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REC...DS AND REPORTING

December 23, 1999

**BY HAND DELIVERY**

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

992014-EI

Re: Tampa Electric Company's Petition for Approval of its Plan to Bring its Generating Units into Compliance with the Clean Air Act

Dear Ms. Bayo:

Enclosed for filing are the original and fifteen (15) copies of Tampa Electric Company's Petition and Comprehensive Clean Air Act Compliance Plan in the above-referenced matter. Also enclosed is a diskette containing the Petition.

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

Thank you for your assistance in this matter.

Sincerely,

Lee L. Willis

LLW/bjd

Enclosures

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FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE

15692 DEC 23 99

FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In re: Tampa Electric Company's<br>Petition for Approval of its Plan to<br>Bring its Generating Units into<br>Compliance with the Clean Air Act. | )<br>)<br>)<br>)<br>) | DOCKET NO. 992014-EI<br>FILED: December 23, 1999 |

**PETITION**

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Section 366.825, Florida Statutes (1999), and Rule 28-106.201, Florida Administrative Code, respectfully submits its plan to comply with the Clean Air Act (42 U.S.C. § 7401, et seq.) ("the Act") for approval by the Florida Public Service Commission ("the Commission"). The central focus of this Petition is to request Commission approval of Tampa Electric Company's Comprehensive Clean Air Act Compliance Plan. Specific cost recovery is not requested in this Petition. Cost recovery of specific projects required to comply with environmental regulation may be filed in subsequent petitions for temporary or permanent rate increase or for recovery of discrete portions of such projects through the Environmental Cost Recovery Clause ("ECRC"). This Petition does request a determination that certain of its costs of environmental compliance are the type of costs which are recoverable through the ECRC. In support of this Petition, Tampa Electric states:

1. The petitioner, Tampa Electric, is a public utility subject to the jurisdiction of the Commission under Section 366, Florida Statutes. Tampa Electric's headquarters are located at 702 North Franklin Street, Tampa, Florida 33602. The petitioner's telephone number is (813) 228-4111.

2. All notices, pleadings and other communications required to be served on Tampa Electric should be directed to Tampa Electric's representatives, as follows:

Lee L. Willis
James D. Beasley
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302

Angela Llewellyn
Administrator, Regulatory Coordination
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601

3. Under Section 366.825(2), Florida Statutes (1999), each public utility which owns or operates at least one generating unit affected by Sections 404 and/or 405 of the Act may submit to the Commission its plan for compliance with the Act.

4. Attached to this Petition as Exhibit "1" is a document entitled Tampa Electric Company's Comprehensive Clean Air Act Compliance Plan ("Compliance Plan") dated as of December 1999. This document generally describes the company's overall plan for achieving compliance with applicable provisions of the Act. The Compliance Plan is based on a strategy that considers the company's long-term achievements and current requirements, along with actual and/or estimated costs associated with environmental compliance activities. Although the Compliance Plan reflects current requirements of the Act, it also identifies potential future requirements. It is intended that the Compliance Plan be continually updated and revised as circumstances warrant. This approach will allow Tampa Electric to adapt to changes in costs, technological and operational developments, and environmental regulatory requirements while maintaining cost-effective approaches to comply with the Act. The company will periodically review its strategy, make such revisions and/or additions as are prudent, and will refile its updated strategy as often as deemed necessary by the company or this Commission. Tampa Electric submits the following information concerning its compliance strategy, pursuant to the requirements of Section 366.825, Florida Statutes.

5. The central focus of this Petition is to request Commission approval of a Compliance Plan that is consistent with requirements specified in the Consent Final Judgment ("CFJ") entered into by and between Tampa Electric and the Florida Department of Environmental Protection (DEP) effective December 16, 1999. A copy of the CFJ is attached hereto as Exhibit "2". The CFJ requires Tampa Electric to remain in compliance with applicable environmental emissions limitations and resolve an enforcement proceeding brought on by DEP while improving the company's ability to reliably and cost-effectively serve its customers' growing demand for electricity. The Compliance Plan sought for approval in this proceeding integrates the activities called for in the CFJ into the environmental compliance efforts already implemented by Tampa Electric.

## INTRODUCTION AND BACKGROUND

6. Tampa Electric is engaged in the generation, purchase, transmission, distribution, and sale of electric energy. Tampa Electric serves over 543,000 retail customers in its service area of approximately 2,000 square miles in West Central Florida, including Hillsborough and parts of Pasco, Pinellas, and Polk counties, with a population of over one million people. Tampa Electric's coal-fired units produced about 90 percent of its system energy requirements in 1998. Total 1998 energy sales including wholesale sales were 18,513 GWh.

7. Tampa Electric is committed to complying with applicable environmental laws and regulations. The purpose of the Compliance Plan is to describe Tampa Electric's current strategies for meeting the requirements of the Act and other regulations that impact energy supply and delivery facilities, and new construction projects. It is also intended to be a reference document to assist in evaluating impacts of environmental laws, regulations and compliance actions in order to develop future operational and compliance strategies.

## SECTION 366.825(2)(a), FLORIDA STATUTES: NUMBER AND IDENTITY OF AFFECTED UNITS

8. Tampa Electric owns and operates generating units that are affected by the provisions of Sections 404 and/or 405 of the Act, as amended in 1990. Phase I of Title IV of the Clean Air Act Amendments of 1990 ("CAAA") began on January 1, 1995 (January 1, 1996 for nitrogen oxides ("$NO_x$") due to a litigation delay) and continues through December 31, 1999. Under the EPA Acid Rain Program, Big Bend Units 1, 2 and 3 were designated Phase I units. Tampa Electric also designated Big Bend Unit 4 as a Phase I substitution unit. Thus, Big Bend Unit 4 became the company's only Phase I $NO_x$ unit, since it has a Group 1 boiler type under the $NO_x$ rules.

9. Phase II of the CAAA begins on January 1, 2000. Phase II further reduces the annual sulfur dioxide ("$SO_2$") and $NO_x$ emissions of Phase I units and sets restrictions on smaller plants (greater than 25 MW) fired by coal, oil and gas as well as all new generating units. Phase II $SO_2$ compliance affects Big Bend, Gannon and Polk coal units as well as Hookers Point and future fossil-fueled generating units such as the combustion turbine units planned for the company's Polk site. Phillips and Dinner Lake Stations and existing combustion turbines are not affected. Phase II $NO_x$ compliance only affects Big Bend Units 1, 2, 3 and 4 and Gannon Units 3, 4, 5, and 6, and limits their emission rates based on the type of boiler. Gannon Units 1 and 2 are not affected since the Phase II $NO_x$ requirements do not apply to cyclone boilers of this size.

## SECTION 366.825(2)(b), FLORIDA STATUTES: $SO_2$ COMPLIANCE STRATEGY

### Phase I

10. In January 1994 the "Tampa Electric Company Clean Air Act Amendments of 1990 Compliance Plan Evaluation–Phase I" was completed and reviewed with this Commission.

That plan described several options to comply with the first phase of the CAAA Title IV Acid Rain $SO_2$ provisions. This initial Phase I plan included the use of fuel blending with low sulfur coal and purchasing $SO_2$ allowances. To accommodate burning lower sulfur coals in Big Bend Units 1 through 3, flue gas conditioning systems were required on these units to provide necessary electrostatic precipitator ("ESP") performance for control of particulate matter ("PM") emissions. As part of an on-going effort to reduce compliance costs and meet compliance requirements in the most cost-effective manner, this plan was followed by a Flue Gas Desulfurization ("FGD") integration study. This study indicated that integrating Big Bend Unit 3 with the existing Big Bend Unit 4 FGD system, in conjunction with fuel blending to reduce $SO_2$ allowance purchases, was the best overall option for compliance with the Phase I $SO_2$ reduction requirements.

**Phase II**

11. Phase II of Title IV of the CAAA, which begins January 1, 2000, further reduces the annual $SO_2$ and $NO_x$ emissions of Phase I units and sets restrictions on smaller plants (greater than 25 MW) fired by coal, oil and gas as well as all new generating units. Phase II $SO_2$ compliance affects Big Bend, Gannon and Polk coal units as well as Hookers Point and future fossil-fueled generating units such as the five combustion turbine units planned for Polk from 2001 to 2008. Phillips and Dinner Lake Stations and existing combustion turbines are not affected.

12. Tampa Electric's Phase II $SO_2$ compliance strategy has included construction of a new FGD system to serve Big Bend Units 1 and 2, and the use of fuel blending and $SO_2$ allowance purchases. These activities were discussed in detail in Docket No. 980693-EI, in which the Commission determined that the Big Bend Units 1 and 2 FGD System was the most

cost-effective alternative available for $SO_2$ compliance and granted the company's request for cost recovery under the ECRC.

**Consent Final Judgment**

13. The CFJ, effective December 16, 1999, requires Tampa Electric to make additional reductions in emissions of $NO_x$, $SO_2$, and particulate matter ("PM"). The CFJ followed negotiations between the DEP and Tampa Electric on the issue of whether the company had applied for appropriate air permits for certain maintenance projects on Gannon and Big Bend units to maintain unit capacities and availabilities. Those negotiations and Tampa Electric's pending litigation with the U.S. Environmental Protection Agency (EPA) are discussed in detail in Section 7 of the Compliance Plan.

14. Under the CFJ, Tampa Electric is required to undertake a ten-year program of activities that will reduce the company's $NO_x$ emissions by approximately 85 percent, $SO_2$ emissions by approximately 80 percent, and PM emissions by approximately 45 percent from 1997 levels.

Gannon Station Repowering

15. As a key element of the CFJ, Tampa Electric is required to repower Gannon Station from coal to natural gas using combustion turbines in a combined cycle mode. This will be accomplished by using existing Units 3, 4 and 5. After Units 3, 4, and 5 are repowered, the original boilers for Units 1 through 5 and the station's coal handling system will be retired. The repowering of Gannon Station is discussed more fully in paragraph 24.

Other Aspects of Compliance with the CFJ

16. The CFJ also requires Tampa Electric to reduce $NO_x$, $SO_2$, and PM emissions at Gannon and Big Bend Station, conduct studies of $NO_x$ removal technologies and PM monitors,

work with DEP on its study of nitrogen deposition in Tampa Bay, and work with DEP to develop and implement state tax policy aimed at emission reductions and other environmental programs. A summary of the CFJ requirements are set forth in Section 7 of the Compliance Plan.

### $SO_2$ Compliance Alternatives

17. Tampa Electric has no additional cost-effective alternatives for compliance with the $SO_2$ emission reduction required by the CFJ other than those specifically required by the CFJ.

## SECTION 366.825(2)(c), FLORIDA STATUTES: $NO_X$ COMPLIANCE STRATEGY

### Phase I

18. The Phase I $NO_x$ program for "Group 1" boilers was effective on January 1, 1996 and affected all dry bottom and tangentially fired boilers that are required to meet $NO_x$ performance standards (40 CFR 76). Big Bend Unit 4, which has a tangentially fired dry bottom boiler with an existing state permit limit of 0.60 pounds of $NO_x$ per mmBtu (30-day rolling average), was Tampa Electric's only unit affected by Phase I of EPA's $NO_x$ program. This was due to Tampa Electric's designating it as a Phase I $SO_2$ substitution unit. As such, effective January 1, 1996, Big Bend Unit 4 $NO_x$ emissions were limited to 0.45 pounds per mmBtu of heat input on an annual average basis under the Acid Rain Program in addition to its existing $NO_x$ limit. This has been accomplished through the unit's original design and controlling $NO_x$ emissions through combustion tuning, and did not require additional modifications.

### Phase II

19. The EPA Phase II $NO_x$ emission limitations apply to Big Bend Units 1, 2, 3, and Gannon Units 3, 4, 5 and 6. Big Bend Unit 4, a Phase I – Group 1 boiler, will continue to be required to meet its Phase I limit. Gannon Units 1 and 2 are not affected since the Phase II $NO_x$

requirements do not apply to cyclone boilers of this size. Polk Unit 1, an integrated gasification combined cycle ("IGCC") unit, is not affected since it is not a defined boiler type for which a $NO_x$ emission limitation has been set by EPA in its Acid Rain rules.

20. EPA Rule 40 CFR 76.11 allows the company to submit a system-wide emission averaging plan which allows for more operational flexibility and can be a more cost-effective compliance method for $NO_x$ emissions. Tampa Electric has submitted a system-wide averaging plan to EPA as part of its Phase II $NO_x$ compliance strategy. The annual system average for $NO_x$ emissions is projected to be 0.77 pounds per mmBtu.

**Consent Final Judgment**

21. Tampa Electric's Compliance Plan, which includes the requirements of the CFJ, will reduce system $NO_x$ emissions by approximately 85 percent.

