologies by Sedway Consulting and Tampa Electric provided added value in looking at the evaluation results from two different perspectives and ensuring that the conclusions were supported from either perspective. However, because Sedway Consulting and Tampa Electric used these different methodologies, the total net present value differences depicted in the final results were understandably different.



Proposal Cost Computation

Most of the input assumptions for the proposals and Tampa Electric's NPGU were directly input into the RSM in a straightforward fashion. There were some key additional external cost estimates that were developed outside of the proposal and input into the RSM or calculated within the model. They entailed the following:

- Firm gas transportation
- Tampa Electric transmission costs
- Third-party transmission costs
- Net equity adjustment
- Surplus/deficient capacity valuation.

Firm gas transportation. Tampa Electric'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 Tampa Electric to estimate the expected annual firm gas transportation charges for each project. Sedway Consulting reviewed Tampa Electric's calculations – which included two different estimates for each project. Sedway Consulting used the lower estimate for each project. In the case of the Proposal A, the bidder had provided its own estimate (which Sedway Consulting used) that was essentially identical to the value developed by Tampa Electric. Table A-3 shows the annual firm gas transportation charges that were assigned to each resource/proposal, as well as the net present value impact on each proposal's economic evaluation.

Table A-3
Firm Gas Transportation Cost Assumptions and NPV Impact

Resource/Proposal	Annual Charges ($M/year)	NPV Impact ($M)
Proposal A	13.7	68
Proposal B	17.4	196
Proposal C	10.6	54
Proposal D	10.6	68
Polk NPGU	0	0

Tampa Electric's Polk NPGU was assumed to have no incremental firm gas transportation charges associated with it. Sedway Consulting had several discussions with Tampa Electric regarding this assumption. Tampa Electric explained that existing firm gas transportation contracts were already in place to provide a firm gas supply to the existing Polk 2-5 CTs. During full load operations of the base combined-cycle capacity of the new project, the gas consumption would not increase because the new project would simply be using the waste heat from the CTs for the incremental generation. During hours when the 120 MW of duct-firing is called on, however, gas consumption would increase. Tampa Electric maintained that it might supplement its firm gas supply with interruptible gas (i.e., higher-commodity-priced gas that did not have firm gas reservation charges associated with it). Sedway Consulting reviewed Tampa Electric's modeling results that indicated that the NPGU could be expected to consume an annual average of 6% of its gas supply in the form of interruptible gas. Sedway Consulting incorporated the annual percentage assumptions into its modeling of the NPGU, thereby increasing the effective commodity price of gas for the NPGU. All of the proposals were modeled as consuming fully firm gas (at a lower commodity price).

Tampa Electric transmission costs. With addition of new generation to a utility system, portions of the utility's transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. For proposals that were outside of Tampa Electric's transmission system, bidders were responsible for including the costs of such network upgrades to the

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other transmission provider's system in their bid pricing. However, with regard to Tampa Electric's transmission system, any proposal for generation supplies – whether located within or outside of Tampa Electric's system – might trigger the need for Tampa Electric network upgrades. Estimates of such investments were calculated by Tampa Electric's transmission department and were not verifiable by Sedway Consulting. Table A-4 provides those estimates, as well as the net present value impact on each proposal's economic evaluation.

Table A-4
Tampa Electric Network Upgrade Assumptions and NPV Impact

Resource/Proposal	Network Upgrades ($M)	NPV Impact ($M)
Proposal A	100	62
Proposal B	17	23
Proposal C	1	1
Proposal D	1	1
Polk NPGU	147	N/A[1]

[1]Included in base revenue requirements for NPGU.

Sedway Consulting and Tampa Electric had several discussions particularly about the Proposal A transmission cost estimate. Given that [redacted], Sedway Consulting thought that it would likely have no network upgrades. However, Tampa Electric's transmission department maintains that [redacted], thereby necessitating Tampa Electric transmission system reinforcements.

