ORIGINAL

TECO
TAMPA ELECTRIC

070467-EI

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 07_____-EI
IN RE: TAMPA ELECTRIC'S
PETITION TO DETERMINE NEED FOR
POLK POWER PLANT UNIT 6

TESTIMONY AND EXHIBIT
OF
WILLIAM A. SMOTHERMAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. 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 the Energy Services Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My responsibilities included the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses. I was also responsible for directing system optimization and overall operating and profitability performance. In May 2007, I became Director, Energy Services. My present responsibilities include directing storeroom operations, parts and material inventory, and procurement for all Energy Supply operations departments. I am also responsible for coal combustion byproduct management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Tampa Electric's integrated resource planning ("IRP") process and the resulting resource plan which supports the need for Polk Unit 6, an integrated gasification combined cycle ("IGCC") unit with 610 MW and 647 MW summer and winter net capacity, respectively. My 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-side alternatives, (3) demonstrate that Polk Unit 6 is the most cost-effective alternative to reliably meet Tampa Electric's customer needs, and (4) explain the adverse consequences if the Polk Unit 6 is deferred or denied.

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

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

Document No. 1 Energy Mix by Fuel Type
Document No. 2 Reliability Analyses
Document No. 3 Resource Plans
Document No. 4 Economic Analysis Results
Document No. 5 Scenario Analysis Results

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk Unit 6 ("Need Study")?

A. Yes. I am sponsoring the following sections of the Need Study: I. "Executive Summary", II. "Introduction, Purpose and Overview", III.A. "Description of Tampa Electric's System", III.E.4. "Advanced Recovery of Carrying Costs During Construction", III.E.5. "Impact of Advanced Recovery of Carrying Costs", III.F.2. "Supply-Side Technologies", IV. "Need for Capacity in 2013" (with the exception of IV.A.2.), V. "Screening of Potential Technologies", VI. "Detailed Economic Analysis", VIII. "Scenario Analysis", IX. "Adverse Consequences if Polk

Unit 6 is Delayed or Denied" and X. "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 654,000 customers as of December 31, 2006.

Q. What types of units make up Tampa Electric's existing generating system?

A. Tampa Electric has five generating stations that include steam coal and IGCC baseload units, natural gas combined cycle ("NGCC") intermediate load units, natural gas and oil combustion turbine peaking load units, and internal combustion peaking units. The total net system generating capacity in summer 2007 is 4,300 MW and represents 44 percent solid fuel, 53 percent natural gas and 3 percent oil on a capacity basis.

Big Bend Station includes four pulverized coal-fired steam units and three distillate fueled combustion turbines. In May 2007, Big Bend Unit 4 was retrofitted with additional environmental control systems including selective catalytic reduction ("SCR") to reduce nitrogen oxides ("NO_X") emissions. The remaining three coal units will be retrofitted in 2008, 2009 and 2010 to complete the station's comprehensive air emissions reduction program.

H. L. Culbreath Bayside Station includes two NGCC 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 HRSG and one steam turbine.

Polk Station includes one baseload and four peaking generating units. Polk Unit 1 is an IGCC unit fired with synthesis gas produced from gasified petroleum coke ("pet coke"), coal or other solid fuels. This unit is capable of using distillate oil as a backup fuel which improves overall unit reliability. Polk Units 2 through 5 are combustion turbines fired by natural gas. Units 2 and 3 can also use distillate oil as a backup fuel.

Partnership Station is comprised of two natural gas-fired internal combustion engines. Phillips Station is comprised of two residual or distillate oil fired internal combustion engines.

Q. Does Tampa Electric include any purchased power in its total supply resource mix?

A. Yes, Tampa Electric has existing purchased power agreements ("PPA") for firm power from cogeneration and renewable generating facilities. Tampa Electric also purchases power, both firm and non-firm, from other utilities and independent power producers operating in the Florida market. Firm purchased power is included in the IRP process for reliability and need assessments.

Tampa Electric's PPA include 822 MW of firm power purchases during summer 2007. In June 2013, however, these purchases are expected to decline to 623 MW, due to contract expirations. These agreements are described in more detail in section III.A.2. of the Need Study.