22. The CFJ also requires either the installation of $NO_x$ control technology, repowering, or shut down of Big Bend Unit 4 by May 2007 and Big Bend Units 1 through 3 by May 2010. The method of $NO_x$ emission controls, which the company may employ on the Big Bend units, has not been established at this time. The alternative methods will be evaluated on a periodic basis until the requirement to install $NO_x$ control technology on each unit at Big Bend Station must be implemented in order to comply with the requirements of the CFJ. The Compliance Plan will be updated from time to time and will take into account, among other things, technology improvements, maintenance requirements, and efficiency of the units and costs.

**$NO_x$ Compliance Alternatives**

23. The various $NO_x$ control technologies considered by Tampa Electric in connection with its Phase II $NO_x$ requirements are identified in Section 3 of the Compliance Plan.

## SECTION 366.825(2)(d)1, FLORIDA STATUTES: EFFECT OF TAMPA ELECTRIC'S PLAN ON REQUIREMENTS FOR CONSTRUCTION AND OPERATION OF PROPOSED OR ALTERNATIVE FACILITIES

24. The CFJ, which has been incorporated in Tampa Electric's Compliance Plan, commits Tampa Electric to a ten-year program which includes numerous projects. Under the CFJ, Tampa Electric will repower Gannon Station from coal to natural gas using combustion turbines and heat recovery boilers in conjunction with the existing steam turbine generators operating in combined cycle mode. The project will include the repowering of the existing coal-fired Units 3, 4, and 5 with gas-fired combustion turbines. After Units 3, 4, and 5 are repowered, the original boilers for Units 1 through 5 and the station's coal handling system will be retired. The station will be fueled by natural gas with fuel oil backup capability. The company will place the steam turbine and generator equipment at Units 1 and 2 on reserve standby. Unit 6 will also be placed on reserve standby, but the company will maintain the turbine, boiler and related equipment so it could be converted to burn natural gas rather than coal and used in an emergency situation. Subject to receiving appropriate permits and making any needed unit modifications, it could serve as contingency capacity during the transition period while Units 3, 4, and 5 are being repowered. By 2004, the repowered plant will provide 1,475 MW of natural gas-fired generating capacity.

Specifically the repowering project anticipates the following activities and schedule:

- Commercial operation of the repowered Gannon Unit 5 by May of 2003. Gannon Unit 5 will be repowered utilizing three state-of-the-art, natural gas-fired General Electric 7FA combustion turbines and three heat recovery steam generators ("HRSG") integrated with the existing steam turbines, generators, and necessary auxiliary equipment.

- Commensurate with repowered Gannon Unit 5 commercial operation, Gannon Units 1 and 2 steam turbines and generators will be taken off-line and placed on reserve status. Gannon Units 1 and 2 boilers and related equipment will then be retired.
- Commercial operation of repowered Gannon Units 3 and 4 is expected by May of 2004. Gannon Units 3 and 4 will be repowered utilizing three state-of-the-art, natural gas-fired General Electric 7FA combustion turbines and three HRSGs integrated with the existing steam turbines, generators, and necessary auxiliary equipment.
- Commensurate with repowered Gannon Units 3 and 4 commercial operation, Gannon Unit 6 turbine, generator, boiler and related equipment will be taken off-line and placed on reserve status.

25. In addition to the Gannon Repowering Project, the CFJ requires the shutdown, repowering or installation of $NO_x$ control technology on Big Bend Unit 4 by 2007 to achieve a unit $NO_x$ emissions rate of 0.10 pounds per mmBtu. The CFJ also requires the shutdown, repowering or installation of $NO_x$ control technology on Big Bend Units 1, 2, and 3 by 2010. The intent of the CFJ is that by 2010 all of the units at Big Bend and Gannon Stations will meet the best available compliance technology ("BACT") standard for $NO_x$ as defined by the CFJ. This issue remains under discussion with EPA.

## SECTION 366.825(2)(d)2, FLORIDA STATUTES: EFFECT OF TAMPA ELECTRIC'S PLAN ON ACHIEVABLE EMISSIONS REDUCTION AND METHODS FOR MONITORING EMISSIONS

### $SO_2$ Emissions

26. Implementation of $SO_2$ controls as required by Title IV Phase II $SO_2$ and the CFJ will reduce Tampa Electric's system $SO_2$ emissions by approximately 80 percent in 2010 as

compared to 1997 emissions levels. These reductions are presented graphically in Figure 7.1 of the Compliance Plan.

### $NO_x$ Emissions

27. Implementation of $NO_x$ controls as required by Title IV Phase II $NO_x$ and the CFJ will reduce Tampa Electric's system $NO_x$ emissions by approximately 85 percent in 2010 as compared to 1997 emissions levels. These reductions are presented graphically in Figure 7.2 of the Compliance Plan.

### PM Emissions

28. Implementation of PM controls as required by the CFJ will reduce Tampa Electric's system PM emissions by approximately 45 percent in 2010 as compared to 1997 emission levels. These reductions are presented graphically in Figure 7.3 of the Compliance Plan.

### Emissions Monitoring

29. The original Phase I $SO_2$ units, Big Bend Units 1, 2, and 3, were required to have Continuous Emissions Monitoring System ("CEMS") installed and operational in November 1993, in accordance with 40 CFR 75. The Phase II units and Big Bend Unit 4 were required to install CEMS by November 1994. CEMS measure, record and electronically report volumetric flue gas flow, $SO_2$ and $NO_x$ to provide the basis of measurement for compliance with the Phase I and Phase II $SO_2$ and $NO_x$ limits.

30. Big Bend Unit 4, which originally had CEMS when built in 1985 to meet the New Source Performance Standards in 40 CFR 60, Subpart Da, was retrofitted with CEMS similar to the other Big Bend units in November 1994. Gannon Units 1 through 6 and the three stacks serving Hookers Point Boilers 1 through 6 were equipped with CEMS by November 1994. The

original equipment associated with Polk Unit 1, placed in service in September 1996, included CEMS, which measure emissions from the IGCC/HRSG stack.

31. As required by the CFJ, Tampa Electric must evaluate the feasibility of installing a PM CEMS on one stack at Big Bend by March 1, 2002. If the PM monitor is determined to be technically feasible by DEP, it will be installed on one stack at Big Bend no later than May 1, 2003.

## SECTION 366.825(2)(d)3, FLORIDA STATUTES: PROPOSED IMPLEMENTATION SCHEDULE

32. The proposed implementation schedule for the activities is set forth in Section 9 of the Compliance Plan. This section includes regulatory compliance dates, project installation dates and actual/projected costs.

## SECTION 366.825(2)(d)4, FLORIDA STATUTES: ESTIMATED COST TO THE CUSTOMER OF IMPLEMENTING TAMPA ELECTRIC'S COMPLIANCE PLAN

33. The actual/estimated costs of implementing Tampa Electric's environmental compliance requirements are reflected in Section 9 of the Compliance Plan. These costs are broken down by the various required environmental activities. Although the details of the costs to comply with the CFJ requirements for 2000 through 2010 are not included in the Compliance Plan, these costs are estimated to be approximately one billion dollars. Of this total, $673 million is the estimated cost of the repowering of Gannon Station. The remaining $327 million represents a high-level estimate of the expected costs for environmental compliance activities required by the CFJ. As the projects are evaluated in more detail in the future, the cost estimates will be refined.

34. Tampa Electric requests that the Commission find that the costs required by the CFJ and associated with emissions monitoring and $SO_2$, $NO_x$ and PM emissions reductions are the types of costs which are recoverable through the ECRC in accordance with Section 366.8255, Florida Statutes (1999). Specifically these costs will be prudently incurred after April 13, 1993. The activities are legally required to comply with governmentally imposed environmental regulations enacted, became effective or whose effect was triggered after the test year in the company's last rate case upon which Tampa Electric's rates are based. These costs are not recovered through some other cost recovery mechanism or base rates.

35. This Petition does not request any specific cost recovery for the investments and activities required by the CFJ at this time. The company does anticipate requesting cost recovery at a later date. The preliminary estimated impact on customers' bills is expected to be between a two to three percent increase from its 2000 rates. The company will make every effort to mitigate this impact. Specific requests for cost recovery will be submitted in subsequent petitions in separate dockets.

## SECTION 366.825(2)(d)5, FLORIDA STATUTES: PRESENT AND POTENTIAL FUTURE FUEL SOURCES

36. Tampa Electric's consideration of present and potential future fuel sources is described in Section 8 of the Compliance Plan. Fuel diversity is a key variable in the company's plans.

37. Natural gas consumption in Florida has increased. Florida's electric utilities have had to rely on one gas transportation pipeline company, Florida Gas Transmission ("FGT"), to supply customers and utility requirements. To date three natural-gas pipelines, with capacity of 1 billion cubic feet per day each, are proposed to be built in Florida with in-service dates of 2002

and 2003. FGT has significant expansions planned for its system in this timeframe. This increased availability and the resulting reduced cost of natural gas transportation combined with environmental benefits has made natural gas a viable fuel alternative for Tampa Electric.

38. Tampa Electric has had discussions with several of these companies. It is anticipated that these discussions will continue well into 2000 when Tampa Electric expects to secure a transportation contract. Natural gas and other fuel related considerations are discussed in Section 8 of the Compliance Plan.

## SECTION 366.825(2)(d)6, FLORIDA STATUTES: PUBLIC INTEREST

39. The proposed Compliance Plan is in the public interest in that it is the most cost-effective alternative to comply with environmental regulations. The repowering of Gannon Station will significantly reduce emissions while helping to reliably meet Tampa Electric's growing energy needs for the next 20 years.

## SECTION 366.825(2)(e), FLORIDA STATUTES: PROPOSED ACTIONS TO COMPLY WITH FEDERAL, STATE AND LOCAL REQUIREMENTS FOR CLEAN AIR ACT COMPLIANCE

### Federal

40. Tampa Electric believes that the commitments it has made in the CFJ should be adequate to satisfy the federal requirements compliance with the Act. The company is hopeful the EPA will recognize this and reach an agreement with Tampa Electric similar to that embodied in the CFJ and incorporated into the Compliance Plan.

### State and Local

41. The CFJ requirements are incorporated in the Compliance Plan. It describes the actions required to satisfy state and local requirements for compliance with the Act.

42. Tampa Electric is not aware of the existence of any disputed issues of material fact in connection with this matter.

43. The ultimate facts alleged are that Tampa Electric Company's Compliance Plan included with this Petition is reasonable, prudent and in the public interest and should be approved by the Commission pursuant to Section 366.825, Florida Statutes.

WHEREFORE, Tampa Electric Company respectfully requests that the Florida Public Service Commission: (1) review the company's Compliance Plan including its plan to implement the requirements of the CFJ and enter an order approving the Compliance Plan as reasonable, prudent and in the public interest; (2) specifically determine that the portion of the Compliance Plan calling for the conversion of its Gannon Station from a six-unit, coal-fired plant to a plant consisting of natural gas-fired combined cycle units is reasonable, prudent and in the public interest; and (3) determine that the costs required by the CFJ and associated with emissions monitoring and $SO_2$, $NO_x$ and PM emissions reductions are the types of costs which are recoverable through the ECRC in accordance with Section 366.8255, Florida Statutes (1999) and provides such additional relief as the Commission finds is appropriate.

DATED this 23rd day of December 1999.

Respectfully submitted,

LEE L. WILLIS
JAMES D. BEASLEY
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

**Exhibit No. 2**
**Docket No. __________**
**Tampa Electric Company**

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL CIRCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.: 99-9730

TAMPA ELECTRIC COMPANY,

Defendant.
_______________________________/

## CONSENT FINAL JUDGMENT

## I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

## II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

## III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

## IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1. TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994

and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; (2) replacement of the cyclone in Gannon Unit 4 in 1994; and (3) replacement of a radiant superheater at Gannon Unit 6 in 1992.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

## V. <u>REQUIREMENTS OF THE CONSENT FINAL JUDGMENT</u>

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 95% but is the first Unit with a large, high velocity tower serving approximately 800 megawatts. TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation and if necessary, to pursue its available remedies against the vendor.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F. TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend by March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain *effective until the actions required hereunder have been implemented.*

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

## VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

## VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this ___ day of __________________, 1999.

ORIGINAL SIGNED

DEC 16 1999

ROBERT H. BONANNO
CIRCUIT JUDGE

Circuit Judge

FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

By: David B. Struhs
Secretary of the Florida Department of Environmental Protection

Date: December 6, 1999

TAMPA ELECTRIC COMPANY

By: J B Ramil
John B. Ramil
President

Date: December 6, 1999

Exhibit No. 1
Docket No.___________
Tampa Electric Company

TAMPA ELECTRIC

# TAMPA ELECTRIC COMPANY
# DOCKET NO.

# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

December 1999

15692-99
12/23/99

# Tampa Electric Company
# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

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# Tampa Electric Company
# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

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# Tampa Electric Company
# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

## Executive Summary


Tampa Electric Company (Tampa Electric or the company) is an investor-owned electric company that serves over 543,000 retail customers in Hillsborough and portions of Pasco, Pinellas, and Polk counties, in West Central Florida. Tampa Electric's system has a net electric generating capacity of approximately 3,600 MW comprised of 23 generating units. The company's 11 coal-fired units produced about 90 percent of its system energy requirements in 1998. Total 1998 energy sales, including wholesale sales, ere 18,513 GWh.

