AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

ORIGINAL
040750-EI

JUL 15 PM 3:43
COMMISSION CLERK
RECEIVED-FPSC

July 15, 2004

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Petition of Tampa Electric Company for approval of new environmental programs for cost recovery through the Environmental Cost Recovery Clause

Dear Ms. Bayo:

Enclosed for filing in the above styled matter are the original and fifteen (15) copies of Tampa Electric Company's Petition for Approval of New Environmental Programs for Cost Recovery Through the Environmental Cost Recovery Clause.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
07700 JUL 15 δ
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Tampa Electric Company for approval of new environmental programs for cost recovery through the Environmental Cost Recovery Clause.	))))	 DOCKET NO. 040750-EI FILED: July 15, 2004

PETITION OF TAMPA ELECTRIC COMPANY FOR APPROVAL OF NEW ENVIRONMENTAL PROGRAMS FOR COST RECOVERY THROUGH THE ENVIRONMENTAL COST RECOVERY CLAUSE

Tampa Electric Company ("Tampa Electric" or "the company"), by and through its undersigned counsel, and pursuant to Section 366.8255, Florida Statutes, and Florida Public Service Commission ("Commission") Order Nos. PSC-94-0044-FOF-EI and PSC-94-1207-FOF-EI, hereby petitions this Commission for approval of four new environmental compliance programs – Big Bend Unit 4 Selective Catalytic Reduction ("SCR"), Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR – for cost recovery through the Environmental Cost Recovery Clause ("ECRC"). In support thereof the company says:

1. Tampa Electric is an investor-owned electric utility subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes. Tampa Electric serves retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The company's principal offices are located at 702 North Franklin Street, Tampa, Florida 33602.

2. The persons to whom all notices and other documents should be sent in connection with this docket are:

Lee L. Willis
James D. Beasley
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115
(850) 222-7952 (fax)

Angela Llewellyn
Administrator, Regulatory Coordination
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601
(813) 228-1752
(813) 228-1770 (fax)

3. On December 16, 1999 Tampa Electric and the Florida Department of Environmental Protection ("DEP") entered into a Consent Final Judgment ("CFJ"). On February 29, 2000 the United States Environmental Protection Agency ("EPA") initiated a Consent Decree ("CD") with Tampa Electric in the Federal District Court. Both the CFJ and the CD ("Orders") embody the resolutions between the agencies and Tampa Electric stemming from disputed issues surrounding Tampa Electric's maintenance practices to its Big Bend and Gannon Stations that were alleged to be in violation of the EPA's New Source Review rules and New Source Performance Standards currently codified in Title I of the Clean Air Act Amendments of 1990. The Orders have been previously provided to the Commission in Tampa Electric's petition filed in Docket No. 000685-EI.

4. Section V.E. of the CFJ states:

> "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 [Selective Catalytic Reduction systems] or similar nitrogen oxide controls are installed, BACT [Best Available Control Technology] for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3."

This establishes the long-term nitrogen oxides ["NO_x"] reduction target for Big Bend Station determined by the DEP.

5. Paragraphs 33 and 36 of the CD require Tampa Electric to declare in writing whether the Big Bend Station units shall continue combustion of coal, repower or shutdown. These declaration dates are May 1, 2005 and May 1, 2007 for Big Bend Unit 4 and Big Bend Units 1 through 3, respectively.

6. Paragraph 34.A of the CD states:

> "If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other approved technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lbs/mmBTU."

7. Paragraphs 37.A-E of the CD and a related amendment discuss the NO_x emission rates and cost requirements for Big Bend Units 1 through 3. Paragraph 37.B discusses the cost indexing to be used to obtain an emission rate of 0.10 lbs/mmBtu, the specifics of which state:

> "Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lbs/mmBTU if the "installation cost ceiling" contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1,2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4."

8. Paragraphs 37.C and D of the CD discuss the required NO_x emission rates if the costs for the SCR systems exceed the "installation cost ceiling." The salient portions of these paragraphs state:

> "If, based on the contract proposals, Tampa Electric determines that the project cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and provide EPA with the basis for Tampa Electric's determination...."

and,

> "Notwithstanding any provision of this Consent Decree, including the "installation cost ceiling," Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lbs/mmBTU."

9. In summary, Tampa Electric is required to meet a maximum NO_x emission rate of 0.15 lbs/mmBtu for Big Bend Units 1 through 3 regardless of any installation cost ceiling, or must achieve an emission rate of 0.10 lbs/mmBtu if the SCR system cost is within the Big Bend Unit 4 "installation cost ceiling." The compliance dates for these units are May 1, 2008 for the first unit, May 1, 2009 for the second unit, and May 1, 2010 for the last unit selected by Tampa Electric to be retrofitted with an SCR system.

10. In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. Attached as Exhibit A is a document entitled The Big Bend Technology Assessment Study and NO_x Compliance Plan ("Study"), which contains the results of the evaluation performed by Tampa Electric and Sargent and Lundy. The Study evaluated the options of: 1) remaining coal-fired, 2) repowering the facility, or 3) shutting down the station and replacing it with new generation. The results of the Study clearly indicate that the option to remain coal-fired at Big Bend Station is the most cost-effective alternative to satisfy the NO_x emissions reductions required by the Orders. This option will require Tampa Electric to install SCR reduction technologies to meet future NO_x emission rates.

11. This Petition seeks approval of recovery through the ECRC of the costs associated with the projects identified in the Study as necessary to begin to cost-effectively meet the NO_x emissions requirements of the Orders, namely, Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. The Big Bend Unit 4 SCR project encompasses the design, procurement, installation and annual operation and maintenance ("O&M") expenses associated with an SCR system for the unit. The Pre-SCR Big Bend Units 1

through 3 projects are necessary for the installation of pre-SRC technologies that are cost-effective precursors to SCR systems. These pre-SCR technologies include a neural network system, secondary air controls and windbox modifications to Big Bend Unit 1; secondary air controls and windbox modifications to Big Bend Unit 2; and a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls on Big Bend Unit 3. The purpose of the pre-SCR technologies on Big Bend Units 1 through 3 is to reduce inlet NO_x concentrations to the SCR systems thereby mitigating overall capital and O&M costs. The installation of these pre-SCR technologies is accepted throughout the industry as the more prudent decision over simply installing larger SCR systems. Tampa Electric will ultimately file for ECRC approval of the recovery of expenditures on each individual SCR system for Big Bend Units 1 through 3 as separate projects and in a timely manner so as to meet the requirements of the Orders.

Qualifications and Estimated Expenditures for ECRC Recovery

12. Tampa Electric will incur costs for the Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR programs in order to meet the compliance requirements specified in the Orders. The new programs meet the criteria established by this Commission in Docket No. 930613-EI, Order No. PSC-94-0044-FOF-EI in that:

(a) all expenditures will be prudently incurred after April 13 1993;

(b) the activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and

(c) none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

13. The costs for which Tampa Electric is seeking ECRC recovery are for the capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance of the four programs. The expenditure projections for Big Bend Unit 4 SCR are $65,350,000 for capital costs and $2,505,000 annually for O&M expenses. The expenditure projections for Big Bend Unit 1 Pre-SCR are $2,135,000 for capital costs and $75,000 annually for O&M expenses. The expenditure projections for Big Bend Unit 2 Pre-SCR are $1,585,000 for capital costs and $40,000 annually for O&M expenses. The expenditure projections for Big Bend Unit 3 Pre-SCR are $2,635,000 for capital costs and $125,000 annually for O&M expenses. The annual O&M estimates are for the first full year of service and may increase over time as the equipment ages. Exhibit B to this Petition details both the capital and O&M expenditures associated with the programs.

14. Tampa Electric expects to begin incurring costs associated with these programs in July 2004. Tampa Electric is not requesting a change in its ECRC factors that have been approved for calendar year 2004. Instead, the company proposes to include in its true up filing for 2004 all program costs incurred subsequent to the filing of this Petition through the end of 2004. The company would then include program costs projected for 2005 and beyond in the appropriate projection filing. All of this would be subject to audit by the Commission.

15. These programs are compliance activities associated with requirements of the Clean Air Act Amendments; therefore, expenditures should be allocated to rate classes on an energy basis.

16. Tampa Electric is not aware of any disputed issues of material fact relative to the matters set forth in this Petition.

WHEREFORE, Tampa Electric respectfully requests the Commission to approve the company's proposed Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR programs and recovery of the costs of these programs through the ECRC in the manner described herein.

DATED this 15th day of July 2004.

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

Tampa Electric Company

Exhibit A

Big Bend Technology Assessment Study

and

NO_x Compliance Plan

TAMPA ELECTRIC COMPANY

Big Bend Technology Assessment Study

and

NO_x Compliance Plan

EXECUTIVE SUMMARY

On December 16, 1999 Tampa Electric and the Florida Department of Environmental Protection entered into a Consent Final Judgment ("CFJ"). On February 29, 2000 the United States Environmental Protection Agency ("EPA") initiated a Consent Decree ("CD") with Tampa Electric in the federal district court. Both the CFJ and the CD ("Orders") embody the resolutions between the agencies and Tampa Electric stemming from disputed issues surrounding Tampa Electric's maintenance practices to its Big Bend and Gannon Stations that were alleged to be in violation of EPA's New Source Review rules and New Source Performance Standards, codified in Title I of the Clean Air Act Amendments of 1990.

The Orders required Tampa Electric to determine long-range plans for the generating units at Big Bend Station to meet nitrous oxides ("NO_x") emission rates by specific dates. To make this determination Tampa Electric contracted with an experienced consulting firm, Sargent and Lundy, and with their assistance performed a comprehensive study, known herein as the Big Bend Technology Assessment Study ("Study"). The Study evaluated the options of: 1) remaining coal-fired, 2) repowering the facility, or 3) shutting down the station and replacing it with new generation. Tampa Electric attempted to identify and investigate all known environmental, operational and technical aspects associated with each of the required scenarios. After the data was collected, Tampa Electric modeled each option to determine which scenario would provide the best alternative for meeting the emission requirements.

The results of the Study clearly indicated that the remaining coal-fired option is the most cost-effective means to accomplish the required emissions reductions at Big Bend Station. This option will require Tampa Electric to install selective catalytic reduction ("SCR") or other approved technologies to meet future NO_x emission rates. The NO_x emission rates established by the Orders are 0.10 lbs/mmBtu and 0.10 to 0.15 lbs/mmBtu for Big Bend Unit 4 and Big Bend Units 1 through 3, respectively, based upon cost indices which were benchmarked against the cost of the Big Bend Unit 4 SCR system. Big Bend Unit 4 must comply with its new NO_x emission rate by June 1, 2007 while units 1 through 3 must be subsequently compliant by May 1, of 2008, 2009 and 2010.

In conjunction with the Study, Tampa Electric developed a NO_x compliance strategy that includes various pre-SCR technologies and determined that SO_3 control systems will be required. The pre-SCR technologies are cost-effective precursors to SCR systems since they mitigate capital and operation and maintenance costs by reducing the inlet NO_x concentrations to the SCR systems. These pre-SCR technologies include the use of neural networks combustion optimization systems, primary air and coal flow control systems, windbox modifications and secondary air control systems. The SO_3 control systems are necessary due to increased levels of SO_3 generated from the catalyst used in the SCR systems. Increased SO_3 creates the potential for violating visible emission regulations.

The work is currently scheduled to commence in July 2004 with the primarily focus being the NO_x compliance for Big Bend Unit 4. Certain pre-SCR work for units 1 through 3 will also be initiated. The total cost of NO_x compliance for the Big Bend Station has been estimated to be $305,450,000. The portion attributable to Big Bend Unit 4 is estimated to be $65,350,000. For 2004, Tampa Electric expects to spend $5,091,000 of which $3,576,000 is for Big Bend Unit 4. The balance of $1,515,000 shall be used for pre-SCR projects.

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Tampa Electric's System

Tampa Electric is an investor-owned electric utility serving over 600,000 customers in west central Florida. Tampa Electric's service territory encompasses Hillsborough County and portions of Polk, Pinellas and Pasco Counties. For summer 2004, Tampa Electric is projecting a firm retail load of approximately 3,685 MW, while maintaining a net electric generating capacity of 4,038 MW located at four different sites: Big Bend Station, H.L. Culbreath Bayside Power Station, Phillips Station, and Polk Power Station.

Historically, coal has been the primary fuel for a significant portion of Tampa Electric's generating system. The Big Bend Station has four pulverized coal units, while the Polk Integrated Gasification Combined Cycle ("IGCC") facility is fired with a synthetic gas produced from gasified coal and other carbonaceous solid fuels. Tampa Electric's other large coal-fired facility, Gannon Station, was repowered as the H.L. Culbreath Bayside Power Station with natural gas-fired combined cycle technology in early 2004. Current 2004 projections for the system's net generation was 39 percent natural gas, 55 percent provided by coal, and the balance with petroleum coke, oil, renewable and purchased power agreements.