Q. What is the expected energy mix by fuel type for Tampa Electric's total supply resources including purchases?

A. The energy mix for 2007 by fuel type is expected to be 49 percent solid fuel, 45 percent natural gas and 6 percent oil and other sources. This is reflected in Document No. 1 of my Exhibit No. ____ (WAS-1).

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 and energy reduction programs for over 30 years. The cumulative effect of these programs has delayed the need for more than three 180 MW generating plants by slowing growth in the company's peak demand and energy requirements. 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, type and amount of additional resources required to maintain system reliability in a cost-effective manner. The process considers expected growth in customer demand and existing and future DSM, renewable and supply-side resources needed to meet reliability requirements.

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-side resources, the process can require multiple iterations to capture the value of deferring new generating units resulting from additional DSM programs.

The supply-side resources are initially screened based on several criteria: construction and operating costs, technology applicability, commercial availability, and construction lead times. Multiple resource plans are developed that consist of various combinations of technologies. The relative impacts of each resource plan are evaluated for total system production costs including purchased power and the incremental costs to build all new generating units in each plan. The plans are then ranked based on the lowest cumulative present worth revenue requirements ("CPWRR") of the system over a 30-year operating period.

The highest ranked plans are then evaluated under various scenarios or sensitivities to test key planning assumptions and compare the relative cost impact on a CPWRR basis. Strategic factors such as reliability, fuel diversity and environmental impacts may be considered in determining the most cost-effective and viable resource mix for both Tampa Electric and Florida.

The preliminary resource plan incorporates an initial demand and energy forecast including DSM and supply-side resources. The supply-side resources in the preliminary plan are then used to determine the avoided cost for an economic analysis of additional viable DSM 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-side resources needed to meet system reliability criteria. Final economic evaluations and sensitivities are performed to determine the recommended resource plan.

Q. Please describe the reliability criteria that Tampa

Electric utilizes in its IRP process to determine the need for additional resources.

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. The company also maintains a minimum seven percent summer supply-side reserve margin criteria, a voluntary yet important qualitative component for reliability purposes. The system firm 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 DSM load reduction programs. Customers participating in these voluntary programs defer the need for additional supply-side resources by reducing peak demands.

SUPPLY-SIDE RESOURCE ANALYSIS

Q. What supply-side alternatives were considered in the analysis that resulted in the selection of Polk Unit 6 as the company's next planned generating unit?

A. Tampa Electric considered a variety of options prior to identifying IGCC technology as the best option for Tampa Electric and its customers. Tampa Electric's screening process included solid fuel, natural gas-fired and renewable technologies. General characteristics of solid fuel technologies include lower variable costs, such as fuel costs, and higher fixed costs, such as capital construction costs. Solid fuel technologies are typically better suited for large capacity and high utilization applications because these assets will operate for longer continuous periods of time due to their lower variable operating costs.

Natural gas-fired generating technologies typically have lower fixed costs and higher variable operating costs that result in energy costs greater than solid fuel technologies. Natural gas is more expensive than solid fuels and this price differential is expected to grow over time. Fuel forecasts are discussed in more detail in the testimony of witness Joann T. Wehle.

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, intermittent and unpredictable operating hours due to the nature of their energy source. Witness Bryant describes Tampa Electric's efforts and achievements in incorporating available renewable energy in system resources.

Q. Which options were determined to be appropriate for Tampa Electric's needs and system characteristics and analyzed in greater detail?

A. Tampa Electric requires peaking and baseload capacity additions to its existing supply-side resource mix. Strategic considerations included fuel price stability, fuel diversity, environmental impacts, technology viability, construction lead times, and site availability. Tampa Electric's screening analysis narrowed the focus to solid fuel and natural gas-fired baseload technologies as well as simple cycle natural gas-fired peaking technologies for further analysis in the IRP process.

Q. Please describe the solid fuel alternatives considered.

A. Tampa Electric considered three different solid fuel alternatives: supercritical pulverized coal ("SCPC"), circulating fluidized bed ("CFB") and IGCC technologies.

