ORIGINAL

TE

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 000007-EI

TESTIMONY
AND EXHIBIT OF

GREGORY M. NELSON

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GREGORY M. NELSON

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

A. My name is Gregory M. Nelson. My mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 6944 U.S. Highway 41 North, Apollo Beach, Florida 33572. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Environmental Affairs in the Environmental and Fuels Department.

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

A. I received a Bachelors Degree in Mechanical Engineering from the Georgia Institute of Technology in 1982 and a Masters of Business Administration from the University of South Florida in 1987. I am a registered Professional Engineer in the State of Florida. I began my engineering career in 1982 in Tampa Electric's Engineering Development Program. In 1983, I worked in the Production Department where I was responsible for power plant performance projects. Since 1986, I have held various environmental permitting and compliance positions. In 1997, I was promoted to Administrator - Air Programs in the Environmental Planning Department. In this position, I was responsible for all air permitting and compliance programs. In 1998, I was promoted to Manager, Environmental Planning and in 2000 I became Director, Environmental Affairs. My present responsibilities include the management of Tampa Electric's environmental permitting and compliance programs.

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

A. Yes, I have provided testimony regarding environmental projects and their associated environmental requirements in Environmental Cost Recovery Clause ("ECRC") proceedings before this Commission.

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

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the ECRC are activities which are necessary for the company to comply with environmental requirements.

Specifically, I will describe the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("DEP") and the Consent Decree lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice ("DOJ"). I will provide an overview of new environmental compliance activities that are the result of the CFJ and Consent Decree ("the Orders"), some of which Tampa Electric has included in its 2001 ECRC projection filing.

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

A. Yes I have. My Exhibit No. _____ (GMN-1) consists of one document.

Q. Please explain how the Orders between Tampa Electric, EPA and DOJ, and DEP came about.

A. 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 Clean Air Act Amendments ("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 nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), and particulate matter ("PM"). The electric utility industry, including Tampa Electric, disagrees with EPA's current interpretation of its NSR rules and believes that the activities performed were routine maintenance and, therefore, were exempt from these requirements.

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 Clean Air Act ("CAA") associated with this NSR issue. Specifically, at issue were the coal-fired Gannon Units 3, 4, and 6 and Big Bend Units 1 and 2. This federal action triggered a 30-day window during which the DEP could resolve these issues as described by Section 113 of the CAA.

Within this 30-day window, DEP filed a complaint which supported EPA's contention 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 discussions on these issues, DEP and Tampa Electric negotiated a settlement agreement in the form of the CFJ effective December 7, 1999. The CFJ addresses the DEP claims that Tampa Electric modified and then operated its generating units at Big Bend and Gannon Stations without first obtaining permits authorizing the modifications and without installing BACT to control NO_X, SO_2, and PM. The CFJ was entered in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County.

The federal action that had been filed on behalf of EPA against Tampa Electric was subsequently settled through a Consent Decree between EPA, DOJ, and Tampa Electric. The Consent Decree addresses EPA's claims that Tampa Electric violated Prevention of Significant Deterioration ("PSD") requirements of the CAA. The Consent Decree was lodged with the United States District Court, Middle District of Florida on February 29, 2000. The requirements of the Consent Decree are similar to those of the CFJ; however, those of the Consent Decree are more specific and detailed.

Q. Has the company's environmental compliance plan been influenced by interactions with DEP and EPA?

A. Yes. Tampa Electric's environmental compliance plan has been significantly influenced by the Orders. Accordingly, the company has updated its compliance plan to reflect the new requirements. The revised plan is included as Document No. 1 of my exhibit.

Q. Are the Orders a fair and reasonable solution for Tampa Electric's ratepayers?

A. Yes. The Orders avoid the uncertainties of protracted litigation and the potential of having to incur greater costs implementing some unpredictable result of that litigation. They call for appropriate actions at less cost than any other alternatives the company could have pursued. Finally, although the company disagrees with DEP and EPA regarding their respective NSR interpretations, the applicable legal requirements and whether Tampa Electric was in compliance with them, the Orders satisfy DEP and EPA's compliance requirements in a fair and reasonable manner. This certainly provides significant value to Tampa Electric and its customers.

Q. Please provide an overview of the environmental compliance requirements of the Orders.

A. The requirements of the Orders include repowering Gannon Station and further reducing NO_X, SO_2, and PM emissions at Gannon and Big Bend Stations.

Q. Please describe in more detail the proposed repowering of Tampa Electric's Gannon Station ("Gannon Repowering Project") as required by the Orders.

A. The Gannon Repowering Project will entail the repowering of Gannon Units 5 and 6 with combined cycle technology utilizing natural gas to replace the current coal-fired technology. Coal-fired Units 1, 2, 3, and 4 will be placed on reserve status by year-end 2004. The company will install selective catalytic reduction systems ("SCR") to control emissions from each of the heat recovery steam generators installed as part of the repowering at Gannon Station. After the repowering is complete, the plant will be capable of generating 1,700 MW of electricity, as compared to the current output of approximately 1,200 MW. Any future use of coal in any of these units is not permitted beyond December 31, 2004 under the terms of the Orders.

