ORIGINAL

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050958-EI

IN RE: Petition for Approval of New Environmental Program for Cost Recovery through Environmental Cost Recovery Clause

TESTIMONY

OF

JOHN V. SMOLENSKI

CMP ____
COM 5 ____
CTR org ____
ECR ____
GCL 1 ____
OPC ____
RCA ____
SCR ____
SGA ____
SEC 1 ____
OTH ____

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN V. SMOLENSKI

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

A. My name is John V. Smolenski. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Senior Consultant II - Advanced Technology, in the Engineering and Construction Services Department.

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

A. I graduated from the Rutgers University in May 1974 with a Bachelor of Science degree in Environmental Science. I completed all of the course work towards a Master of Science degree in Environmental Engineering from the New Jersey Institute of Technology. I was employed at Combustion Engineering's Krisinger Development Laboratory as a Research and Product Development Engineer from May 1974 through January 1977 working on flue gas desulfurization and coal gasification. I was employed at

Research-Cottrell Inc, as a Research and Product Development Engineer from January 1977 through January 1978 working on flue gas desulfurization. I was employed at Stone & Webster Engineering Corp. as Lead Environmental Engineer and Flue Gas Desulfurization Specialist from January 1978 through October 1989. In 1989, I joined Tampa Electric Company as a Consultant in the Generation Engineering Department. In my current position as Senior Consultant II, I am a technical consultant to the project engineering groups responsible for the company's air pollution control projects. I am a member of the American Institute of Chemical Engineers, past Chairman of the Electric Power Research Institute's SO_2 Control Program Committee and have published over a dozen papers on air pollution control technology.

Q. Did you prepare any exhibits in support of your testimony?

A. Yes. Exhibit ____ (JVS-1) consists of one document which is Tampa Electric's Big Bend Flue Gas Desulfurization System Reliability Study.

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

A. The purpose of my testimony is to present, for the Commission's review and approval for cost recovery through the Environmental Cost Recovery Clause the Big Bend Flue Gas Desulfurization System Reliability Program ("FGD Reliability Program") based upon the process Tampa Electric used to determine the individual project components that are necessary to meet the 2010 and 2013 requirements of the Consent Decree ("CD") as discussed in the testimony of Tampa Electric's witness Gregory M. Nelson. I will discuss each component of the FGD Reliability Program and describe the methodology employed to determine its cost-effectiveness. Finally, I will address why Tampa Electric chose to perform the installation of the FGD Reliability Program concurrently with the ongoing installation of the selective catalytic reduction ("SCR") systems at Big Bend Station and provide the associated benefits.

Q. Why are the SCRs being installed at Big Bend Station?

A. The installation of the SCRs at Big Bend Station is a requirement of the CD based upon the company's decision to remain coal-fired at the generating facility. Tampa Electric made that declaration on August 19, 2004 in a letter to the United States Environmental Protection

Agency. A discussion and copy of the declaratory letter can be found in the testimony of Tampa Electric's witness Gregory M. Nelson. Additionally, the Commission has approved prudent expenditures associated with the SCR installations in Docket Nos. 040750-EI and 041376-EI.

Q. Did Tampa Electric conduct a study to determine the appropriate actions necessary for Big Bend Station to meet the more stringent 2010 and 2013 SO_2 emissions requirements of the CD?

A. Yes. Document No. 1 of my Exhibit is Tampa Electric's Big Bend Flue Gas Desulfurization System Reliability Study ("Study"). The Study had three main purposes which were to: 1) determine the specific projects that could provide reliability improvements to the FGD systems at Big Bend Station to meet the more stringent 2010 and 2013 requirements of the CD; 2) determine the cost-effectiveness of the proposed reliability improvements; and 3) determine the cost-effectiveness of performing several of the projects earlier than required to meet the 2010 and 2013 deadlines in the CD. This early work would coincide with the construction activities associated with the installation of SCRs occurring at Big Bend Station.

Q. Please summarize the results of the Study.

A. The Study determined 13 specific projects Tampa Electric must complete in order to meet the more stringent 2010 and 2013 requirements of the CD. Additionally, the Study examined the cost-effectiveness of these projects and found the range of cost-benefit-ratios to be from 1.2 to 21 while the net benefit to customers was estimated to be $34 million. Lastly, the Study provided an analysis that demonstrated the benefit of implementing the projects associated with Big Bend Units 1 and 2 concurrent with the installation of SCRs on those units. This benefit to customers is estimated to be $2.7 million. The FGD Reliability Program is the culmination of Tampa Electric's decision to implement the recommendations of the Study in order to meet the 2010 and 2013 requirements of the CD.