SCPC technology is similar to the pulverized coal technology used at Big Bend Station; however, SCPC units operate at higher operating pressures and temperatures. Where pulverized coal boilers like the Big Bend units operate at pressures under 3,208 psi and have a reheat temperature of 1,000 degrees Fahrenheit, supercritical boilers operate at pressures between 3,200 psi and 4,500 psi and have steam temperatures of approximately 1,050 degrees Fahrenheit or greater.

CFB boilers are designed to operate in a significantly different manner. In a CFB boiler, a portion of the combustion air is introduced through the bottom of the furnace. This air is spread evenly across the bottom of the furnace to produce a "fluidized bed" of air with entrained fuel where combustion occurs. In addition to solid fuel, limestone and other agents may be added to control sulfur dioxide ("SO_2") emissions.

IGCC technology uses a gasification process operated at high pressures utilizing pure oxygen instead of air to convert coal, pet coke, and biomass into synthesis gas that is used to fuel a combined cycle unit. The gasification process allows for the removal of impurities from the synthesis gas prior to combustion in the combined cycle power block. The overall IGCC process is described in the testimony of witness Mark J. Hornick.

Q. Please describe the results of Tampa Electric's screening analysis used to select the best supply-side alternatives for the detailed economic analyses.

A. Tampa Electric's screening analysis of the various alternatives compared the levelized annual cost of each technology at various capacity factors. Tampa Electric selected IGCC, NGCC, and SCPC as viable baseload options and combustion turbines as peaking options. The results of the levelized cost screening curves are depicted in Figures 6 and 7 of the Need Study.

DEMAND-SIDE RESOURCE ANALYSIS

Q. How were demand-side resources factored into the IRP process?

A. Tampa Electric included all DSM programs in its preliminary demand and energy forecast, which effectively reduced system peaks and energy requirements. Through 2006, approved DSM programs achieved a cumulative 2006 summer and winter peak reduction of 222 MW and 659 MW, respectively. In 2007, Tampa Electric proposed new and modified DSM programs which increase its DSM goals. Upon Commission approval of the proposed programs, the summer and winter cumulative reductions through 2012 are expected to increase to 263 MW and 707 MW, respectively. The updated DSM impacts and the effects of appliance efficiency standards mandated by the Energy Policy Act of 2005 ("EPACT") were included in the revised final system demand and energy forecast.

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 available cost-effective DSM reductions and utilized that potential in the assessment of 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 2013.

RESOURCE PLAN

Q. Please describe the results of the preliminary reliability analysis.

A. The preliminary reliability analysis was based on generating unit operating data and projected system firm peak and energy requirements which were developed in 2006. This data supported the development of Tampa Electric's 2007 Ten-Year Site Plan filed with the Commission in April 2007. This analysis indicated incremental capacity resources were needed in every year from 2008 through 2016 to meet the 20 percent reserve margin criteria as shown in Document No. 2 of my Exhibit No. ____ (WAS-1).

Q. Please describe the results of the preliminary IRP analysis.

A. The preliminary resource plan identified the need for simple cycle combustion turbines or firm peaking purchase additions from 2008 through 2012, an IGCC unit at Polk Station in 2013, and additional simple cycle combustion turbines in 2014, 2015, and 2016. Tampa Electric's economic evaluation process and consideration of qualitative factors determined that constructing IGCC technology at Polk Station represented the most cost-effective option for Tampa Electric and its customers.

The preliminary expansion plan was then used to develop avoided cost parameters to evaluate new DSM programs.

The final economic analysis included the impacts of the new and modified DSM programs which were ultimately reflected in the revised system demand and energy forecast.

Q. Please describe, in more detail, the company's 2013 capacity need.

A. In the preliminary resource plan, Tampa Electric identified the need for additional demand and supply resources of 501 MW and 590 MW in the summer and winter of 2013, respectively. The minimum capacity need for 2013 was revised in 2007 to reflect an updated load forecast. The load forecast was updated to reflect the impacts of revised cost-effective DSM programs and EPACT effects. Operating and financial assumptions were also updated. These revised assumptions resulted in a 2013 capacity need of 482 MW and 576 MW in summer and winter 2013, respectively. Both the preliminary and final reliability analyses are shown in Document No. 2 of my Exhibit No. ____ (WAS-1). The testimony of witness Lorraine L. Cifuentes presents the demand and energy forecasts.

