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TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 992014-EI

TESTIMONY
AND EXHIBIT OF

MARK D. WARD

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK D. WARD

Q. Please state your name, address and occupation.

A. My name is Mark D. Ward. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Energy Supply.

Q. What is your educational background and business experience?

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1984 from the University of Alabama in Huntsville. Prior to my employment with Tampa Electric, I held a number of engineering and manager positions with various aerospace companies and the Department of Defense. In 1996, I began my employment as a Consulting Engineer with Tampa Electric's Generation Planning department. In 1997, I was promoted to Manager, Resource Planning. I was responsible for managing Tampa Electric's resource planning activities that included energy resource utilization studies, production cost studies, system reliability studies, and the company's integrated resource planning process. In late 1999, I was promoted to Manager, Energy Supply where I am responsible for coordinating activities associated with repowering Gannon Station ("Gannon Repowering Project").

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. In Docket No. 990001-EI, I supported Tampa Electric's calculation of fuel and purchased power costs associated with the Gannon Unit 6 accident and established that the purchased power agreement between the company and Hardee Power Partners was prudent and reasonable. I have also participated in the Commission's Ten-Year Site Plan review process.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the analytical basis underlying Tampa Electric's conclusion that the Gannon Repowering Project is the most reasonable and prudent means for the company to comply with the requirements of the Consent Final Judgement ("CFJ"), entered into by and between Tampa Electric and the Florida Department of Environmental Protection ("DEP"), while meeting our customers' need for reliable service. My testimony provides an overview of the cost-effectiveness studies developed and utilized including an explanation of the methodology. It also provides a description of the alternatives and assumptions used in the analysis along with sensitivities considered, and a summary of the results. Finally, my testimony provides an overview on how the Gannon Repowering Project impacts Tampa Electric's system and state reliability.

Q. Have you prepared an exhibit supporting your testimony in this proceeding?

A. Yes. My Exhibit No. 1 (MDW-1), consisting of one document titled "Gannon Resource Utilization Study", was prepared under my direction and supervision.

Q. Is this the same "Gannon Resource Utilization Study" originally submitted in this proceeding as "Appendix B" of the "Comprehensive Clean Air Compliance Plan"?

A. Yes, however, this study has been revised and updated. I will address these changes later in my testimony.

Q. What has been Tampa Electric's Resource Planning Department's ("Resource Planning") role in connection with the Gannon Repowering Project?

A. Resource Planning has always worked closely with the company's Environmental Planning Department in evaluating viable and cost-effective alternatives to comply with environmental requirements. The department had a significant role in evaluating Clean Air Act ("CAA") Phase I and Phase II compliance alternatives and in recommending the company's ultimate compliance plan.

In addition to the environmental concerns, a significant consideration for the company in reviewing compliance alternatives is the need to provide reliable and cost-effective additions to its mix of generating resources to meet its customers growing demands for electricity. Accordingly, Resource Planning developed and evaluated multiple alternatives that complied with the more stringent environmental requirements of the Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("DEP") while reliably meeting our increasing customer demand at reasonable prices.

The more stringent environmental requirements proposed by the EPA and the DEP are in relation to the EPA's revised interpretation of maintenance relative to Section 114 of the New Source Review ("NSR") Standards. This interpretation would require Tampa Electric's Gannon Station units to meet the present NSR Standards which are significantly lower than the emissions imposed by the CAA.

Q. Please describe the methodology typically utilized by Resource Planning in evaluating the most cost-effective alternatives.

A. Tampa Electric employs an integrated resource planning process as submitted and approved by the Commission in Docket 930551-EG, whereby combinations of supply-side and demand-side resources are evaluated on a fair and consistent basis to satisfy future capacity and energy requirements in a cost-effective and reliable manner.

PROMOD, a widely used and accepted industry standard production costing computer model developed by New Energy Associates, is used to calculate the fuel and purchased power expense associated with each alternative. PROMOD simulates an economic dispatch for Tampa Electric's generating system based on incremental production energy costs. The PROMOD model is used to simulate unit operating characteristics and system dispatch effects associated with different compliance alternatives.

PROSCREEN, another widely used and accepted industry standard computer model developed by New Energy Associates, is used to calculate incremental revenue requirements associated with generation capital expenditures, transmission and distribution capital expenditures, generating unit operating and maintenance ("O&M") costs, and sulfur dioxide ("SO_2") allowance costs. PROSCREEN is a planning tool used to evaluate long-range system operating costs associated with particular generation expansion plans.

As part of the integrated resource planning process, impacts of demand-side management ("DSM") were included in the analysis. For all alternatives, Tampa Electric incorporated the proposed available cost-effective conservation measures that resulted in the Commission-appproved DSM goals in Docket No. 971007-EG, Order No. PSC-99-1942-FOF-EG, issued October 1, 1999, and as discussed in the direct testimony of Tampa Electric Witness Howard Bryant.

Q. Please describe, more specifically, the methodology utilized by Resource Planning in evaluating alternatives given the requirements for reduced emissions while satisfying increasing customer demand for reliable electric service at reasonable costs.

A. Resource Planning utilized its planning process as described above. First, we identified viable resource alternatives that may meet our dual objectives. We completed a screening process that initially eliminated several resource alternatives because they either failed to meet environmental requirements; failed to meet the company's reliability criteria; were technically infeasible; failed to meet operational criteria (e. g. dispatching flexibility, maintenance scheduling); or showed obvious disadvantages, economic or otherwise, relative to other alternatives.

A detailed economic analysis was conducted on each alternative that passed the initial screening phase to determine its relative cost-effectiveness. This evaluation compared the cumulative present worth revenue requirements of each alternative against a reference case. The differential between each alternative and the reference case resulted in the "incremental" costs or savings associated with each alternative. The revenue requirements for each alternative included the capital costs associated with generation and transmission resource additions, fixed and variable O&M, and fuel and purchased power expenses. In addition, because some alternatives involved replacing the existing Gannon Station with generation sources located away from Tampa Electric's major load center, other transmission impacts including system losses were quantified for each alternative.

Q. What common assumptions were used in the analyses?

A. Resource Planning used several common assumptions for each alternative considered in its analysis. The unit performance parameters for Tampa Electric's existing and planned generating units, including generating unit capacity, heat rate, unit availability, fuel availability and price, were common to each alternative. These assumptions were developed based on historical operating experience, engineering judgment, and planned utilization of the aggregate resources. Specifically, unit capacity and heat rate projections were based on historical unit performance test values that were adjusted as needed for current and planned unit operations. These common assumptions along with the company's customer demand and energy forecast are consistent with those used in Tampa Electric's Fuel and Interchange Forecast for Year 2000 as filed with the Commission in Docket No. 990001-EI.

Another common assumption relates to our system reliability criteria. Resource Planning used the planning reserve margin adopted by Tampa Electric in December 1999 as a result of a stipulation approved by the Commission. In addition, Tampa Electric informed the Commission in a letter dated December 23, 1999 of its intent to include a minimum seven percent summer supply-side reserve contribution to the minimum 20 percent firm reserve margin target established in the stipulation. The company has until the summer of 2004 to achieve this minimum reserve level, and this level was the basis for adding new resources on the Tampa Electric system for all of the alternatives considered.

Tampa Electric's Fuels Department developed the fuel assumptions that were used in all of the alternatives. These assumptions were based on the fuel price forecast included in the company's fuel adjustment proceedings and used for internal business planning purposes. This forecast is described in more detail in the direct testimony of Tampa Electric witness Mark Hornick.

For all alternatives, the incremental transmission system capital improvements and losses associated with each alternative were quantified via transmission load flow analyses. The additional cost for capacity and energy needed to offset the transmission impacts on Tampa Electric's transmission system for each of the alternatives were based on the location of replacement generation sites or replacement power sources. The transmission impacts to Tampa Electric's system are described in more detail in the direct testimony of Tampa Electric Witness Greg Ramon.

Finally, TECO Energy's Treasury Department provided the common financial assumptions including values for tax rates, debt to equity ratio, debt rate, equity rate, preferred rate, discount rate, and Allowance for Funds Used During Construction ("AFUDC") rate. Tampa Electric's Load Forecasting Section provided the inflation and escalation rate assumptions. These assumptions are summarized in Table B-1 on Page B-3 of my Exhibit.