Q. Was an outside consultant used in the development of the projects associated with the FGD Reliability Program?

A. Yes. Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to provide costs and conceptual designs for a number of the projects associated with the FGD Reliability Program. However, Tampa Electric performed the cost-effectiveness analyses of the various projects and determined the related benefits.

Q. How did you identify the projects that could provide the needed reliability improvements to the FGD systems at Big Bend Station?

A. As part of the Study process, Tampa Electric identified and evaluated specific maintenance needs, outage requirements and previous or potential equipment failures on the FGD systems which would require a generating unit to come off line. These determinations were made from a combination of actual operating experiences and empirical knowledge of the FGD systems. From these determinations, corrective actions were devised to prevent, minimize or mitigate the detrimental effects of the identified occurrences. Once these corrective actions were identified, Tampa Electric established the reliability projects that were necessary to meet the 2010 and 2013 requirements in the CD.

Q. Please describe the various components of the FGD Reliability Program.

A. There are 13 individual projects that comprise the FGD

Reliability Program. A detailed description and an estimated cost of each project can be found in Document No. 1 of my Exhibit, pages 16 through 24 of the Study.

Q. How were the costs of the projects determined?

A. Project costs were estimated by either the company's outside consultant, Sargent and Lundy, or Tampa Electric. The estimation process began with conceptual engineering designs of the proposed projects. Once the designs were rendered, costs were assigned to each project using standard in-house cost estimating tools. These estimating tools used a combination of currently known commodity costs, vendor supplied estimates and currently known labor rates which were applied to the material estimates and construction man-hour forecasts derived from the conceptual engineering designs.

Q. How were the benefits determined for each project?

A. The benefits for each project were determined in several steps. First, the time necessary to complete repairs or perform necessary maintenance was established as if the project did not exist. Next, the unit outage duration was determined based on the time requirement from the first step. Finally, the associated purchased power and fuel costs associated with the unit outage was determined. These costs were then identified as being avoided due to the implementation of the various reliability projects and thus became the benefits for the projects.

Q. How was the cost-effectiveness of the reliability projects determined?

A. In order to determine the economic viability of the projects, the following steps were utilized:

- Establish a baseline by creating a base case;
- Modify the base case with the project specific improvements to Big Bend Station's availability to create a change case;
- Subtract the change case from the base case to provide the total system savings;
- Layer the total system savings into the capital costs of the project; and
- Calculate the net present value ("NPV") of the cases.

If NPV is positive for the impact of all projects, the FGD Reliability Program is determined to be beneficial to Tampa Electric customers.

Q. What were the results of the cost-effectiveness analysis on the FGD Reliability Program?

A. The results of the analysis performed by Tampa Electric demonstrated that all of the projects that comprise the FGD Reliability Program have positive benefits for the customers with cost-benefit-ratios ranging from 1.2 to 21. These favorable results were obtained by using conservatively estimated benefits. By utilizing the conservatively estimated benefits, the net savings to the customers is estimated to be $34 million.

Q. Why were some of the reliability projects grouped together as one item for the cost benefit analysis?

A. Some reliability projects were grouped together because of their interdependent functionality. For example, to improve the reliability of scrubbing flue gas, the entire absorber module must remain on line. Therefore, improvements to only one internal part of the module will not keep the module on line if the other parts are allowed to fail. This is analogous to a watch. If the function of the watch is defined strictly as the ability to display the time in hours, minutes and seconds and that all three time elements must be correctly displayed or the watch is to be considered inoperative, then each of the three independent mechanisms driving the three arms on the watch's dial must be made more reliable because the failure of any one mechanism would constitute the failure of all three.

Q. Why were some of the projects evaluated for early implementation as opposed to a later date that coincided with the applicable operating changes required by the CD?