Q. Please describe the results of the final IRP analysis.

A. The final resource plan confirmed the need for additional peaking capacity in each year from 2008 through 2012 and the baseload capacity in 2013. The final resource plan is shown in Document No. 3 of my Exhibit No. ____ (WAS-1). The final plan also demonstrated a CPWRR savings of $184 million and $93 million when the IGCC plan was compared to a NGCC or SCPC plan, respectively. A summary of the economic analysis is shown in Document No. 4 of my Exhibit No. ____ (WAS-1).

Q. Did Tampa Electric conduct an RFP to solicit proposals to meet its peaking needs from 2008 through 2012?

A. Yes. In August 2006, a request for proposals ("RFP") yielded several proposals to provide Tampa Electric peaking capacity via PPA. All PPA are contingent upon securing firm transmission service to support required reliability criteria. The company is negotiating with leading bidders regarding potential peaking PPA.

Q. Did Tampa Electric conduct an RFP to solicit alternatives to meet its baseload need in 2013?

A. Yes. In February 2007, Tampa Electric issued an RFP soliciting firm offers for cost-effective alternatives to

Polk Unit 6. The RFP development and assessment process are discussed in detail in the testimony of witnesses Alan S. Taylor and Wehle.

Q. What was the result of the RFP for baseload capacity?

A. Tampa Electric did not receive any bids in response to its RFP.

Q. Please describe Tampa Electric's proposed Polk Unit 6.

A. Polk Unit 6 will be an IGCC facility located at Polk Station, the site of Tampa Electric's existing IGCC unit. Polk Unit 6 will have a net summer and winter rating of 610 MW and 647 MW, respectively.

The proposed unit is conceptually similar to Tampa Electric's Polk Unit 1, a highly reliable IGCC unit which began commercial operation in 1996. Tampa Electric's strategy in designing Polk Unit 6 is to utilize General Electric's ("GE") proven IGCC technology currently utilized at Polk Unit 1. The proposed unit's overall reliability will be enhanced with a second gasification train. Enhancements to the technology also include an improved acid gas removal system that minimizes SO_2

emissions and the addition of SCR equipment to minimize NO_X emissions. Finally, overall reliability will be enhanced with natural gas as a backup fuel. The backup fuel provides an alternative to synthesis gas in the event that one or both gasification trains are not available. The proposed Polk Unit 6 design is further described in the testimony of witness Michael R. Rivers.

Q. Did any assumptions change from the preliminary resource plan in developing the final recommended plan?

A. Yes. As described in the testimony of witness Rivers, Tampa Electric has continued to work with the GE and Bechtel teams to develop the engineering scope of the project since early 2006. The revised Polk Unit 6 in-service costs are projected to be \$2.013 billion. While the Polk Unit 6 construction costs have increased, proportionate increases in construction costs have also occurred for other solid fuel and gas-fired technologies.

Another significant update to the preliminary plan occurred in November 2006 when Tampa Electric was awarded federal tax credits totaling \$133.5 million for the proposed Polk Unit 6. The tax credits are contingent upon several conditions which are further discussed in the testimony of witness Chrys A. Remmers.

In addition, House Bill 549 was signed into law June 12, 2007. The law expands the 2006 statute that authorized advanced cost recovery of carrying costs during construction and other preconstruction activities for IGCC technology. Stemming from legislative and executive branch concerns over the growing dependency on natural gas-fired electric generation in Florida, the law expressly states that the intent is to "promote" and "encourage" investor owned utility investment in nuclear power and IGCC technology.