Q. Is the Gannon Repowering Project compatible with other environmental compliance activities already implemented by Tampa Electric?

A. Yes it is. Regardless of the requirements of the Orders, Tampa Electric was required to meet the Title IV Phase II SO_2 and NO_x limitations by January 1, 2000. Tampa Electric has taken significant steps to date to meet the Phase I and II SO_2 limitations through the integration of Big Bend Unit 3 with the Big Bend Unit 4 flue gas desulfurization ("FGD" or "scrubber") system and the construction of a second FGD system to serve Big Bend Units 1 and 2.

Another significant compliance activity for the company has been its NO_x combustion optimization projects. These projects have achieved significant reductions for Phase II compliance and will make future NO_x reduction projects more cost effective.

The Gannon Repowering Project is entirely consistent and compatible with the company's SO_2 and NO_x environmental compliance projects to date and will also result in decreased emissions of other pollutants such as PM and mercury. As stated above, SO_2 and NO_x emissions as well as overall emissions of pollutants have been and are expected to continue to be significantly reduced.

Q. Please describe the other compliance requirements of the Orders.

A. Generally the Orders require the company to reduce SO_2, NO_x and PM emissions as summarized below:

Reduction of SO_2 Emissions

The key requirements include:

- The Big Bend Units 1 and 2 scrubber must be operating at all times that either Big Bend Unit 1 or 2 is operating, with certain limitations, by the later of September 1, 2000 or the entry date of the Consent Decree.
- The Big Bend Unit 3 scrubber must be operating at all times that Big Bend Unit 3 is in operation, with certain limitations, by the entry date of the Consent Decree.
- The company must submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1, 2 and 3.

Reduction of NO_x Emissions

Tampa Electric is required to evaluate "zero-ammonia" NO_x control technology at Gannon Station and, if found to be commercially viable, install such technology on one of the repowered units provided the incremental capital cost differential above the cost of a SCR is less than $8 million. If found not to be commercially viable, then by December 31, 2004, Tampa Electric must spend up to $8 million to demonstrate alternative commercially viable NO_x reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and Tampa Electric. Specifically, Tampa Electric must submit to EPA a plan to spend up to $3 million to reduce NO_x emissions from Big Bend Units 1 and 2 by at least 30 percent and reduce the NO_x emissions rate for Big Bend Unit 3 by at least 15 percent on or before December 31, 2001. The remaining $5 to $6 million must be spent to demonstrate innovative NO_x control technologies on any of its units or boilers at Gannon or Big Bend Station and/or reduce the NO_x emission rate for any Big Bend coal-combusting unit.

Reduction of Particulate Emissions

Tampa Electric is required to:

- Complete an optimization study that recommends the best operational practices to minimize emissions from each electrostatic precipitator ("ESP') at Big Bend within 12 months after entry into the Consent Decree and implement the recommendations within 60 days after EPA has approved them.
- Complete a BACT analysis for upgrading each existing ESP at Big Bend within 12 months after entry into the Consent Decree and complete the installation of the recommendations of the BACT analysis.
- Revise the previous optimization study to incorporate new requirements resulting from the BACT analysis.
- Install and operate a PM monitor by March 2002 and evaluate the possibility for Tampa Electric to install a second PM monitor.

Other Requirements

Tampa Electric is required to spend up to $2 million for performance of air chemistry work in Tampa Bay Estuary. Tampa Electric is also required to pay a civil penalty of $3.5 million to the U.S. government.

Q. What benefits will the requirements of the Orders bring by way of reduced emissions?

A. Repowering with natural gas at Gannon Station along with high-efficiency, state-of-the-art controls at Big Bend Station, will enable Tampa Electric to reduce SO_2 emissions by almost 80 percent, reduce NO_x by more than 85 percent and carbon dioxide (CO_2) emissions by more than 20 percent.

Q. Does Tampa Electric plan to seek cost recovery through the ECRC for the projects required under the Orders?

A. Yes. To date, Tampa Electric has filed two petitions with the Commission seeking approval of three programs required by the Orders. Tampa Electric believes that all of the environmental control projects required by the Orders, except for the repowered generating facility and the civil penalty, are the types of projects that are eligible for recovery through the ECRC. As the company begins to evaluate each project individually, it will seek approval of these projects by way of separate petitions as the company has done with all of its environmental projects in the past.

Q. Why does Tampa Electric believe that these projects are the types of projects that are eligible for recovery through the ECRC?

A. The projects are legally required by the Orders and they impose more stringent environmental standards than previously existed. As described in more detail in the direct testimony of Tampa Electric witness Karen O. Zwolak, these projects meet all requirements for ECRC cost recovery established in Commission Order No. PSC-94-0044-FOF-EI.

Q. Do the CAAA regulation programs that Tampa Electric has already implemented and which are currently being recovered through the ECRC meet the requirements specified in the Orders?