1.2 Overview of Regulatory Requirements

On December 16, 1999 Tampa Electric and the Florida Department of Environmental Protection entered into a Consent Final Judgment ("CFJ"). On February 29, 2000 the United States Environmental Protection Agency ("EPA") initiated a Consent Decree ("CD") with Tampa Electric in the federal district court. Both the CFJ and CD ("Orders") embody the resolutions between the agencies and Tampa Electric stemming from disputed issues surrounding Tampa Electric's maintenance practices to its Big Bend and Gannon Stations that were alleged to be in violation of EPA's New Source Review rules and New Source Performance Standards, currently codified in Title I of the Clean Air Act Amendments of 1990. Pertinent portions of those agreements are listed below.

Paragraphs 33 and 36 of the CD require Tampa Electric to declare in writing whether the Big Bend Station units shall continue combustion of coal, repower or shutdown. These declaration dates are May 1, 2005 and May 1, 2007 for Big Bend Unit 4 and Big Bend Units 1 through 3, respectively.

Paragraph 34.A states,

> "If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of [selective catalytic reduction ("SCR")], or other approved technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of [nitrous oxides ("NO_x")] from Unit 4 to no more than 0.10 lbs/mmBtu."

Paragraphs 37.A-E of the CD and a related amendment discuss the NO_x emission rates and cost requirements for Big Bend Units 1 through 3. Paragraph 37.B discusses the cost indexing to be used to obtain an emission rate of 0.10 lbs/mmBtu, the specifics of which state,

> "...Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lbs/mmBtu if the "installation cost ceiling" contained in this Paragraph will be exceeded

by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1,2 and 3 shall be three times the cost of installing SCR at Big Bend plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4."

The design basis for the Big Bend Unit 4 SCR is further defined in the Amendment to the CD which states,

> "In calculating the "installation cost ceiling" all references to "installing SCR at Big Bend Unit 4" are to one which would maintain a NO_x removal efficiency of no less than seventy-five percent, and thus would have produced a NO_x Emission Rate no greater than 0.10 lbs/mmBtu at Big Bend Unit 4, based on that Unit's 1998 configuration and emissions."

Paragraphs 37.C and D discuss the required NO_x emission rates if the costs for the SCR systems exceed the "installation cost ceiling." The salient portions of these paragraphs state,

> "If, based on the contract proposals, Tampa Electric determines that the project cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and provide EPA with the basis for Tampa Electric's determination…."

and,

> "…Notwithstanding any provision of this Consent Decree, including the "installation cost ceiling," Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lbs/mmBtu."

In summary, Tampa Electric is required to meet a maximum NO_x emission rate of 0.15 lbs/mmBtu for Big Bend Units 1 through 3 regardless of any installation cost ceiling, or must achieve an emission rate of 0.10 lbs/mmBtu if the SCR system cost is within the Big Bend Unit 4 "installation cost ceiling." The compliance dates for these units are May 1, 2008 for the first unit, May 1, 2009 for the second unit, and May 1, 2010 for the last unit selected by Tampa Electric to be retrofitted with an SCR system.

1.3 Overview of Tampa Electric's Big Bend Technology Assessment Study

To evaluate the best approach to comply with the Orders, Tampa Electric, with the assistance of Sargent and Lundy, performed the Big Bend Technology Assessment Study ("Study") that considered all the requirements of the Orders and future capital and operation and maintenance ("O&M") expenses. The Study addressed three main options:

- Remain coal-fired and install NO_x compliance strategies to meet the CD rates;
- Repowering the facility; or
- Shutdown the facility and replace the lost generation at a greenfield site.

For the remain coal-fired option the new NO_x emission rates identified within the Orders along with SO_3 were investigated and cost estimates developed. Other cost data from prior work efforts for other known and potential environmental regulatory requirements were also used as inputs to the Study. Heat rate, reliability and fuel forecasting were also included in the Study. Each option took into account affects to Tampa Electric's generation expansion plan.

Specific to NO_x compliance for the remain coal-fired option, Tampa Electric developed a layered approach to achieve the required NO_x emission rates for the Big Bend units. This approach included both pre-SCR and SCR technologies to ensure reliable compliance. The evaluation of pre-SCR technologies was primarily based upon the company's experience with NO_x emissions control equipment utilized for the early NO_x reduction requirements of the Orders. These technologies, when used as a precursor to SCR installations, will reduce the overall cost of NO_x emission abatement strategies by decreasing the cost of an SCR by a greater amount than the cost of the pre-SCR technologies. Simply stated, these pre-SCR NO_x emission control technologies will provide cost-effective reductions as compared to the incremental capital and O&M costs of an SCR system alone.

The repowering options evaluated in the Study included reboilering with subcritical pulverized coal ("PC") boilers, circulating fluidized bed ("CFB") boilers, conversion of the existing boilers to natural gas, combined cycle ("CC") gas turbine technology and IGCC similar to the Polk facility.

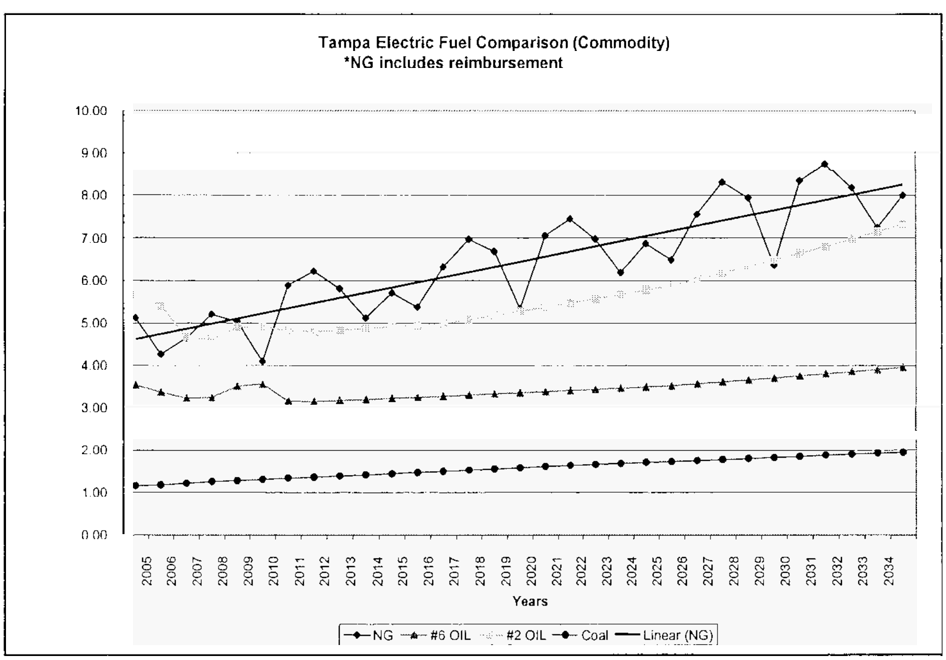
The greenfield options evaluated in the Study included all the foregoing repowering technologies with the exceptions that new PC boilers would be supercritical, and natural gas fired Rankin cycle units would not be evaluated due to lower cycle heat rates.

2.0 ASSUMPTIONS

2.1 System Assumptions

Several assumptions were used to develop the financial and operational projections to determine the most prudent NO_x compliance strategy for the Study.

Fuel commodity price forecasting was performed by using an analysis of historical and current price forecasts obtained by various consultants and agencies. Sources included the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Daily, Energy Ventures Analysis, Inc., and various coal, oil, natural gas and propane pricing publications and periodicals such as Inside FERC, Natural Gas Week and Platt's Oilgram. Additionally, NYMEX forward pricing curves were utilized in conjunction with the fundamental forecasts to derive the final forecast. The following chart shows the fuel prices, excluding fixed transportation components, used in the Study:



Other assumptions used by Tampa Electric included unit operating characteristics for the existing facility, plant balance sheet information used to derive accelerated depreciation schedules for various early retirement cases and environmental assumptions.

2.2 Economic and Financial Assumptions

The economic and financial assumptions used to determine the present worth revenue requirements associated with the Study are provided below:

- Inflation 2.50%
- Income Tax Rate 38.58%
- Other Tax Rate 3.00%
- Debt Ratio 41.30%
- Equity Ratio 58.70%
- Debt Rate 7.50%
- Equity Rate 12.75%
- Discount Rate 9.39%
- AFUDC Rate 7.79%

2.3 Big Bend Technology Assessment Study Assumptions

2.3.1 Remain Coal-Fired

It was assumed that all units would have a maximum life of 50 years and would be shutdown or repowered at that time.

Other remain coal-fired assumptions included:

- The maximum dependable capacity, availability and heat rate of the units would degrade over time due to normal aging.

2.3.1.1 NO_x Control for Remaining Coal-Fired

Tampa Electric used the Orders as the basis for developing the technical and financial alternatives for NO_x compliance in the remain coal-fired option. The Orders identified the NO_x emission rates and the dates by which those rates must be achieved. Primary assumptions included:

- Outlet NO_x rates – Preliminary conceptual designs and their associated costs were developed based upon an SCR outlet emission rate of 0.10 lbs/mmBtu for all the Big Bend units.
- Inlet NO_x rates – Inlet rates after the completed pre-SCR work were assumed to be 0.28 lbs/mmBtu for Big Bend Unit 4, 0.48 lbs/mmBtu for Big Bend Unit 3, and 0.60 lbs/mmBtu for Big Bend Units 1 and 2.
- Calculation of NO_x emission rates – NO_x was to be calculated and reported on a 30-day rolling average for each unit.
- NO_x trading – Pursuant to the requirements of the Orders, Tampa Electric was not permitted to buy, sell or otherwise distribute NO_x credits or allowances in its system or market them to other utilities. NO_x emissions rates were to be obtained on a per unit basis and no

station averaging scheme was permitted.

- Compliance dates – The Orders set June 1, 2007 as the compliance date for Big Bend Unit 4. The compliance dates for Big Bend Units 1 through 3 were not firmly set within the Orders, but rather generically labeled by May 1, 2008 for the first, by May 1, 2009 for the second and by May 1, 2010 for the third unit. Tampa Electric has assumed the following dates for each unit; by May 1, 2008 for Big Bend Unit 3, by May 1, 2009 for Big Bend Unit 2, and by May 1, 2010 for Big Bend Unit 1.
- NO_x technology transfer – As required by the Orders, Tampa Electric was required to implement an early NO_x reduction program whereby various technologies were employed on the Big Bend Units 1 through 3 to achieve NO_x reduction targets. Based upon the NO_x reduction effectiveness of those demonstrated technologies, Tampa Electric assumed that it will realize similar NO_x reductions through the implementation of selected technologies on the other Big Bend units.
- Fuels – Tampa Electric assumed that it would use the same or similar fuels and blends that are currently permitted at Big Bend Station, which included bituminous coal and petroleum coke.
- SCR NO_x system design - The design and materials used for the system would allow for non-restrictive supply of equipment. This would ensure implementation of a cost-effective solution and allow Tampa Electric to obtain future materials, reagents and parts from a broad spectrum of the market.

2.3.2 Repowering

In developing the estimates, it was assumed that repowered units would provide the same or similar total station generating capacity as the existing station.

Other repowering assumptions included:

- The availability of the units would degrade over time due to normal aging.
- Repowered units would be required to meet all Best Available Control Technology ("BACT") emission rates for regulated air pollutants. Consideration was also given to forthcoming air pollution requirements.
- Construction schedules would be sufficiently aggressive to meet the unit shutdown deadlines identified in the Orders. Extensive transitional purchase power requirements would be needed for some options.

2.3.3 Greenfield

In developing the estimates for the greenfield options, it was assumed that a suitable site complete with necessary resources could be obtained and permitted for each of the technologies. The plant generating capacity would be approximately 1,800 MW.

Other greenfield assumptions included:

- The site would be inland and in Florida.

- Condenser and balance of plant cooling would be provided by a cooling pond built on site. An abandoned phosphate mining area or a similar area would be procured for the plant.
- New plants would be required to meet BACT emission rates for regulated air pollutants. Consideration was also given to forthcoming air pollution requirements.
- A 27 month duration was assumed for site selection. This task could take significantly longer.
- Transmission lines would be permitted and included in the assumption.

3.0 METHODOLOGY

Tampa Electric commissioned the Study with the support of a consultant, Sargent and Lundy, to investigate various options available for the Big Bend facility. Tampa Electric conducted a survey of the market to determine what technologies were commercially available and viable for the Study. Each option considered capital costs, scheduling, compatibility with the existing equipment, fuel sources, emissions requirements, generation forecast and O&M costs. The options were then ranked relative to cost. The Study included:

Remain Coal-Fired

- Big Bend station current configuration with the addition of SCR systems and other pre-SCR NO_x reduction technologies.

Repowering Big Bend

- Natural Gas Combined Cycle
- Integrated Gasification Combined Cycle
- Subcritical Atmospheric Circulating Fluidized Bed Boilers
- Subcritical Pulverized Coal Boilers
- Natural Gas Conversion of Existing Boilers

Greenfield

- Natural Gas Combined Cycle
- Integrated Gasification Combined Cycle
- Subcritical Atmospheric Circulating Fluidized Bed Boilers
- Supercritical Pulverized Coal Boilers

3.1 Remain Coal-Fired

For the remain coal-fired option, a wide range of issues were included. Tampa Electric considered ways to achieve compliance with the Orders and as previously noted, utilized cost data from prior work efforts for other known and potential environmental regulatory requirements. The Study also evaluated and included the capital and O&M requirements due to the affects of aging. The station configuration consists of three Riley Turbo wet bottom units, and one Combustion Engineering ("CE") tangentially fired unit.