Q. Were there any other assumptions that were common to all alternatives considered?

A. Yes. In accordance with the requirements of the CFJ, nitrogen oxide ("NO_X") control technology must be installed on the Big Bend coal units beginning in 2007 with completion by 2010. Although the NO_X control technology has not yet been determined, selective catalytic reduction ("SCR") technology was used as a proxy for the purpose of the analysis. The Environmental Planning Department accordingly estimated the cost of installing and operating SCR systems on the Big Bend units.

Q. Please describe the initial alternatives you considered.

A. Resource Planning initially considered a wide range of alternatives. In summary, they included the following with many variations of each:

- Install environmental controls - Retrofit the Gannon units with flue gas desulfurization ("FGD") and SCRs for SO_2 and NO_X control, respectively.

- Switch Fuels - Convert Gannon units to burn natural gas instead of coal.

- Replace Capacity - Shutdown all Gannon Station coal units and build replacement generation.

- Purchase Power - Shutdown all Gannon Station coal units and purchase replacement power from other Florida resources.

- Repower Gannon Station - Repower various combinations of the six Gannon coal units utilizing both "F" and "G" combined cycle ("CC") technologies with various in-service dates. Operating assumptions for "F" and "G" series CC units are listed in Table B-3 on Page B-6 of my Exhibit.

Q. What alternatives were eliminated by your initial screening process and why?

A. The screening process eliminated alternatives that were technically infeasible; did not comply with environmental regulations; failed to meet the company's reliability criteria; did not meet operational criteria; or had obvious disadvantages, economic or otherwise, over other alternatives.

The fuel-switching alternative was eliminated for various reasons. The gas-converted Gannon units, although having efficiencies and fuel prices similar to new combustion turbines ("CTs"), would have higher maintenance costs, potentially lower reliability, and less operating flexibility than new CTs. The resulting higher variable costs of the units would have significant impacts on system dispatch and fuel costs than other alternatives considered. In addition, this fuel-switching alternative may trigger Prevention of Significant Deterioration ("PSD") or NSR permitting which may require the installation of SCRs to meet NO_X emission requirements. The potential capital and O&M costs associated with the environmental equipment and the higher fuel costs of this alternative lead to its elimination from further consideration at that time.

We also eliminated alternatives that involved shutting down Gannon Station coal units and building replacement generation at the Polk Power Station site or at undetermined greenfield sites. These alternatives were eliminated because of the significant impacts on the statewide transmission grid and the significant costs associated with mitigating these impacts for both Tampa Electric and the state.

Several Gannon Station repowering alternatives were eliminated in the initial phase of the process. The operating characteristics of "F" and "G" combined cycle technologies were compared with those of the existing Gannon units to determine the best fit for integrating these technologies with the existing units' equipment. The "G" technology was eliminated due to the equipment manufacturer's reluctance to sell the CTs for repowering applications and our concerns about the limited track record for the technology with so few "G" turbines in service. Gannon Units 1 and 2 were considered less attractive as repowering candidates due to output and operating characteristics. Gannon Units 3 and 4 were chosen over Gannon Unit 6 because of the reliability advantage of having two steam turbines available instead of one.

Q. Please describe the alternatives that were selected for further evaluation.

A. From initial evaluations of alternatives, certain variations of alternatives were determined to be potentially feasible solutions for the company. The alternatives selected for final evaluation included the *Environmentally Adjusted Alternative*, the *Gannon Non-*

Repower Replacement Alternative, the *Purchased Power Alternative*, and the *Gannon Repowering Alternative*.

The *Environmentally Adjusted Alternative*, the reference case, involved retrofitting all six Gannon coal units with FGD and SCR systems to address SO_2 and NO_X emissions, respectively. This reference case was selected for further evaluation because it met the more stringent environmental Best Available Control Technology ("BACT") requirements of the EPA. This alternative enables the company to continue to burn coal and avoids the significant transmission impacts associated with shutting down Gannon Station.

The *Gannon Non-Repower Replacement Alternative* involved shutting down Gannon Units 1 through 6 over a period of 12 months beginning in 2003. The units would be replaced with three "F" technology combined cycle units constructed at the Gannon site. "F" combined cycle technology was chosen for the replacement generation because the technology is currently available and technically proven. The company has experience with this technology from its existing operations at the Polk Power Station and is planning to use "F" technology for the future CTs at the Polk Power Station as well. Therefore, additional opportunities for cost savings in terms of spare parts, operations, etc. are created. In addition to the three replacement units, two CTs with in-service dates of 2003 and 2006 would be constructed at Polk Power Station and a "G" technology combined cycle unit would be built at an undetermined future site in 2007. This "G" Frame machine is a more viable supply option by 2007, at which time the technology should have established an operating and performance history.

The *Purchased Power Alternative* assumes that Gannon Station's coal units would be shut down and Tampa Electric would enter into one or more long-term purchased power agreements with third parties for replacement power.

Also selected for further evaluation was the *Gannon Repowering Alternative*. This alternative integrates new dual-fueled 7FA CTs, new heat recovery steam generators ("HRSGs"), and the existing steam turbines of Gannon units in a phased repowering to combined cycle.

The expansion plans associated with each alternative are included in my Exhibit in Table B-4 on Page B-9.

Q. To evaluate the market for purchase power, did the company assess the long term availability, deliverability, and price for purchase power alternatives?

A. Yes. Through various sources, Tampa Electric evaluated the availability and all-in costs for Independent Power Producers (IPP) and Utility projects. This information was used to develop a reasonable proxy to establish a baseline for assessing the Purchase Power alternative.

The evaluation included specific project information including financing structure, capital cost, installation cost, water and land, and expected permitting expense to develop a proxy for the fixed cost component of purchase power. The variable operating expense was developed from generally accepted industry information at comparable operating conditions. The resultant combination of fixed and variable expenses produced an all-in cost (less wheeling) for the Purchase Power alternative. Wheeling charges, transmission impacts, and transmission losses were applied separately in the economics of the Purchase Power alternative.

Q. Please describe the assumptions used in evaluating the

Purchased Power Alternative.

A. Capacity and energy prices for the purchased power were based on published combined cycle technology costs applicable to the Florida market. Installed capital costs, estimated to be $450 per kilowatt (1999 dollars), included all direct and indirect costs (e.g. owners' costs, switchyard costs, land, interest during construction, etc.). These costs were modeled using the set of representative financing assumptions for third party resources as shown in Table B-2b on Page B-4 of my Exhibit and using a standard discounted cash flow analysis.

The capacity component of the costs was determined using two constraints. First, the cost for capacity and fixed O&M on a $/kW/year basis was levelized over the time period of the analysis. Secondly, the resulting internal rate of return ("IRR") of the analysis was equal to the weighted average cost of capital ("WACC").

The energy component of the power purchase was set equal to the total of variable costs (fuel and variable O&M). By setting the energy component of the purchased power cost equal to variable costs, the analysis simulated an economically efficient energy market that has prices based on marginal costs. Solving for an IRR equal to the WACC provides the minimum additional cash flow that would meet the requirements of equity and debt investors. This approach is conservative in that it simulates the marginal or breakeven investment.

Since we do not know the location of the ultimate resource(s), an "average" case transmission load flow analysis was performed. It assumed the replacement power would be purchased from several announced projects within Florida. These assumptions and resources are described in more detail in Mr. Ramon's direct testimony. In determining the transmission impacts and wheeling charges associated with the replacement power, a percentage weighting of the total purchased power was estimated from each hypothetical project.

A financial risk adjustment was also included in the cost of purchased power to capture Tampa Electric's financial risk associated with entering into a long-term contract for purchased power. This adjustment reflects the additional cost associated with maintaining higher equity amounts under the Standard and Poors' methodology. This methodology imputes purchased power capacity payments as a debt equivalent. The rating agencies require additional equity in order to maintain the financial strength needed to justify current bond ratings.

Q. Are there other costs associated with the Purchased Power Alternative that were not included in the analysis?

A. Yes. Statewide transmission impacts (i.e. bulk transmission reactive devices and the cost of generation to cover statewide system losses not quantified through contractual energy rates); stranded costs; environmental insurance/indemnification of Tampa Electric by third party power providers to guarantee Tampa Electric's compliance with the CFJ; and dismantling costs were not included in the analysis. These costs were omitted due to the significance of transmission impacts already quantified in the analysis. Omission of these additional costs leads to a more conservative analysis to the benefit of the Purchased Power Alternative.