A. The components of the FGD Reliability Program associated with Big Bend Units 1 and 2 were evaluated for early implementation for two reasons. First, there were obvious cost savings that would be realized by coordinating their construction activities in conjunction with the construction activities occurring for the Big Bend Station SCR projects. There would be cost savings realized by having a single site mobilization and demobilization of construction equipment and labor, and a shared construction management team and services. Second, maintaining the FGD de-integration days to the end of their calendar life would have required the expenditure of addition capital to accommodate the boiler draft modifications occurring in conjunction with the Big Bend Station SCR projects. This additional capital equipment would have been operational for only two to three years and then rendered inoperable in order to comply with the CD. Furthermore, the company would have incurred the additional capital and fuel costs to accommodate the very low sulfur coal requirements of the CD which would be in effect any time Big Bend Units 1 and 2 were operating unscrubbed from 2010 through 2012.

Q. How did you determine the cost-effectiveness of performing some of the reliability projects earlier than the deadlines defined in the CD?

A. Tampa Electric utilized ProMOD, the company's resource planning model, to calculate the net fuel and purchase power cost difference between the cases to account for the five additional days of maintenance outage per unit required with the early retirement of de-integration days. In addition, Tampa Electric accounted for the timing difference of the capital expenditures for the reliability projects and the value of the SO_2 credits that the company would lose by emitting more SO_2 when running the units un-scrubbed. The analysis also included the premium paid for very low sulfur coal as well as the capital costs to modify the duct work, add dampers and modify the generating units to accommodate for the burning of the low sulfur coal and thus allow for continued de-integration operation.

Q. Please describe the results of the analyses.

A. The result of the analyses performed by Tampa Electric to determine the cost-effectiveness of implementing certain components of the FGD Reliability Program early demonstrated a benefit to customers over $2.7 million. Again, this favorable result was obtained with conservatively estimated component benefits. Also, some benefits were not included, most notably the potential savings from equipment and labor site mobilization and demobilization costs achieved by performing the work simultaneously with the SCR construction.

Q. What alternatives were considered for inclusion in the FGD Reliability Program?

A. There were no specific alternatives extensively evaluated for each of the projects. Those measures that were identified with any potential for consideration were immediately dismissed for either technical or economic reasons. However, one general alternative was considered early in Tampa Electric's discussions and evaluations.

The alternative was to build a spare absorber tower of the same size as the Big Bend Units 1 and 2 absorber tower. But this alternative was quickly dismissed once it was determined that it would not provide as much reliability as the individual components of the FGD Reliability Program and the estimated cost would be in excess of $40 million, well in excess of the total estimated cost for the FGD Reliability Program.

Q. Would Tampa Electric perform the FGD Reliability Program but for the requirements of the CD?

A. No. In the absence of the CD Tampa Electric would be able to operate Big Bend Units 1, 2 and 3 without scrubbing the flue gas for an unlimited number of days per year. Consequently, reliability of the FGD system would have virtually no impact on the generating capability of the units. Therefore, increasing the reliability of the FGD systems would have virtually no beneficial economic impact to customers. It is solely the requirements of the CD that absolutely and directly tie unit generating capability to FGD system reliability. As for Big Bend Unit 4, FGD scrubbing has been a requirement since commercial operation began for that unit.

Q. If the CD had existed prior to the purchase and installation of the FGD system on Big Bend Units 1 and 2 and the integration of Big Bend Unit 3 into the FGD system on Big Bend Unit 4, would Tampa Electric have specified and purchased FGD systems of a different design for these units than those that currently exist at Big Bend Station?

A. Yes. The creation of a generating unit's operational dependency being tied to the uninterrupted functionality of its FGD system would have a definitive impact upon the design of the FGD systems for these units. This is clearly demonstrated by examining the design of the Big Bend Unit 4 FGD system where such a dependency has always existed. The Big Bend Unit 4 FGD system was designed with a spare absorber module, redundant rotating equipment for internal system functionality, spare tankage, redundant limestone preparation systems, redundant gypsum dewatering systems and a host of other spare and back up systems none of which exist on the other FGD systems.