3.1.1 NO_x Compliance for Remain Coal-Fired

In regard to the remain coal-fired option, a detailed engineering analysis was performed to evaluate NO_x emission control strategies which would provide the lowest overall cost of compliance. This included SCR and pre-SCR technologies. Detailed descriptions of these technologies are provided in Appendices II and III.

On units with high initial NO_x emission rates, industry practice is to obtain the maximum amount of NO_x emission reductions through more cost-effective combustion modifications and then remove the balance of NO_x with the higher cost post-combustion control methods. This strategy is more economical than using a larger post-combustion system to treat higher baseline emissions. The following technologies were included in the evaluation:

- Low NO_x Burners ("LNB")
- Overfire Air Systems ("OFA")
- Underfire Air ("WIR")

- Neural Networks ("NN")
- Reburning
- Lean-Gas Reburning
- Selective Non-Catalytic Reduction ("SNCR")
- NO_xSTAR
- LoTOx
- Fuel Switching
- Water Cannons
- Coal/Air Control

The factors used to determine if a technology was suitable for the NO_x compliance strategy included:

- NO_x emission reduction potential – A determination of whether or not the technology by itself or in conjunction with other technologies could provide significant reductions.
- Cost-effectiveness – A comparison of the capital and O&M expense of the pre-SCR technology against the savings in SCR capital and O&M through the reduction in inlet NO_x to the SCR.
- Reliability of the system – This addressed the issue of the technology having a proven record in the industry whereby stable and sustained NO_x emissions can be obtained.
- Compatibility with SCR – The system and its by-products must be benign to the operation of an SCR system.
- Avoid adverse environmental impacts – The technology should avoid, where feasible, triggering other known or potential future environmental regulatory requirements.

There are various pre-SCR technologies claiming to have the ability to provide substantial reductions. However, no suppliers were willing to provide:

- Guarantees to meet the requirements of the Orders.
- Cost-effectiveness as compared to an SCR system.
- Demonstrated proven performance of Tampa Electric's required NO_x reductions from previously installed applications, either as a stand-alone technology or layered with other pre-SCR technologies.

3.2 Repowering Configurations

The Study looked at all potentially viable options for repowering Big Bend Station. The repowering configurations evaluated were limited to those that were commercially proven and were in the size range of the existing Big Bend units. For example, CFB technology has not been proven in the 450 MW size. Therefore, two 225 MW units were studied. Experimental technologies and cycle configurations were not evaluated. The repowering configurations were planned to approximate the generating capacity of the existing station. The most economically and technically viable fuel choices were used for each of the repowering configurations. A summary of each technology is provided below, while a complete description is provided in Appendix I.

<u>Natural Gas Combined Cycle</u>

This scope assumed the shutdown of Big Bend Units 1 and 2 and repowering Big Bend Units 3 and 4 with two 4x4x1 natural gas fired combined cycle units powered by General Electric Frame 7FA combustion turbines.

Integrated Gasification Combined Cycle

This scope assumed the shutdown of Big Bend Units 1 and 2 and repowering of Big Bend Units 3 and 4 with two 3x3x1 IGCC units powered by General Electric Frame 7FA+e (or Advanced IGCC) combustion turbines. The gasifiers were assumed to be the Texaco radiant-type. The gasifiers would convert 100 percent petroleum coke into syngas. The combustion turbines would fire syngas only without duct firing.

Subcritical Circulating Fluidized Bed Boilers

This scope assumed the repowering of Big Bend Units 1 through 3 with three 2x1 CFB boilers each nominally rated for 450 MW. The anticipated fuels for this option were 15 percent coal and 85 percent petroleum coke.

Subcritical Pulverized Coal Boiler

The scope assumed the replacement of Big Bend Units 1 through 3 boilers with three subcritical PC boilers each nominally rated for 450 MW. The anticipated fuels for this option were 80 percent coal and 20 percent petroleum coke.

Natural Gas Conversion

This scope assumed converting Big Bend Units 1 through 4 from coal to gas fired. This would include gas burners, windboxes, ducts, boiler modifications, combustion air supply changes, instruments and valves for controlling the flow of natural gas, and safety valves to meet National Fire Protection Association ("NFPA") requirements.

3.3 Greenfield Configurations

For the shutdown option, Tampa Electric developed estimates for replacing the Big Bend Station capacity at a greenfield site. The greenfield options were based upon using coal or natural gas fueled technologies and retiring Big Bend Station. For the natural gas fueled technology, a combined cycle design was selected. For the coal technologies, an integrated gasification combined cycle, a subcritical atmospheric circulating fluidized bed boiler design and a super-critical pulverized coal boiler design were evaluated. A summary of each technology is provided below, while a complete description is provided in Appendix I.

Natural Gas Combined Cycle

This scope assumed four 2x2x1 natural gas fired combined cycle configurations powered by General Electric Frame 7FA combustion turbines.

Integrated Gasification Combined Cycle

This scope assumed three 2x2x1 IGCC configurations powered by General Electric Frame 7FA+e (or Advanced IGCC) combustion turbines. The gasifiers were assumed to be the Texaco radiant-type. The gasifiers would convert 100 percent petroleum coke into syngas. The combustion turbines would fire syngas only without duct firing.

Subcritical Atmospheric Circulating Fluidized Bed Boiler

This scope assumed four 2x1 CFB boilers each nominally rated for 450 MW.

The anticipated fuels for this option were 15 percent coal and 85 percent petroleum coke.

Supercritical Pulverized Coal Boiler

This scope assumed included three 600 MW supercritical PC boilers. The anticipated fuels for this option were 80 percent coal and 20 percent petroleum coke.

3.4 Environmental Factors

The Orders required Tampa Electric to address three primary air pollutants, particulate matter ("PM"), SO_2 and NO_x. Accordingly, these were evaluated as part of the Study inclusive of technical feasibility and cost development. Tampa Electric included the investigation of SO_3 control as part of the Study because a byproduct of an SCR installation is a potential increase in SO_3 emissions. The results from prior work studies for various other known and potential environmental regulatory requirements were included as inputs into the Study. The following provides a summary level description of the environmental issues.

Particulate Matter

The remain coal-fired option for mitigating PM emissions was evaluated using a modified BACT analysis and Best Operating Practices ("BOP") as required by the Orders. The results of these studies were submitted to and approved by the EPA. The costs for outstanding work associated with the BACT and BOP have been included in the Study.

The control of PM for all PC and CFB generating technologies in the repowering and greenfield options was assumed to be accomplished using fabric filter control technologies. The IGCC technology for both the repowering and greenfield studies assumed the control of PM using particulate scrubbers that were integral to the cold gas cleanup systems utilized with the technology.

Sulfur Dioxide

For the remain coal-fired option, SO_2 emissions were evaluated under the Flue Gas Desulphurization ("FGD") Optimization study required by the Orders. The costs associated with outstanding work required for FGD modifications to meet the Orders requirements were used in the Study.

A limestone forced oxidization FGD, currently being used at Big Bend Station, was assumed as the technology to meet BACT rates for SO_2 emissions for all PC generating technologies in the repowering and greenfield options. The CFB generating technology assumed the use of in-bed limestone injection followed by a polishing spray dryer FGD system for the repowering and greenfield options. The IGCC technology for both the repowering and greenfield options assumed the use of amine scrubbers that were integral to the cold gas cleanup systems. The natural gas generating technologies required no SO_2 emissions control.

Mercury

Proposed mercury regulations will require emissions reductions of between 70 and 90 percent. Tampa Electric selected a baseline level of 70 percent mercury reduction.

Based upon the mercury removal effectiveness inherently associated with the combined use of a SCR and wet FGD, Tampa Electric used an FGD system additives as an input for the remain coal-fired option.

For the PC repowering options, the use of an SCR, wet FGD and FGD system additives were selected as the most effective means to control mercury emissions. The CFB and IGCC options used various forms of activated carbon as the best mercury control technology. The natural gas fired options did not require any form of mercury control.

Visible Emissions

As previously stated, an SCR catalyst will increase the concentration of SO_3 in flue gas, especially downstream of a wet FGD system. These higher levels of SO_3 may violate visible emission regulations. It will be necessary to include an SO_3 reduction technology as part of any SCR retrofit project for the Big Bend Station units. Tampa Electric evaluated the following technologies as part of the Study for achieving an emission level of no more than 5 parts per million ("ppm") SO_3 inlet to the FGD system:

- Wet Electrostatic Precipitator
- Alkali Injection
- Magnesium Oxide
- Sodium Bi-Sulfite
- MARSULEX "Clean-Stack"
- Lime Injection/Chemical Lime

The remain coal-fired and the PC and CFB options for repowering and greenfield options included the use of alkali injection upstream of the wet FGD system for the control of SO_3 in the flue gas. The natural gas and IGCC generating technologies for both the repowering and greenfield studies required no SO_3 emissions control.

Land and Water

Tampa Electric used input data from prior work studies for these environmental aspects for the remain coal-fired, repowering and greenfield options.

Circulating Water

Due to the sensitivity and extensive work performed on this environmental issue prior to commissioning the Study, Tampa Electric included the cost estimates for compliance with 316.a and 316.b requirements for the remain coal-fired, repowering and greenfield options.

3.5 Quantitative Analysis

The quantitative portion of the evaluation compared the costs of each alternative plan in terms of the cumulative net present worth revenue requirements. Costs included capital, O&M, net fuel and purchased power and depreciation expenses. Impacts to the Tampa Electric generation expansion plan were included.

A forward curve for market electricity prices was developed using the *Aurora* computer simulation model developed by EPIS, Inc. For purposes of the Study, Tampa Electric's market was considered to be the Florida Reliability Coordinated Council region. Assumptions relating to fuel prices, unit characteristics and energy requirements were supplied to the model which simulated an economic market dispatch. The same forward curve was utilized for all options, based on the assumption that given the relative magnitudes of Tampa Electric's system and the market as a whole, Tampa Electric's choice of technology would have limited impact on market forward curves.

The next phase of the evaluation was to determine an optimal generation expansion plan taking into account each alternative. Future generating resources were determined through an alternative technology screening analysis designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric service area.

Tampa Electric used the *Proview* module of *Strategist* (developed by New Energy Associates) to evaluate the supply side resources. *Proview* used a dynamic programming approach to develop an estimate of the timing and type of capacity additions which would most economically meet the system demand and energy requirements.

A detailed cost analysis for each of the plans was performed using the *CER* module of *Strategist*. The *CER* module calculated the capital revenue requirements for all of the construction projects, including both the base scenario projects and the expansion plan projects. Fixed operating expenses were also consolidated using the *CER* module and expressed in terms of revenue requirements.

Promod IV, a production costing computer model, was used to determine the net fuel and purchased power costs associated with each scenario. Forward curve assumptions from *Aurora*, expansion plan assumptions from *Proview* and the other system assumptions were used to simulate an economic dispatch of Tampa Electric's system. In addition to the fuel and purchased power costs, *Promod IV* determined the forecasted unit operating characteristics, including net generation and fuel consumption for each scenario. The forecasted unit generation was used to develop the variable O&M expenses associated with each scenario.

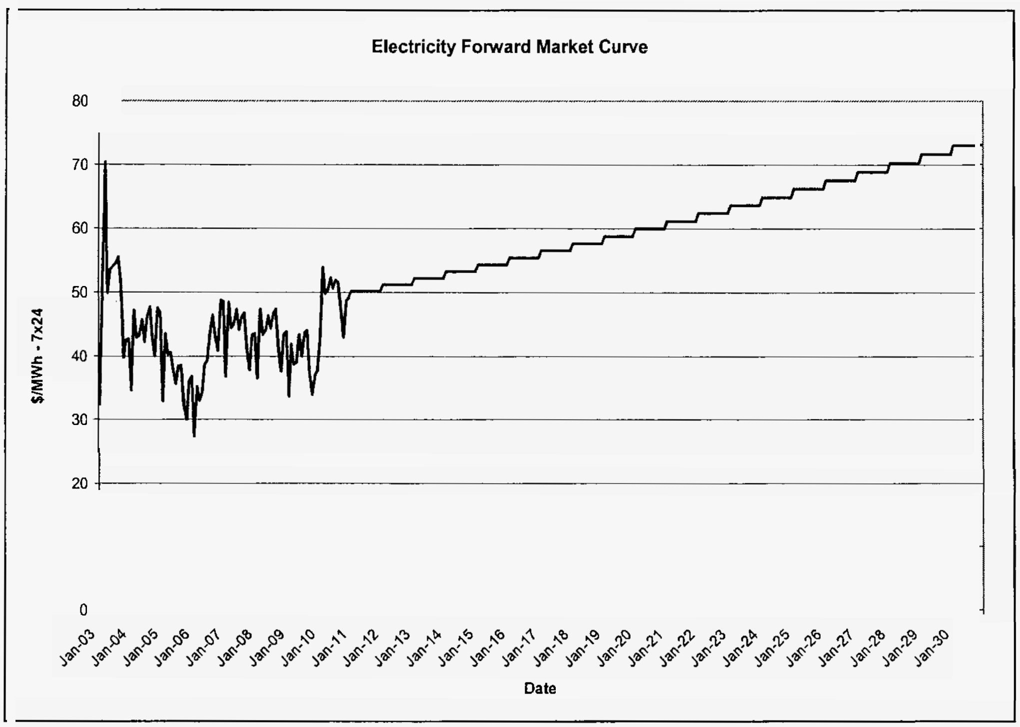
Accelerated depreciation effects appropriate for certain options were developed using a qualitative assessment to determine the timing and percent of various FERC plant accounts to be accelerated. Once determined, a spreadsheet model was used to simulate the net effective depreciation cash flows associated with each scenario.