A. No. The programs already in place and being recovered through the ECRC, such as the Gannon and Big Bend Station classifier replacements, the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD system were performed to achieve compliance with Title IV of the CAAA. 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. Each company was assessed an amount of reductions to achieve. The Orders, however, require more stringent reductions of SO_2 and NO_x emissions to levels reaching those of new generation with state-of-the-art environmental control technology. The Orders also require significantly more reductions than the Acid Rain requirements.

Q. The Commission had previously approved cost recovery for mercury testing, an ESP study and stack extensions on Gannon Units 5 and 6, yet no additional costs have been identified for 2001. Will Tampa Electric incur any costs for these activities?

A. At this time, Tampa Electric has no plans to incur additional costs in 2001 for these activities. The Gannon ESP study was completed and submitted to DEP and the Environmental Protection Commission of Hillsborough County for review. To date, no further recommendations by the agencies have been received. Tampa Electric also completed the mercury testing and does not anticipate any future costs. In consideration of the short time span until Gannon Station is repowered, the DEP and Tampa Electric have agreed to an interim plan to mitigate impacts to ambient air quality, therefore stack extensions are no longer being considered. This plan involves the stepwise reduction of fuel sulfur content to

1.7 lb/mmbtu on a station wide basis in concert with the repowering project.

Q. Please summarize your testimony.

A. Tampa Electric has entered into settlement agreements with DEP and EPA which require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations while avoiding lengthy and expensive litigation. The Orders establish definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. The projects described in my testimony are legally required by the Orders and will enable Tampa Electric to meet the more stringent environmental standards prescribed in the Orders. As described in more detail in the direct testimony of Tampa Electric witness Zwolak, these projects meet all the requirements for ECRC cost recovery established in Commission Order No. PSC-94-0044-FOF-EI.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 000007-EI
WITNESS: GREGORY M. NELSON
EXHIBIT NO. ____ (GMN-1)
FILED: SEPTEMBER 21, 2000

TAMPA ELECTRIC COMPANY

EXHIBIT OF GREGORY M. NELSON

INDEX

TE

TAMPA ELECTRIC

TAMPA ELECTRIC COMPANY
DOCKET NO.

COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

September 2000

Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

Table of Contents

Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

Table of Contents (cont.)

Tables and Figures

Appendices

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 550,000 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 88 percent of its system energy requirements in 1999. Total 1999 energy sales, including wholesale sales, were 17,965 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 oxides of nitrogen (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 began January 1, 2000, the company installed a new Flue Gas Desulfurization (FGD) system at Big Bend Units 1 and 2, and plans to continue using fuel blending and SO_2 allowances. 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 7, 1999, entered into with the Florida Department of Environmental Protection (DEP). They are also contained in a Consent Decree with the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Justice (DOJ), filed February 29, 2000. These requirements call for additional reductions in SO_2, NO_X, and PM. Further emission reductions may be required in the future as a result of the EPA's New Source Review (NSR) enforcement initiative, EPA's NSR regulatory reform, and other potential EPA emission-limiting regulations for ozone, fine particulate matter ($PM_{2.5}$) hazardous air pollutants, mercury, carbon dioxide (CO_2), and/or acid rain. It is Tampa Electric's goal to meet all of these requirements in a cost-effective and prudent manner.

Tampa Electric Company
COMPREHENSIVE CLEAN AIR ACT COMPLIANCE PLAN

Introduction and Purpose

Tampa Electric is an investor-owned electric utility that is engaged in the generation, purchase, transmission, distribution, and sale of electric energy. Tampa Electric serves over 550,000 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 88 percent of its system energy requirements in 1999. Total 1999 energy sales, including wholesale sales, were 17,965 GWh.

The company has six electric generating plants, five of which are in operation, with a total net winter generating capability of 3,795 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 Station (1,742 MW capability from four coal-fired steam units), Gannon Station (1,180 MW capability from six coal-fired steam units), Hookers Point Station (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 Stations (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 and with No. 2 oil as alternate fuel and 180 MW capability from one combustion turbine) in southwestern Polk County; and Phillips (34 MW capability from two No. 6 oil-fired slow-speed diesel units) and Dinner Lake Stations in Highlands County. Dinner Lake Station (11 MW from one natural gas-fired steam electric unit) was placed on long-term reserve standby status in March 1994. Polk Unit 3, another 180 MW capability combustion turbine unit fueled with natural gas, was permitted with Polk Unit 2 and is expected to begin commercial operation in May 2002. With this additional generation the company's total net winter generating capability will be 3,975 MW effective May 2002.

Units at Hookers Point Station began commercial service from 1948 to 1955, at Gannon Station from 1957 to 1969, and at Big Bend Station from 1970 to 1985. The Polk IGCC unit began commercial service in September 1996. Dinner Lake Station began commercial service in 1966 and Phillips Station 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 Statutes (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 continued 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 began 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 units as well as Hookers Point and future fossil-fueled generating units. Phillips and Dinner Lake Stations and combustion turbines existing prior to Phase II implementation 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.