This Comprehensive Clean Air Act Compliance Plan (Compliance Plan) describes the many programs by which Tampa Electric is fulfilling required environmental responsibilities, as well as several emerging issues with the potential to impact Tampa Electric and the utility industry as a whole.

Title IV of the Clean Air Act Amendments of 1990 (CAAA) requires significant reductions in sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) from electric utility generating facilities. During Phase I, from January 1, 1995 through December 31, 1999, Tampa Electric began scrubbing $SO_2$ at its Big Bend Unit 3, switched to lower sulfur fuels through fuel blending, and utilized purchased $SO_2$ emission allowances. For Phase II, which begins January 1, 2000, the company installed a new Flue Gas Desulfurization (FGD) system at Big Bend Units 1 and 2, and plans to continue fuel blending and using $SO_2$ allowances. In order to comply with the Phase II $NO_X$ emission limits, Tampa Electric has implemented combustion optimization projects at Big Bend and Gannon Stations, and plans to use system-wide averaging.

Beyond Phase II, Tampa Electric is required to make additional reductions in emissions of $NO_X$, $SO_2$ and particulate matter (PM). These requirements are contained in a Consent Final Judgment (CFJ), effective December 16, 1999, entered into with the Florida Department of Environmental Protection (DEP). These requirements will achieve additional reductions in $SO_2$, $NO_X$ and PM.

Further emission reductions may be required as a result of the U.S. Environmental Protection Agency's (EPA) New Source Review (NSR) enforcement initiative, EPA's NSR regulatory reform and other potential EPA emission-limiting regulations for ozone, fine particulate matter ($PM_{2.5}$), mercury, carbon dioxide ($CO_2$) and/or acid rain.

# Tampa Electric Company
# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

## Introduction and Purpose

Tampa Electric is an investor-owned electric utility. Tampa Electric is engaged in the generation, purchase, transmission, distribution, and sale of electric energy. Tampa Electric serves over 543,000 retail customers in its service area of approximately 2,000 square miles in West Central Florida, including Hillsborough County, and parts of Pasco, Pinellas, and Polk counties, with a population of over one million people. Tampa Electric's coal-fired units produced about 90 percent of its system energy requirements in 1998. Total 1998 energy sales, including wholesale sales, were 18,513 GWh.

The company has six electric generating plants, five of which are in operation, with a total net winter generating capability of 3,615 MW, consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle (IGCC) unit. The six plants are: Big Bend (1,742 MW capability from four coal-fired steam units), Gannon (1,180 MW capability from six coal-fired steam units), Hookers Point (215 MW capability from five generators served by six No. 6 oil-fired boilers), and four No. 2 oil-fired combustion turbine units located at Big Bend and Gannon (194 MW), all in the Tampa Bay area; Polk Power Station (250 MW capability from one IGCC unit fueled with synthesis gas derived from coal and petcoke; alternate fuel is No. 2 oil) in southwestern Polk County; and Phillips (34 MW capability from two No. 6 oil-fired slow-speed diesel units) and Dinner Lake in Highlands County. Dinner Lake (11 MW from one natural gas-fired steam electric unit) was placed on long-term reserve standby status in March 1994

Units at Hookers Point began commercial service from 1948 to 1955, at Gannon from 1957 to 1969, and at Big Bend from 1970 to 1985. The Polk IGCC unit began commercial service in September 1996. Dinner Lake began commercial service in 1966 and Phillips in 1983. Tampa Electric purchased Phillips and Dinner Lake Stations from the Sebring Utilities Commission in 1991.

Tampa Electric is committed to compliance with applicable environmental laws and regulations. The purpose of this Compliance Plan is to describe Tampa Electric's current strategies for meeting the requirements of federal, state and local environmental laws and regulations, and changes in the application and enforcement thereof, that impact existing and planned electric generating and delivery facilities. It is intended to be a reference document to assist in evaluating impacts of agency compliance activities and to assist in developing future operational and compliance strategies. These strategies must allow flexibility for future operations.

# Tampa Electric Company
# COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

## 1. Summary

The federal Clean Air Act (CAA), 42 United States Code, beginning at Section 7401 (42 U.S.C. 7401, et seq.), enacted in 1970, empowers the EPA to regulate air quality and emissions from a wide variety of sources. EPA rules implementing the statute are found in Parts 50-99 of "Title 40-Protection of Environment," in the Code of Federal Regulations (40 CFR 50-99).

DEP regulates air quality and emissions under its authority in Chapter 403 of the Florida Statues (Ch. 403, FS) and through its rules in Chapter 62 of the Florida Administrative Code (Ch. 62, FAC). DEP's authority includes the rules which Florida has the responsibility to administer and enforce under the federally-approved Florida State Implementation Plan (SIP) and the separate EPA delegation of Prevention of Significant Deterioration (PSD) authority.

In November 1990, Congress passed the CAAA, which brought about many new air pollution control programs. The main titles of the CAAA are:

Title I - Attainment and Maintenance of National Ambient Air Quality Standards (AAQS)

Title II - Mobile Sources

Title III - Hazardous Air Pollutants

Title IV - Acid Deposition Control

Title V - Permits

Title VI - Stratospheric Ozone Protection

Titles VII through XI - Various Provisions

Some of the EPA rules that implement the CAAA titles relevant to electric power generation are:

Title I - 40 CFR 50, 52, 60, 61, 81

Title II - 40 CFR 85

Title III - 40 CFR 63, 68

Title IV - 40 CFR 72, 73, 75, 76

Title V - 40 CFR 70

Title VI - 40 CFR 82

The titles of the implementing EPA rules, in the order listed above are:

40 CFR 50 - National Primary and Secondary Ambient Air Quality Standards (AAQS)

40 CFR 52 - Approval and Promulgation of Implementation Plans

40 CFR 60 - Standards of Performance for New Stationary Sources

40 CFR 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR 81 - Designation of Areas for Air Quality Planning Purposes

40 CFR 85 - Control of Air Pollution from Mobile Sources

40 CFR 63 - NESHAPS for Source Categories

40 CFR 68 - Chemical Accident Prevention Provisions

40 CFR 72 - Permits Regulation

40 CFR 73 - Sulfur Dioxide Allowance System

40 CFR 75 - Continuous Emission Monitoring

40 CFR 76 - Acid Rain Nitrogen Oxides Reduction Program

40 CFR 70 - State Operating Permit Programs

40 CFR 82 - Protection of Stratospheric Ozone

Title I of the CAAA empowers EPA to manage air quality through ambient air quality standards, to conduct pre-construction reviews of new stationary emission sources, and to permit construction of stationary emission sources. Under Title II, EPA regulates air emissions from mobile sources such as cars, trucks, buses and planes. Title III requires EPA to identify the hazardous air pollutant chemicals that must be controlled and the categories of major emission sources of the chemicals. EPA is responsible for setting maximum achievable control technology standards for each category. Title IV contains provisions for the $SO_2$ allowance and emission reduction programs; the $NO_X$ emission reduction program; acid deposition permits and compliance plans; monitoring, reporting and recordkeeping; and clean coal technology incentives. Title V establishes the program for facility-wide operating permits regulating air emissions. Title VI provides for phasing out the production and import of ozone-depleting substances, and governs the use and recycling of the substances.

Although all sections of the CAAA affect Tampa Electric, Title IV has had the most significant impact on the company. The EPA Acid Rain Program under Title IV of the CAAA set as its primary goals the reduction of annual $SO_2$ emissions by 10 million tons and annual $NO_X$ emissions by 2 million tons below 1980 levels. To achieve these reductions, the law requires a two-phase program that reduces the allowable $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants.

Phase I of the CAAA Title IV began on January 1, 1995 (January 1, 1996 for $NO_X$ due to a litigation delay) and continues through December 31, 1999. Under the EPA Acid Rain Program, Big Bend Units 1, 2 and 3 were designated Phase I units. Tampa Electric also designated Big Bend Unit 4 as a Phase I substitution unit. Thus, Big Bend Unit 4 became Tampa Electric's only Phase I $NO_X$ unit since it has a Group 1 boiler type under the $NO_X$ rules.

Phase II of the CAAA Title IV begins January 1, 2000. Phase II further reduces the annual $SO_2$ and $NO_X$ emissions of Phase I units, and sets restrictions on smaller plants (greater than 25 MW) fired by coal, oil and gas as well as all new utility units. Phase II $SO_2$ compliance affects Big Bend, Gannon and Polk coal units as well as Hookers Point and future fossil-fueled generating units. Phillips and Dinner Lake Stations and existing combustion turbines are not affected. Phase II $NO_X$ compliance affects only Big Bend Units 1, 2, 3 and 4 and Gannon Units 3, 4, 5, and 6, and limits their emission rates based on the type of boiler.

Tampa Electric initially concluded that fuel blending for reduced coal sulfur content, along with the use of purchased $SO_2$ allowances, was the most viable strategy for CAAA Title IV $SO_2$ compliance. The use of low sulfur coal required the addition of flue gas conditioning systems on Big Bend Units 1 through 3 to maintain performance of the electrostatic precipitators (ESP) used for controlling PM emissions. The company subsequently determined that it was feasible to integrate Big Bend Unit 3 with the existing Big Bend Unit 4 Flue Gas Desulfurization (FGD) system to allow burning high sulfur coal in Unit 3 in addition to Unit 4, fuel blending at Big Bend Units 1 and 2, and purchasing $SO_2$ emission allowances when economical. The Big Bend Unit 3 FGD integration project was completed and the system was placed in service June 1995, which reduced the amount of $SO_2$ allowance purchases and also reduced Tampa Electric's purchases of higher cost, lower sulfur coal. Big Bend Unit 4, Tampa Electric's only unit affected by EPA's Phase I $NO_X$ program, must meet a $NO_X$ emissions limit of 0.45 pounds per million Btu's of heat input on an annual average basis, effective January 1, 1996. This is accomplished by controlling $NO_X$ emissions through combustion tuning inherent to this boiler's original design and did not require any modifications.

For Phase II of CAAA Title IV, Tampa Electric developed several compliance alternatives. A screening process was conducted on selected alternatives, and detailed engineering and economic analyses were completed to determine the most practical and cost effective Phase II compliance plan. Construction of a FGD system retrofit for Big Bend Units 1 and 2 was determined to be the most cost effective $SO_2$ compliance alternative for Tampa Electric's system. The Big Bend Units 1 and 2 FGD system will reduce $SO_2$ emissions by about 70,000 tons per year, thus allowing greater fuel flexibility at Gannon Station. Although Tampa Electric, through the Big Bend pollution controls, has more allowances to utilize at Gannon, current regulations limit emissions of $SO_2$ under the CAAA Title I AAQS. For Gannon, Tampa Electric will comply with the Title IV Phase II $SO_2$ requirements through the use of lower sulfur fuels and/or through the acquisition of more allowances, if necessary. The degree of fuel sulfur reductions required to comply with AAQS will be established through the Title V operating permit process.

Phase II $NO_X$ reduction requirements dictate annual average emission rate limits affecting Big Bend Units 1, 2, 3 and 4, and Gannon Units 3, 4, 5 and 6. Tampa Electric's $NO_X$ compliance strategy includes combustion optimization/tuning with the replacement of coal classifiers at Big Bend Units 1 and 2 and Gannon Units 5 and 6. It also includes the use of high-moisture, low-Btu coals at Gannon Units 3, 4, 5, and 6 which requires the addition of two fine-mesh coal crushers in the Gannon coal field. In addition to these emission reduction projects, Tampa Electric will exercise the option to achieve compliance with the Title IV Phase II $NO_X$ requirements by using a system-wide annual average $NO_X$ emission rate applicable to all affected units.

The projects associated with implementing Tampa Electric's CAAA Title IV Phase I and II compliance plans for $SO_2$ and $NO_X$ have been reviewed by the Florida Public Service Commission (FPSC). The FPSC has approved Tampa Electric's requests to recover certain environmental compliance costs associated with these projects.