Once each scenario was completed, the production costs, capital revenue requirements, O&M expenses, fuel, net purchased power costs and depreciation expense associated with the scenario were combined and expressed in terms of net present worth to determine the total cost of each alternative.

4.0 RESULTS

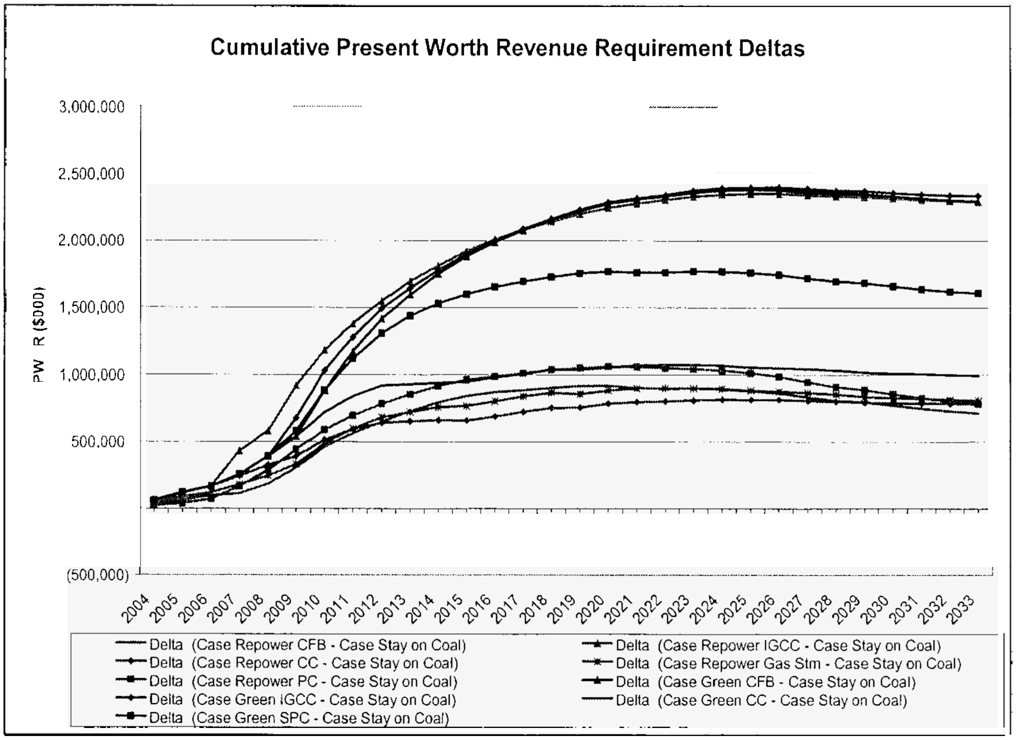
After compilation of the input assumptions and completion of the modeling phase on the analysis, the Cumulative Present Worth Revenue Requirements ("CPWRR") of the various options were compared. The initial task was to develop the electricity forward market curve, as this output was an important factor in comparing the dispatch costs of different technologies. The *Aurora* Market Model was used to derive the forecast, graphically presented below.

Electricity Forward Market Curve



The forward curve, as well as the other assumptions related to the alternatives, were analyzed using *Promod IV* to determine the fuel and purchased power costs of each scenario. The capital and O&M, net fuel and purchased power costs, as well as the accelerated depreciation costs were then consolidated in a spreadsheet model for comparison. The CPWRR curves, as well as the net fuel costs for each scenario are shown below.

Cumulative Present Worth Revenue Requirements

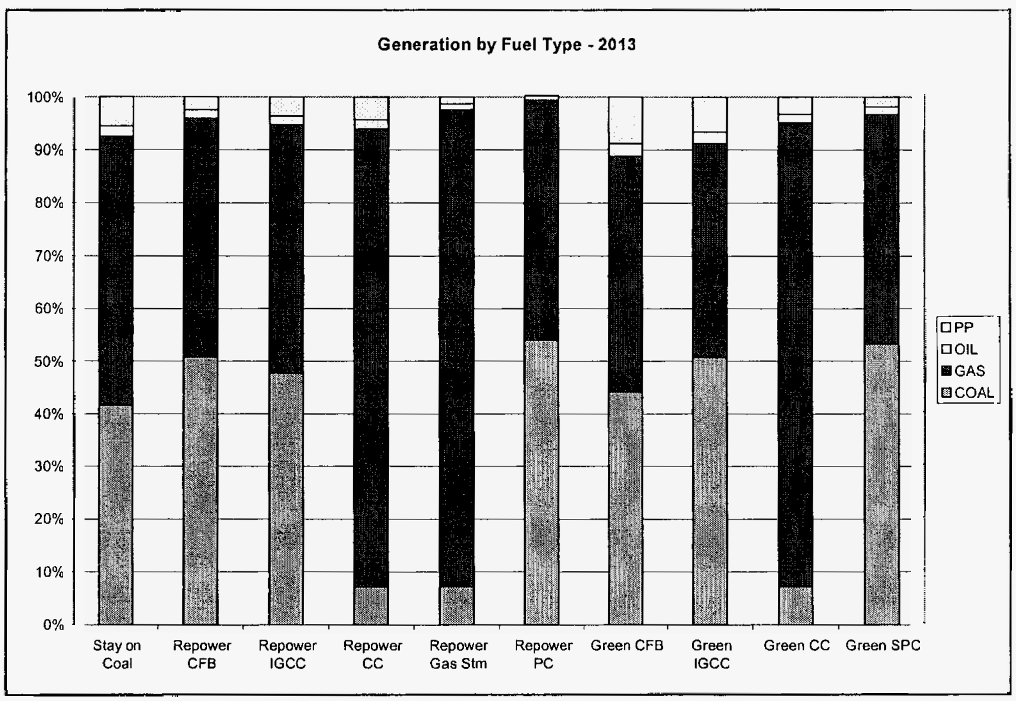


For the CPWRR graph, the horizontal axis represents the cost for the remain coal-fired option. As the graph illustrates, all the repowering and greenfield options require substantially more revenue over time. The costs include the capital cost of the technology, O&M, compliance with other environmental requirements, fuel and recurring capital. The next closest option, repowering with CFB, had a CPWRR over $700M higher in 2033 than the remain coal-fired option.

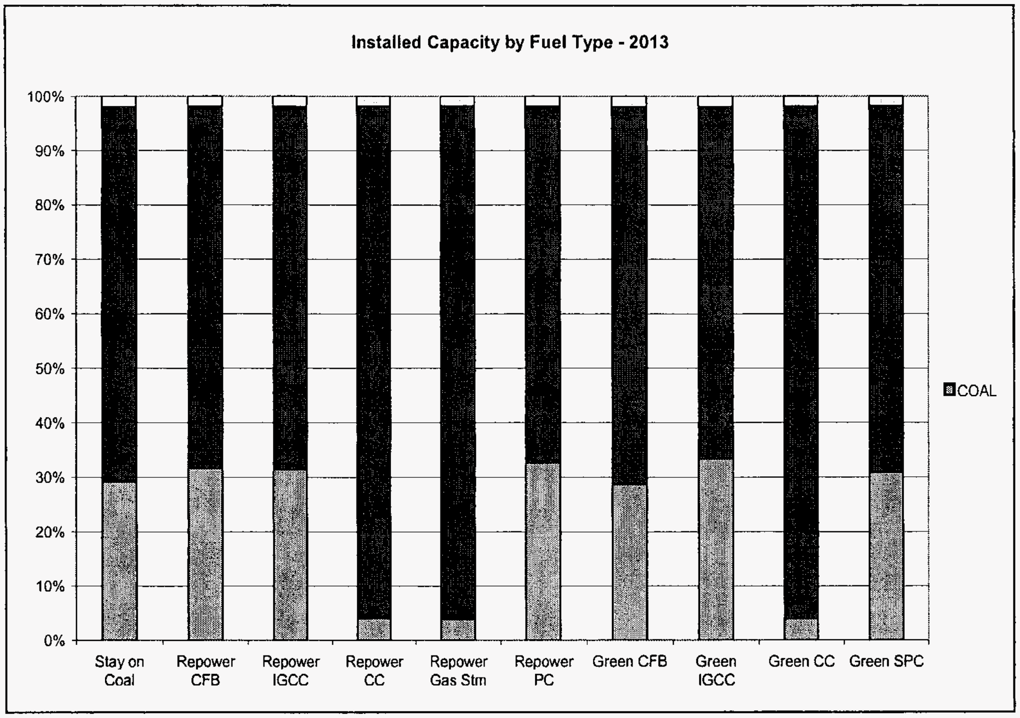
Another key factor in analyzing any alternative to remain coal-fired at Big Bend Station was the mix of portfolio assets that would comprise the generation fleet after any new strategy was completed. The following graphs compare the generation contribution and installed capacity by fuel type in 2013 that resulted from each scenario. The options that included conversion of Big Bend Station's generation contribution to a gas alternative (repowering CC, repowering gas steam, greenfield CC) resulted in almost a complete system reliance on natural gas. This would not only result in higher costs to Tampa Electric's customers, but would introduce significant volatility and fuel supply risk while decreasing system reliability.

For purposes of the fuel and resource type comparisons, 2013 was chosen as a comparison year. This was the first full year when all options had completed core construction programs and enabled a relatively unbiased side-by-side comparison.

Generation by Fuel Type - 2013



Installed Capacity by Fuel Type - 2013

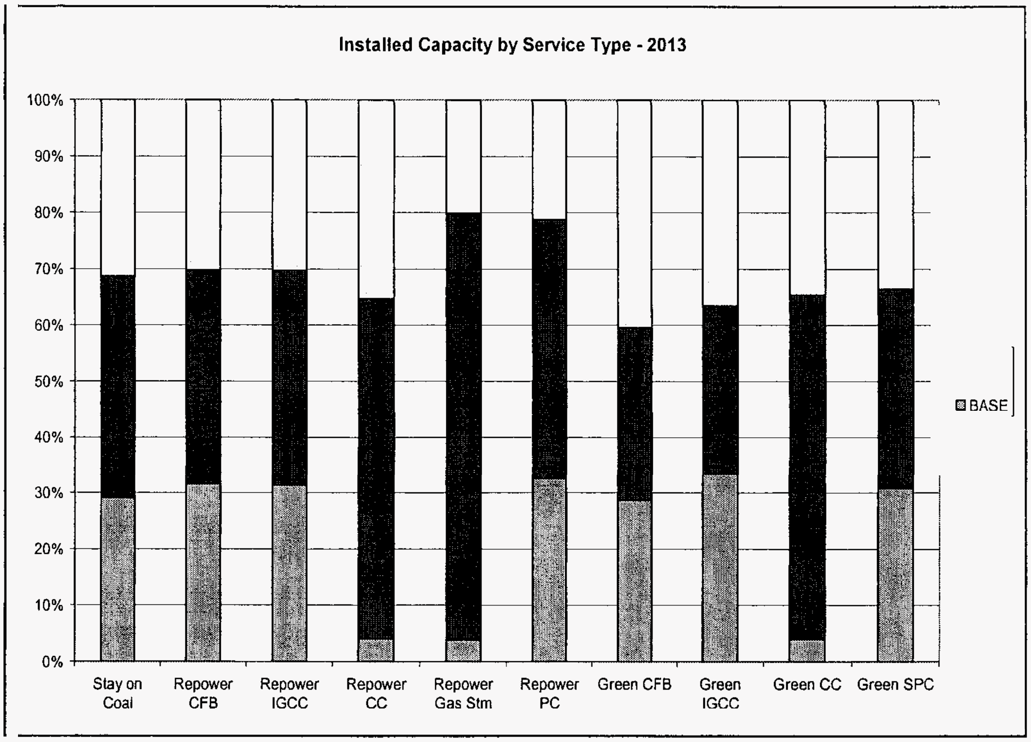


Technologies are often classified by traditional service types; base load, intermediate, peaking or largely on the basis of variable generation fuel costs. Base load units have low variable costs, usually at the expense of higher capital or fixed operating costs. Peaking units have higher fuel and O&M costs, but are less expensive to install. For purposes of comparison, technologies were classified as follows:

Baseload:	PC, IGCC, CFB (coal technologies)
Intermediate:	Gas Combined Cycle, Gas Steam
Peaking:	Gas/Oil Combustion Turbines

Below is a comparison of Tampa Electric's portfolio mix by service type for each of the considered options (as of 2013). Non-coal alternatives resulted in no base load units remaining on the system. Even the coal alternatives resulted in only approximately 30 percent base load capacity, below historically targeted levels.