For Phase I, 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 more economical and feasible to integrate Big Bend Unit 3 with the existing Big Bend Unit 4 Flue Gas Desulfurization (FGD) system. This allowed the company to burn high sulfur coal in Big Bend Unit 3 in addition to Big Bend Unit 4, utilize fuel blending at Big Bend Units 1 and 2, and purchase 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 number of SO_2 allowances purchased 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, was required to 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 is expected to reduce Tampa Electric's SO_2 emissions by about 70,000 tons per year. Although Tampa Electric, through the Big Bend Station pollution controls, has more allowances to utilize at Gannon Station, current regulations limit emissions of SO_2 under the CAAA Title I AAQS. For Gannon Station, 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 unit or system 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 Station coal field. In addition to these emission reduction projects, Tampa Electric may 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. Specifically, at issue were 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 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 Stations 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 in the Circuit Court of the Thirteenth Judicial Circuit in and for Hillsborough County. It is included as Appendix A.

In addition, the November 3, 1999 DOJ complaint against Tampa Electric was settled through a Consent Decree between EPA, DOJ, and Tampa Electric, which addresses EPA claims that Tampa Electric violated PSD requirements of the CAA. Like the CFJ, the Consent Decree requires that Gannon Station be repowered and requires further reductions in SO_2, NO_x, and PM emissions at Gannon and Big Bend Stations. The Consent Decree was lodged with the United States District Court, Middle District of Florida, on February 29, 2000. The Consent Decree is included as Appendix B.

The requirements of the CFJ and the Consent Decree (the Orders) include repowering Gannon Station and further reducing NO_X, SO_2, and PM emissions at Gannon and Big Bend Stations. A key element of the Orders is that Tampa Electric is required to repower Gannon Station units from coal to natural gas using combustion turbines in a combined cycle mode. The Consent Decree requires that a minimum of 200 MW be repowered by May 1, 2003. Additional coal-fired generating capacity equal to or greater than the difference between 550 MW and the amount repowered by the May 1, 2003 deadline must be repowered by December 31, 2004. All remaining coal-fired generation at Gannon Station must be shutdown before January 1, 2005. All coal-related assets at Gannon Station, including coal-handling equipment, must be retired before that date. Units which are shutdown and placed on reserve standby will be available to Tampa Electric as future supply-side resource options via repowering to meet the growing demand and energy needs of its customers. The company does not currently have plans to utilize the units, but it may, at some time in the future, repower or convert the units to natural gas if those options prove to be cost-effective.

Engineering on the repowering project started in January 2000. The repowered Gannon Unit 5 is scheduled for commercial operation by May 1, 2003. The repowered Gannon Unit 6 is scheduled for commercial operation by May 1, 2004. When these two units are repowered, total station capacity will increase from about 1,200 MW to about 1,700 MW.

The Orders also require Tampa Electric to reduce SO_2, NO_X, and PM emissions at Big Bend and Gannon Stations and to meet specific time deadlines for required studies of NO_X removal technologies. The CFJ mandates that the company 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.

The types of additional environmental controls to be installed at Big Bend Station will be dependent upon the outcome of the various studies. Tampa Electric has begun some of these required evaluations but will provide the results and complete analyses of the most cost-effective compliance options to the DEP, EPA, and FPSC.

Over time, Tampa Electric has operated its electrical generating facilities in a 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.

As a general practice, 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, are 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 was required to 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 combustion turbines existing prior to Phase II implementation. 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 Stations, 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), Polk Unit 2 (combustion turbine), 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.

Title IV requires further reductions beyond 2010, and for the 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	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 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 with 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 and most cost-effective 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 were provided to the FPSC. By incorporating the results of previous studies and the successful operation of the Big Bend Units 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 Tampa Electric's system. The FGD system was installed on Big Bend Units 1 and 2 in December 1999 and is expected to reduce SO_2 emissions by approximately 70,000 tons per year. For Gannon Station, Tampa Electric plans to 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 expects Phase II Acid Rain Permits to be issued either in conjunction with Title V Operating Permits or separately.

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 Stations have been issued. DEP is expected to issue the Big Bend and Gannon Stations Title V permits by 2001. 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 used a computer model to determine SO_2 ambient air concentrations. Computer-modeled exceedances of the three-hour SO_2 ambient air quality standard were found. To address this, Tampa Electric investigated two alternatives for reducing SO_2 emissions from Gannon Station. The first alternative involved raising the stacks at Gannon Units 5 and 6 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.

In consideration of the short time span until Gannon Station is repowered, the DEP and Tampa Electric have agreed to an interim plan to mitigate impacts to ambient air quality. This plan involves the stepwise reduction of fuel sulfur content to 1.7 lb/mmBtu on a station wide basis in concert with the repowering of some of the Gannon units.

2.5 SO_2 Compliance Under the Orders

The SO_2 requirements of the Orders are more stringent than the Title IV requirements. Therefore, Tampa Electric must evaluate the most cost-effective manner in which to comply with these new requirements given Title IV solutions already in place. This involves the repowering of units or upgrade or improvement of the existing Title IV controls to increase reliability, improve efficiency, and lower SO_2 emission rates.