In 1997, EPA began an investigation into alleged violations by Tampa Electric and several other coal-fired electric utilities of EPA's New Source Review (NSR) policy, a segment of Title I of the CAAA. EPA asserted that certain electric utilities, including Tampa Electric, should have applied for pre-construction permits for certain unit maintenance projects, and that the permitting review of such projects would have included NSR, resulting in requirements that the units meet best available control technology (BACT) standards for $NO_X$, $SO_2$ and PM. The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules. 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 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 BACT for $NO_X$, $SO_2$ and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. Effective December 16, 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. The requirements of the CFJ include repowering Gannon Station and further reducing $NO_X$, $SO_2$ and PM emissions at Gannon and Big Bend Stations. The CFJ was entered on December 16, 1999 in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County. The CFJ is included as Appendix A.

Tampa Electric monitors and evaluates the development of future federal, state, and local regulations and policies relating to environmental compliance requirements. The company evaluates potential future outcomes and impacts on its operations. The company also evaluates various possible degrees of emissions reductions and corresponding options in terms of control technologies that might be needed to meet potential future requirements.

## 2. $SO_2$ Compliance Plan

### 2.1 Overview of Compliance Requirements

The Acid Rain Program, created under Title IV of the CAAA, sets as its primary goal a nationwide reduction of annual $SO_2$ emissions by 10 million tons below 1980 levels to be achieved in two phases. $SO_2$ emissions from electric utilities, encompassing over 2,000 units, will be capped at 8.95 million tons per year. The primary goal of the program is to achieve this nationwide reduction in $SO_2$ emissions, which involves allocating a fixed number of annual $SO_2$ emission allowances to electric utilities. In order to emit $SO_2$, one allowance is required for each ton of $SO_2$ emitted.

Phase I of the Acid Rain Program began January 1, 1995 and required 110 power plants to reduce their emissions to a level equivalent to the product of an $SO_2$ emissions rate of 2.5 pounds per mmBtu times the average of their 1985 through 1987 heat input based on fuel usage. Unused allowances may be bought, sold, traded, or banked by facilities for future use. Big Bend Units 1, 2 and 3 were designated by EPA as Phase I units, and Tampa Electric later chose to designate Big Bend Unit 4 as a Phase I substitution unit. Under the Acid Rain Program, utilities may trade allowances among the units within their systems and/or buy or sell allowances from other sources.

Table 2.1 shows for Phase I, the 86,485 annual $SO_2$ allowances EPA granted to Tampa Electric for the 1,742 MW capacity of Big Bend Units 1 through 4:

**Table 2.1**

**TOTAL PHASE I $SO_2$ ALLOWANCES**

**YEARS 1995 - 1999**

| BIG BEND UNIT | ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Big Bend 1 | 27,662 |
| Big Bend 2 | 26,387 |
| Big Bend 3 | 26,036 |
| Big Bend 4 | 6,400 |
| **TOTAL** | **86,485** |

With the exception of all combustion turbine generating units existing at the time of enactment, Phase II of the CAAA Title IV $SO_2$ reduction requirements affects all existing fossil-fueled electric power generating units over 25 MW and all new fossil-fueled units. This includes over 2,000 existing generating units. Phase II requires these units to reduce emissions to a level equivalent to the product of a $SO_2$ emission rate of 1.2 pounds per mmBtu times the average of their 1985 through 1987 heat input based on fuel usage. $SO_2$ emissions from these utilities will be capped at 8.95 million tons per year, about 10 million tons less than 1980 levels.

Phase II compliance must be implemented by January 1, 2000, and affects all of Tampa Electric's existing and future electric generating units, with the exception of the Phillips and Dinner Lake Stations and existing combustion turbines. For Phase II, EPA allocated annual $SO_2$ allowances to Tampa Electric for years 2000 through 2009, based on 1985 through 1987 emissions from Big Bend, Gannon, and Hookers Point, as shown in Table 2.2. The total 84,609 $SO_2$ allowances includes 83,882 original base allowances plus 727 allowances that EPA reallocated due to corrections required in 1998 (See Federal Register, September 28, 1998).

**Table 2.2**

**TOTAL PHASE II $SO_2$ ALLOWANCES**

**YEARS 2000 — 2009**

| BIG BEND UNIT | ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Big Bend 1 | 12,132 |
| Big Bend 2 | 12,196 |
| Big Bend 3 | 11,444 |
| Big Bend 4 | 8,780 |
| **TOTAL** | **44,552** |

| GANNON UNIT | ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Gannon 1 | 3,842 |
| Gannon 2 | 4,425 |
| Gannon 3 | 5,664 |
| Gannon 4 | 6,223 |
| Gannon 5 | 6,537 |
| Gannon 6 | 10,081 |
| **TOTAL** | **36,772** |

| HOOKERS POINT | ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Hookers Point Boiler 1 | 177 |
| Hookers Point Boiler 2 | 207 |
| Hookers Point Boiler 3 | 469 |
| Hookers Point Boiler 4 | 701 |
| Hookers Point Boiler 5 | 1,253 |
| Hookers Point Boiler6 | 478 |
| **TOTAL** | **3,285** |

| POLK UNIT | ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Polk Unit 1 IGCC | 0 |
| Polk Unit 2 CT | 0 |
| Polk Unit 3 CT | 0 |
| Polk Unit 4 CT | 0 |
| Polk Unit 5 CT | 0 |
| Polk Unit 6 CT | 0 |
| Polk Unit 7 CT | 0 |
| All other future Polk units | 0 |
| **TOTAL** | **0** |
| **TOTAL TAMPA ELECTRIC** | **84,609** |

The company must account for its total actual tons of $SO_2$ emissions from all applicable generating units, and offset emissions in excess of the allocation with the acquisition of additional $SO_2$ allowances. The applicable Tampa Electric units are Big Bend Units 1 through 4, Gannon Units 1 through 6, Hookers Point boilers 1 through 6 (which serve turbine-generator Units 1 through 5), Polk Unit 1 (IGCC/HRSG stack), the future Polk combustion turbine units, and all future fossil-fueled units.

Thus, Phase II provides 84,609 annual allowances in years 2000 through 2009 for 3,372 MW of generating capacity (in 2000) compared to 86,485 allowances for 1,742 MW in Phase I.

For years 2010 through 2020, the number of $SO_2$ annual allowances reduces to 83,944 as shown in Table 2.3:

**Table 2.3**

**TOTAL PHASE II $SO_2$ ALLOWANCES**

**YEARS 2010 — 2020**

| STATION | TOTAL EPA ANNUAL $SO_2$ ALLOWANCES |
|---|---|
| Big Bend | 44,644 |
| Gannon | 36,018 |
| Hookers Point | 3,282 |
| Polk | 0 |
| **TOTALTAMPA ELECTRIC** | **83,944** |

The original Phase I $SO_2$ units, Big Bend Units 1, 2, and 3 were required to have Continuous Emission Monitor Systems (CEMS) installed and operational in November 1993, in accordance with 40 CFR 75. The Phase II units and Big Bend Unit 4 were required to install CEMS by November 1994. The systems measure, record, and electronically report volumetric flue gas flow, $SO_2$, $NO_X$, and $CO_2$ to provide the basis of measurement for compliance with the Phase I and Phase II $SO_2$ and $NO_X$ limits.

Big Bend Unit 4, which had installed CEMS installed when built in 1985, met the New Source Performance Standards (NSPS) in 40 CFR 60, Subpart Da. In November 1994, the CEMS were retrofitted similar to the other Big Bend units to become compliant with the Phase I and II requirements,. Gannon Units 1 through 6 and the three stacks serving Hookers Point Boilers 1 through 6 were equipped with CEMS by November 1994. The original equipment associated with Polk Unit 1, placed in service in September 1996, included CEMS that measure emissions from the IGCC/HRSG stack. The company expects that all future units of applicable size will have similar CEMS.

## 2.2 CAAA Title IV Phase I Compliance

Tampa Electric began its CAAA compliance plan in 1990. In January 1994, the "Tampa Electric Company Clean Air Act Amendments of 1990 Compliance Plan Evaluation - Phase I" was completed and was provided to the FPSC. This plan reviewed several options to comply with the first phase of the CAAA Title IV Acid Rain provisions. This initial Phase I plan included fuel blending with low sulfur coal and purchasing $SO_2$ allowances. To accommodate burning lower sulfur coals in Big Bend Units 1 through 3, flue gas conditioning systems were required to provide necessary ESP performance for control of PM emissions. As part of an ongoing effort to reduce compliance costs and meet compliance requirements in the most cost-effective manner, this plan was followed by an FGD integration study. This study indicated that integrating Big Bend Unit 3 with the existing Big Bend Unit 4 FGD system, in conjunction with fuel blending for reduced $SO_2$ emissions, and $SO_2$ allowance purchases, was the best option for compliance with the Phase I $SO_2$ reduction requirements.

### 2.3 CAAA Title IV Phase II Compliance

Tampa Electric continued its efforts with a study of compliance options for the CAAA Title IV Phase II $SO_2$ emissions reduction requirements. The results were published in the May 1998 document "Tampa Electric Company CAAA Phase II Compliance" and was provided to the FPSC. By incorporating the results of previous studies and the successful operation of the Big Bend Unit 3 and 4 FGD system integration, Tampa Electric developed viable options to meet the more stringent Phase II regulations. The study concluded that a stand-alone retrofitted FGD system for Big Bend Units 1 and 2, along with fuel blending and purchasing $SO_2$ allowances, was the most cost-effective option for the Tampa Electric system. The FGD system installed on Units 1 and 2 will reduce $SO_2$ emissions by approximately 70,000 tons per year. For Gannon, Tampa Electric will utilize fuel blending and, as necessary, purchase $SO_2$ allowances as part of its system-wide $SO_2$ compliance strategy. Emissions resulting from Tampa Electric's other Phase II generating units do not exceed the amount of $SO_2$ allowances allocated for the Tampa Electric system.

### 2.4 CAAA Title IV and V Permitting

Tampa Electric was issued Phase I Title IV Acid Rain Permits. Tampa Electric has also applied for the Phase II Acid Rain Permits, which will be issued as part of the facilities' Title V Operating Permits.

Tampa Electric applied for the required CAAA Title V Operating Permits for Big Bend, Gannon, Hookers Point, Polk, Phillips and Dinner Lake Stations. Thus far, the permits for Hookers Point, Polk, Phillips and Dinner Lake have been issued. DEP is expected to issue the Big Bend and Gannon Title V permits in 2000. The Title V Operating Permits are extremely detailed and provide comprehensive air-related information regarding required operating conditions, monitoring and testing, emission limits, and reporting requirements, including all of the CAAA Title IV requirements. Tampa Electric's Title V permit applications, including emissions inventories, contain detailed descriptions of all air-related systems, site activities, regulatory requirements, potential emissions and pre-existing emission limits.

As part of the Gannon Station Title V permitting process, DEP modeled $SO_2$ ambient air concentrations and found modeled exceedances of the three-hour $SO_2$ ambient air quality standard. To address this, Tampa Electric investigated two alternatives for reducing $SO_2$ emissions from Gannon Station. The first alternative involved raising the Gannon Unit 5 and 6 stacks by 14 meters to a height of 110 meters to prevent plume downwash and, therefore, prevent $SO_2$ from reaching the ground prematurely. The second alternative involved the use of lower sulfur coal to comply with the standard. Tampa Electric is continuing to evaluate these two alternatives.

# 3. $NO_X$ Compliance Plan

## 3.1 Overview of Compliance Requirements

The Acid Rain Program under Title IV of the CAAA requires a 2 million-ton reduction in $NO_X$ emissions from 1980 levels. The EPA $NO_X$ Emission Reduction Program is implemented in two phases for two groups of coal-fired electric utility boilers. The $NO_X$ program differs from the $SO_2$ program in that it neither caps the $NO_X$ emissions nor uses an allowance trading system.

The Phase I $NO_X$ program for Group 1 boilers became effective on January 1, 1996, and affected all dry-bottom and tangentially-fired boilers that are required to meet $NO_X$ performance standards (40 CFR 76). Big Bend Unit 4, a tangentially-fired dry-bottom boiler with an existing state $NO_X$ permit limit of 0.60 pounds per mmBtu (30-day rolling average) was Tampa Electric's only unit affected by Phase I of EPA's $NO_X$ program. This was due to Tampa Electric designating it as a Phase I $SO_2$ substitution unit. As such, effective January 1, 1996, Big Bend Unit 4 $NO_X$ emissions were limited to 0.45 pounds per million Btu of heat input on an annual average basis under the Acid Rain Program in addition to its existing $NO_X$ limit. This is being accomplished through the unit's original design, which controls $NO_X$ emissions through combustion tuning. This approach did not require any physical or design modifications.