Installed Capacity by Service Type - 2013



4.1 Remain Coal-Fired

The CPWRR for the remain coal-fired coal option is shown below (costs are CPWRR for 2004-2033 in 2004 dollars).

Stay on Coal CPWRR

CPWRR ($Millions, $2004)	
Capital	$2,936
O&M	$2,121
Fuel & Purchase Power	$11,614
Accelerated Depreciation	$394
Total	$17,067

By continuing to burn coal at Big Bend Station, the fuel diversity of Tampa

Electric's generation portfolio is balanced, resulting in an estimated average fuel cost to the customers of $38.46 MWh in the 2013 comparison year.

Remain Coal-Fired Generation Portfolio – 2013

	Coal	Gas	Oil	Purchased
Generation	42%	51%	2%	5%
Capacity	29%	69%	2%	0%

4.1.1 Remain Coal-Fired NO_x Compliance Plan

The best overall NO_x emission reduction control strategy will be the utilization of both pre-SCR and SCR technologies. Based upon a thorough investigation of alternative technologies, SCR systems were determined to be the only means to achieve final compliance with the NO_x emission rates required by the Orders. Tampa Electric has also determined that the use of other selected NO_x emission reduction technologies as precursors to an SCR system will result in both lower SCR system capital and O&M expenses. Since an SCR catalyst will likely increase the concentration of SO_3 in the flue gas stream and potentially create visible emission violations, Tampa Electric has included the cost of an SO_3 visible plume mitigation technology as part of the overall NO_x compliance strategy.

The pre-SCR technologies were evaluated for both qualitative and quantitative properties. The technologies were first ranked based upon their effectiveness as measured by dollars/ton of NO_x removed. An analysis was then performed using annual levelized cost comparisons to determine the threshold of diminishing returns for pre-SCR technologies versus the savings that could be realized in capital and O&M for an SCR system. Appendix III contains detailed information regarding the description of the technologies and cost development.

The capital and O&M costs associated with the Big Bend Station remain coal-fired NO_x compliance strategy are shown in the following tables.

Big Bend Estimated NO_x Capital Costs

Estimated Capital	Unit 1	Unit 2	Unit 3	Unit 4	Total
SCR	$74.7M	$74.9M	$73.9M	$61.4M	$284.9M
Non-SCR	$2.1M	$1.6M	$2.6M	$0.6M	$7.4M
SO_3 Control	$3.4M	$3.4M	$3.5M	$3.4M	$13.7M
Total	$80.2M	$79.9M	$79.9M	$65.4M	$305.4M

Big Bend SCR & SO_3 Estimated Annual O&M Costs

Estimated O&M	Unit 1	Unit 2	Unit 3	Unit 4	Total
SCR	$2.50M	$2.50M	$2.10M	$1.50M	$8.6M
Non-SCR	$0.07M	$0.04M	$0.12M	$0.03M	$0.31M
SO_3 Control	$0.97M	$0.97M	$0.97M	$0.97M	$3.88M
Total	$3.54M	$3.56M	$3.19M	$2.50M	$12.79M

4.2 Repowering

Five options for repowering Big Bend Station were considered: IGCC, CFB, PC, CC and gas-fired steam. The CPWRR results are shown below for the five options.

Repowering CPWRR ($Millions, $2004)

Repowering CPWRR ($Millions, $2004)					
Component	CFB	IGCC	CC	Gas	PC
Capital	$4,568	$5,990	$3,237	$2,678	$4,808
O&M	$2,060	$2,135	$1,492	33	$2,042
Fuel & PP	$10,681	$10,672	$12,552	$12,841	$10,577
Accel Depr	$471	$556	$566	$522	$421
Total	$17,781	$19,355	$17,849	$17,876	$17,850

The following charts compare the generation and capacity fuel source diversity for the various repowering options.

Repowering Generation by Fuel Type

	Coal	Gas	Oil	Purchased
CFB	51%	45%	2%	2%
IGCC	47%	47%	2%	4%
CC	7%	87%	2%	4%
Natural Gas	7%	91%	1%	1%
Pulv. Coal	54%	45%	1%	0%

Repowering Capacity by Fuel Type

	Coal	Gas	Oil	Purchased
CFB	32%	66%	2%	n/a
IGCC	31%	67%	2%	n/a
CC	4%	94%	2%	n/a
Natural Gas	4%	94%	2%	n/a
PC	33%	65%	2%	n/a

4.3 Greenfield

Four options in which Big Bend was shutdown and new generation built at an unidentified site were considered. The technologies studied were CC, IGCC, CFB and SPC. The CPWRR results for each of these options are shown below.

Greenfield CPWRR ($Million, $2004)

Greenfield CPWRR ($Millions, $2004)				
Component	CFB	IGCC	CC	PC
Capital	$5,368	$5,795	$3,457	$5,073
O&M	$2,169	$2,171	$1,598	$2,069
Fuel & PP	$11,209	$10,823	$12,389	$10,917
Accel Depr	$615	$615	$615	$615
Total	$19,363	$19,405	$18,061	$18,675

The comparison of generation by fuel type and installed capacity by fuel type are shown below.

Greenfield Generation by Fuel Type

	Coal	Gas	Oil	Purchased
CFB	44%	45%	2%	9%
IGCC	50%	41%	2%	7%
CC	7%	88%	2%	3%
PC	54%	43%	1%	2%

Greenfield Capacity by Fuel Type

	Coal	Gas	Oil	Purchased
CFB	29%	69%	2%	n/a
IGCC	33%	65%	2%	n/a
CC	4%	94%	2%	n/a
Pulv. Coal	31%	67%	2%	n/a

5.0 CONCLUSIONS

Tampa Electric performed a comprehensive study of the options to remain coal-fired, repowering or shutdown the Big Bend Station to meet the NO_x emission rates required by the Orders. The results of the Study clearly indicate that the option to remain coal-fired is the most cost-effective alternative to satisfy the NO_x emissions reductions required by the Orders. This option will require Tampa Electric to install SCR reduction technologies to meet future NO_x emission rates. These NO_x emission rates have been established to be 0.10 lbs/mmBtu for Big Bend Unit 4, and 0.10-0.15 lbs/mmBtu for the remaining Big Bend Units 1 through 3. Big Bend Unit 4 must comply with its new NO_x emission rate by June 1, 2007 while the remaining units must be subsequently compliant by May 1, of 2008, 2009 and 2010.

In support of the Study, Tampa Electric developed a NO_x compliance strategy that included both SCR and pre-SCR technologies. Tampa Electric also determined that SO_3 control systems will be necessary as part of the SCR systems. The pre-SCR technologies are cost-effective precursors to an SCR system since they mitigate capital and O&M by reducing the inlet NO_x concentrations to the SCR systems. These pre-SCR technologies include the use of neural networks, primary air and coal flow control systems, windbox modifications and secondary air control systems. The SO_3 control systems are necessary due to increased levels of SO_3 generated from the catalyst used in the SCR systems that may violate visible emission regulations.

The NO_x compliance work is currently scheduled to commence in July 2004 and focus upon NO_x compliance for Big Bend Unit 4. Certain pre-SCR work for Big Bend Units 1 through 3 will also be initiated at that time. The total cost of NO_x compliance for the Big Bend Station has been estimated to be \$305,450,000 and the portion attributable to Big Bend Unit 4 is estimated to be \$65,350,000. For 2004, Tampa Electric expects to spend \$5,091,000 of which \$3,576,000 is for Big Bend Unit 4. The balance of \$1,515,000 shall be used for pre-SCR projects.

5.1 Project Costs and Schedule

The following table contains a description of the major elements associated with the SCR systems, the pre-SCR and the SO_3 systems. Current cost estimates for each of these activities are included. These estimates are subject to change based upon the results of preliminary and detailed engineering, market pricing at the time of construction for materials and labor and other factors.

Tampa Electric's NO_x Compliance Cost Estimates ($ Thousands)

SCR Systems	Unit 1	Unit 2	Unit 3	Unit 4	Total
Foundations	$835	$835	$834	$1,255	$3,759
SCR Station Modifications	$2,443	$2,443	$2,443	$1,010	$8,339
Ductwork & Steel	$12,619	$12,776	$13,295	$10,640	$49,330
SCR Reactor	$8,952	$8,952	$8,952	$8,895	$35,751
Catalyst	$4,583	$4,583	$4,639	$3,895	$17,700
APH Enameled Baskets	$6,350	$6,350	$6,350	$7,150	$26,200
Ammonia System	$4,274	$4,274	$4,274	$2,605	$15,427
Electrical Additions	$6,209	$6,209	$5,059	$3,337	$20,814
Permitting/Start-up	$1,775	$1,775	$1,775	$1,775	$7,100
Owners Cost	$7,206	$7,229	$7,144	$6,084	$27,663
Engineering	$6,971	$6,994	$6,822	$4,500	$25,287
Contingency	$12,444	$12,484	$12,318	$10,229	$47,475
SCR Project Total	**$74,661**	**$74,904**	**$73,905**	**$61,375**	**$284,845**
Pre-SCR Projects					
Neural Networks	$550		$550	$550	$1,650
S/A Control	$585	$585	$585		$1,755
Windbox Modifications	$1,000	$1,000	$1,000		$3,000
Coal/Air Control			$500		$500
Pre-SCR Totals	**$2,135**	**$1,585**	**$2,635**	**$550**	**$6,905**
SO_3 Capital Cost	**$3,425**	**$3,425**	**$3,425**	**$3,425**	**$13,700**
Total NO_x Compliance Cost	**$80,221**	**$79,914**	**$79,965**	**$65,350**	**$305,450**

Tampa Electric has included certain pre-SCR work to be conducted in conjunction with the SCR systems. For 2004, Tampa Electric has included preliminary engineering of the SCR system for Big Bend Unit 4 and pre-SCR work for Big Bend Units 1 through 3. The pre-SCR work is required to be initiated at this time to allow sufficient time for installation and testing of the projects in advance of the design phase for the Big Bend Station units. The 2004 dollars associated with the pre-SCR work for Big Bend Units 1 and 3 do not represent the entire project cost. The balance of the costs for these pre-SCR projects is expected to be incurred in 2005.

Tampa Electric's 2004 NO_x Compliance Cost Estimates

Unit Number	Project Description	$ (Thousands)
Big Bend Unit 1	Initiate neural network system	$430
Big Bend Unit 2	Secondary air control	$585
Big Bend Unit 3	Coal/air balancing system	$500
Big Bend Unit 4	SCR preliminary engineering	$3,576
Station	**Total 2004 NO_x Projects**	**$5,091**

APPENDIX I

TECHNOLOGY ASSESSMENT OPTIONS FOR REMAIN COAL-FIRED, REPOWERING & GREENFIELD

Remain Coal-Fired Assumptions

Performance

Each of the four Big Bend units shall remain as currently configured. Big Bend Units 1 through 3 are Riley Turbo wet bottom boilers. Big Bend Unit 4 is a CE tangentially fired unit. The gross capacity ratings (winter) used for the Study were:

- Big Bend Unit 1: 447 MW with a heat rate of 11,224 Btu/kWh
- Big Bend Unit 2: 452 MW with a heat rate of 10,998 Btu/kWh
- Big Bend Unit 3: 455 MW with a heat rate of 11,127 Btu/kWh
- Big Bend Unit 4: 488 MW with a heat rate of 10,808 Btu/kWh

Emissions

The emissions from the existing Big Bend facility shall comply with all current Federal, State and local requirements, inclusive of that mandated by the Orders. Compliance with other potential environmental regulatory requirements was also included. The remain coal-fired configuration emission rates include:

- NO_x: 0.10 lbs/mmBtu on a 30-day rolling average for all units.
- PM: 0.010 lbs/mmBtu for Big Bend Unit 4 and 0.030 lbs/mmBtu for Big Bend Units 1-3.
- SO_2: Big Bend Units 1 and 2 - 95 percent reduction on 30-day rolling average; Big Bend Units 3 and 4 - 93 percent reduction when operated together until 2010 after which it will be 95 percent reduction. When either Big Bend Unit 3 or 4 are operated alone the required reductions are 95 percent and 90 percent, respectively.

Capital Costs

Total capital costs to comply with all the Orders requirements and other environmental requirements as well as projected ongoing capital expenses were included in the development of this option.

Operations and Maintenance Costs

Total O&M costs to comply with all the Orders requirements and other environmental requirements, as well as projected ongoing O&M expenses, were included in the development of this option.

Repowering Natural Gas Combined Cycle Assumptions

The scope assumed shutting down Big Bend Units 1 and 2 and repowering Big Bend Units 3 and 4 with two 4x4x1 natural gas fired combined cycle units powered by General Electric Frame 7FA combustion turbines. To mitigate some risk of a single gas line dependence, Tampa Electric included two separate gas lines to the site.