Tampa Electric is required by the Orders to repower or shutdown the units at the Gannon Station, to maximize FGD utilization for the Big Bend units, and to optimize FGD efficiency for the Big Bend Units 1 and 2 with a minimum of 95 percent removal. A schedule for reducing SO_2 emissions at Big Bend Station is outlined in the Consent Decree. The agreement requires that Big Bend Units 1 and 2 meet a 95 percent removal rate effective at the date of entry of the Consent Decree. The Consent Decree also restricts the amount of time the units may operate without a FGD system and the type of coal that may be used when the units' FGD system is not operating.

Another requirement of the Consent Decree is that the FGD system on Big Bend Units 3 and 4 must operate with a minimum 93 percent removal rate when both units are in operation, beginning upon the Consent Decree's date of entry. When Big Bend Unit 3 alone operates, SO_2 emissions are limited by the 93 percent removal rate or an emission rate of 0.35 lb/mmBtu. Big Bend Unit 3 is subject to restrictions on operations without the FGD system and on the type of coal burned when the FGD system is not being used. Effective May 1, 2002, the minimum removal rate is 95 percent (or an emission rate of 0.30 lb/mmBtu) when Big Bend Unit 3 operates alone. Big Bend Unit 3 must meet a minimum removal rate of 95 percent or an emission rate of 0.25 lb/mmBtu as of January 1, 2010. Beginning January 1, 2013 for Big Bend Units 1 and 2 and May 1, 2010 for Big Bend Unit 3, the units may not operate without a FGD system.

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. Under the Consent Decree, Tampa Electric submitted Phase I (of two phases) of its plan detailing how the company will maximize FGD system utilization at Big Bend Station to EPA on May 31, 2000. The FGD system utilization maximization plan must be implemented no later than 60 days after the EPA approves the plan.

The repowering of Gannon Station will dramatically reduce total emissions of SO_2 from this facility by replacing the coal-fired generation with natural gas-fired combined cycle units. Effective December 31, 2004, no coal-fired generation will remain in service at this facility.

The projects required by the Orders 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 decrease by approximately 87 percent as shown in Figure 7.1 below.

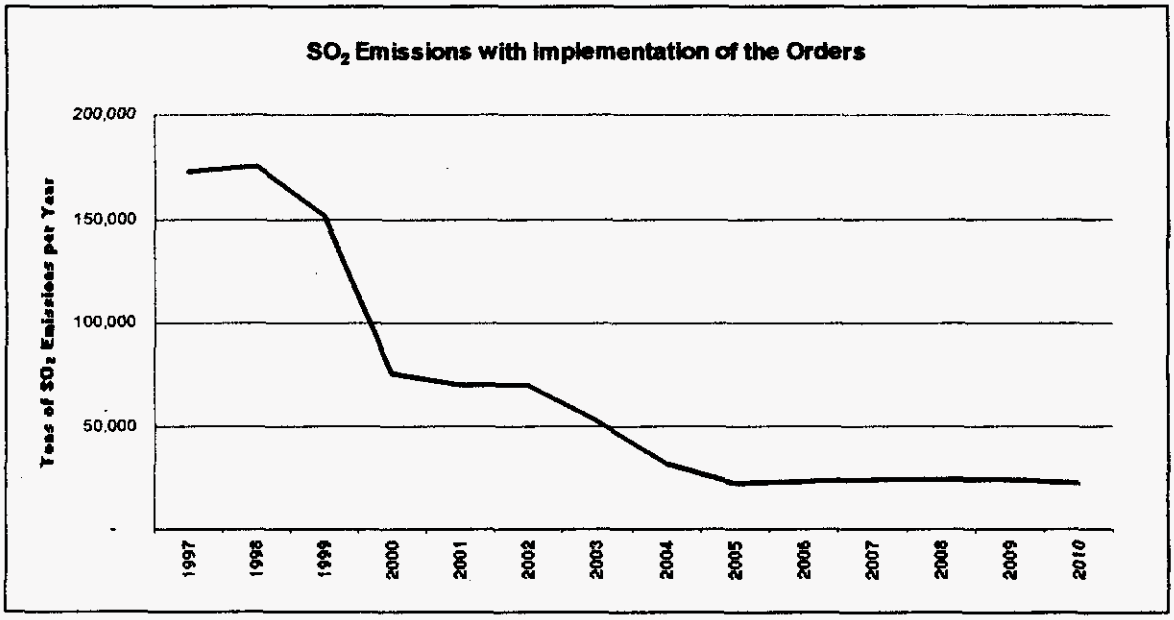

Figure 2.1: Estimated SO_2 Emissions with Implementation of the Orders

3. NO_X Compliance Plan

3.1 Overview of Compliance Requirements

The Acid Rain Program under Title IV of the CAAA requires a two million-ton reduction in annual 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 emission limitations 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 a 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. 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 wet bottom boilers on Big Bend Units 1, 2, and 3 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 is expected to 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 wet bottom 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 and cannot be provided by the original 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 DEP and 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.