The EPA Phase II $NO_X$ emission limitations, as outlined in 40 CFR 76 and adopted by EPA in December 1996, apply to Big Bend Units 1, 2, 3, and 4, and Gannon Units 3, 4, 5 and 6, effective January 1, 2000. Big Bend Unit 4, a Phase I Group 1 boiler, will continue to be required to meet the Phase I limit of 0.45 pounds per mmBtu. Gannon Units 1 and 2 are not affected since the Phase II $NO_X$ requirements do not apply to cyclone boilers of this size. Polk Unit 1, an IGCC unit, is not affected since it is not a defined boiler type for which EPA has set $NO_X$ emission limitations in its Acid Rain rules.

The Phase II $NO_X$ limits reflect maximum annual average limits based on the type of boiler, and are applicable to each unit individually. Big Bend Units 1, 2 and 3, and Gannon Units 5 and 6, all with wet bottom boilers, are limited to 0.84 pounds per mmBtu, annual average, effective January 1, 2000. Gannon Units 3 and 4, both with cyclone boilers, are limited to 0.86 pounds per mmBtu, annual average, effective January 1, 2000. As an alternative to unit-specific emission limits, EPA Rule 40 CFR 76.11 allows the company to submit a petition to EPA for system-wide emission averaging plan, which allows more operational flexibility and can be a more cost-effective compliance method.

## 3.2 $NO_X$ Compliance Alternatives

During EPA's rule development process for the Title IV Phase II $NO_X$ program, Tampa Electric continued to demonstrate to EPA that higher emission limits for the uniquely designed Riley Stoker Turbo-Furnace wet bottom boilers were necessary. Big Bend Units 1, 2 and 3 and Gannon Units 5 and 6 have these turbo-fired furnace boilers.

Tampa Electric has achieved better than expected $NO_X$ reductions from its Phase II affected units through the use of combustion optimization. Tampa Electric has committed to attain the $NO_X$ reduction levels required by the Title IV $NO_X$ Reduction Rule with system-wide averaging in the initial years of Phase II.

In developing methods and approaches to comply with the CAAA Title IV Phase II $NO_X$ requirements, the following $NO_X$ control technologies were evaluated for cost-effectiveness for the Riley Stoker Turbo-Furnace boilers on Big Bend Units 1 and 2 and Gannon Units 5 and 6:

1. Selective Non-Catalytic Reduction (SNCR)
2. Selective Catalytic Reduction (SCR)
3. Natural Gas Reburning
4. Coal Reburning
5. Overfire Air
6. Low $NO_X$ Burners
7. Combustion Optimization

For the degree of $NO_X$ reduction required, combustion optimization was found to be the most cost-effective approach in meeting the Phase II $NO_X$ requirements. The emission rates achieved for Big Bend Units 1, 2 and 3 and Gannon Units 5 and 6 will allow Tampa Electric to meet system-wide average compliance when the emission rates of these units are averaged with the emission rates of Big Bend Unit 4 and Gannon Units 3 and 4. Except for low $NO_X$ burners, which cannot be applied to the cyclone boilers of Gannon Units 3 and 4, the same control technologies were evaluated for the cyclone units.

## 3.3 CAAA Title IV Phase II Compliance

Based on the costs and the operational criteria used to judge the potential $NO_X$ control options for Big Bend Units 1, 2 and 3 and Gannon Units 3, 4, 5, and 6, Tampa Electric's approach to meet the CAAA Title IV Phase II $NO_X$ limits has been through combustion optimization. This control option, which provides $NO_X$ reductions from least-cost control measures first, was found to be the optimal first choice in a "top down approach." This approach may also reduce the costs for additional $NO_X$ controls if higher levels of reductions are required in the future.

Replacement of the existing coal classifiers has been an integral part of combustion optimization for the Riley Stoker Turbo-Furnace boilers on Big Bend Units 1 and 2 and Gannon Units 5 and 6. The new classifiers provide the coal fineness and fuel distribution that is needed for low $NO_X$ combustion in these boilers that cannot be provided by the existing classifiers. The classifier installations were completed in July 1999 and are necessary to continue to burn coal at these facilities.

Based on the costs and operational criteria used to judge the potential $NO_X$ control options for the Gannon Units 3 and 4 cyclone boilers, the optimal first "top down" choice of $NO_X$ control is combustion optimization. For these cyclone boilers, combustion optimization consists of burning optimal percentages of high moisture, low BTU coal, increasing the fineness of the coal through the addition of two coalfield crushers, and performing combustion tuning through boiler air flow and fuel balancing.

In addition, Tampa Electric submitted a system-wide averaging plan to EPA as part of its Phase II $NO_X$ compliance strategy to incorporate additional compliance flexibility. The system-wide annual average will be applicable to Big Bend Units 1, 2, 3, and 4, and Gannon Units 3, 4, 5, and 6 and is projected to be 0.76 pounds per mmBtu. The submittal was filed with EPA.

If the system-wide averaging plan and the combustion optimizations cannot achieve the required $NO_X$ reductions, Tampa Electric may, as feasible, implement neural networks for the Riley Stoker Turbo-Furnaces and water injection and/or overfire air for the cyclone units. In the event these measures are not feasible or do not meet the required limit, the installation of other $NO_X$ controls will be considered for one or more of the affected units.

## 4. Particulate Matter Compliance Plan

Requirements to limit PM emissions are addressed under Title I of the CAAA. Accordingly, Tampa Electric has complied with and will continue to comply with all applicable PM ambient air quality standards as defined by EPA. To date, Tampa Electric operates ESPs on all of its coal-fired units at Big Bend and Gannon Stations to control PM emissions. In 1999, Tampa Electric performed an optimization study, as required by the Gannon Station Fuel Yard Permit issued by DEP, to evaluate the ESP operations at Gannon. The results of the study will identify the optimum parameter ranges required to operate the ESP at the required efficiency. These operating ranges will then be incorporated into the permit by a date mutually agreed-upon by DEP and Tampa Electric.

# 5. Air Toxics Compliance Plan

## 5.1. Overview of Compliance Requirements

The CAAA required the EPA to perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of hazardous air pollutants (HAPs), to prepare a report to Congress containing the results of the study, and to regulate electric utility steam generating units if EPA finds that such regulation is appropriate and necessary. The Final Utility Study Report was issued on February 24, 1998. The report stated that mercury is the HAP emission of greatest potential concern from coal-fired utilities, and that additional research and monitoring are merited. However, the EPA deferred making any determination as to whether regulation of electric utility steam generating units is appropriate and necessary. Instead, under the authority provided in Section 114 of the CAA (42 U.S.C. 7414) the EPA required that all coal-fired electric utility steam generating units provide certain information to allow EPA to calculate the annual mercury emissions from each such unit. Under authority of Section 114, EPA is authorized to administer and request information and data collection related to compliance with the CAAA. EPA will use the requested information to evaluate, if it is appropriate and necessary, to regulate emissions of HAPs from electric utility steam generating units. Future mercury regulations could range from no change to requiring the installation of wet FGD systems or activated carbon injection.

In addition, CAA Section 112 (r) and 40 CFR Part 68 require certain companies to plan and implement prevention plans and procedures to decrease the likelihood of releases of 77 toxic and 63 flammable chemicals, particularly to the extent that there would be off-site consequences. Nationally, more than 66,000 businesses are covered by these Risk Management Program requirements. These requirements range from a less stringent Program 1 to a most stringent Program 3, depending on the chemicals present, off-site consequence potential, and the accident history of the facilities. The Risk Management Plans (RMPs) for applicable facilities were required to be submitted to EPA by June 21, 1999. Tampa Electric's RMP is discussed in Section 5.3.

## 5.2. Mercury Information Collection Request (ICR)

EPA issued the Mercury Information Collection Request (ICR) to gather data on mercury emissions from electric utility power station during 1999. Part I of the ICR required all electric utilities to identify their unit types, fuel types and pollution control devices. Part II requires all coal-fired electric utility units to submit quarterly reports on the mercury and chlorine content in coal. Part III requires selected utilities to conduct a one-time speciated mercury stack emissions test. Tampa Electric was required to participate in this information-gathering project. Tampa Electric is conducting fuel sampling and analysis for all coals at Big Bend, Gannon and Polk Stations during 1999 and is submitting quarterly reports of these analyses to EPA. In addition, Tampa Electric was required to perform mercury stack emissions testing at Big Bend and Polk Stations. The emissions stack testing was performed on Polk Unit 1 and Big Bend Unit 3 in November 1999. At Big Bend, a testing platform was constructed on the Unit 3 stack to facilitate completion of the required testing method. The results of these stack tests will be provided to EPA within 90 days after the test completion date.

### 5.3. Risk Management Program

Tampa Electric submitted a RMP to the EPA for the hydrogen in the syngas system at Polk Power Station. Because there are no off-site consequences and there have been no accidental releases of hydrogen in the past five years that resulted in any of the consequences covered by 40 CFR Part 68, Polk is only subject to the Program 1 RMP requirements.

EPA's RMP rule also applies to facilities storing more than 10,000 pounds of propane. Tampa Electric's Eastern Operations Center and Central Operations Center in Tampa, and its Plant City Operations Center have propane vehicle fuel stored in quantities above the 10,000 pound threshold. Currently, RMPs are not required for these three facilities due to a U.S Court of Appeals judicial stay of the rule for liquefied propane gas, as well as an EPA administrative stay of the effective date of the rule for facilities storing no more than 67,000 pounds of RMP flammable hydrocarbon fuels including propane.

If EPA is allowed to regulate propane in the future, EPA rule revisions could possibly allow Tampa Electric to manage the three operating centers with quantities of propane below the threshold to require the submittal of RMPs. If ammonia systems for SCRs or other developing technologies are installed at Gannon or Big Bend in the future and those systems contain greater than 10,000 pounds of ammonia, then it will be necessary to develop and submit RMPs to EPA for these facilities.

## 6. Other Potential Future Compliance Issues

There are several evolving environmental issues that may impact future operations. Some of the issues have the potential to result in requirements for additional emission reductions from current levels. Tampa Electric has considered these potential requirements in its development of options selected in this Compliance Plan.

### 6.1 Ozone Non-Attainment Status of the Tampa Bay Airshed

Description:

The Tampa Bay airshed is likely to be designated as non-attainment for ozone concentrations in the ambient air. If this designation is made, the state will have to formulate a method to reduce emissions of $NO_X$ and volatile organic compounds to resolve the non-attainment status. Part of the state plan may include requirements for reduction in $NO_X$ emissions from utility sources.

Time Frame:

Although rulemaking concerning the new ozone standards is currently in dispute, the Tampa Bay airshed ozone measurements are near the trigger level for the one-hour standard.

### 6.2 $PM_{2.5}$ Non-Attainment Status of the Tampa Bay Airshed

Description:

The Tampa Bay airshed may possibly be designated as non-attainment for $PM_{2.5}$ concentrations in the ambient air. If this designation is made, the state will have to formulate a method to reduce emissions of $NO_X$, $SO_2$ and PM to resolve the non-attainment status. Part of the state plan may include requirements for the reduction of $NO_X$, $SO_2$ and PM emissions from utility sources. PM reductions can be accomplished through several means, such as ESP upgrades and baghouses for coal units. $SO_2$ reductions can be accomplished through lower sulfur fuel on coal units, additional FGD systems for coal units, natural gas reburn for coal units, purchase of emission allowances and repowering of coal units. $NO_X$ reductions can be accomplished through the options described above under the ozone non-attainment issue.

Time Frame:

If the Tampa Bay airshed is designated non-attainment, Tampa Electric's system may be impacted between 2004 and 2008.

## 6.3 Potential Mercury Regulations for Utility Sources

Description:

The EPA is currently evaluating the necessity of proposing mercury regulations. These regulations would likely be source-specific emission limitations. The options to reduce mercury emissions include carbon injection or repowering the Big Bend units. The degree to which one or more of the technologies would be used and the generating units to which the technology would be applied depends upon the amount of emission reductions required.

Time Frame:

The time frame is uncertain but is not likely to occur prior to 2005.

## 6.4 Potential $CO_2$ Regulations for Utility Sources

Description:

The EPA is currently evaluating the necessity of proposing $CO_2$ regulations. These regulations would likely be imposed as part of a system-wide limit and/or trading program similar to the Title IV Acid Rain Program. The options which may be potential remedies include implementing carbon sequestration projects, purchasing $CO_2$ emission allowances and repowering coal units.

Time Frame:

The time frame is uncertain but is likely to occur after 2008.

## 6.5 Potential NSR Regulations Reform

Description:

The EPA is in the process of drafting changes to the NSR regulations and is near promulgation of stricter language. In connection with the EPA's actions into the investigation of possible NSR violations, a dialogue between UARG and other industries occurred with the EPA in an attempt to resolve the EPA's concerns through an agreement on NSR regulation reform. One possible action that could result would be to set a future date for implementation of NSPS for utility boilers at some date certain (after 2010 and before 2030) and in exchange, utilities would be afforded more operational and maintenance flexibility in the interim.