Q. Please describe the assumptions used in evaluating the *Gannon Repowering Alternative*.

A. The *Gannon Repowering Alternative* includes integrating six new dual-fuel fired GE 7FA CTs and six HRSGs with the existing Gannon Units 3, 4 and 5's steam turbines. Specifically the first phase includes integrating three CTs and three HRSGs with the Gannon Unit 5 steam turbine. The second phase of repowering includes integrating three additional CTs and three HRSGs with the existing steam turbines/generators of Gannon Units 3 and 4.

The repowered Gannon Station generating units would burn natural gas as the primary fuel source and distillate oil as a backup fuel. However, in modeling the fuel costs for these units, it was assumed that the primary fuel was firm natural gas and the secondary fuel was interruptible natural gas with unlimited availability. We assumed 100,000 MMBtu/day of firm natural gas with 50,000 MMBtu/day dedicated to the first repowered unit and 50,000 MMBtu/day dedicated to the subsequent repowered units.

The repowered Gannon Station unit performance parameters are shown in Table B-3 on Page B-6 of the Exhibit.

The book values associated with the existing Gannon Station coal-related assets were considered sunk costs and were treated accordingly in the determination of cumulative incremental revenue requirement impacts.

However, the impact of recovering these costs on an accelerated schedule due to the earlier retirement of these assets was factored into the analysis.

Q. With these four remaining alternatives, what process was used to determine the most cost-effective alternative?

A. A detailed economic analysis was completed to determine the cumulative present worth revenue requirements ("CPWRR") for each alternative. The values were represented in 1999 dollars for comparability.

Each alternative was compared incrementally to the *Environmentally Adjusted Alternative*, the reference case. The results are shown in the risk curves included in my Exhibit as Figure B-1 on Page B-11.

In addition, selected sensitivity analyses were completed on each alternative to determine the relative impact that changes in key assumptions might have on the total system revenue requirements.

Q. Please summarize the results of your analyses.

A. Based upon this analysis, the *Gannon Repowering Alternative* offered the greatest savings. The savings were $349.1 million (CPWRR in 1999 dollars) compared to the *Environmentally Adjusted Alternative*, the reference case. The *Non-Repower Alternative* and *Purchased Power Alternative* showed CPWRR savings of approximately $297.6 million and $12.2 million, respectively, relative to the *Environmentally Adjusted Alternative*.

The CPWRR of the *Purchased Power Alternative* was $336.9 million higher than the *Gannon Repowering Alternative*. The difference in CPWRR was primarily due to the significant costs associated with maintaining the reliability of the peninsular Florida transmission grid should Gannon Station be shutdown. The incremental transmission capital revenue requirements and transmission system losses alone amounted to $188.5 million (CPWRR) of the total differential between this alternative and the *Gannon Repowering Alternative*.

The *Gannon Non-Repower Replacement Alternative* was closer in cost to the *Gannon Repowering Alternative* with a differential CPWRR of $51.5 million. This option showed greater fuel savings over the repowering option due to the utilization of the more efficient "G" combined cycle technology scheduled for in-service by 2007. However, the fuel savings were realized later in the study period and, as a result, the magnitude of the savings was not significant enough to overcome the higher capital and O&M costs of this alternative.

Q. Did Resource Planning conduct any sensitivities in its cost-effectiveness analyses?

A. Yes, we conducted sensitivities on SO_2 allowance costs, natural gas transportation charges, and natural gas commodity prices.

Q. Please summarize the results of these sensitivity analyses.

A. The first sensitivity was an evaluation utilizing a lower SO_2 allowance price. This sensitivity assumed that the forecasted price of an allowance would eventually approach a value comparable to the operating cost of an FGD system (approximately $90 per allowance). The re-marketing of excess SO_2 allowances was assumed for each alternative. By lowering the market value of these allowances, the credit back to customers was reduced and, therefore, the overall revenue requirements were higher.

This sensitivity increased the incremental CPWRR of each alternative by between $12.0 and $13.2 million depending on the alternative relative to the *Environmentally Adjusted Alternative.* The *Purchase Power Alternative* exceeds the *Environmentally Adjusted Alternative* by $1.0 million in this sensitivity.

The second sensitivity assumed higher natural gas transportation costs. Firm gas transportation costs for Tampa Electric's gas-fired units were assumed to be 25 cents per MMBtu higher than the base assumption. Relative to the *Environmentally Adjusted Alternative,* this increase in transportation costs increased the incremental CPWRR by approximately $40.3 million for the *Gannon Repowering Alternative* and $36.6 million for the *Gannon Non-Repowering Alternative*. The incremental CPWRR of the *Purchased Power Alternative* rose $57.0 million, $44.8 million higher than the *Environmentally Adjusted Alternative*. The impact to the *Purchased Power Alternative* was higher because all gas utilized for purchased power was assumed to be firm, whereas the repower and non-repower replacement options assumed a combination of firm and interruptible gas transportation.

The third sensitivity completed assumed a high natural gas price forecast for the commodity only. This resulted in a significant impact to the CPWRR for each alternative. The CPWRR savings decreased by $207.9 and $200.5 million for the *Gannon Repowering Alternative and* the *Gannon Non-Repowering Replacement Alternative,* respectively, relative to the *Environmentally Adjusted Alternative.* The *Purchased Power Alternative* actually showed a net cost of approximately $199.4 million, relative to the *Environmentally Adjusted Alternative.*

Through all sensitivities, the *Gannon Repowering Alternative* remained the most cost-effective alternative. This was because each alternative included natural gas-fired combined cycle technology and, therefore, would be impacted similarly by the natural gas and SO_2 allowance sensitivities. The results of the sensitivity analyses are shown in the graphs on Pages B-13 and B-14 of my Exhibit.

Q. Was a low coal price sensitivity performed?

A. No. As discussed in Witness Hornick's testimony, coal prices are not expected to fall below current prices.

Q. Did you conduct a sensitivity to quantify the effect of conservation programs on the alternatives considered by Tampa Electric?

A. No. The Gannon re-powering project results in an avoided unit with similar characteristics as the avoided unit identified using Tampa Electric's resource plan without the re-powering project. Given this similarity, Witness Bryant's testimony addresses more specifically the fact that there would be a very minimal impact, if any at all, on available conservation. Therefore, Tampa Electric saw no reason to conduct a conservation sensitivity.

Q. Earlier in this testimony you mentioned your Exhibit had been revised from the original "Gannon Resource Utilization Study". Please describe the revisions.

A. Minor refinements to the estimates used in the analysis have been incorporated into my testimony. For the Purchase Power Alternative, the associated transmission and distribution capital costs and system transmission loss impacts were better quantified. Minor improvements to the transmission and distribution capital cost in other alternatives were also included. Also, in the original study, the high gas commodity and high gas transportation impacts were not applied to the purchase power case sensitivities.

Q. Does the *Gannon Repowering Alternative* satisfy Tampa Electric's environmental, reliability, and other operational requirements?

A. Yes, the *Gannon Repowering Alternative* provides customers of Tampa Electric with the most cost-effective option for significantly reducing emissions while maintaining system generation and transmission reliability and maximizing operational flexibility. Specifically, this alternative is expected to result in reduced emissions of SO_2, NO_X, and PM by as much as 80 percent, 85 percent, and 45 percent below 1997 levels, respectively. These meet the DEP's required emission reduction levels.

From a reliability standpoint, this alternative addresses several issues. By installing highly efficient and reliable natural gas-fired combined cycle technology, concerns over reduced efficiencies and availabilities of aging coal units are addressed.

The *Gannon Repowering Alternative* also maintains the reliability of the peninsular Florida transmission system in a cost-effective manner and, overall, has the lowest impact to Tampa Electric's and peninsular Florida's transmission system. Significant expenditures would be required to maintain transmission system reliability if an alternative were selected that necessitated shutting down Gannon Station and purchasing replacement power or building replacement capacity at a different site.

After considering this detailed analysis and all environmental factors and agency requirements, the *Gannon Repowering Alternative* emerged as the most cost-effective alternative and the best solution for the company.