Q. When are the individual projects of the FGD Reliability Program scheduled to be completed?

A. The individual projects of the FGD Reliability Program are scheduled to be completed by the following dates:

- Big Bend Units 1 through 4 Electric Isolation - 2010
- Big Bend Units 3 and 4 Split Inlet Duct - 2007
- Big Bend Units 3 and 4 Split Outlet Duct - 2007
- Big Bend Units 1 and 2 Gypsum Blow Down Line Addition - 2010
- Controls Additions - 2010
- Big Bend Units 3 and 4 FGD Booster Fan Capacity Expansion - 2008
- Big Bend Units 1 through 4 Mist Eliminator Upgrades - 2010
- Big Bend Units 1 through 4 On-line Mist Eliminator Wash System Addition - 2010
- Big Bend Units 1 though 4 On-line Nozzle Wash System Addition - 2007
- Big Bend Units 1 and 2 Recycle Pump Discharge Isolation Bladders Addition - 2008
- Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper Addition - 2006
- Gypsum Fines Filter Addition - 2009
- Gypsum Filter Vacuum Pump Upgrades - 2009

Start times for each of the projects have been identified. At the start, a Project Scope Authorization will be produced and a project team will be assembled from various departments throughout Tampa Electric. The project team is responsible for the detailed design, engineering, project management, construction and cost containment of the project.

Q. Describe how the projects will be monitored and progress reported.

A. Tampa Electric has a proven methodology to provide quality assurance and control on its construction activities. Specifically, a project administrator is selected for each project. The administrators monitor projects and lead the various project teams from project inception to completion and equipment start-up. Competitive bidding is integral to the process. Monthly expenditure and schedule reports are produced and reviewed for variances with adjustments made to maintain project budget and progress.

Q. What is the present status of the active projects?

A. There are already several active projects and their status are listed below.

- Big Bend Units 1 through 4 Electric Isolation - Detailed design and engineering has been initiated for this project and it is proceeding on schedule.

- Big Bend Units 3 and 4 Split Outlet Duct - The detailed design and engineering for this project has been completed. Also, the materials have been purchased, fabrication of components completed and delivery of product to the plant site has commenced with construction scheduled to occur during the fall 2006 outage of Big Bend Unit 4. The project completion is projected to be on time and under budget.
- Control Additions - For this project, preliminary design and engineering has begun and is proceeding on schedule.
- Big Bend Units 1 through 4 Mist Eliminator Upgrades - The detailed design and engineering, material purchases and fabrication of the new mist eliminators for Big Bend Units 3 and 4 have been completed. Product delivery to the plant site has begun and the installation is scheduled to occur during the fall 2006 outage of Big Bend Unit 4. The work associated with the new mist eliminators for Big Bend Units 1 and 2 is scheduled to commence next year.
- Big Bend Units 1 through 4 On-Line Nozzle Wash System - The preliminary design and engineering has begun for this project and is proceeding on schedule.
- Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper -

This project is complete and final costs are being compiled. The project is expected to be on budget.

Q. Please summarize your testimony.

A. Tampa Electric conducted a study with the assistance of an experienced consulting firm, Sargent and Lundy, to determine the appropriate actions necessary for Big Bend Station to meet the more stringent 2010 and 2013 SO_2 emissions requirements of the CD. After thorough evaluations, the company identified 13 specific projects that will cost effectively maximize the reliability of the generating units at Big Bend Station. These projects have cost-benefit-ratios ranging from 1.2 to 21 with an estimated net savings to customers of $34 million. Furthermore, the evaluations conducted by the company demonstrate that implementing some these projects earlier than required by the CD and in conjunction with the SCR installations occurring on the Big Bend generating units will result in additional savings to customers of approximately $2.7 million. The Commission has previously approved for recovery through the ECRC prudent expenditures the company has incurred in meeting the CD and CFJ requirements. It is appropriate for the Commission to reaffirm its five-zero decision made at the

June 20, 2006 Agenda Conference that approved the company's prudent costs associated with the Big Bend FGD Reliability Program for cost recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 050958-EI
FILED: 11/17/06

EXHIBIT TO THE TESTIMONY OF

JOHN V. SMOLENSKI

Big Bend Station Flue Gas Desulfurization System
Reliability Study

TAMPA ELECTRIC COMPANY

Big Bend Station
Flue Gas Desulfurization System
Reliability Study

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") entered into 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 operate the flue gas desulfurization ("FGD") system whenever coal was being combusted in Units 1, 2 or 3 except as summarized below:

- Big Bend Units 1 and 2 can operate on coal without the FGD system in operation for 60 days during calendar year 2000.
- Big Bend Units 1 and 2 can operate without the FGD system for 45 days during calendar years 2001 – 2012.
- Big Bend Unit 3 can operate without the FGD system for 30 days during calendar years 2000 – 2009.
- Big Bend Units 1, 2 and 3 can operate without the FGD system in response to a system-wide or state-wide emergency as declared by the Governor or to avoid interruption of electrical service to its customers under interruptible service tariffs.
- When both Big Bend Units 1 and 2 operate without the FGD system during the same day that will count as two of the 60 or 45 days it is allowed to operate without the FGD system.
- When Big Bend Units 1, 2 or 3 operate without the FGD system, that unit will combust coal with sulfur content no greater than 2.2 lbs. SO_2/MMBtu during

calendar years 2000 – 2009 and 1.2 lbs. SO_2/MMBtu for calendar years 2010 – 2012.