Sedway Consulting employed a different methodology for developing the cost impacts of network upgrades than Tampa Electric. Sedway Consulting calculated levelized annual transmission revenue requirements[4] 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). Tampa Electric developed revenue requirements from the transmission investment estimates and applied them for all years of the study period for all bids. Neither approach is right or wrong. Sedway Consulting's approach simply assumes that a transaction's transmission investments may benefit Tampa Electric's customers after the expiration of the current PPA or be associated with other power purchase transactions in the future and thus only attributes annual transmission charges to the current PPA during the years that the PPA is active. Tampa Electric's approach assumes that no future benefits will exist and the full study period revenue requirements of the transmission investment must be associated with the PPA regardless of the PPA's duration. The only proposal where this resulted in any significant net present value difference was the [redacted]. Tampa Electric's approach yielded an NPV

[4] Assuming a 30-year asset life.

cost impact for this project of $130 million, approximately $68 million more than Sedway Consulting's approach.

Third-party transmission costs. As noted above, bidders were required to include network upgrade investments on other transmission owners' systems in their bid pricing. In addition, 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 Tampa Electric. Table A-5 depicts the assumptions that were provided by the bidders and verified by the evaluation team. Wheeling charges were assumed to remain flat over the duration of the transaction – likely a conservative assumption.

Table A-5
Transmission Wheeling Cost Assumptions and NPV Impact

Resource/Proposal	Annual Wheeling Charges ($M/year)	NPV Impact ($M)
Proposal A	0	0
Proposal B	6.8	77
Proposal C	5.3	27
Proposal D	5.3	34
Polk NPGU	0	0

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

Sedway Consulting estimated for each PPA proposal (i.e., Proposals A, C and D) the costs for Tampa Electric to rebalance its capital structure if it were to enter into the PPA. This estimate was referred to as an "equity adjustment" because it reflected the present value of the incremental cost of the additional equity that Tampa Electric would need to raise to preserve the integrity of its balance sheet. The net present value of the equity adjustment for the Proposal A was in the range of $16-$17 million; it was $8 million and $13 million for Proposal C and Proposal D, respectively.

Surplus/Deficient Capacity Valuation. In Sedway Consulting's analysis, projects were evaluated on a stand-alone basis rather than in the context of a 30-year generation expansion plan, as was the case with Tampa Electric's detailed model. Sedway Consulting therefore accounted for the different capacity of each resource by recognizing to what extent it either exceeded or failed to meet Tampa Electric's capacity need in 2017-2019 and valuing the surplus or deficient capacity based on Tampa Electric's generic Frame 7FA CT costs. Specifically, if a resource provided more than Tampa Electric's cumulative capacity need in 2017-2019, then the resource was deemed to provide surplus capacity. This capacity had value because it would reduce Tampa Electric's capacity needs in 2019 and beyond and reduce the need in future power supply solicitations.[5] Using the costs and expected energy benefits of a generic Frame 7FA CT, Sedway Consulting derived a 2017 value of $8.90/kW-month, escalating thereafter at 3% per year. This stream represented trended values for the net cost of the surplus/deficient capacity.

The same arithmetic applied to those resources that were too small to meet Tampa Electric's 2017-2019 capacity needs, although in the other direction. In those cases, the deficient capacity in each year (2017-2019 and beyond) was assigned a cost that was based on the same trended net cost of Tampa Electric's generic Frame 7FA CT. In essence, such offers were being packaged with a CT to create a compliant portfolio, much the same way that Tampa Electric's generation expansion plan model did.

The inclusion of a surplus/deficient capacity benefit/cost in the RSM results placed those results on a more comparable footing with the Tampa Electric detailed production costing and generation expansion results. While no explicit surplus/deficient capacity benefit/cost was calculated to supplement the model results in Tampa Electric's analysis, this cost or benefit was captured in the long-range expansion plans that were developed around each resource.