Q. Describe in more detail how the Gannon Repowering Project improves Tampa Electric's reliability.

A. The combined cycle capacity resulting from the Gannon Repowering Project is expected to have an estimated equivalent availability factor ("EAF") of 91 percent. This EAF, approximately 18 percent higher than Gannon Station's current EAF, significantly improves the station's equivalent capacity to serve retail customers. The improved availability results from the differences between natural gas and coal technology and the relative age of the coal-based generating equipment. The higher availability of the repowered units equates to more energy being available during periods of peak operating hours. This reduces Tampa Electric customers' exposure to energy price spikes during periods when capacity is tight or during peak demand conditions.

Q. Are there other aspects to the Gannon Repowering Project that improve system reliability?

A. Most likely, yes. Tampa Electric is evaluating a repowered Gannon Unit 5 configuration that will enable one of the three CTs to operate in a simple cycle mode. This would provide 180 MW of available capacity, 24 percent of the total capacity, in the event that Unit 5's steam turbine experiences an outage.

The repowering of Units 3 and 4 involves integrating two steam turbines with three CTs and three HRSGs. In this configuration, if one of the steam turbines is out of service, the three CTs, the three HRSGs and the remaining steam turbine will remain operational at a reduced capacity. Aside from occasional outages, the Gannon Units 3, 4, and 5 steam turbines have historically provided over 99 percent availability. If a CT loss occurs in either repowered unit, the remaining generating equipment will continue to be operational. As stated in the direct testimony of Tampa Electric Witness Charles R. Black, the dual fuel capability will allow the repowered units to operate during short interruptions to the gas supply.

Q. What effect will this project have on Gannon Station's capacity?

A. The Gannon Repowering Project will result in increased capacity even though only three of the six existing steam turbines/generators will be utilized. The capacity will increase incrementally by 272 MW (nominal) in 2003 and 23 MW (nominal) in 2004 for a total incremental increase of 295 MW (nominal) by the completion of the Gannon Repowering Project.

Q. What impacts will the Gannon Repowering Project have on Tampa Electric's planned reserve margins?

A. The Gannon Repowering Project enables the company to achieve its 20 percent minimum firm reserve margin for both winter and summer periods by the summer of 2004 in accordance with the stipulation approved by this Commission in the reserve margin docket, PSC 992507-5-EU, issued December 22, 1999. It also helps the company meet its seven percent minimum summer supply-side reserve margin criterion.

Q. How will the Gannon Repowering Project impact peninsular Florida's reserve margins?

A. The Gannon Repowering Project's capacity will not only contribute to Tampa Electric's system, but will also contribute to statewide reserve margins by being made available to peninsular Florida's firm customers during emergency capacity and energy conditions.

Q. Please summarize your testimony.

A. Tampa Electric has evaluated the most cost-effective means of meeting the stringent environmental requirements of the CFJ while simultaneously satisfying increasing customer demand for reliable electricity at reasonable prices. The company utilized its integrated resource planning process to determine the most cost-effective resource option. As part of the process, common assumptions were developed and applied to a wide range of alternatives. Many alternatives and variations of the alternatives were eliminated from further evaluation if they were technically infeasible; did not comply with environmental regulations; failed to meet the company's reliability criteria; or had obvious disadvantages, economic or otherwise, over other alternatives. As a result, the company further evaluated four viable alternatives; the *Environmentally Adjusted Alternative*, the *Gannon Non-Repower Replacement Alternative*, the *Purchased Power Alternative*, and the *Gannon Repowering Alternative*.

Cost estimates for each alternative were compiled on a CPWRR basis and reported in 1999 dollars. Each alternative was compared incrementally to the *Environmentally Adjusted Alternative*, the reference case, to produce risk curves. Based upon this analysis, the *Gannon Repowering Alternative was* the most cost-effective alternative. Throughout the sensitivity analyses for natural gas commodity and transportation prices, and SO_2 allowance prices, the *Gannon Repowering Alternative* remained the most cost-effective alternative. Therefore, after considering this detailed analysis and all environmental factors and agency pressures, it was clear that the *Gannon Repowering Alternative* was the most cost-effective alternative and the best solution for the company, its customers, and the state of Florida.

Not only does the Gannon Repowering Project address many requirements of the CFJ entered into by and between Tampa Electric and DEP; it also enhances the company's and peninsular Florida's reliability and enables the company to meet the reserve margin requirements contained in the stipulation approved by this Commission in the reserve margin docket on December 22, 1999. The project will provide incremental capacity that helps Tampa Electric and peninsular Florida achieve the planning reserve margin criteria. Also, the repowered units will have a higher availability and equivalent capacity than the existing Gannon coal-fired units. For all of these reasons, the Gannon Repowering Project is prudent and the most cost effective means for Tampa Electric to achieve compliance with the CAA and the CFJ while reliably serving its customers' growing demand and energy needs.

Q. Does that conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 992014-EI
WITNESS: MARK D. WARD
EXHIBIT NO.____ (MDW-1)

TAMPA ELECTRIC COMPANY

EXHIBIT OF MARK D. WARD

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APPENDIX B

GANNON RESOURCE UTILIZATION STUDY

Overview

Tampa Electric periodically completes resource utilization studies, evaluating various planning and operating alternatives to current operations, with objectives ranging from meeting compliance requirements in the most cost-effective and reliable manner to maximizing operational flexibility and minimizing operational costs. The most recent resource utilization study, involving the Gannon coal units, began in late 1998 and continued into 1999.

In the 1998/99 study, Tampa Electric evaluated various options for Gannon Station designed to address a variety of issues. These issues included: the anticipated designation of the Tampa Bay region as an ozone non-attainment area; the anticipated promulgation of new ambient air standards including fine particulate matter ($PM_{2.5}$); local community environmental issues: the probability of higher natural gas availability (announcements of several proposed pipeline projects had occurred); the reduced efficiency and availability of the aging Gannon units, and the fact that considerable maintenance would be required to maintain acceptable performance levels from these units exacerbating the existing issue with the Environmental Protection Agency (EPA) over its interpretation of maintenance relative to Section 114 of the New Source Review (NSR) Standards

Many alternatives were evaluated in the Gannon utilization study including the following:

- Fuel switching the Gannon units from coal to natural gas;
- Repowering the Gannon coal units;
- Installing flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems on all of the Gannon coal units;
- Placing Gannon Station on reserve standby and purchasing replacement power to serve Tampa Electric's power requirements; and
- Placing Gannon Station on reserve standby and building replacement generation

Several alternatives were eliminated from further consideration during the initial screening process for various reasons (e.g. cost, technological issues, statewide transmission system reliability issues, etc.). Of the remaining alternatives, the repowering of Gannon Units 3, 4, and 5 was determined to be the most cost-effective alternative while meeting reliability and environmental considerations.

The Gannon utilization study was updated in the fall of 1999 to include NO_X control on the Big Bend coal units as a result of the Consent Final Judgement (CFJ) with the Florida Department of Environmental Protection (DEP) which requires, among other things, the repowering of Gannon Units 3, 4, and 5 by the end of 2004 and the installation of NO_X control technology on the Big Bend coal units beginning in 2007 with completion by the end of 2010. The events leading up to the CFJ are as follows:

> On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually agreeable settlement with the EPA, the Department of Justice (DOJ) sued Tampa Electric and seven other electric utilities on behalf of EPA for alleged violations of the Clean Air Act ("CAA") associated with this NSR issue. At issue are the coal-fired Gannon Units 3, 4, and 6, and Big Bend Units 1 and 2.
>
> Following this federal action, DEP also contended that Tampa Electric had not applied for appropriate air permits for certain unit maintenance projects at Gannon and Big Bend Stations and, therefore, had operated the coal-fired units without Best Available Control Technology (BACT) for NO_X, SO_2, and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. On December 7, 1999, DEP and Tampa Electric entered into a CFJ which addresses the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon without first obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2, and PM.

As a key element of the CFJ, all coal-related assets including coal-handling equipment will be retired. The steam turbines/generators and associated non-coal related equipment from Units 1 and 2 will be shut down and placed on reserve standby coincident with the repowering of Unit 5. Unit 6 will be shut down and placed on reserve standby by the end of 2004. These units will be available to Tampa Electric as future supply-side resource options via repowering to meet the growing demand and energy needs of its customers. The company does not currently have plans to utilize the units, but it may, at some time in the future, repower or convert the units to natural gas if those options prove to be cost-effective.