Performance

Each 4x4x1 combined cycle would have a net output of approximately 1,000 MW for a total site output of 2,000 MW. The net plant heat rate would be 7,150 Btu/kWh high heating value ("HHV").

Emissions

By firing solely natural gas, the plant would be able to achieve very low overall emissions. The only pollutant requiring control is NO_x. To meet projected BACT emission rates, an SCR system would be installed. The projected NO_x BACT emission rate for this option was assumed to be 0.013lbs/mmBtu.

Capital Costs

The estimated cost for two 4x4x1 power blocks, including common site portions are approximately $849,062,000. This cost represents the initial first cost of the generating technology. Costs do not include recurring capital, major capital modifications of existing systems such as the condenser cooling water system or capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel annual fixed cost is assumed to be $4.03/kW-yr. The non-fuel variable cost is $0.31/MWh.

Repowering Integrated Gasification Combined Cycle Assumptions

The scope assumed shutting down Big Bend Units 1 and 2 and repowering Big Bend Units 3 and 4 with two 3x3x1 IGCC units powered by General Electric Frame 7FA+e (or Advanced IGCC) combustion turbines. The gasifiers are assumed to be the Texaco radiant-type. The gasifiers would convert 100 percent petroleum coke into syngas. The combustion turbines would fire syngas only without duct firing.

Performance

The two 3x3x1 IGCCs would have a net output of approximately 1,860 MW. This is sufficient to replace the existing 1,800 MW at Big Bend. The net plant heat rate would be 8,900 Btu/kWh (HHV). The performance is based on a 7FA+e combustion turbine for syngas firing with a gross output of 210 MW. This predicted performance is from General Electric and the technology is expected to be available in 2006. The performance data does not include duct firing.

Emissions

The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_X: 0.056 lbs/mmBtu
- PM: 0.010 lbs/mmBtu

The anticipated fuel for the IGCC is 100 percent petroleum coke with a 7 percent sulfur content. The material balance assumed a 98 percent removal efficiency for SO_2 resulting in an emission rate of 0.20 lbs/mmBtu.

Capital Cost

The estimated cost for two 3x3x1 power blocks, including the common site portions and gasifiers is $2,259,887,000. These costs represent the initial cost of the generating technology. It does not include recurring capital, major capital modifications of existing systems such as the coal yard or capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel fixed cost is estimated to be $38.97/kW-yr. The non-fuel variable cost is $0.79/MWh.

Repowering Subcritical CFB Boiler Assumptions

The scope assumed repowering Big Bend Units 1 through 3 with three 2x1 CFB boilers each nominally 450 MW. The design basis is for the CFB boilers to burn 15 percent coal and 85 percent petroleum coke.

Performance

Each 2x1 CFB would have a gross output of approximately 450 MW for a total site output of 1,825 MW. This is sufficient to replace the existing 1,800 MW at Big Bend Station. The net plant heat rate would be 9,893 Btu/kWh (HHV).

Emissions

The emission controls for a CFB boiler were the admission of limestone into the furnace followed by a polishing scrubber for SO_2, a baghouse for PM and a selective non-catalytic reduction system for NO_x. The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_x: 0.08 lbs/mmBtu
- PM: 0.012 lbs/mmBtu

The anticipated fuel for the CFB is 15 percent coal and 85 percent petroleum coke with 7 percent sulfur content. The material balance assumed a 98 percent removal efficiency for SO_2 resulting in an emission rate of 0.19 lbs/mmBtu.

Capital Costs

The costs for three 2x1 power blocks, including the common site portions are approximately $1,423,407,000. Installed costs for the second and third power blocks have been prorated. This cost represents the initial cost of the generating technology. It does not include recurring capital, major capital modifications of existing systems such as the condenser cooling water intake system or capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The estimated non-fuel annual fixed cost is $30.63/kW-yr. The non-fuel variable cost is $2.97/MWh.

Repowering with Subcritical PC Boiler Assumptions

The scope assumed replacing Big Bend Units 1 through 3 boilers with three subcritical PC boilers each nominally 450 MW to enhance unit reliability. The design basis is for the boilers to burn 80 percent coal and 20 percent petroleum coke, as currently permitted.

Performance

Each PC boiler would have a net output of approximately 450 MW for a total site output of 1,825 MW. The net plant heat rate would be 9,763 Btu/kWh (HHV).

Emissions

The emission controls for a PC boiler would include reuse of the existing wet FGD, new baghouses and new SCR systems. The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_x: 0.07 lbs/mmBtu
- PM: 0.012 lbs/mmBtu

The material balance assumed a 98 percent removal efficiency of SO_2 resulting in an emission rate of 0.13 lbs/mmBtu based on the blend of 80 percent coal and 20 percent petroleum coke.

Capital Costs

The costs for the power blocks, including common site portions are approximately $1,339,689,000. These costs represent the initial cost of this generating technology. It does not include recurring capital, major capital modifications of existing systems such as the FGD system or capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel annual fixed cost is estimated to be $25.49/kW-hr. The non-fuel variable cost is $1.80/MWh.

Repowering Natural Gas Conversion Assumptions

The scope assumed converting Big Bend Station Units 1 through 4 from coal-fired to gas-fired. This would include gas burners, windboxes, duct and boiler modifications; combustion air supply changes; instrumentation and valves for controlling the flow of natural gas; and safety valves for NFPA requirements for retrofitting the boilers to burn natural gas.

Performance

Each unit would have a net output of approximately 429 MW for a total site output of 1,716 MW. The net plant heat rate would be 9,899 Btu/kWh (HHV).

Emissions

By firing solely natural gas, the plant would inherently achieve low emission levels. The only pollutant requiring control is NO_x. To meet the projected BACT emission rates, an SCR system would be installed. The projected NO_x BACT emission rate for this option was assumed to be 0.013 lbs/mmBtu.

Capital Costs

The costs for converting four units are estimated to be $363,250,000. These costs represent the initial first cost of the generating technology. They do not include recurring capital, major capital modifications of existing systems such as the condenser cooling water intake system or capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel annual fixed cost is $14.61/kW-yr. The non-fuel variable cost is $0.93/MWh.

Greenfield - Natural Gas Combined Cycle Assumptions

Scope

The scope assumed four 2x2x1 combined configurations powered by General Electric Frame 7FA combustion turbines. The combustion turbines would fire natural gas.

Performance

Each 2x2x1 combined cycle would have a net output of approximately 500 MW for a total site output of 2,000 MW. The net plant heat rate would be 6,850 Btu/kWh (HHV).

Emissions

By firing solely natural gas, the plant would inherently achieve low emission levels. The only pollutant requiring control is NO_x. To meet the projected emission rates, an SCR system would be installed. The projected NO_x BACT emission rate for this option was assumed to be 0.013 lbs/mmBtu.

Capital Costs

The costs for four 2x2x1 power blocks, including common site portions are approximately $1,079,349,000.

Operations and Maintenance Costs

The non-fuel annual fixed cost is $4.18/kW-yr and the non-fuel variable cost is $0.31/MWh.

Greenfield - Integrated Gasification Combined Cycle Assumptions

Scope

The scope assumed three 2x2x1 IGCC powered by General Electric Frame 7FA+e (or Advanced IGCC) combustion turbines. The gasifiers are assumed to be the Texaco radiant-type. The gasifiers would convert 100 percent petroleum coke into syngas. The combustion turbines would fire syngas only without duct firing.

Performance

The three 2x2x1 IGCCs would have a net output of approximately 1,750 MW. The net plant heat rate would be 8,400 Btu/kWh (HHV). The performance is based on a 7FA+e combustion turbine with a gross output of 210 MW. This is predicted performance from General Electric and the technology is expected to be available in 2006. This performance data does not include duct firing.

Emissions

The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_x: 0.056 lbs/mmBtu
- PM: 0.010 lbs/mmBtu

The anticipated fuel for the IGCC is 100 percent petroleum coke with 7 percent sulfur content. The material balance assumed a 98 percent SO_2 removal efficiency resulting in SO_2 emissions of 0.20 lbs/mmBtu.

Capital Costs

The costs for three 2x2x1 power blocks, including the common site portions and gasifiers are estimated to be $2,525,475,000. This does not include capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel annual fixed cost is \$37.79/kW-hr and the non-fuel variable cost is \$0.81/MWh.

Greenfield - Subcritical CFB Boiler Assumptions

Scope

The scope assumed four 2x1 CFB boilers each nominally rated at 450 MW. The design basis is for the boilers to burn 15 percent coal and 85 percent petroleum coke.

Performance

Each 2x1 CFB would have a net output of approximately 404 MW for a total site output of 1,616 MW. The net plant heat rate would be 9,584 Btu/kWh (HHV).

Emissions

The emission controls for a CFB boiler were the addition of limestone in the furnace followed by a polishing scrubber for SO_2, a baghouse for PM and an SNCR system for NO_x. The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_x: 0.08 lbs/mmBtu
- PM: 0.012 lbs/mmBtu

The anticipated fuel for the CFB is 15 percent coal and 85 percent petroleum coke with 7 percent sulfur content. The material balance assumed a 98 percent removal efficiency for SO_2 resulting in an emission rate of 0.19 lbs/mmBtu.

Capital Costs

The costs for four 2x1 power blocks, including the common site portions are approximately $2,533,278,000. This does not include capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel annual fixed cost is \$26.65/kW-yr and the non-fuel variable cost is \$2.91/MWh.

Greenfield - Supercritical PC Boiler Assumptions

Scope

The scope included three 600 MW supercritical PC boilers. The design basis is for the boilers to burn 80 percent coal and 20 percent petroleum coke.

Performance

Each PC boiler would have a net output of approximately 559 MW for a total site output of 1,677 MW. The net plant heat rate would be 8,980 Btu/kWh (HHV).

Emissions

The emission controls for a PC boiler are a wet FGD, a baghouse and an SCR system. The projected BACT emission rates for this option were assumed to be:

- SO_2: 98 percent removal efficiency
- NO_x: 0.07 lbs/mmBtu
- PM: 0.012 lbs/mmBtu

The material balance assumed a 98 percent removal efficiency resulting in SO_2 emissions of 0.13 lbs/mmBtu based on the blend of 80 percent coal and 20 percent petroleum coke.

Capital Costs

The estimated costs of the power blocks, including common site portions are $2,094,822,000. This does not include capital for compliance with probable future environmental regulations.

Operations and Maintenance Costs

The non-fuel fixed annual cost is \$24.05/kW-hr and the non-fuel variable cost is \$1.73/MWh.

APPENDIX II

SELECTIVE CATALYTIC REDUCTION

TECHNOLOGY AND COSTS

Selective Catalytic Reduction Summary

Background

An SCR system is a capital intensive, post-combustion technology that uses catalyst elements installed in the flue gas stream to promote the NO_x emission reduction. Ammonia is used as the reducing agent and is injected into the flue gas within a temperature window of 580°F to 750°F. Byproducts of the reaction are nitrogen, water and SO_3 when sulfur containing fuels are burned. Discharged flue gas and fly ash also contain low concentrations of ammonia that have slipped past the catalyst. Ammonia slip in the flue gas is a specified environmental and performance constraint usually limited to no more than 2 ppm.

SCR system equipment can be installed on gas, oil or coal-fired boilers. The two basic SCR configurations applicable to Big Bend Station are high-dust and low-dust. Due to the location of the electrostatic precipitators and other major equipment at Big Bend Station, high-dust configurations are the preferred and least cost option available. The high-dust configuration locates the catalyst between the economizer outlet and the air preheater inlet. This arrangement is applicable to all four Big Bend units.

An SCR system conceptual design study for the existing Big Bend Station was originally performed in 2001 and was updated in 2003. This latest study identified suitable locations for each unit's SCR system along with the associated capital and O&M costs. The major aspects of these studies included the following:

- Design of an SCR system and sizing
- Process considerations

- System impacts
- Balance of plant impacts
- Installation considerations
- Budgetary capital and operation and maintenance cost estimates

The SCR configuration on each of the units would be a high-dust hot-side configuration. Capital costs for the SCR systems are currently estimated in the following table.

Estimated Capital	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**
SCR Capital	$74.7M	$74.9M	$73.9M	$61.4M

The annual O&M costs (fixed plus variable, excluding auxiliary power costs) for each of the four units are estimated in the following table.

Estimated O&M[1]	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**
SCR O&M	$2.50M	$2.50M	$2.10M	$1.50M

(1) Assumes SCR inlet NO_x levels of 0.60 lbs/mmBtu for Big Bend Units 1 and 2, 0.48 lbs/mmBtu for Big Bend Unit 3, and 0.28 lbs/mmBtu for Big Bend Unit 4.