Q. Please describe, in more detail, the benefits of the qualitative factors considered in the selection of Polk Unit 6.

A. The use of solid fuel for Polk Unit 6 will help ensure diverse fuel source mix and fuel price stability. With Polk Unit 6, Tampa Electric's energy mix by fuel type will be 64 percent solid fuel and 34 percent natural gas. If the company's 2013 need was met by a NGCC unit, Tampa Electric's reliance on natural gas for energy would increase to 51 percent.

Another significant consideration was the fuel flexibility of IGCC technology. Polk Unit 6 will be able to use a wide variety of solid fuels, including biomass and high amounts of pet coke, which is typically difficult for other technologies to burn. The unit's fuel flexibility will allow utilization of several fuel transportation options resulting in lower delivered fuel costs.

The gasification process produces lower emissions than other currently proposed solid fuel technologies and the unit can be retrofitted to meet future environmental requirements. Polk Unit 6 will have lower emissions than other proposed solid fuel fired units in the state. Witness Paul L. Carpinone provides a comparison of the expected emissions from these proposed units.

Polk Unit 6 will require less water than a conventional coal unit because IGCC technology derives a smaller portion of generating capability from the steam cycle. A comparison of water use by technology is provided in the testimony of witness Mark J. Hornick.

Additional benefits of Polk Unit 6 are that Tampa Electric has more than a decade of successful experience with IGCC technology and the existing infrastructure at Polk Station can be modified to support Polk Unit 6. There are numerous opportunities for efficiencies in the operations of Polk Unit 6.

SCENARIO ANALYSIS

Q. Did Tampa Electric conduct scenario analyses related to the selection of Polk Unit 6?

A. Yes. Tampa Electric conducted three scenario analyses to assess the Polk Unit 6 plan against potential price sensitivities. The first scenario analysis tested the sensitivity of the base fuel forecast using both high and low price bands around the base fuel forecast. High and low fuel forecast bands are discussed in the testimony of witness Wehle. The analysis held all other factors constant while varying the prices of coal and natural gas. The 30-year production cost streams were calculated for each sensitivity.

The second scenario analysis assessed the relative cost impacts of potential carbon dioxide ("CO_2") emission restrictions. Tampa Electric utilized three price bands for CO_2 reductions. The three price bands used were $5, $15 and $30 per ton of CO_2 with a five percent yearly escalation starting in 2010. This wide range of price signals was chosen since the detail of potential CO_2 regulations, if any, is unknown.

The third scenario analysis assessed lower and higher than expected capital costs for the NGCC, SCPC and IGCC technologies. Recognizing that the estimated in-service costs for Polk Unit 6 are based on preliminary estimates, capital cost sensitivities were analyzed. The high and low cases were established utilizing 15 percent higher and lower in-service costs.

Q. Please summarize the results of the sensitivity analysis.

A. Polk Unit 6 was more cost-effective than the SCPC plan in all of the sensitivities except for the low fuel price sensitivity. Polk Unit 6 continued to demonstrate the lowest system CPWRR compared to the NGCC plan in the high fuel, low capital, and low and medium CO_2 price sensitivities. The results of these scenarios reinforce Tampa Electric's selection of Polk Unit 6 as the best alternative for Tampa Electric and its customers. Document No. 5 of my Exhibit No. ____ (WAS-1) contains a summary of the sensitivity analyses.

Q. What is the expected relative rate impact of Polk Unit 6 compared to the NGCC alternative?

A. The relative residential customer rate for the two technologies was calculated and compared on MWH basis. In 2013, the projected rate impact for the IGCC plan is $2.72 per MWH higher than the NGCC plan, driven by higher capital costs; however, the rate impact for IGCC is estimated to be lower by 2017 and through the balance of the remaining life of the unit due primarily to lower fuel and purchased power costs.

Whether or not Tampa Electric requests advanced cost recovery for carrying costs during construction, the overall CPWRR savings for the IGCC plan is $184 million and $93 million when compared to the NGCC and SCPC plans, respectively.

BASIS FOR DETERMINATION OF NEED

Q. Has Tampa Electric adequately established that there is a need for Polk Unit 6?

A. Yes. Tampa Electric will require an additional 482 MW of firm supply resources in summer 2013 and 576 MW in winter 2013 based upon the updated 2007 reliability analysis which reflects the revised system demand and energy requirements.