The study was also updated with the most current planning assumptions initially including minimum reliability criteria of 15 percent firm reserve margin with a minimum 7 percent reserve margin from supply-side resources. The reserve margin criteria of 15 percent was subsequently updated to 20 percent based on the stipulation between the FPSC and the three Florida investor owned utilities to carry a 20 percent reserve margin.

Sensitivities on natural gas commodity prices, transportation prices, and SO_2 allowance treatment were included in the study. The Gannon Repowering Alternative remained the most cost-effective alternative in all of these sensitivities.

Assumptions

Economic and Financial Assumptions

- The economic and financial assumptions used to determine the cumulative present worth revenue requirements (CPWRR) associated with each compliance alternative are summarized in Table B-1. This table shows key parameters such as inflation rates, income tax rates, rates of return, other discount rates, and the allowance for funds used during construction (AFUDC) rate.

- Financial assumptions for each alternative evaluated are provided in Tables B-2a and B-2b.

TABLE B-1
TAMPA ELECTRIC COMPANY
FINANCIAL ASSUMPTIONS

INFLATION/ESCALATION	
O&M	
1999	1.9%
2000	2.1%
2001+	2.3%
CAPITAL	
1999	1.5%
2000	2.0%
2001+	2.2%
TAX RATE	
OTHER TAXES	1.49%
FEDERAL & STATE	38.58%
FINANCIAL CAPITALIZATION RATIOS	
DEBT	41.80%
PREFERRED	0.00%
COMMON EQUITY	58.20%
RATE OF RETURN	
DEBT	7.75%
PREFERRED	10.66%
COMMON EQUITY	12.75%
DISCOUNT RATE	9.41%
AFUDC RATE	7.79%

TABLE B-2a
TAMPA ELECTRIC COMPANY
COST ASSUMPTIONS FOR COMPLIANCE ALTERNATIVES

COMPONENTS OF COMPLIANCE ALTERNATIVES	GANNON REPOWERING UNIT 3/4 & UNIT 5	COMMON FUTURE CTS (IN ALL EXPANSION PLANS)	GANNON REPLACEMENT PLAN FUTURE CC "F" FRAME	GANNON REPLACEMENT PLAN FUTURE CC "G" FRAME
NOMINAL COST * $/kW	$366	$295	$439	$427
ANNUAL FIXED CAPITAL 99$000/unit	$3,454	$0	$2,283	$2,283
ANNUAL FIXED O&M 99$000/unit	$4,600	$368	$3,067	$3,067
VARIABLE O&M 99$/MWH	$0.57	$2.80	$0.57	$0.57
TAX LIFE	20 Years	15 Years	20 Years	20 Years
BOOK LIFE	30 Years	30 Years	30 Years	30 Years
IN-SERVICE DATE	May 2004	Oct 2000	May 2003	Jan 2007

* Nominal costs are based on winter unit capabilities and do not include AFUDC and Transmission & Distribution

TABLE B-2b
TAMPA ELECTRIC COMPANY
COST ASSUMPTIONS FOR PURCHASE POWER ALTERNATIVE

PURCHASED POWER ALTERNATIVE	VALUE
Levelized Capacity Component	73.99 $/kW-YR
Energy Component (2003$)	26.07 $/MWH
Wheeling Component (2003$)	17.9 $/kW-YR
CAPITALIZATION RATIOS	
Debt	75.0%
Common Equity	25.0%
RATE OF RETURN	
Debt	8.5%
Common Equity	15.0%
Risk Adjustment Factor Per Standard & Poor's Method	25.0%

Fuel Assumptions

- For the Gannon Repowering Alternative, natural gas availability was assumed to be 100 percent. However, 100,000 MMBtu/day of firm gas was assumed for the Gannon Repowering Alternative with 50,000 MMBtu/day dedicated to the first repowered unit and 50,000 MMBtu/day dedicated to the subsequent repowered units.

- Natural gas transportation costs of $0.55/MMBtu and $0.80/MMBtu were used for the base case and high transportation case sensitivity, respectively.

- The fuel assumptions for existing and future units were based on the company's current Fuel and Interchange Forecast for year 2000 and beyond.

- The purchase power fuel availability was assumed to be 100 percent with firm transportation. This assumes that the power provider would not have dual fuel capability.

Environmental Control Technology Assumptions

- Sargent & Lundy was contracted to prepare a study to develop more detailed capital cost estimates, along with schedule, staffing requirements, O&M costs, and thermodynamic performance for the repowering alternative. In addition, another study was performed by Sargent & Lundy to develop cost estimates for retrofitting Gannon Units 5 and 6 with FGD systems and SCR's for use in the previously mentioned environmentally adjusted alternative. The results of this FGD/SCR study were extrapolated for developing estimates for all of the Gannon units.

- Although the NO_X control technology to be utilized with the Big Bend coal units has not yet been determined, an estimated cost of installing SCRs on these units was substituted for the purpose of this analysis.

Load Assumptions

- Load forecasts used in the analysis are from the company's 2000 Fuel and Interchange Forecast.

Unit Operating Assumptions

- Unit operating parameters used in the analysis are from the company's 2000 Fuel and Interchange Forecast

- Operating assumptions for each alternative evaluated are provided in Table B-3.

TABLE B-3
TAMPA ELECTRIC COMPANY
OPERATING ASSUMPTIONS

COMPONENTS OF COMPLIANCE ALTERNATIVES	WINTER CAPACITY MW	SUMMER DERATION MW	HEAT RATE* Mbtu/MWh	EQUIVALENT AVAILABILITY FACTOR** %
GANNON REPOWERING				
UNIT 3/4	802	91	7.050	91.0%
UNIT 5	796	98	7.080	91.0%
EXISTING GANNON STATION				
UNIT 1	114	0	11.909	75.6%
UNIT 2	113	0	12.028	66.5%
UNIT 3	155	10	11.413	81.1%
UNIT 4	189	10	11.047	69.8%
UNIT 5	242	10	10.196	75.2%
UNIT 6	392	20	10.376	72.2%
COMMON FUTURE CT'S (In all expansion plans)	180	25	10.580	94.0%
GANNON REPLACEMENT PLAN				
FUTURE CC'S				
USING GE "F" FRAME CT'S	523	78	7.081	91.0%
USING WESTINGHOUSE "G" FRAME CT'S	675	103	6.590	91.0%

* Heat rates of Gannon Repowering Units 3/4 and 5 are higher heating values (HHV) and based on average ambient temperatures
* EAF's are based on Winter Capacity

Purchased Power Assumptions

- The incremental capital cost of maintaining transmission system reliability of the transmission grid associated with placing Gannon Station on reserve standby was estimated conservatively at $71 million (20-year CPW in 1999 dollars). This assumes the medium case scenario with firm purchased power being provided from several areas with peninsular Florida.

- In addition to these transmission capital costs required to maintain transmission system reliability, further investigation and consultation with Power Technologies Inc. (PTI) indicates that significant bulk transmission system reactive power devices will be required for TEC or Florida system voltage support. Based on preliminary estimates, these devices could cost as much as $50 million (20-year CPW in 1999 dollars). Because a detailed analysis of these requirements has not been made, this economic cost was not included in this assessment.

- In evaluating impacts to the state transmission system related to this project, it became apparent that transmission losses will increase well above the amount accounted for by utility transmission tariff loss percentages. Contractual tariff losses were included in the analysis and were quantified with an effective loss rate of 2.17%. However, actual incremental transmission losses throughout the state will greatly exceed this contractual rate. As this is not an actual economic cost to Tampa Electric, it was not included in this assessment.

- Generic assumptions for an IPP-financed combined cycle plant were used to calculate the price of replacement power.

- For the purposes of determining wheeling charges, transmission impacts, and transmission losses associated with replacement power, the power was assumed to be purchased from several power projects throughout Florida that are associated with various independent power producers (i.e. Duke/New Smyrna Beach, Okeechobee Generating Company, Reliant, Constellation and Panda). A percentage, estimated for each project, was utilized to calculate weighted average wheeling charges, transmission losses, and transmission impacts.

- A financial risk adjustment was included in the cost of purchased power to capture the impact on the company related to the financial risk associated with entering a long-term contract for purchased power.

Repowering Assumptions

- Gannon Units 3, 4, and 5 were selected to be repowered based on the generation requirements for meeting expansion plan criteria, the physical operating characteristics of the existing equipment, and the overall condition and age of the existing units.