If the system-wide averaging plan and combustion optimization cannot achieve the required NO_X reductions, Tampa Electric may, as deemed 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.

3.4 NO_X Compliance Under the Orders

The NO_X requirements of the Orders are more stringent than the Phase I & II Title IV requirements. Therefore, Tampa Electric must continue cost-effective reduction of NO_X through a range of NO_X control strategies.

Tampa Electric is required by the Orders to repower or shutdown the units at Gannon Station on or before December 31, 2004; shutdown, repower, or install NO_X controls on Big Bend Unit 4 by May 31, 2007; and shutdown, repower, or install NO_X controls on Big Bend Units 1, 2, and 3 by 2010. The Consent Decree requires that implementation of NO_X reduction at Big Bend Units 1, 2, and 3 occur by shutting down, repowering, or installing NO_X controls. The first unit must meet the required NO_X reductions by May 1, 2008. NO_X reduction measures must be in place at the second unit by May 1, 2009 and at the third unit by May 1, 2010. The intent of the Orders is that by 2010 all of the units at the Big Bend and Gannon Stations will meet BACT standards, as defined in the Consent Decree, for NO_X. The methodology of NO_X emission controls for these units has not been established at this time.

Completion of the repowering of Gannon Station will result in NO_X emissions reduction 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 "zero ammonia" NO_X control technology on a unit as part of the repowering process at Gannon Station. The installation of this technology is subject to the conditions that the technology is found to be commercially viable by the DEP and that the incremental capital cost differential above the cost of SCR is not greater than \$8 million. If these conditions are not met, 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 reduce the size or number of SCRs needed at Big Bend Station.

The Consent Decree requires that Tampa Electric spend between \$10 and \$11 million total project dollars on reducing NO_X emissions. This includes up to \$2 million for air chemistry work in Tampa Bay Estuary, up to \$3 million on combustion optimization techniques at Big Bend Units 1, 2, and 3 and an estimated \$5 to \$6 million for additional NO_X reductions project(s). The \$3 million expenditure to reduce emissions from Big Bend Station has the goal of reducing emissions from Big Bend Units 1 and 2 by 30 percent from 1998 levels and from Big Bend Unit 3 by 15 percent from 1998 levels. These measures comprise an 'early reduction' plan, which must be completed in 2002. Further NO_x reductions will be required should the company decide to maintain Big Bend Units 1, 2, and 3 as coal-fired units.

Project dollars required for additional NO_X reductions must be spent to demonstrate innovative NO_X control technologies on any of Tampa Electric's units or boilers at Gannon Station or Big Bend Station and/or to reduce the NO_X emission rate for any Big Bend coal-combustion unit below the lowest rate otherwise applicable under the Consent Decree. Thus, some or all of Tampa Electric's expenditures on innovative NO_X control technologies may be represented by the investment in "zero ammonia" technology required by the CFJ.

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 87 percent as shown in Figure 7.2 below.