<u>Summary of Major Design Changes Associated with an SCR System Addition</u>

The major project aspects of the SCR system capital costs include:

- Demolition of existing flue gas ductwork as necessary to tie-in the SCR system

- Demolition of existing structural steel, modification and reinforcement of existing steel supports for a new duct from the existing steel
- Economizer bypass (on Big Bend Units 3 and 4 only for gas temperature control)
- Gas ductwork from economizer outlet to the SCR inlet (includes hoppers, mixers and turning vanes)
- SCR reactor (includes equipment for catalyst management)
- Gas ductwork between the SCR & air heater
- Foundations for ductwork and structural steel
- Structural modifications for construction cranes
- Catalyst
- Urea to ammonia conversion system
- Air heater modifications
- Electrical modifications
- Relocation of existing equipment and utilities
- Mobilization/demobilization
- Equipment rental
- Engineering/construction management
- Asbestos removal
- Boiler reinforcement
- New Induced Draft ("ID") fans and motors
- ID fan foundations
- ID fan electrical
- New and modified ductwork
- ESP reinforcement
- Auxiliary power modifications
- Controls modifications

Ammonia System Design

The Study assumed a urea based ammonia generating system would be used to produce and supply ammonia to the SCR catalyst system. For the ammonia flow rates needed at Big Bend Station, the installed cost for each unit is estimated to be $1,500,000 to $2,500,000 million. This cost is based on essentially a 1x100 percent system for each unit with redundant equipment for critical components.

Schedule and Required Outage Time

The Study assumed work would begin in 2004 and Big Bend Unit 4 would be completed by June 1, 2007, Unit 3 by May 1, 2008, Unit 2 by May 1, 2009, and Unit 1 by May 1, 2010. Most of the construction would take place prior to the tie-in outage. An outage duration of ten weeks per unit is anticipated for the final construction and tie-in activities.

SO_3 Emission Control

Since an SCR catalyst will increase the concentration of SO_3 in the flue gas stream and may violate visible emission regulations, Tampa Electric has included the cost of an alkali injection/magnesium oxide mitigation technology as part of the overall NO_x compliance strategy. The estimated costs associated with this system are:

SO_3 Costs	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**
SO_3 Capital Estimates	$3.4M	$3.4M	$3.5M	$3.4M
SO_3 O&M Estimates	$0.97M	$0.97M	$0.97M	$0.97M

APPENDIX III

PRE-SELECTIVE CATALYTIC REDUCTION TECHNOLOGIES AND COSTS

Tampa Electric performed a comprehensive evaluation of commercially available or emerging NO_x control technologies applicable to Big Bend Units 1 through 4. These included combustion modification and post-combustion technologies. Tampa Electric's evaluation included technical and financial analysis of these options and compared the potential benefits against the capital and O&M savings that would be realized by providing lower inlet NO_x levels to the SCR systems. The tables and their respective descriptions that follow provide the evaluation results. Also, information specific to each of the technologies is provided at the end of this Appendix.

Table 1 provides a comprehensive listing of both qualitative and quantitative information for all the technologies evaluated. The technologies are listed based upon their effectiveness as measured by \$/ton of NO_x removed. It must be noted that the final predicted NO_x emission reduction is non-additive. The qualitative aspects of each technology were also considered to ensure their overall compatibility.

Table 2 provides the financial analyses for the various NO_x emission control options and compares their cost effectiveness to the savings realized in capital and O&M for an SCR system. The analyses were performed using annual levelized cost comparisons. The analysis determined the threshold of diminishing returns for pre-SCR technologies versus the savings that could be realized in capital and O&M for an SCR system. The reductions expected from each potential NO_x technology listed are non-additive. For Big Bend Units 1 and 2, the cumulative NO_x emission reduction expected for the proposed pre-SCR technologies is approximately 17 percent or a reduction of 0.13 lbs/mmBtu. For Big Bend Unit 3, the projected cumulative reduction is 18 percent or 0.11 lbs/mmBtu, and for Big Bend Unit 4, the reduction has been estimated to provide a 9 percent reduction, or 0.03lbs/mmBtu. Big Bend Unit 4 neural network reductions are predicted to be slightly higher than that of the

Riley Turbo units. This is due to the design of the CE tangentially fired unit which has more controllable parameters to reduce NO_x emissions.

Table 1
BIG BEND UNITS PRE-SCR NO_x OPTIONS

	NO_x Reduction	Reliability	Synergies with SCR	Other Environmental Impacts	Capital Cost	Annual O&M Cost	Annual Levelized Cost	$/Ton
Neural Networks[1,2]	7%	high	High	n/a	$550,000	$35,000	$123,495	$276
Primary Coal/Air Control	6%	med	High	Low	$500,000	$50,000	$130,450	$340
Windbox Secondary Air Mods	8%	high	High	Low	$1,000,000	$20,000	$180,900	$353
Secondary Air Damper Control	5%	high	High	Low	$585,000	$20,000	$114,254	$357
Water Cannons	10%	low	Med	Low	$1,400,000	$60,000	$285,260	$446
Lean Gas Reburn	20%	med	Low	Low	$3,000,000	$2,667,000	$3,149,700	$2,460
SNCR	25%	med	n/a	High	$13,000,000	$2,220,000	$4,311,700	$2,694
NO_xStar	60%	med	n/a	High	$41,600,000	$7,078,300	$13,771,740	$3,585
Fuel Switch	30%	high	Low/high	High	$69,300,000	$0	$11,150,370	$5,806
Low NO_x Burners[3]	installed	installed	Installed	installed	Installed	installed	installed	installed
Over Fired Air[4]	installed	installed	Installed	installed	Installed	installed	installed	installed
WIR	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Reburn	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
$LoTO_x$	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) Neural networks already installed on Big Bend Unit 2
2) Neural network reductions for Big Bend Unit 4 predicted to be 10 percent
3) Low NO_x burners already installed on all Big Bend units
4) Over-fired air already installed on Big Bend Unit 4

Table 2

TAMPA ELECTRIC PRE-SCR COST SUMMARY

(BASED UPON ANNUAL LEVELIZED COST)

	Combustion Neural Network	P/A Coal/Air Control	Windbox SA Mods	Secondary Air Controls	Total Pre-SCR NO_x	SCR Capital Avoidance	SCR O&M Avoidance	SCR $ Avoided
BB1[1]	$123,495	n/a	$180,900	$114,254	$418,649	$500,000	$472,340	$552,790
BB2[1]	n/a	n/a	$180,900	$114,254	$233,154	$500,000	$472,340	$552,790
BB3[2]	$123,495	$130,450	$180,900	$114,254	$549,099	$500,000	$513,333	$593,783
BB4[3]	$123,495	n/a	n/a	n/a	$123,495	$250,000	$156,000	$196,225

1) Big Bend Units 1 and 2 – 0.13lbs/mmBtu reduction
2) Big Bend Unit 3 - 0.11lbs/mmBtu reduction
3) Big Bend Unit 4 - 0.03lbs/mmBtu reduction

Neural Networks

The NN adjusts combustion set points to reduce NO_x emissions and improve heat rate. NN technology models NO_x formation in the furnace during various modes of operation. Once modeled, the NN retrains itself using current boiler information to optimize set points. The NN periodically updates the model based on recent data to correspond with changes in operating conditions. It is estimated that a NN will reduce NO_x emission levels by approximately 10 to 15 percent. The estimated capital cost of a NN installation is $550,000. The estimated O&M cost is $35,000 per year. Due to the relatively low cost of this technology and its ability to reduce NO_x emissions on Big Bend Unit 2, it has been selected as a prudent project for Big Bend Units 1, 3 and 4.

Primary Air Coal/Air Control

The balancing of fuel-to-air ratio is key to successfully lowering NO_x emissions. The balancing is typically a key requirement for LNB and OFA technology. Big Bend Units 1 through 3 cannot be installed with an OFA system. Therefore, coal and airflow balancing will be beneficial for these units. An automatic monitoring system required for such balancing is estimated to have a capital cost of $500,000 and a $50,000 per year O&M expense.

Windbox Secondary Air Modifications

Similar to the control of primary air to optimize fuel-to-air ratios, the control of secondary air, which makes up approximately 80 percent of the total air supplied to the combustion process, is critical for NO_x emission control. This work will be designed specifically for the Riley Turbo units since these are the only known units of this type and size in operation. Through modifications of internal dampers, vanes and other air control devices within the burner compartments, combustion air can be metered and directed to specific areas of the combustion zone to reduce NO_x emissions. The capital cost estimates for these modifications are $1,000,000 with $20,000 for annual O&M expenses.

Secondary Air Damper Control

In conjunction with the primary air and secondary air modifications listed above, the control of bulk combustion air to each compartment corresponding to the fuel delivered will provide NO_x emission reductions. The control for the secondary air dampers is made through real-time monitoring of the coal, the use of a multi-grid excess oxygen measurement system and overall optimization provided by the neural network project. The capital cost estimates for these modifications are $585,000 with $20,000 for annual O&M expenses.

Water Cannons

Water cannons have been used by some utilities to assist in reducing NO_x emissions. Tests performed at Texas Utilities Martin Lake Power Plant in 1998 indicated that keeping the boiler walls clean with water cannons promoted efficient combustion. These tests showed a reduction in NO_x emissions of about 10 percent. Also, using a similar system, Dairyland Power Cooperative is said to have achieved a 30 percent NO_x emissions reduction in its Riley Turbo dry bottom boiler. Currently, Tampa Electric is investigating the potential of connecting the sootblowing operation with a NN to lower NO_x emissions and potentially lower sootblower steam consumption. It is estimated that the installation of water cannons, on a per unit basis, will require approximately $850,000 in capital cost and $60,000 per year in O&M cost, excluding additional auxiliary power. The auxiliary power usage and cost is estimated to be approximately 50 kW or $16,000 per year. The potential reductions for this technology are currently being evaluated as part of a United States Department of Energy sponsored project.

Lean-Gas Reburning

The combustion of coal in the primary furnace creates a high-temperature, low-oxygen flue gas containing NO_x. The injection of the reburn fuel in a temperature window of 2,000°F to 2,400°F results in chemical reactions that reduce NO_x to molecular nitrogen. The desired injection temperature should also be as low as possible and consistent with the requirements of the reburn fuel (ignition and burnout points). The process relies on using high-velocity turbulent jets for penetration of the reburn fuel into the center of the furnace. The amount of reburn fuel is controlled to maintain an overall fuel-lean stoichiometry in the upper furnace.

The Gas Research Institute has documented NO_x emission reductions of up to 40 percent using 7 percent natural gas as the fuel-lean reburn fuel on a 320 MW cyclone furnace. This process has also been demonstrated to reduce NO_x emissions by 35 percent by using 7 percent natural gas as the controlled injection reburn fuel on a roof-fired 100 MW boiler. In one particular option, the baseline NO_x emission level of 0.495 lbs/mmBtu (with optimized combustion and SOFA already in place) was reduced to 0.313 lbs/mmBtu by using 5 percent natural gas (heat input basis).

The NO_x emission reduction capability of this technology is limited to 15 to 20 percent on Big Bend Units 1 through 3 and 25 percent on Big Bend Unit 4 based on approximate residence times through the boilers. To achieve these NO_x emission reductions, the approximate capital cost for lean-gas reburning would be $3,000,000 and 4 percent of the fuel would have to be replaced by natural gas. This cost does not include a gas pipeline to the site. The approximate annual O&M cost, including fuel costs, would be $2,700,000 for Big Bend Units 1 through 3, and $2,900,000 for Big Bend Unit 4, based on the fuel differential cost of $2.50 per mmBtu. For all Big Bend Station units, this technology is not practical based upon limited experience with existing unit sizes and capital and O&M costs as compared to the NO_x emission reduction potential.

Selective Non-Catalytic Reduction

SNCR is a process that injects either ammonia or urea into the flue gas within a temperature window of 1,600°F to 2,000°F in order to reduce NO_x to nitrogen and water. Multiple injection levels are employed to maintain NO_x emission reduction efficiencies as boiler load changes. The temperature window that ammonia or urea is injected is critical to the process because at high temperatures (above 2,000°F) ammonia and urea react with oxygen to form additional NO_x. At low temperatures (below 1,600°F) excess ammonia can lead to the formation of ammonium salts. For high-sulfur units, the slip must be lowered to between 2 to 3 ppm to avoid severe plugging of the air heaters.

Removal efficiencies of 20 to 40 percent have been reported with SNCR technology with ammonia slips of approximately 5 ppm. The installation of this process at Big Bend Station would require all of the air heaters to be retrofitted with enamel-coated air heater baskets. The estimated capital cost for an SNCR installation with air preheater basket modifications would be $13,000,000. The O&M cost (fixed and variable cost) for running this system (without inclusion for additional auxiliary power) would be approximately $2,200,000 per year for Big Bend Units 1 and 2, $1,800,000 per year for Big Bend Unit 3, and $1,200,000 per year for Big Bend Unit 4. The approximate auxiliary power requirement for this system would be 200 kW for each of the four units or approximately $65,000 per year. With this system in place, a boiler efficiency penalty of 0.2 percent and 0.1 percent would need to be assessed on Big Bend Units 1 through 3 and Big Bend Unit 4, respectively.

Due to the high cost of this technology, adverse operational issues, and the need for a full size SCR system, it was not considered practical for Big Bend Station units.