Time Frame:

The time frame for potential reform is uncertain but will likely occur between 2010 and 2030.

6.6 New Acid Rain Regulations

Description:

EPA is considering requiring further reductions of $SO_2$ and $NO_X$ emissions from utility sources.

Time Frame:

The time frame is uncertain but will likely occur after 2005.

6.7 Impact of Tampa Electric's Current Compliance Activities on Potential Future Compliance Issues

Tampa Electric is monitoring and evaluating potential future environmental issues as they develop to determine possible strategies. Tampa Electric's overall strategy is to approach each air emission parameter on a system-wide basis considering the applicable generating units.

Tampa Electric's future actions with regard to the CFJ will address and mitigate potential requirements for the majority of these issues since the repowering of Gannon and the use of $NO_X$ control technologies at Gannon and Big Bend will significantly lower overall $NO_X$ emissions.

Significant reductions in all pollutant emissions will be realized with the implementation of the CFJ. In addition, the $NO_X$ controls on the Gannon and Big Bend units and optimization of the FGD systems will greatly reduce Tampa Electric's contribution to the $NO_X$ budget in the Tampa Bay airshed, thereby helping to mitigate ozone non-attainment issues, PM, NSR reform, and potential new Acid Rain regulations. The reduction in emissions of these pollutants should allow Tampa Electric to meet the requirements of or at least mitigate the impact of potential future compliance issues described in Sections 6.1 through 6.6 above.

# 7. Consent Final Judgment

## 7.1 Objectives and Overview

In 1997, EPA began an investigation into alleged violations by Tampa Electric and several other coal-fired electric utilities of EPA's NSR policy, a segment of Title I of the CAAA. EPA asserted that certain electric utilities, including Tampa Electric, should have applied for pre-construction permits for certain unit maintenance projects, and that the permitting review of such projects would have included NSR, resulting in requirements that the units meet BACT standards for $NO_X$, $SO_2$ and PM. The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules. On November 3, 1999, despite Tampa Electric's longstanding efforts to reach a mutually agreeable settlement with the EPA, the DOJ sued Tampa Electric and seven other electric utilities on behalf of EPA for alleged violations of the 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 BACT for $NO_X$, $SO_2$ and PM. Following negotiations within the CAA 30-day notice period, DEP and Tampa Electric reached a settlement. Effective December 16, 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.

The requirements of the CFJ include repowering Gannon Station and further reducing $NO_X$, $SO_2$ and PM emissions at Gannon and Big Bend Stations. The CFJ was entered on December 16, 1999 in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County.

As a key element of the CFJ, Tampa Electric is required to repower Gannon Station (Gannon Repowering Project) from coal to natural gas using combustion turbines in a combined cycle mode. This will be accomplished by using existing Units 3, 4 and 5. After Units 3, 4, and 5 are repowered, the original boilers for Units 1 through 5 and the station's coal handling system will be retired. Units 1 and 2 will be on reserve standby. Unit 6 will also be placed on reserve standby, but the company will maintain the turbine, boiler and related equipment so it could be converted to burn natural gas and used in an emergency situation.

The repowering schedule anticipates starting engineering on the project in January 2000 with commercial operation of the repowered Unit 5 on May

1, 2003. The repowering of Units 3 and 4 will be completed on May 1, 2004. When these three units are repowered, the total station capacity will increase from about 1,200 MW to 1,475 MW.

The CFJ also requires Tampa Electric to reduce SO2, NOX and PM emissions at Big Bend and Gannon conduct studies of NOX removal technologies and PM monitors, work with DEP on its study of nitrogen deposition in Tampa Bay, and work with DEP to develop and implement state tax policy aimed at emission reductions and other environmental programs.

## 7.2 Gannon Repowering Project Analysis

Tampa Electric's analysis demonstrating that the Gannon Repowering Project is the most cost-effective alternative is provided in Appendix B. This analysis demonstrates the feasibility of repowering and also includes $NO_X$ *control technologies at Big Bend beginning in 2007* and completed by 2010. The repowering option was compared with several other options including continuing Tampa Electric's current Phase II compliance plan, installing environmental equipment on each Gannon unit, closing Gannon and purchasing power, and building new replacement generation. Under the CFJ, Tampa Electric was required to reduce emissions, so it was not feasible to continue with the current Phase II plan. The repowering option was the most cost-effective option given the more stringent environmental requirements of the CFJ.

The types of additional environmental controls to be installed at Big Bend will be dependent on the outcome of the various studies. Tampa Electric has not yet begun these required evaluations but will provide the results and complete analyses of the most cost-effective compliance options to both the DEP and FPSC.

Over time, Tampa Electric has operated its electrical generating facilities in the most cost-effective and prudent manner to ensure safe, reliable supply of electricity while complying with applicable environmental requirements. To date, Tampa Electric has put into place economical and effective measures to comply with the CAAA Title IV Phase I and Phase II requirements, as detailed above. Tampa Electric has continued to operate its existing generating facilities, as well as plan and build new generation capacity, in accordance with environmental regulations. The decision to go forward with the Gannon Repowering Project is consistent with Tampa Electric's environmental and operational policies.

Ongoing operation and maintenance activities, which are essential to ensure reliability of the Tampa Electric system, are in danger of curtailment due to the determination by EPA and DEP that certain maintenance activities at existing coal-fired generation triggered more stringent requirements to install new and costly emissions control technology. While there is no doubt that Gannon, despite being 40 years old, has many years of service remaining, the installation of emissions control technology such as FGD systems or SCRs on each unit would not be cost-effective nor would the discontinuation of ongoing maintenance be practical or prudent due to safety and reliability concerns. The recent proposals to bring additional gas supply into Florida made the option of natural gas repowering at Gannon a viable option. Therefore, the repowering of Gannon Units 3, 4 and 5 was able to meet the more stringent environmental requirements while maintaining reliability with the added benefit of increasing Tampa Electric's fuel diversity.

## 7.3 Impact of CFJ on $SO_2$ Compliance

Tampa Electric is required by the CFJ to repower or shutdown the units at the Gannon Station, maximize the FGD utilization for the Big Bend units and optimize the FGD efficiency for the Big Bend Units 1 and 2 with a minimum of 95 percent removal. The Gannon Repowering Project will dramatically reduce total emissions of $SO_2$ from this facility by replacing the coal-fired generation with natural gas-fired combined cycle units. At the conclusion of the conversion project, no coal-fired generation will remain in service at this facility.

The requirement to maximize the FGD system's utilization at Big Bend Station will require detailed engineering, testing and evaluation, and potential operational changes of the existing and the recently-constructed wet limestone FGD system. This compliance activity is a prudent and cost-effective measure to reduce $SO_2$ emissions. This requirement allows continued fuel flexibility to maintain stable and competitive fuel expenses, while ensuring the maximum utilization of existing capital investments in $SO_2$control equipment.

These projects will significantly reduce total emissions of $SO_2$ from the Tampa Electric system. In the interim, Tampa Electric's Phase II $SO_2$ compliance plan continues to be the most cost effective means to meet Phase II $SO_2$ requirements. Overall, Tampa Electric's $SO_2$ emissions from 1997 to 2010 are expected to be reduced by approximately 80 percent as shown in Figure 7.1 below.

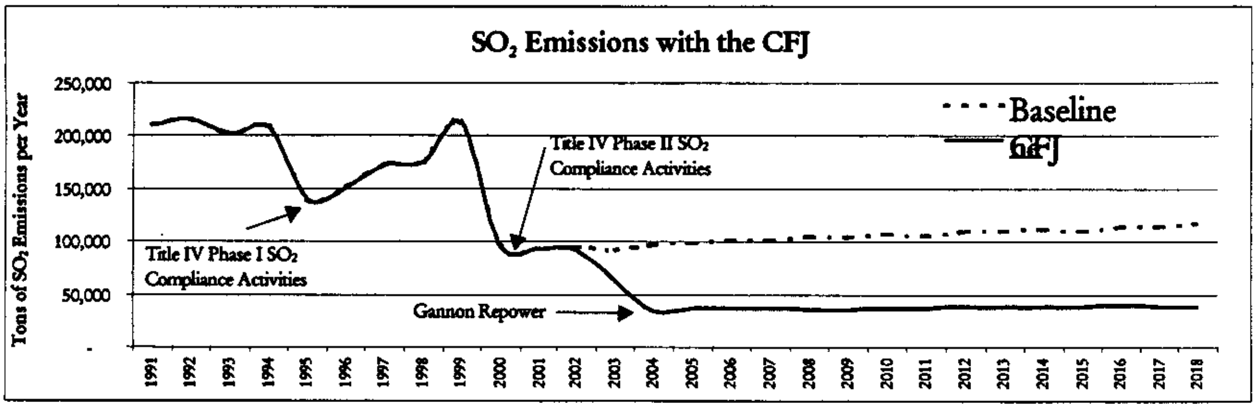



Figure 7.1: Estimated $SO_2$ Emissions with the Implementation of the CFJ

## 7.4 Impact of CFJ on $NO_X$ Compliance

Tampa Electric is required by the CFJ to repower or shutdown the units at Gannon Station; shutdown, repower or install $NO_X$ controls on Big Bend Unit 4 in 2007; and shutdown, repower or install $NO_X$ controls on Big Bend Units 1, 2 and 3 by 2010. The intent of the CFJ is that by 2010 all of the units at the Big Bend and Gannon Stations will meet BACT standards for $NO_X$. The methodology of $NO_X$ emission controls for these units has not been established at this time.

The Gannon Repowering Project will have the result of reducing $NO_X$ emissions through the replacement of coal-fired generation with natural gas combined cycle generation. The combined cycle units will be required to meet a $NO_X$ emission limit of 3.5 pounds per mmBtu.

As required by the CFJ, Tampa Electric may install a "zero ammonia" $NO_X$ control technology on one of the units during the repowering project if this technology is found to be commercially viable by the DEP. If there are no "zero ammonia" technologies found to be commercially viable or the incremental cost of the technology is more than $8 million greater than the cost of an SCR, then Tampa Electric will review other $NO_X$ reduction technologies for natural gas-fired or coal-fired generating facilities. The reduction of $NO_X$ emissions resulting from the application of the reviewed technologies, in addition to the combustion optimization and tuning already performed, may eliminate or reduce the need for SCRs at Big Bend.

These projects will significantly reduce total emissions of $NO_X$ from the Tampa Electric system. In the interim, Tampa Electric's Phase II $NO_X$ compliance plan continues to be the most cost-effective means to meet Phase II $NO_X$ requirements. Overall, Tampa Electric's $NO_X$ emissions from 1997 to 2010 are expected to be reduced by approximately 85 percent as shown in Figure 7.2 below.

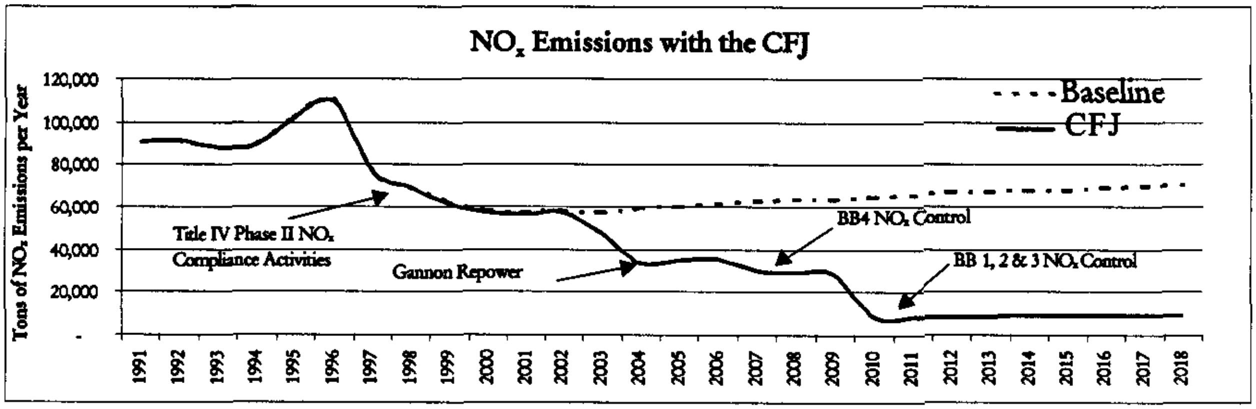



Figure 7.2: Estimated $NO_X$ Emissions with the Implementation of the CFJ

7.5 Impact of CFJ on PM Emissions

Since the repowered units at Gannon Station will be fired with natural gas, PM emissions will be reduced by approximately 45 percent in 2010 compared to 1997 emission levels. Figure 7.3 below shows the effect of the Gannon Repowering Project on system PM emissions.