- The configuration of the repowered units is as follows: The first phase of the repowering includes integrating three new dual-fuel (natural gas and oil) fired GE 7FA combustion turbines and three new heat recovery steam generators (HRSGs) with the existing Gannon Unit 5's steam turbine. The second phase of the repowering includes integrating three more new GE 7FA combustion turbines and three new HRSGs with the two existing steam turbines associated with Gannon Units 3 and 4.

- The capital costs associated with the existing Gannon Station were considered sunk costs, and were treated as such in the determination of customer rates and overall revenue requirement impacts. However, the impact of recovering these dollars on a faster schedule (due to the advanced retirement date) than previous life estimates was factored into the analysis.

Methodology

Initial Screening

Early in the resource utilization study many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible options, overall. Those alternatives that failed to meet environmental acceptability, economics, technical feasibility, operational criteria, maintainability, and reliability were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in the more detailed economic analysis.

Alternatives Evaluated

A description of the Gannon utilization study alternatives chosen by Tampa Electric for quantitative evaluation are listed below. The generation expansion plans associated with each alternative are shown in Table B-4.

1) **Environmentally Adjusted Alternative**
This alternative has an all-CT expansion plan. It also includes the installation of environmental equipment that meets the more stringent interpretations of the NSR standards proposed by the EPA. The environmental equipment includes the addition of FGD and SCR systems on all of the Gannon coal units.

In this alternative, NO_X control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

2) **Gannon Repowering Alternative**
The Gannon Repower Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA and the requirements of the CFJ by repowering Gannon Units 3, 4, and 5 with natural gas-fired technology by the end of 2004. The first phase of the repowering includes integrating three new dual-fuel (natural gas and oil) fired GE 7FA combustion turbines and three new HRSGs with the existing Gannon Unit 5's steam turbine. The second phase of the repowering includes integrating three more new GE 7FA combustion turbines and three new HRSGs with the two existing steam turbines associated with Gannon Units 3 and 4. The Gannon Repowering Alternative also includes the installation of SCR systems for all of the CTs utilized in the repowering.

In this alternative, NO_X control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

3) **Gannon Non-Repower Replacement Alternative**
The Gannon Non-Repower Replacement Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by

retiring the existing Gannon coal assets by 2004 and replacing the retired generation with on-site GE 7FA combined cycle technology. The replacement units were all equipped with SCRs.

This alternative also includes NO_X control technology on the Big Bend coal units beginning 2007 with completion by the end of 2010.

4) **Purchased Power Alternative**

The Purchased Power Alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the Gannon coal-fired units and purchasing capacity and energy to meet system demand and energy requirements. The transmission cost of maintaining the reliability of the transmission grid associated with the placing Gannon Station on reserve standby was included in this alternative. An adjustment to the cost of purchased power was made to reflect the financial risk to Tampa Electric associated with entering a long-term contract for purchased power.

This alternative also includes NO_X control technology on the Big Bend coal units beginning 2007 with completion by the end of 2010.

TABLE B-4
TAMPA ELECTRIC COMPANY
EXPANSION PLANS FOR EACH COMPLIANCE ALTERNATIVE

YEAR	ENVIRONMENTALLY ADJUSTED ALTERNATIVE	GANNON REPOWERING ALTERNATIVE	GANNON NON-REPOWERING REPLACEMENT ALTERNATIVE	PURCHASED POWER ALTERNATIVE
2000	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)	HPS CT2B Polk CT (Oct)
2001	—	—	—	—
2002	Polk CT (May)	Polk CT (May)	Polk CT (May)	Polk CT (May)
2003	Polk CT (May)	Repower 5 (May) LTRS Gannon 1 & 2	Gannon "F" CC Polk CT LTRS Gannon 1, 2, & 5	Firm purchase to replace Gannon Repowering Alternative
2004	Polk CT (May)	Repower 3 & 4 (May) LTRS Gannon 6	2 ea - Gannon "F" CC LTRS Gannon 3, 4, & 6	Firm purchase to replace Gannon Repowering Alternative
2005	Polk CT (May)	Polk CT	—	Polk CT
2006	—	Polk CT	Polk CT	Polk CT
2007	Future Site CT		Future Site "G" CC	
2008	Future Site CT	Polk CT		Polk CT
2009	Future Site CT	Future Site CT		Future Site CT

<u>Economic Analysis</u>

The analysis compares the related costs of each utilization alternative based on incremental CPWRR. The relative costs were developed on an incremental basis relative to the Environmentally Adjusted Alternative assumptions. The CPWRR include system fuel and purchase power expense, incremental generation capital, incremental transmission and distribution capital, incremental O&M expense, incremental SO_2 allowance costs, depreciation, working capital, incremental transmission losses, transmission wheeling expense and other incremental costs associated with the compliance alternatives and construction of new generating resources.

PROMOD, a production costing computer model, was used to determine fuel and purchased power expense associated with each of the alternatives. PROMOD simulates an economic dispatch of Tampa Electric's generating system based on incremental production costs. In addition to fuel and purchase power expense, PROMOD simulates the unit operating characteristic impacts, and system dispatch effects associated with different compliance alternatives.

PROSCREEN, another planning model, was used to develop incremental capital revenue requirements, SO_2 allowance costs and incremental O&M expense associated with each alternative. The incremental capital revenue requirements and incremental O&M expenses were added to the fuel costs, purchase power expense, incremental transmission wheeling expense, and incremental transmission system losses expense to determine the total revenue requirements of each alternative. Also incorporated were Gannon Station coal working capital reductions, depreciation timing impact associated with the earlier retirement of coal-related Gannon Station assets and the financial risk adjustment associated with purchased power contracts.

The financial risk adjustment was included in the cost of purchased power to capture the impact on the company of the financial risk associated with entering a long term contract for purchased power. This adjustment reflects the additional cost associated with maintaining the higher equity amounts required by rating agencies in order to maintain the financial strength needed to justify current bond ratings. The financial risk adjustment was calculated using Standard and Poors methodology which imputes purchased power capacity payments as a debt equivalent. The financial adjustment represents the imputed cost of this higher source of capital that replaces lower cost debt.

The units to be repowered in the Gannon Repowering Alternative were selected based on the generation requirements for meeting expansion plan criteria, the physical operating characteristics of the existing equipment, and the overall condition and age of the existing units.

Study Results

Base Analysis

The incremental CPWRR in 1999 dollars for all of the alternatives evaluated are provided in Figure B-1. These incremental CPWRR are differentials to the Environmentally Adjusted Alternative and provide a graphical summary of the results from the quantitative analysis. The analysis concluded that the Gannon Repowering Alternative was the most cost-effective option for environmental compliance.

The Environmentally Adjusted Alternative was used as the basis for comparison to each of the other alternatives. The incremental CPWRR of the other alternatives show a savings relative to the Environmentally Adjusted Alternative over the study period.

The incremental CPWRR of the Purchased Power Alternative was $337.0 million higher than the Gannon Repowering Alternative. This is due primarily to the *transmission costs associated with maintaining transmission reliability after* Gannon Station is placed on reserve standby.

The Gannon Non-Repower Replacement Alternative was $51.5 million higher in cost than the Gannon Repowering Alternative. Although this option resulted in lower overall fuel costs due to the higher efficiency of the "G" technology included in the expansion plan, the fuel savings were not great enough to offset the higher capital costs and O&M expense of the Gannon Non-Repower replacement alternative. The capital costs were higher due to expansion plan differences and because the plan did not make use of existing equipment at Gannon Station (i.e. steam turbines). Higher O&M expense was associated with this expansion plan. In the optimization of the expansion plan for this alternative, "G" combined cycle technology was restricted from the early years of the planning window due to technology risk.