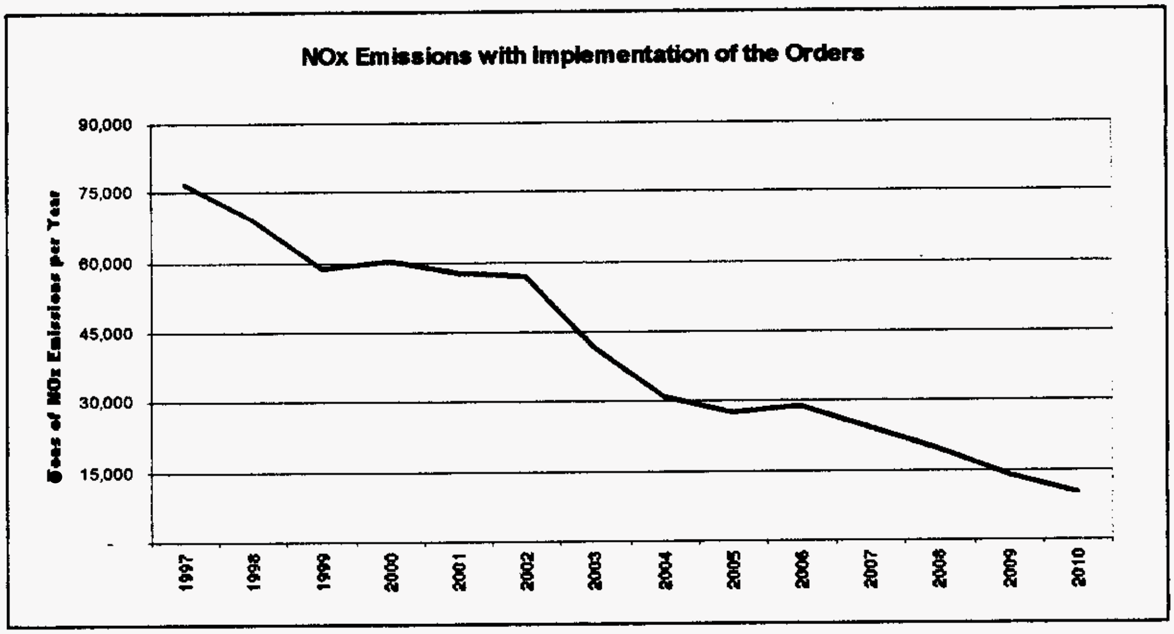

Figure 3.1: Estimated NOx Emissions with Implementation of the Orders

4. Particulate Matter Compliance Plan

4.1 Overview of Compliance Requirements

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 Station. The results of the study identified the operating ranges required for the ESP to function at optimum efficiency. These operating ranges may be incorporated into the permit by a date mutually agreed upon by DEP and Tampa Electric. The Orders require further reductions in PM emissions through a BACT analysis and best operation practices evaluation.

4.2 PM Compliance Under the Orders

In addition to repowering Gannon Station with natural gas, the CFJ stipulates that an ESP optimization study and BACT determination must be performed for each of the ESPs at Big Bend Station. The Consent Decree requires the ESP optimization study be submitted within 12 months after the date of entry of the Consent Decree and implemented within 60 days of the date the plan receives EPA approval. Also within 12 months of the Consent Decree's date of entry, Tampa Electric must submit a BACT analysis to EPA. Tampa Electric is required to implement the BACT analysis recommendations by May 1, 2004. Within six months of BACT implementation and no later than November 1, 2004, the ESP optimization plan must be revised to take into account the recommendations of the BACT analysis. Big Bend Station must then be operated in accordance with the EPA-approved revised ESP optimization plan 180 days after being approved. The results of these studies may identify operating practices or physical changes that may 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.

The Consent Decree requires Tampa Electric to install a PM CEM on the duct at Big Bend Station's Unit 4 by March 1, 2002. If Big Bend Unit 1, 2, or 3 is still fueled by coal after 2008 and the first PM CEM is still being operated, Tampa Electric must install a second PM CEM on another duct at Big Bend Station by May 1, 2007. Tampa Electric is currently evaluating the monitoring technologies available to comply with this requirement.

Significant PM emission reductions will be realized as a result of repowering Gannon Station. These emission reductions, in addition to PM emission reductions at Big Bend Station, will result in 2010 emission levels that are approximately 59 percent less than 1997 emission levels. Figure 7.3 below shows the effect of these reductions on system PM emissions.

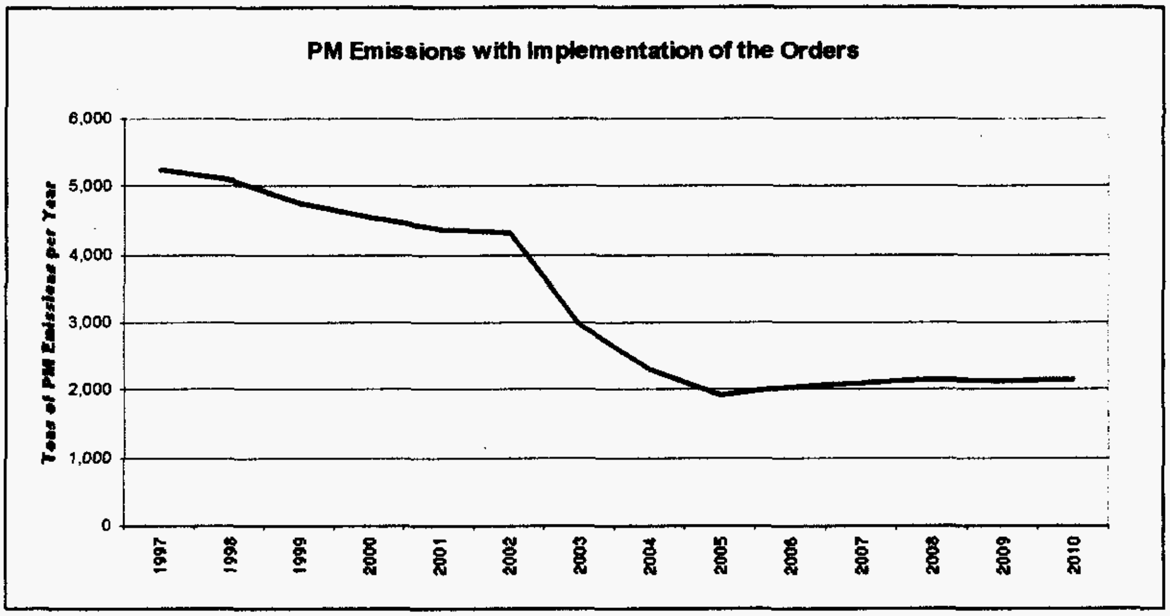

Figure 4.1: Estimated PM Emissions with Implementation of the Orders

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, and, 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 least 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 stations during 1999. Part I of the ICR requires 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 conducted fuel sampling and analysis for all coals at Big Bend, Gannon, and Polk Stations during 1999 and submitted 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. A testing platform was constructed on the Big Bend Unit 3 stack to facilitate completion of the required testing method. As required, the results of these stack tests were 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 Power Station 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, located 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 Stations 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 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 the firing of 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.