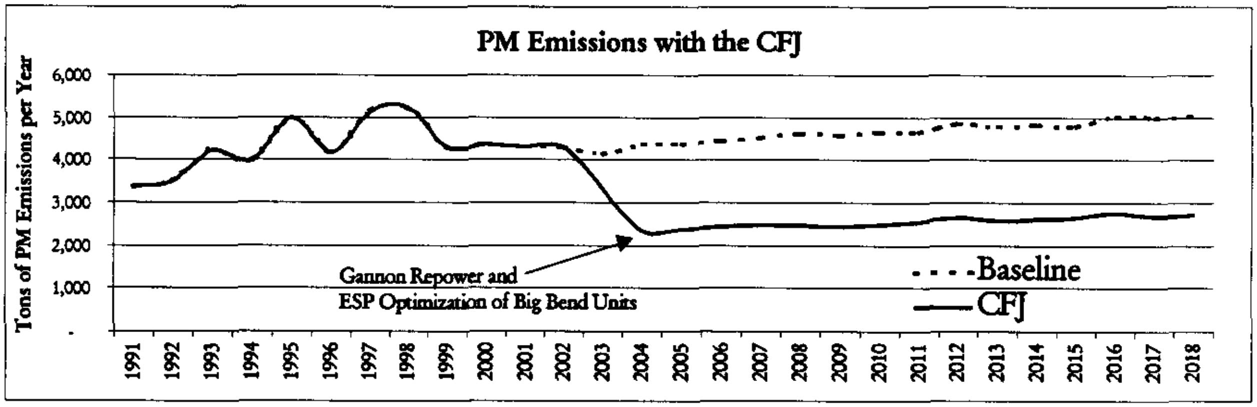



Figure 7.3: Estimated PM Emissions with the Implementation of the CFJ

In addition to repowering Gannon Station with natural gas, the CFJ stipulates that an ESP optimization study must be performed at Big Bend Station. The results of this study may identify measures that can be implemented to allow Tampa Electric to operate the ESPs at Big Bend Station in a manner that will further reduce PM emissions from each unit.

As required by the CFJ, Tampa Electric will also evaluate and report to the DEP the feasibility of installing a continuous in-stack PM monitor on one of the Big Bend stacks by March 1, 2002. DEP will then evaluate the feasibility and may require the installation of the monitor by May 1, 2003. Tampa Electric is currently evaluating the available monitoring technologies available to comply with the requirement.

## 8. Fuel Sources

Fuel diversity is a key variable in Tampa Electric's CAAA Title IV Phase I and II $SO_2$ compliance plans. Tampa Electric's Phase I and II $SO_2$ compliance plans have combined the use of lower sulfur coals in certain units with the installation of FGD systems and the use of higher sulfur coals for other units to meet the overall CAAA Acid Rain Program requirements. Tampa Electric has tested alternative power plant fuels in an effort to augment traditional fuels with useful by-products and renewable sources. Petroleum coke (pet coke) and wood-derived fuel have been tested, and the company has received approval from DEP to burn these fuels on a regular basis. Although wood-derived fuel (essentially waste paper) has been used on a limited basis, pet coke produced an estimated 234 GWh of net energy in 1998.

These strategies have also reduced the number of $SO_2$ allowances used over time. Through ongoing monitoring of fuel and allowance market prices, Tampa Electric operates its units to meet environmental limits and minimize overall costs. Tampa Electric's present sources of fuel primarily include coal and oil. However, three natural gas pipelines with capacity of 1 billion cubic feet per day each are presently proposed for Florida with in-service dates of 2002 and 2003. The Florida Gas Transmission pipeline has announced major expansions of its system as well. This increased availability and the resulting reduced cost of natural gas transportation has made natural gas a viable fuel alternative for Tampa Electric.

Under the CFJ, future sources of fuel will include coal, natural gas and oil. Light oil will be used as secondary fuel for gas-fired generating units and for the existing simple-cycle combustion turbines. The future use of natural gas will greatly reduce $NO_X$, $SO_2$ and PM emissions.

## 9. Regulatory Compliance Dates and Costs

The CAAA have established many new requirements, which affect Tampa Electric's environmental compliance plans. Table 9.1 lists several of the key CAAA Phase I, Phase II and CFJ requirements that specifically impact Tampa Electric's compliance strategy. Table 9.2 provides a summary of the project costs that have been undertaken to date by Tampa Electric. Table 9.2 does not provide a breakdown of the estimated projects costs associated with the CFJ requirements. The total cost of compliance with the CFJ is currently estimated to be approximately one billion dollars. Of this total, $673 million is the estimated cost of repowering Gannon Station. The remaining $327 million represents a high-level estimate of the expected costs for additional environmental projects and activities required by the CFJ. As the projects are evaluated in more detail, the cost estimates will be refined.

# Table 9.1

## REGULATORY COMPLIANCE DATES

| Regulatory Compliance Requirement | Applicable Regulation | Affected Units | Compliance Date |
|---|---|---|---|
| Phase I CEMS operational | Title IV – Phase I | Big Bend 1-4 | November 1993 |
| Phase II CEMS operational | Title IV - Phase I | Gannon 1-6<br>Hookers Point Boilers 1-6 | November 1994 |
| Phase I $SO_2$ allowance compliance begins using CEMS | Title IV – Phase I | Big Bend 1-4 | January 1, 1995 |
| Phase I $NO_x$ annual average emission limits measurement with CEMS begins | Title IV – Phase I | Big Bend 4 | January 1, 1996 |
| Submit Polk Risk Management Plan | Section 112(r) | Polk Power Station | June 21, 1999 |
| Phase II $SO_2$ allowance compliance begins using CEMS | Title IV – Phase II | Gannon 1-6<br>Hookers Point Boilers 1-6<br>Polk IGCC 1<br>Any future fossil fuel-fired units | January 1, 2000 |
| Phase II $NO_x$ annual average emission limits measurement with CEMS begins | Title IV – Phase II | Gannon 3-6<br>Big Bend 1-4 | January 1, 2000 |
| Complete Mercury testing including coal and stack testing | Section 114 | Big Bend Station<br>Gannon Station<br>Polk Power Station | December 1999 |
| Conduct feasibility study for PM monitor | CFJ | One Big Bend Unit | March 1, 2002 |
| Optimize FGD utilization and efficiency | CFJ | Big Bend 1-4 | May 1, 2002 |
| Perform ESP optimization study, BACT analysis and implement upgrades | CFJ | Big Bend Station | May 1, 2003 |
| Install PM monitor, if feasible | CFJ | One Big Bend Unit | May 1, 2003 |
| Complete phase-in natural gas units | CFJ | Gannon Station | May 2004 |
| Study $NO_x$ control methodology and installation | CFJ | Big Bend 4<br>Big Bend 1-3 | May 2007<br>May 2010 |

## Table 9.2

| INSTALLATION DATES AND COSTS | | | |
|---|---|---|---|
| **Project** | **Installation Date** | **Affected Units** | **Project Costs (Millions)** |
| Phase I CEMS installation | November 1993 | Big Bend 1-3 | $2.612 |
| Flue Gas Conditioning System | December 1993 | Big Bend 1<br>Big Bend 2<br>Big Bend 3 | $2.676<br>$2.342<br>$2.595 |
| Phase II CEMS installation | November 1994 | Big Bend 4<br>Gannon 1-6<br>Hookers Point Boilers 1-6 | $0.866<br>$3.939<br>$1.473 |
| BB3 FGD Integration | June 21, 1995 | Big Bend 3 | $8.559 |
| BB 1 & 2 FGD | December 31, 1999 | Big Bend 4 | $83.395 |
| Mercury Testing | December 31, 1999 | Big Bend Station<br>Gannon Station<br>Polk Power Station | $0.150 |
| Electrostatic Precipitator Optimization Study | December 31, 1999 | Gannon 1-6 | $0.110 |
| Classifier Replacement for Phase II $NO_x$ compliance | December 1998<br>May 1998<br>December 1997<br>July 1999 | Big Bend 1<br>Big Bend 2<br>Gannon 5<br>Gannon 6 | $1.316<br>$0.985<br>$1.357<br>$1.412 |
| Coalfield Crusher for Phase II $NO_x$ compliance | June 1999 | Gannon Station | $5.211 |

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL C.RCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.: 99-9737

TAMPA ELECTRIC COMPANY,

Defendant.
_______________________________/

## CONSENT FINAL JUDGMENT

### I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

## II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

## III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

## IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1. TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994

and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; (2) replacement of the cyclone in Gannon Unit 4 in 1994; and (3) replacement of a radiant superheater at Gannon Unit 6 in 1992.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

## V. REQUIREMENTS OF THE CONSENT FINAL JUDGMENT

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 95% but is the first Unit with a large, high velocity tower serving approximately 800 megawatts. TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation and if necessary, to pursue its available remedies against the vendor.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F. TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend by March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain effective until the actions required hereunder have been implemented.

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

## VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

## VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this ___ day of ___________________, 1999.

ORIGINAL SIGNED

DEC 16 1999

ROBERT H. BONANNO
CIRCUIT JUDGE

Circuit Judge

| | |
|---|---|
| FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION | TAMPA ELECTRIC COMPANY |
| By: David B. Struhs | By: J. B. Ramil |
| Secretary of the Florida Department of Environmental Protection | John B. Ramil<br>President |
| Date: December 6, 1999 | Date: December 6, 1999 |

## 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 stability 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 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 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.

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 criterion of 15 percent was subsequently updated to 20 percent based the stipulation between the FPSC and the three Florida investor owned utilities to carry a 20 percent reserve margin.

Sensitivities on natural gas commodity, 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 | $399 | $342 | $491 | $478 |
| ANNUAL FIXED CAPITAL 99$000 | $3,454 | $0 | $2,283 | $2,283 |
| ANNUAL FIXED O&M 99$000 | $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 2008 |

* without AFUDC and Transmission & Distribution
Nominal cost based on combined winter and summer unit capabilities

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

| PURCHASED POWER ALTERNATIVE | VALUE |
|---|---|
| Levelized Capacity Component | 69.52 $/kW-YR |
| Energy Component (2003$) | 24.70 $/MWH |
| Wheeling Component (2003$) | 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 Meth | 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.

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 | 6.689 | 91.0% |
| UNIT 5 | 796 | 98 | 6.689 | 91.0% |
| EXISTING GANNON STATION | | | | |
| UNIT 1 | 114 | 0 | 11.546 | 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) | 179 | 24 | 10.580 | 94.0% |
| GANNON REPLACEMENT PLAN | | | | |
| FUTURE CC'S | | | | |
| USING GE "F" FRAME CT'S | 523 | 78 | 7.081 | 91.0% |
| USING GE "G" FRAME CT'S | 675 | 103 | 6.590 | 91.0% |

* EAF's are based on Winter Capacity

## Purchased Power Assumptions

- The incremental capacity cost of maintaining voltage stability of the transmission grid associated with placing Gannon Station on reserve standby was estimated conservatively at $71 million (2-year CPW in 1999 dollars). This assumes the "best case" senario in that the firm purchased power will be provided from several areas within the state.
- 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 through-out 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, which 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 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 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 and Westinghouse G 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 stability 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<br>Polk CT (Oct) | HPS CT2B<br>Polk CT (Oct) | HPS CT2B<br>Polk CT (Oct) | HPS CT2B<br>Polk CT (Oct) |
| 2001 | — | — | — | — |
| 2002 | Polk CT (May) | Polk CT (May) | Polk CT (May) | Polk CT (May) |
| 2003 | Polk CT (May) | Repower 5 (May)<br>LTRS Gannon 1 & 2 | Gannon "F" CC<br>Polk CT<br>LTRS Gannon 1, 2, & 5 | Firm purchase to replace Gannon Repowering Alternative |
| 2004 | Polk CT (May) | Repower 3 & 4 (May)<br>LTRS Gannon 6 | 2 ea - Gannon "F" CC<br>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 |

## Economic Analysis

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 capital, incremental O&M expense, incremental transmission and distribution costs, incremental $SO_2$ allowance costs, depreciation, working capital, transmissions 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, $SO_2$ allowance costs, 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 and incremental O&M expense associated with each alternative. The incremental capital revenue requirements and incremental O&M expenses were added to the $SO_2$ compliance costs, fuel costs, purchase power expense, and incremental transmission wheeling 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 transmission losses 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