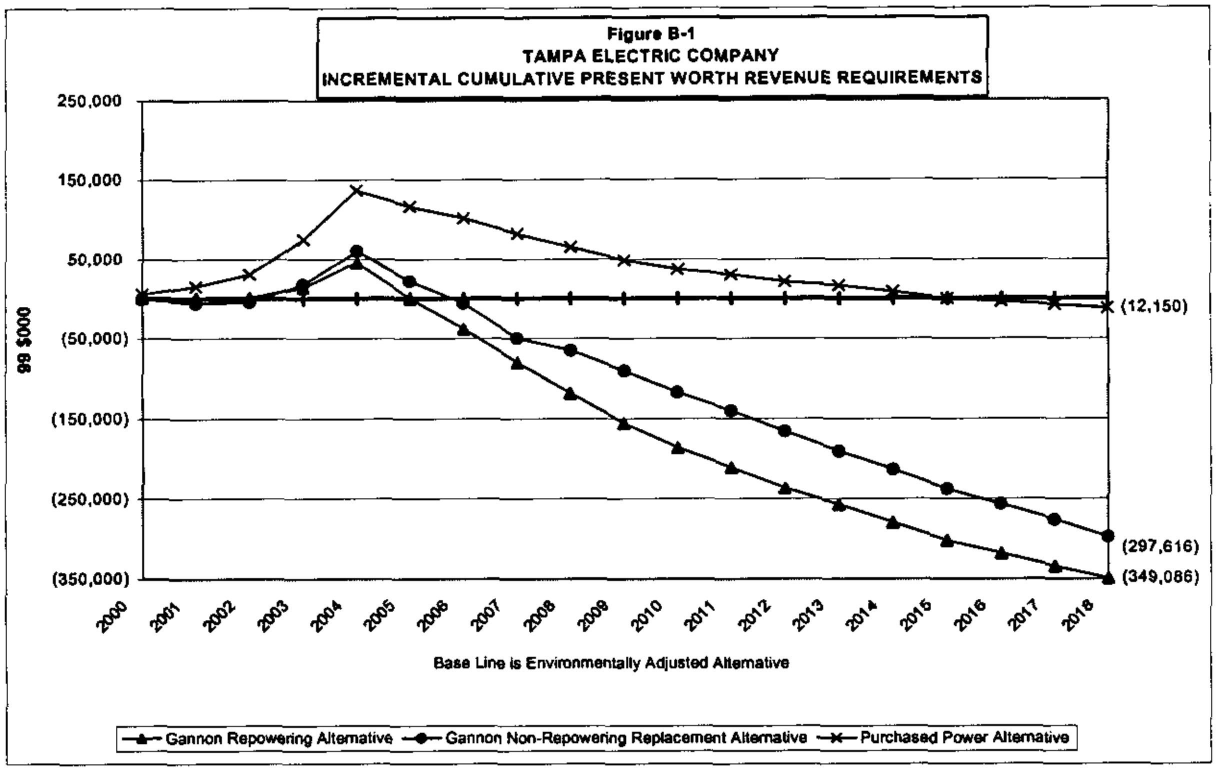


Figure B-1
TAMPA ELECTRIC COMPANY
INCREMENTAL CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS

<u>Sensitivities</u>

To ensure that the Gannon Repowering Alternative was prudent given a wide range of contingencies, Tampa Electric completed a series of additional analyses incorporating various sensitivities. These additional analyses include sensitivities on lower SO_2 allowance prices and higher natural gas transportation and commodity prices. The results of these sensitivities on the Gannon Repowering Alternative are provided in Figures B-2, B-3, and B-4.

The lower SO_2 allowance price sensitivity assumed that the forecasted price of an allowance would eventually drop to a value that approaches the operating cost of an FGD system on a $/Ton basis. Remarketing excess SO_2 allowances was assumed in the base analysis of each alternative. By lowering the market value of these allowances, the credit back to the customer is reduced and, therefore, the overall revenue requirements are higher. Relative to the Environmentally Adjusted Alternative, the lower SO_2 allowance reduced the differential CPWRR by approximately $12.0 million for the Gannon Non-Repowering Alternative and by $13.2 million dollars for the Gannon Repowering Alternative. The incremental CPWRR of the Purchased Power Alternative was increased by approximately $13.2 million making it the highest cost alternative at $1 million over the CPWRR of the Environmentally Adjusted Alternative.

In the higher natural gas transportation sensitivity, transportation costs for Tampa Electric's gas-fired units were assumed to be higher by 25 cents per MMBtu over the base assumption. Relative to the Environmentally Adjusted Alternative, this increase in transportation cost reduced the CPWRR savings by approximately \$36.6 million for the Gannon Non-Repowering Alternative and by \$40.3 million dollars for the Gannon Repowering Alternative. The Purchased Power Alternative assumed 100 percent firm natural gas whereas the repowering and non-repower replacement alternatives assumed a combination of firm and interruptible gas. Therefore, the increase to the CPWRR of the Purchased Power Alternative was greater at approximately \$57.0 million. This increase changed the order of the alternatives making the Purchased Power Alternative higher in cost by \$44.8 million relative to the Environmentally Adjusted Alternative.

The high natural gas sensitivity used a high price forecast for the commodity only. A significant impact to the CPWRR of each alternative resulted from raising the natural gas price. The incremental CPWRR increased by \$200.5 million for the Gannon Non-Repowering Alternative and by \$207.9 million dollars for the Gannon Repowering Alternative. The incremental CPWRR of the Purchased Power Alternative was increased by approximately \$211.6 million dollars and exceeded the CPWRR of the Environmentally Adjusted Alternative by \$199.4 million. The relative order of the Gannon Non-Repowering and Gannon Repowering alternatives remained the same.

Through all sensitivities the Gannon Repowering Alternative remained the most cost-effective alternative. This was expected considering that each alternative included natural gas-fired combined cycle technology and, therefore, would be impacted similarly by the natural gas and SO_2 allowance sensitivities.

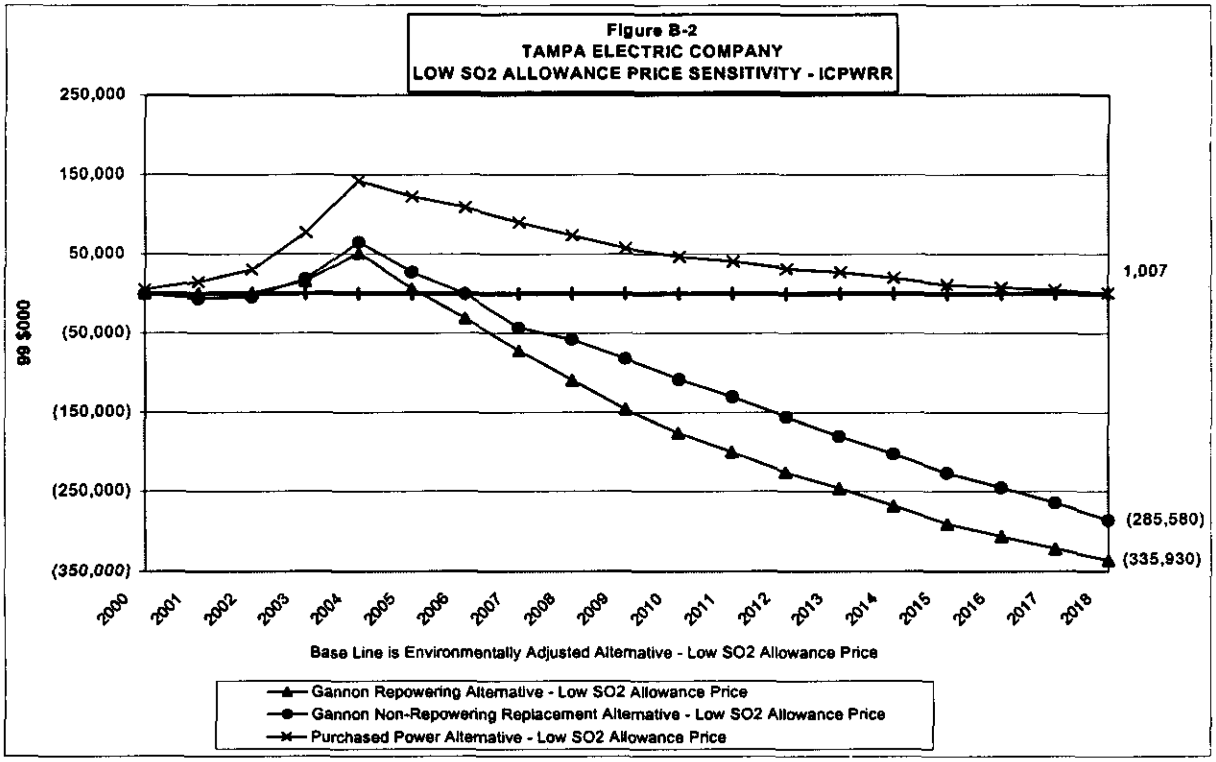


Figure B-2
TAMPA ELECTRIC COMPANY
LOW SO2 ALLOWANCE PRICE SENSITIVITY - ICPWRR
250,000
150,000
50,000
(50,000)
(150,000)
(250,000)
(350,000)
99 $000
1,007
(285,580)
(335,930)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Base Line is Environmentally Adjusted Alternative - Low SO2 Allowance Price
Gannon Repowering Alternative - Low SO2 Allowance Price
Gannon Non-Repowering Replacement Alternative - Low SO2 Allowance Price
Purchased Power Alternative - Low SO2 Allowance Price