Q. Is the addition of Polk Unit 6 consistent with the needs of peninsular Florida?

A. Tampa Electric's need for additional solid fuel capacity in January 2013 is consistent with the Peninsular Florida energy mix of 25.8 percent coal-fired generation to meet the Peninsular Florida net energy for load of 284,886 GWH in 2013, as identified by the Florida Reliability Coordinating Council ("FRCC") and reported in the FRCC 2007 Regional Load and Resource Plan. The FRCC 2007 plan uses Tampa Electric specific data in conjunction with similar information from other Florida electric utilities. Polk Unit 6 is consistent with state policy actions that encourage fuel diversity and avoid the reliance on any single fuel. The 2007 Regional Load and Resource Plan published by the FRCC indicates that reliance on natural gas-fired resources will increase from 2007 projections of 38 percent to 49 percent, in 2011. State reliance on natural gas will decrease to 44 percent in 2014 after the addition of Polk Unit 6 and other planned solid fuel-fired units in the state that are included in the reserve margin and energy mix assessment in the FRCC plan.

ADVERSE CONSEQUENCES

Q. What would be the adverse consequences if the Polk Unit 6 in-service date were delayed from 2013 to 2014?

A. In the event that Polk Unit 6 is delayed by one year, Tampa Electric would forfeit the advanced coal project federal tax credits of $133.5 million, project costs would increase, and fuel savings for 2013 would not be realized. It is likely that system energy requirements would be served by natural gas fired generators in Florida resulting in higher fuel costs, due to increased dependence on natural gas and a greater exposure to the supply disruptions and price volatility associated with this fuel.

Q. What would be the adverse consequences if the proposed Polk Unit 6 were denied?

A. If Tampa Electric's proposed Polk Unit 6 is denied, Tampa Electric would most likely construct an NGCC unit in 2013. This would result in higher costs for customers of $184 million on a CPWRR basis. The customers would experience an increase in supply and price volatility resulting from an increased reliance on natural gas. Tampa Electric's energy mix by fuel type would be 51 percent natural gas in 2013.

Q. Should Tampa Electric's petition for determination of need for Polk Unit 6 be approved?

A. Yes. For the reasons I have described, Polk Unit 6 is the best option for Tampa Electric to cost-effectively maintain system reliability and enhance fuel diversity. Tampa Electric requests that the Commission issue an affirmative determination of need for Polk Unit 6 in this proceeding.

Q. Please summarize your testimony.

A. Tampa Electric's IRP process determined that Tampa Electric will have future capacity needs in 2013. It also determined that Polk Unit 6 is the most cost-effective option while providing additional benefits in the areas of reliability, fuel diversity, price stability and environmental impacts.

Despite consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk Unit 6 for a January 2013 in-service date cannot be deferred. Tampa Electric also determined that fuel diversity is a key objective and the addition of coal technology in 2013 maintains a prudent balance in Tampa Electric's energy mix.

The selection of Polk Unit 6 was supported by subsequent economic analysis of viable supply-side alternatives, demonstrating that the unit provides the lowest CPWRR compared to natural gas-fired and other solid fuel technologies. Polk Unit 6 provides significant savings of $93 million to $184 million to Tampa Electric's customers when compared to other possible alternatives. The results of these scenarios reinforce Tampa Electric's selection of Polk Unit 6 as the best alternative for Tampa Electric and its customers.