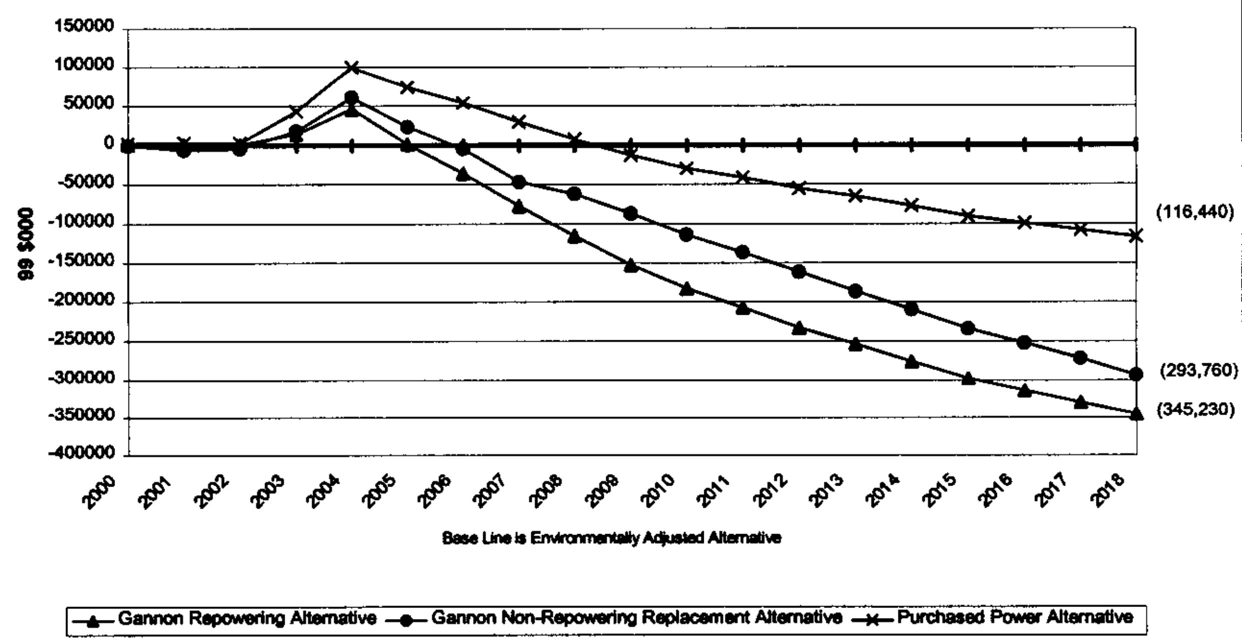
The incremental CPWRR in 1999 dollars for all of the alternatives evaluated are provided in Figure B-1. These incremental CPWRR are differentials to the Environmentally Adjusted Alternative and provide a graphical summary of the results from the quantitative analysis. The analysis concluded that the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

The Environmentally Adjusted Alternative was the highest cost option. Therefore, it 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 $229 million higher than the Gannon Repowering Alternative. This is due primarily to the transmission costs associated with maintaining voltage stability after Gannon Station is placed on reserve standby; the imputed financial risk to Tampa Electric associated with IPP financing; and the costs associated with wheeling the purchased power. The differential would have been even greater had a less conservative approach for determining transmission impacts of purchasing such a large amount of power been assumed.

The Gannon Non-Repower Replacement Alternative was $51 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. 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 the "G" technology. 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



## Sensitivities

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 drop to a value equal to the operating cost of an FGD system on a $/Ton basis (approximately $90 per allowance). 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. This sensitivity reduced the differential CPWRR of each alternative, relative to the Environmentally Adjusted Alternative, by between $26 and $28 million depending on the alternative. The relative order of the alternatives did not change.

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 differential CPWRR by approximately $36 million for the Gannon Non-Repowering Alternative and by $40 million dollars for the Gannon Repowering Alternative. The differential CPWRR of the Purchased Power Alternative was increased by approximately $12 million because the higher transportation costs were not applied to the sources of the purchased power. The relative order of the alternatives was not impacted by this sensitivity.

The higher natural gas sensitivity used a high price forecast for the commodity. A significant impact to the CPWRR of each alternative resulted from raising the natural gas price. The differential CPWRR decreased by $200 million for the Gannon Non-Repowering Alternative and by $208 million dollars for both the Gannon Repowering and Purchased Power alternatives, relative to the Environmentally Adjusted Alternative. The CPWRR of the Purchased Power Alternative actually exceeded that of the Environmentally Adjusted Alternative by $91 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.

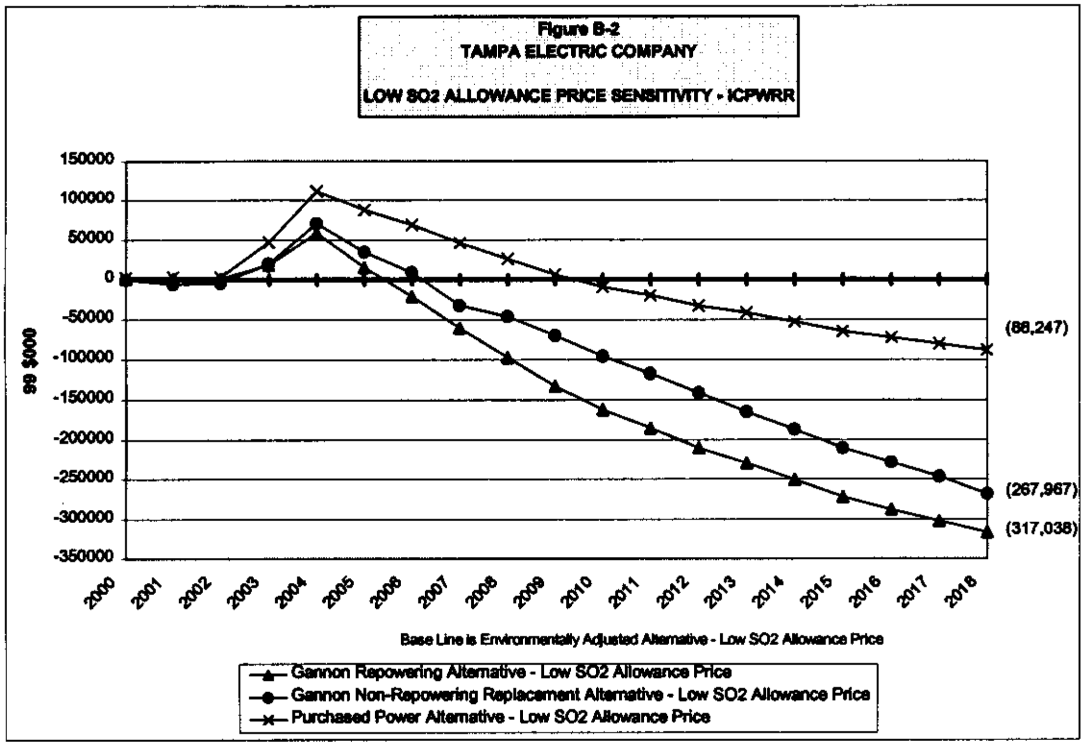


Figure B-2
TAMPA ELECTRIC COMPANY
LOW SO2 ALLOWANCE PRICE SENSITIVITY - ICPWRR
150000
100000
50000
0
-50000
-100000
-150000
-200000
-250000
-300000
-350000
99 $000
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
(88,247)
(267,967)
(317,038)
Base Line is 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

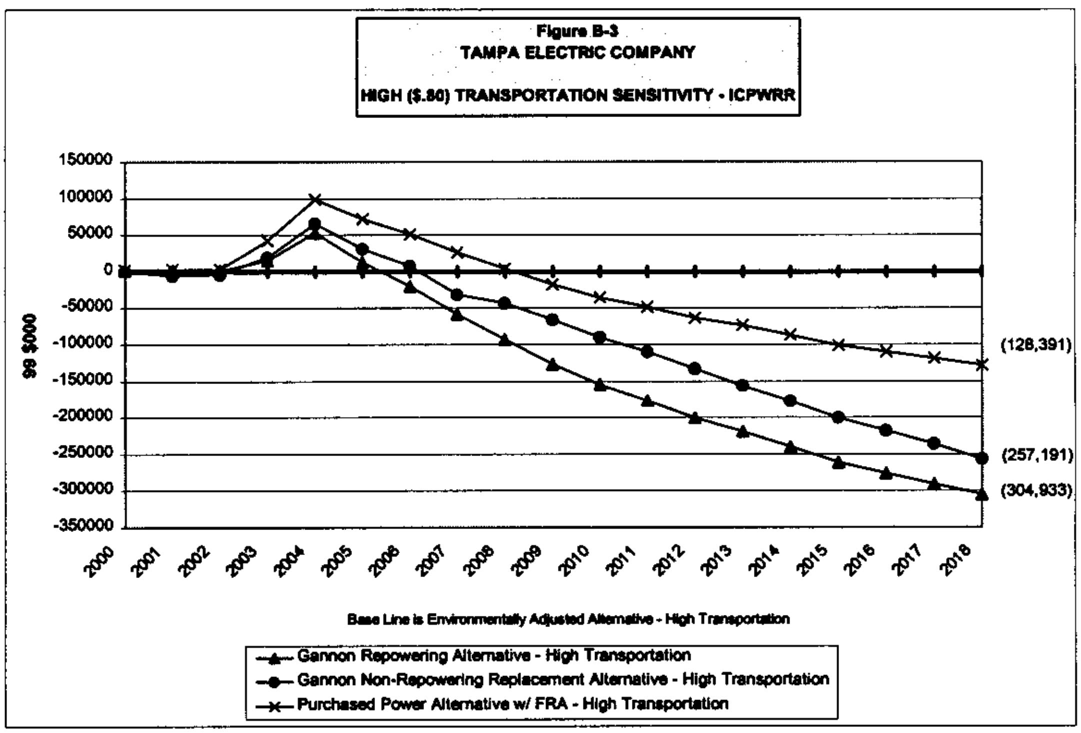
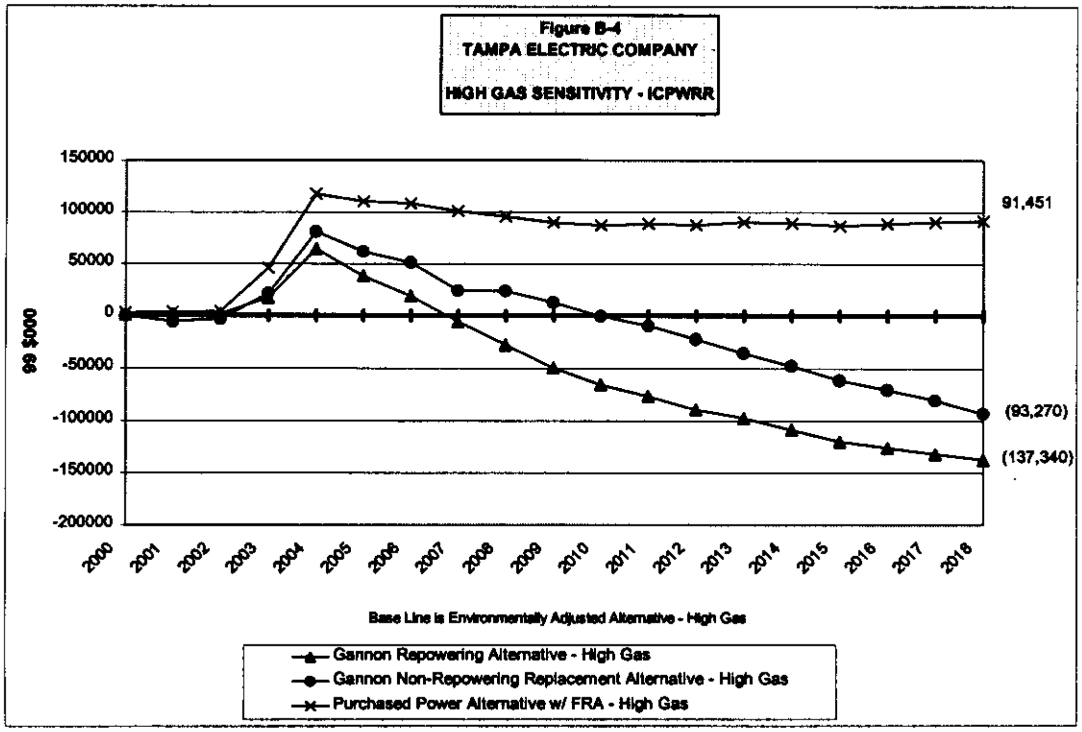



Figure B-3
TAMPA ELECTRIC COMPANY
HIGH ($.80) TRANSPORTATION SENSITIVITY - ICPWRR
150000
100000
50000
0
-50000
-100000
-150000
-200000
-250000
-300000
-350000
99 $000
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
(128,391)
(257,191)
(304,933)
Base Line 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 efficiencies and availabilities 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 stability 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 Electrric'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 stability, and maximizing operational flexibility.