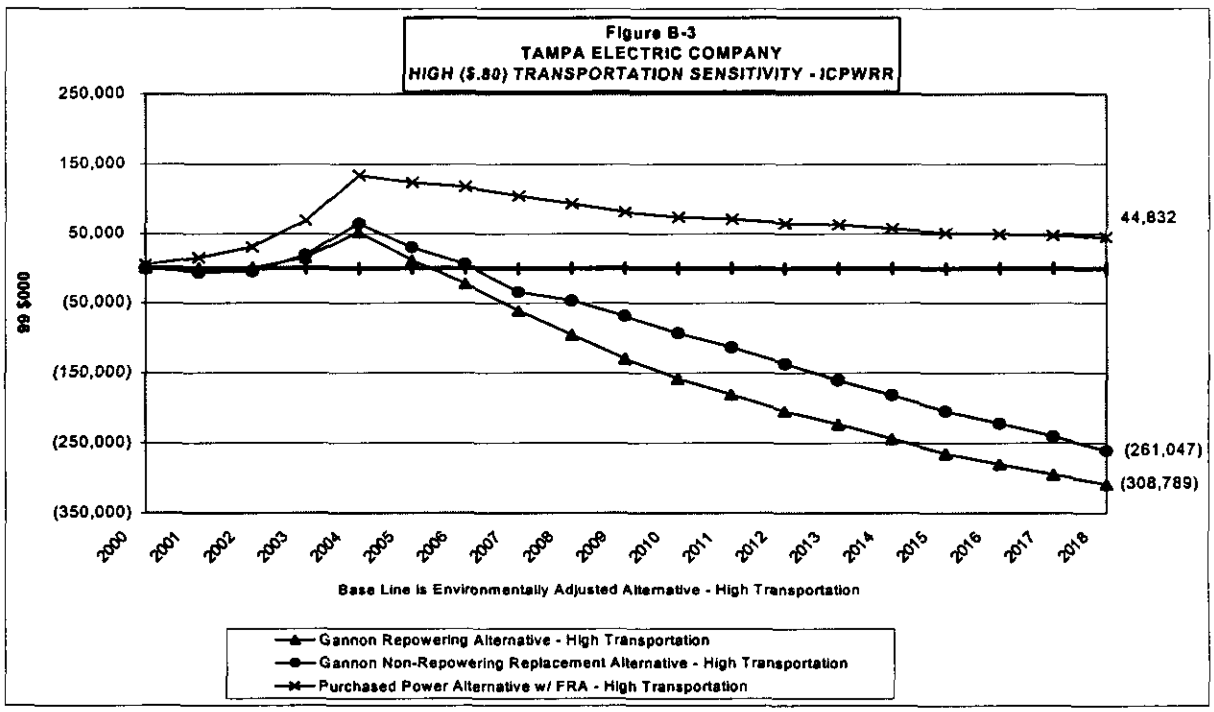
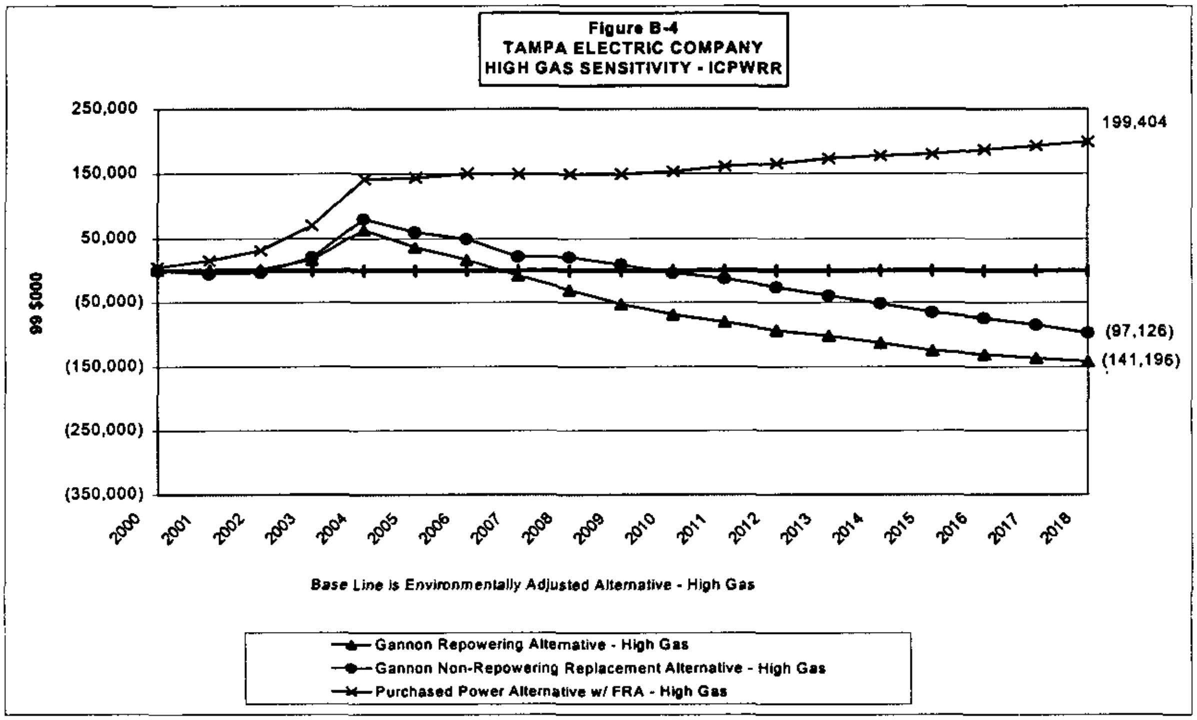


Figure B-3
TAMPA ELECTRIC COMPANY
HIGH ($.80) TRANSPORTATION SENSITIVITY - ICPWRR
250,000
150,000
50,000
(50,000)
(150,000)
(250,000)
(350,000)
99 $000
44,832
(261,047)
(308,789)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Base Line is Environmentally Adjusted Alternative - High Transportation
Gannon Repowering Alternative - High Transportation
Gannon Non-Repowering Replacement Alternative - High Transportation
Purchased Power Alternative w/ FRA - High Transportation



Conclusion

The Gannon Repowering Alternative has been shown to be the most cost-effective option for Tampa Electric's customers when compared to other alternatives. This alternative has significantly lower CPWRR, both annually and over the entire study period, in the base analysis and each sensitivity evaluated.

This alternative would result in significant reductions in SO_2, NO_X, and PM as shown in Figures 7.1, 7.2, and 7.3, respectively, of the Compliance Plan. It is anticipated that emissions of SO_2, NO_X, and PM would be reduced as much as 80 percent, 85 percent, and 45 percent below 1997 levels, respectively. The Gannon Repowering Alternative is also a key component of Tampa Electric's agreement with DEP and meets the more stringent interpretation of the NSR proposed by the EPA.

From a reliability standpoint, this alternative addresses several issues. The issues of reduced efficiency and availability of aging coal units and meeting the incremental power requirements are addressed by installing highly efficient and reliable natural gas-fired combined cycle technology.

The Gannon Repowering Alternative maintains the reliability of the peninsular Florida transmission system in a cost-effective manner and has, overall, the lowest impact to Tampa Electric's transmission system. Significant expenditures would be required to maintain transmission system reliability if an alternative were selected that necessitated placing Gannon Station on reserve standby (i.e. purchasing replacement power or building replacement capacity at a different site).

Tampa Electric's utilization study concluded that the Gannon Repowering Alternative provides Tampa Electric's customers with the most cost-effective option for significantly reducing emissions while maintaining system reliability, statewide transmission grid reliability, and maximizing operational flexibility.