Q. Does this conclude your testimony?

A. Yes, it does.

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ENERGY MIX BY FUEL TYPE
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DOCUMENT NO. 1
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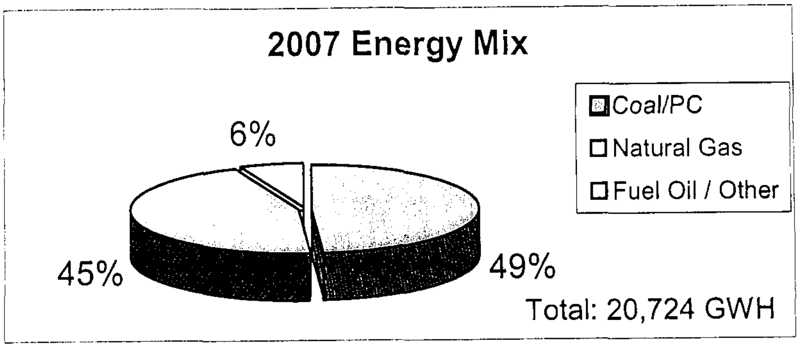
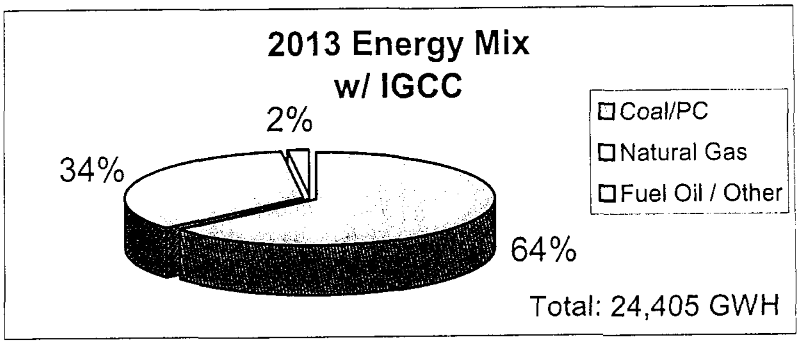
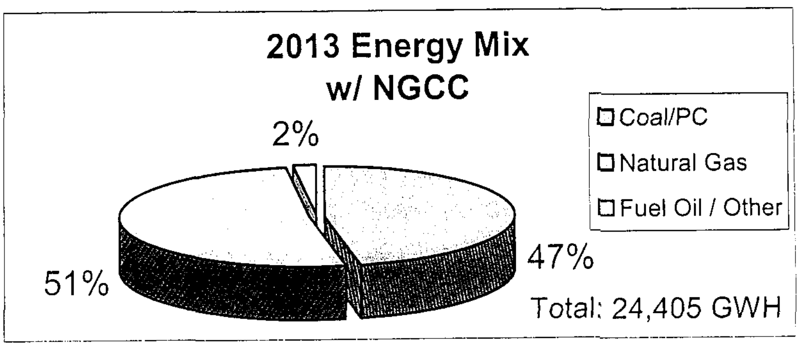
Energy Mix by Fuel Type







Preliminary Reliability Analysis

Minimum Capacity Needed to Maintain Summer 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Summer Peak Demand MW	Whls Firm Summer Peak Demand MW	System Firm Summer Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2008	4,332	89	526	65	5,012	3,991	186	4,176	835	20%
2009	4,461	95	526	65	5,146	4,113	176	4,288	858	20%
2010	4,555	169	526	42	5,292	4,235	175	4,410	882	20%
2011	4,724	231	356	42	5,353	4,357	104	4,461	892	20%
2012	4,955	171	356	23	5,505	4,484	104	4,588	918	20%
2013	5,126	501	0	23	5,650	4,620	89	4,709	942	20%
2014	5,627	159	0	23	5,810	4,765	77	4,841	968	20%
2015	5,670	297	0	23	5,990	4,915	77	4,991	998	20%
2016	5,967	207	0	0	6,173	5,068	77	5,144	1,029	20%

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RELIABILITY ANALYSES
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Preliminary Reliability Analysis

Minimum Capacity Needed to Maintain Winter 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Winter Peak Demand MW	Whls Firm Winter Peak Demand MW	System Firm Winter Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2007-08	4,686	0	611	65	5,362	4,178	188	4,365	997	23%
2008-09	4,656	63	611	65	5,395	4,308	188	4,496	899	20%
2009-10	4,729	156	611	42	5,538	4,440	176	4,615	923	20%
2010-11	4,875	183	592	42	5,692	4,568	176	4,743	949	20%
2011-12	5,068	233	441	23	5,764	4,700	104	4,804	961	20%
2012-13	5,300	590	0	23	5,913	4,839	89	4,928	986	20%
2013-14	5,890	164	0	23	6,077	4,988	77	5,064	1,013	20%
2014-15	5,916	348	0	0	6,264	5,143	77	5,220	1,044	20%
2015-16	6,264	192	0	0	6,456	5,304	77	5,380	1,076	20%