RSM Evaluation Results

As noted in the Introduction and Background section and Table A-1 of this report, Tampa Electric's 2012 Ten-Year Site Plan included three load forecasts (a low-load scenario, a base case, and a high-load scenario). Sedway Consulting and Tampa Electric decided to conduct the evaluation of all resources under each of those load forecasts. In addition, each load scenario would be coupled with a fuel price scenario. Thus, the base load scenario would be run with the base fuel price forecast, and the high and low load forecasts would be paired with fuel prices that were approximately 35% higher or lower, respectively, than the base forecast. All such assumption details were anchored before proposals were received.

Under all scenarios, Sedway Consulting found that Tampa Electric's NPGU was the least-cost option. Table A-6 depicts the cost differences that Sedway Consulting's analysis determined for each proposal under each of the three fuel price/load scenarios.

[5] Sedway Consulting assumed that little opportunity for short-term capacity sales in the Tampa Electric area would exist in 2017 and 2018 and therefore assigned no surplus capacity value in those years; surplus capacity was only valued for 2019 and beyond.

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Table A-6
Cost Differences Relative to Tampa Electric's NPGU
($M, NPV_{2012})

Proposal	Low Case	Base Case	High Case
Proposal A [redacted]	62	148	242
Proposal A [redacted]	52	131	210
Proposal A [redacted]	15	69	120
Proposal B	291	592	947
Proposal C	240	508	802
Proposal D	260	553	876

On a net present value basis, the NPGU was found to be $69 million less expensive than the lowest-cost proposal under base case assumptions. However, it is important to note that this cost differential was associated with Proposal A's [redacted]. It is Sedway Consulting's understanding that Tampa Electric did not initially evaluate this or the [redacted] offer because they were not compliant with the RFP [redacted]. Sedway Consulting's results for the [redacted] offer are fairly close to Tampa Electric's results, after accounting for the transmission revenue requirement methodology differences described above.

Sedway Consulting's evaluation of all of the Proposal A offers is predicated on the assumption that Tampa Electric's Polk NPGU could be deferred until the end of the PPAs ([redacted]). However, at that time, the existing Polk 2-5 CTs will be approaching an age where it may not make economic sense to invest in their conversion. Sedway Consulting followed the same process with Proposal C and Proposal D (replacing them with Tampa Electric's NPGU at the expiration of the PPAs in [redacted] and [redacted]) and thus the same or stronger caveat applies. Proposal B did not entail an expiration of the resources (i.e., the resources were assumed to continue operating through the end of the study period, 2046) and therefore they were never "replaced" with the NPGU. This is consistent with Sedway Consulting's stand-alone bid evaluation process. However, in reviewing the details behind Tampa Electric's results, Sedway Consulting noted that Tampa Electric optimized the bid-specific generation expansion plans. This optimization resulted in the NPGU resource being included in the bid plans, commencing operations in 2018 in the Proposal B base case analysis and 2023 in the Proposal C and Proposal D base case analyses. Tampa Electric's NPGU is a very cost-effective resource; its expected system production cost savings more than offset the project's investment costs in Sedway Consulting's base and high gas price results. Thus, its inclusion in the Proposal B analysis and its earlier inclusion in the Proposal C and Proposal D analyses significantly improved the economics of those resources' analyses. In essence, Tampa Electric's Proposal B base case evaluation is largely an analysis of a one-year deferral of the NPGU. Sedway Consulting's analysis was based more on a stand-alone bid evaluation process.

Conclusions

Sedway Consulting performed an independent evaluation of Tampa Electric's Polk NPGU relative to the responses to Tampa Electric's 2012 resource RFP and concluded that the NPGU represents the lowest-cost resource for meeting Tampa Electric's 2017 resource need. The NPGU was found to be $69 million on a cumulative present value of revenue requirements basis (CPVRR) less expensive than the next cheapest option under base case assumptions.