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. 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

As a general practice, Tampa Electric monitors and evaluates 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 Orders will address and mitigate potential requirements for the majority of these issues since the repowering of Gannon Station and the use of NO_X control technologies at Gannon and Big Bend Stations will significantly lower overall NO_X emissions.

Significant reductions in all pollutant emissions will be realized with the implementation of the Orders. 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. 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 for units that burn higher sulfur coal 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- and paper-derived fuels have been tested, and the company has received approval from DEP to burn these fuels on a regular basis. Wood- and paper-derived fuels have been used on a limited basis, and pet coke produced an estimated 255 GWh of net energy in 1999. Tampa Electric is seeking permits for additional units at Gannon Station to burn wood-derived fuel.

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. On June 19, 2000 Tampa Electric and FGT announced that they entered into a long-term firm natural gas transportation contract, under which FGT will provide 180 million cubic feet per day of additional capacity to serve the company's repowered Gannon Station. Under the Orders, 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.

8. Regulatory Compliance Dates and Costs

The CAAA have established many new requirements, which affect Tampa Electric's environmental compliance plans. Table 8.1 lists some of the key CAAA Phase I, Phase II, and Orders requirements that specifically impact Tampa Electric's compliance strategy. Table 8.2 provides a summary of the project costs that have been undertaken to date by Tampa Electric.

Table 8.1

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 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 Hookers Point Boilers 1-6 Polk IGCC 1 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 Big Bend 1-4	January 1, 2000
Complete Mercury ICR including coal and stack testing	Section 114	Big Bend Station Gannon Station Polk Power Station	December 1999
Install PM monitor	Consent Decree	Big Bend 4	March 1, 2002
Optimize FGD availability	Orders	Big Bend 1-4	60 days after EPA approval of plan
Perform ESP optimization study and submit plan	Orders	Big Bend Station	12 months after Consent Decree Date of Entry
Implement ESP optimization plan	Orders	Big Bend Station	60 days after EPA approves plan
Perform BACT analysis	Orders	Big Bend Station	12 months after Consent Decree Date of Entry
Implement BACT analysis recommendations	Orders	Big Bend Station	May 1, 2004

Table 8.1 (cont.)

REGULATORY COMPLIANCE DATES (cont.)			
Regulatory Compliance Requirement	**Applicable Regulation**	**Affected Units**	**Compliance Date**
Revise ESP optimization study to account for BACT analysis	Consent Decree	Big Bend Station	6 months after BACT implementation but no later than November 1, 2004
Implement revised ESP optimization plan	Consent Decree	Big Bend Station	180 days after EPA approval
Install second PM monitor if necessary	Consent Decree	Big Bend 1, 2 or 3	May 1, 2007
Complete phase-in natural gas units	Orders	Gannon Station	May 2004
Submit plan for early reductions of NO_x emissions	Consent Decree	Big Bend 1-3	December 31, 2001
Implement NO_x reduction plan	Consent Decree	Big Bend 1-3	December 31, 2002
Submit report documenting implementation	Consent Decree	Big Bend 1-3	April 1, 2003
Implement NO_x control methodology and installation if units remain coal-fired	Orders	Big Bend 4 Big Bend 1-3 First Unit Second Unit Third Unit	May 2007 May 1, 2008 May 1, 2009 May 1, 2010

Table 8.2

INSTALLATION DATES AND COSTS			
Project	**Installation Date**	**Affected Units**	**Capital Project Costs (Millions)**
Phase I CEMS installation	November 1993	Big Bend 1-3	$2.612
Flue Gas Conditioning System	December 1993	Big Bend 1 Big Bend 2 Big Bend 3	$2.676 $2.342 $2.595
Phase II CEMS installation	November 1994	Big Bend 4 Gannon 1-6 Hookers Point Boilers 1-6	$0.866 $3.939 $1.473
BB3 FGD Integration	June 1995	Big Bend 3	$8.559
BB 1 & 2 FGD	December 1999	Big Bend 4	$83.181
Mercury Testing	December 1999	Big Bend Station Gannon Station Polk Power Station	$0.121
Classifier Replacement for Phase II NO_x compliance	December 1998 May 1998 December 1997 July 1999	Big Bend 1 Big Bend 2 Gannon 5 Gannon 6	$1.316 $0.985 $1.357 $1.418
Coal field Crusher for Phase II NO_x compliance	June 1999	Gannon Station	$5.227
BB FGD Optimization	Consent Decree Date of Entry	Big Bend 1, 2 and 3	$12.400
ESP Optimization Study & BACT Analysis / *Implement study recommendations*	Within 12 months of Consent Decree Date of Entry / 60 days after EPA approval	Big Bend Station	$0.500
NO_x Emission Reductions	Consent Decree by December 31, 2002	Big Bend 1, 2, 3	$3.000