NO_XSTAR

The NO_XSTAR or selective auto catalytic reduction ("SACR") process was developed by NO_XTech and is licensed to Mitsui Babcock. In this process, a controlled amount of hydrocarbon (in liquid or gaseous fuel) is introduced into the flue gas where, at elevated temperatures (1,400°F to 1,700°F), the hydrocarbons auto-ignite forming a plasma of free radicals. Ammonia is introduced into this environment and the free radicals auto-catalyze their reaction with NO_x to produce nitrogen and water. The hydrocarbon fuel and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

Mitusi Babcock completed a commercial demonstration of this technology on a 200 MW unit at Tennessee Valley Authority's Kingston Power Station, Unit 9 (tangentially-fired coal boiler). Prior to installation at Kingston Unit 9, the process was demonstrated at Mitsui Babcock's 160 kW and 90 MW combustion test facilities in Renfrew, Scotland. Tests at Kingston showed an approximate 41 percent NO_x emission reduction with boosted overfire-air ("BOFA") and a 53 percent NO_x emission reduction with the SACR process. When the two technologies were combined, a total NO_x removal of up to 68 percent was measured. Outlet NO_x emissions were measured during the demonstration tests. Since BOFA and SOFA are similar technologies, and Big Bend Unit 4 already has a SOFA system installed, additional NO_x emission reductions of 68 percent would not be expected.

Mitsui Babcock has estimated that this technology would cost $16,000,000. An addition of approximately $9,800,000 on Big Bend Unit 4 would be required to incorporate the cost of a urea-to-ammonia system and the conversion of the air heater to enamel-coated baskets. The total capital cost for Big Bend Unit 4, exclusive of a natural gas supply line and metering station, is estimated to be $40,200,000. The annual O&M cost (fixed plus variable) associated with this technology (excluding additional auxiliary power) would be approximately $4,600,000. The auxiliary power usage is estimated to be 240 kW resulting in an estimated annual cost of $78,000.

For Big Bend Unit 4, it should be noted that the NO_XSTAR process would require a stoichiometric ratio ("SR") of 2.8 for lowering the outlet NO_x emissions from 0.28 to 0.10 lbs/mmBtu. To obtain the same results, an SCR system would only require a SR of 0.66. With urea estimated at $330/ton, the differential cost would be approximately $1,960,000 per year (assuming a 74 percent capacity factor).

There is no long-term experience with this technology and the reliability of the equipment has not been proven. Additionally, if the system failed to meet the required limit of 0.10 lbs/mmBtu, other technologies would have to be installed. This makes the overall cost of compliance higher than that of an SCR system. This technology is not practical for any of the Big Bend Station units.

Fuel Switching

For the Big Bend units, the two primary fuel switching options available are either a conversion to Power River Basin ("PRB") coal or to natural gas. The discussion on converting to PRB coal is given below. Neither of these two conversion options appears to be economical. With PRB, an SCR system would need to be installed on each of the four units to meet the Orders requirements. The natural gas conversion would need either an SCR or SNCR system. The SCR system required for a gas unit is sized substantially smaller than for a coal unit.

PRB coal is a low-sulfur western (sub-bituminous) coal. Switching to PRB coal from a high-sulfur eastern (bituminous) coal has the benefit of reducing NO_x emissions due to the higher moisture, lower nitrogen and lower fixed carbon to volatile matter ratio found in it. Most PRB coal conversions are not done to attain these benefits. The conversions are primarily performed as a proven approach to reduce SO_2 emissions or to reduce overall fuel costs. Although the conversion to PRB coal would reduce NO_x emissions by approximately 30 to 40 percent when compared with eastern coal emission, this reduction would not be significant enough to eliminate the need for an additional NO_x removal technology.

One significant disadvantage of switching to PRB coal from eastern coal is its lower heating value (8,500 lbs/mmBtu HHV versus 12,300 lbs/mmBtu HHV). This lower heating value results in a higher burn rate and requires the coal handling and transport systems to be able to move a greater amount of coal over the same comparable time period. In order to meet these increased throughput rates, coal handling and transport systems often need to be modified. Other disadvantages of PRB coal as compared to eastern coal is its overall operating characteristics. These include: poor ash quality, greater tendency for ash slagging, greater tendency for coal pluggage during conveyance, greater safety risk of fire and explosion and poorer electrostatic precipitator performance. All of these characteristics combined will require changes and modifications to be made to the existing coal handling, storage, fuel burning, emission control and other related systems. The use of PRB coal when compared to eastern coal produces the greater release of elemental mercury during combustion. This increased release of mercury may require the installation of additional pollution control equipment and sorbent such that the mercury levels can be reduced to meet proposed environmental regulations.

The following list provides the likely modifications that need to be made to the Big Bend Station if converted from eastern to PRB coal:

- Installation of additional dust suppression equipment
- Increased ventilation equipment for electrical, equipment, and control rooms
- Installation of dust-resistant electrical components
- Additional fire detection and protection equipment
- Sootblower upgrades and water cannons for de-slagging
- Installation of hopper heaters
- Equipment modifications to prevent pluggage
- Forced draft, primary air and seal air fan modifications
- Additional power distribution
- Coal mill modifications
- Installation of baghouse and sorbent injection system for mercury control
- Installation of an SO_3 conditioning system for dust removal

The cost to convert to PRB coal would be approximately \$154/kW or \$69,300,000 for a 450 MW unit. This figure does exclude the costs associated with the installation of a NO_x removal technology or induced draft fan installations/modifications. The variable cost impact does not include the cost reduction in limestone usage and revenue lost from gypsum sales. If another technology fails to meet the Orders, it is possible that a low-percentage blend of PRB coal may be able to lower NO_x emissions slightly.

Low NO_x Burners

Big Bend Units 1 through 3 are Riley Turbo wet bottom boilers. The commercially available LNBs for this type of unit are less effective than the burners that are available for the other boiler types. Also, due to the relatively low NO_x emissions from the Big Bend units, LNBs would not be expected to further reduce NO_x emissions. Tampa Electric contracted with a computational fluid dynamic modeling firm experienced in low NO_x burner design to design burners suited for these unique boilers. The burners were manufactured and installed on all three Riley Turbo units. Big Bend Unit 4 is a CE tangentially fired boiler which has many suppliers and manufacturers for LNBs. Tampa Electric purchased and installed Foster Wheeler's LNBs and a close-coupled over-fired air ("CCOFA") system.

Although LNBs have been installed on all the Big Bend Station units, Tampa Electric is continuing its efforts on Big Bend Units 1 through 3 design to further enhance their ability to reduce NO_x emissions while providing reliable operation of the units. These enhancements were made at the time of normal replacement and are minor in nature. No costs have been included for this minor work.

Overfire-Air

The operating principle behind OFA is to divert a portion of the existing combustion airflow from the burners to air injection ports located above the top burner elevation. The resultant combustion air staging reduces NO_x emissions because the in-service burners are operated with lower air-to-fuel ratios, i.e., fuel-rich. This staging process locally limits oxygen availability thereby reducing fuel and thermal NO_x formation at the burners. Thermal NO_x formation is also reduced by delaying fuel and air mixing on a bulk furnace basis and alters peak flame temperatures.

OFA is categorized as either SOFA or CCOFA, depending on the burner and OFA port arrangement. OFA systems do not reduce the amount of combustion air; they redistribute a portion of the air from the burner zone.

Based on detailed modeling efforts, the installation of an OFA system would not be feasible on Big Bend Units 1 through 3 since it would not support the minimum temperatures necessary on the floor of the furnace to keep the slag molten. A SOFA system has been successfully installed on Big Bend Unit 4 and the preliminary results indicate that NO_x emission reductions are higher than anticipated. For study purposes, a sustainable level of 0.28 lbs/mmBtu was assumed.

Underfire Air

WIR technology was developed at the St. Petersburg Polytechnic Institute in Russia and brought to the United States by the Research Triangle Institute. The system is operating in more than twenty coal-fired boilers in Central Europe. Progress Energy's Weatherspoon plant, near Lumberton, North Carolina, was the first to demonstrate the system in the United States.

WIR, loosely translated as "vortex," describes this technology. The Progress Energy demonstration of WIR was in a tangentially fired boiler. In a typical tangentially fired boiler, the burners on the boiler's furnace walls blow pulverized coal and air into the furnace at an angle, creating a spinning effect. In this demonstration, the WIR process re-aimed the burners and injected new airflows at the bottom of the boiler. These airflows produced a pair of horizontal vortices beneath the normal vertical one. This process created more turbulence and had a beneficial effect on the combustion process.

In this process, the horizontal vortices helped create a larger combustion region in the boiler and the coal remained for a longer time and burned at a lower temperature than normal. This condition lead to a reduction in NO_x formation that was aided by the formation of an oxygen-starved region in the lower part of the boiler furnace.

WIR technology has not been applied to wet bottom turbo-boilers due to the potential of solidifying the slag. Also, the size of the Big Bend Units 1 through 3 furnaces would not permit the installation of this technology.

Reburning

Reburning is an in-furnace technology that uses combustion modification techniques to reduce NO_x emissions. The main combustion zone is operated at a reduced heat input (typically 80 to 85 percent), and allows for normal operating stoichiometry fuel/air ratios. Also, the main combustion zone is operated at no less than 1 percent excess oxygen (stoichiometry of 1.05).

The reburning fuel, generally coal, oil or gas, is introduced above the main combustion zone into the reburn zone through new burners. The furnace reburning zone stoichiometry is in the range of 0.85 to 0.95 and produces NO_x emission reductions. Intermediate hydrocarbon and nitrogen compounds formed in the reburn zone react to reduce NO_x that was formed in the main combustion zone. A sufficient furnace residence time within the reburn zone is required for flue gas mixing and NO_x reduction kinetics to occur. For optimal performance, the reburn zone residence times should typically be no less than 0.5 seconds for gas reburn.

Following the reburn zone is the burnout zone. In the burnout zone, the balance of the required combustion air is introduced through new OFA ports. As with the reburn zone, a satisfactory residence time within the burnout zone is required for complete combustion. Overall carbon burnout becomes a function of the mixing achieved between the OFA and flue gas emanating from the reburn zone. The residence time available before reaction rates are effectively quenched through the decrease in flue gas temperature in the convective pass is a key design criteria. Typically, 0.5 seconds within the burnout zone is required for acceptable carbon burnout.

This technology has been shown to achieve 40 to 60 percent NO_x emission reductions with gas, oil and coal as the reburn fuel. The technology has not been applied to units greater than 150 MW. The technology would not be applicable to Big Bend Units 1 through 3 since there is not enough residence time for OFA ports to be effective. The application of this technology to Big Bend Unit 4 is not considered practical due to high operating and capital costs, unproven experience at this unit size and unproven experience at low inlet NO_x concentrations.

LoTO$_x$

The LoTO$_x$ process was developed by British Oxygen Company. The LoTO$_x$ process uses oxygen to produce ozone as the primary reagent. In this process, the ozone is injected into the flue gas stream where it reacts with relatively insoluble NO and NO_2 to form N_2O_3 and N_2O_5. Both N_2O_3 and N_2O_5 are highly water soluble and are easily removed and neutralized in a wet scrubbing system. A demonstration project was funded by the Ohio Coal Development on a 25 MW stoker boiler at the Medical College of Ohio. The demonstration was done over a nine month period. NO_x removal efficiencies of 90 percent or higher were achieved.

Within this process, the rapid reaction with ozone produces a corrosive environment that may require corrosion-resistant materials to be used at the injection point and at downstream areas. Depending upon the scrubber used, N_2O_5 is converted to either nitric acid or calcium nitrate. Due to the high level of nitrates discharged from this process, a waste treatment facility would likely be required as part of the project. This would add to the capital cost and disposal cost of calcium nitrate. Major cost components of this process are large quantities oxygen and auxiliary power; both are required to convert the oxygen into ozone. Economics associated with the installation of a LoTOx system are heavily weighted by the ozone requirements of this process.

The amount of ozone required by this process is directly proportional to the amount of NO_x emission reductions desired. In relation to Big Bend Units 1 through 3, it is anticipated that capital and O&M costs would be high because of the large amount of oxygen required by the process and the cost of the ozone generator. The developer of the process stated that it is much more economical when used on low concentrations of inlet NO_x (typically 100 ppm, i.e., 0.15 lbs/mmBtu or lower).

Due to the high level of capital required and the substantial O&M costs associated with this technology, it is not considered an economically viable technology for any of the Big Bend Station units. In addition, no utility has experience with this technology.

Tampa Electric Company

Exhibit B

Forecast of Expenditures for NO_x Reduction Programs

Forecast of Expenditures for NO_x Reduction Programs

Program	2004	2005	2006	2007	Total Capital	Annual O&M
Big Bend Unit 1 Pre-SCR	$430,000	$1,705,000	$0	$0	$2,135,000	$75,000
Big Bend Unit 2 Pre-SCR	$585,000	$1,000,000	$0	$0	$1,585,000	$40,000
Big Bend Unit 3 Pre-SCR	$500,000	$2,135,000	$0	$0	$2,635,000	$125,000
Big Bend Unit 4 SCR	$3,576,000	$9,500,000	$31,291,000	$20,983,000	$65,350,000	$2,505,000
Total	$5,091,000	$14,340,000	$31,291,000	$20,983,000	$71,705,000	$2,745,000

Total Capital: $71,705,000

Annual O&M[1] $2,745,000

[1] Estimate is for first full year of service. Some increase may occur annually as equipment ages.