Final Reliability Analysis

Minimum Capacity Needed to Maintain Summer 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Summer Peak Demand MW	Whls Firm Summer Peak Demand MW	System Firm Summer Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2008	4,255	134	526	64	4,979	3,963	186	4,149	830	20%
2009	4,379	125	526	64	5,093	4,069	176	4,244	849	20%
2010	4,509	151	526	40	5,226	4,179	175	4,355	871	20%
2011	4,664	222	356	32	5,274	4,291	104	4,395	879	20%
2012	4,886	157	356	23	5,422	4,415	104	4,519	904	20%
2013	5,048	482	0	23	5,553	4,539	89	4,627	925	20%
2014	5,530	143	0	23	5,696	4,670	77	4,747	949	20%
2015	5,570	263	0	23	5,856	4,803	77	4,880	976	20%
2016	5,833	189	0	0	6,022	4,942	77	5,018	1,004	20%

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RELIABILITY ANALYSES
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Final Reliability Analysis

Minimum Capacity Needed to Maintain Winter 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Winter Peak Demand MW	Whls Firm Winter Peak Demand MW	System Firm Winter Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2007-08	4,650	0	611	64	5,325	4,130	188	4,318	1,006	23%
2008-09	4,610	42	611	64	5,326	4,250	188	4,438	888	20%
2009-10	4,662	119	611	64	5,455	4,370	176	4,546	909	20%
2010-11	4,785	166	611	32	5,594	4,486	176	4,662	932	20%
2011-12	4,951	242	441	23	5,657	4,610	104	4,714	943	20%
2012-13	5,198	576	0	23	5,797	4,742	89	4,831	966	20%
2013-14	5,774	146	0	23	5,944	4,876	77	4,953	991	20%
2014-15	5,786	302	0	23	6,112	5,016	77	5,093	1,019	20%
2015-16	6,089	194	0	0	6,283	5,159	77	5,236	1,047	20%

2007 Detailed Economic Analysis Resource Plans

	IGCC	SCPC	NGCC
2008	Peaking Need	Peaking Need	Peaking Need
2009	Peaking Need	Peaking Need	Peaking Need
2010	Peaking Need	Peaking Need	Peaking Need
2011	Peaking Need	Peaking Need	Peaking Need
2012	Peaking Need	Peaking Need	Peaking Need
2013	Polk IGCC	SCPC	NGCC and NGCT
2014	Peaking Need	Peaking Need	Peaking Need
2015	Peaking Need	Peaking Need	Peaking Need
2016	Peaking Need	Peaking Need	Peaking Need

Final Economic Analysis Results

Total System Costs[1]

(2007 $ Million)

IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
$ 24,622	$ 24,715	$ 24,806	$ 93	$ 184

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.

Fuel Scenario CPWRR Results

Total System Costs [1]
(2007$ million)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Fuel	$ 18,673	$ 18,553	$ 17,507	$ (120)	$ (1,167)
Base Fuel	$ 24,622	$ 24,715	$ 24,806	$ 93	$ 184
High Fuel	$ 30,435	$ 30,659	$ 31,577	$ 224	$ 1,142

Environmental Scenario CPWRR Results

Total System Costs [1]
(2007$ million)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Price Band	$ 26,224	$ 26,312	$ 26,348	$ 88	$ 125
Medium Price Band	$ 29,426	$ 29,505	$ 29,432	$ 79	$ 5
High Price Band	$ 34,231	$ 34,295	$ 34,057	$ 64	$ (173)

Capital Cost Scenario CPWRR Results

Total System Costs [1]
(2007$ million)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Capital Cost	$ 24,245	$ 24,401	$ 24,715	$ 156	$ 470
High Capital Cost	$ 24,999	$ 25,030	$ 24,898	$ 31	$ (102)

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.