The result of these Orders is that Big Bend Units 1 through 3 will not be able to remain on line if the FGD system is off line or its capacity reduced beginning on January 1, 2010 for Unit 3 and January 1, 2013 for Units 1 and 2. This will have a very significant impact on a unit's availability unless its respective FGD system availability is improved through cost-effective FGD equipment modifications.

Tampa Electric conducted an investigation to determine the leading causes of FGD system outages and capacity reductions and their respective durations. With the assistance of Sargent & Lundy, a renowned power generation consulting firm, Tampa Electric then determined the appropriate modifications necessary to reduce or eliminate the causes and their associated costs. Finally, the costs were studied to determine which modifications should be implemented based upon their benefits.

The result of this FGD system reliability study indicated that the list below of FGD system additions and modifications were economically beneficial to implement due to their cost-to-benefit ratios ("CBR") being greater than 1.0. A number of the planned modifications that will provide reliability improvements were combined due to the fact that the FGD system is not a single piece of equipment but a very complex system. Therefore, improving only one part of the system would make an imperceptible change in the whole system. The modifications that were considered together are identified by a group letter (i.e., A, B and C). All of the modifications are improvements that would otherwise occur after the expiration of the un-scrubbed operating days.

- Big Bend Units 1 through 4 Electric Isolation
- Big Bend Units 3 and 4 Split Inlet Duct - Group A
- Big Bend Units 3 and 4 Split Outlet Duct - Group A
- Big Bend Units 1 and 2 Gypsum Blow Down Line Addition
- Controls Additions

- Big Bend Units 3 and 4 FGD Booster Fan Capacity Expansion
- Big Bend Units 1 through 4 Mist Eliminator Upgrades - Group B
- Big Bend Units 1 through 4 On-line Mist Eliminator Wash System Addition - Group B
- Big Bend Units 1 through 4 On-line Nozzle Wash System Addition - Group B
- Big Bend Units 1 and 2 Recycle Pump Discharge Isolation Bladders Addition
- Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper Addition
- Gypsum Fines Filter Addition - Group C
- Gypsum Filter Vacuum Pump Upgrades - Group C

Table 1 below summarizes the analysis results of the listed additions and modifications.

Table 1 Big Bend FGD Reliability Analysis Results

Projects	Project Cost	NPV of Capital Expenditure	NPV of Savings	Net Savings	CBR
Group A	$4,945	$4,463	$7,131	$2,668	1.6
Big Bend Units 3-4 Split Inlet Duct					
Big Bend Units 3-4 Split Outlet Duct					
Group B	3,617	3,126	3,882	755	1.2
Big Bend Units 1-4 Mist Eliminator Upgrades					
Big Bend Units 1-4 On-line Mist Eliminator Wash System					
Big Bend Units 1-4 On-line Nozzle Wash System					
Group C	3,489	2,855	5,768	2,913	2.0
Gypsum Fines Filter					
Gypsum Filter Vacuum Pump Upgrades					
Other Projects					
Big Bend Units 1-4 Electric Isolation	6,600	5,802	7,131	1,329	1.2
Big Bend Units 1-2 Gypsum Blow Down Line	284	232	436	203	1.9
Controls Additions	406	352	2,404	2,052	6.8
Big Bend Units 3-4 FGD Booster Fan Capacity Expansion	1,849	1,620	18,205	16,585	11.2
Big Bend Units 1-2 Recycle Pump Discharge Isolation Bladders	227	192	4,023	3,831	21.0
Big Bend Units 1-2 Inlet Duct C-276 Wallpaper	234	221	3,882	3,661	17.6
Grand Total	**$21,651**	**$18,862**	**$52,860**	**$33,998**	

Notes:
1) All Dollars in $000
2) All Capital Expenditures were assumed to be in 2005 dollars
3) An inflation rate of 3.0% was assumed
4) A discount rate of 9.09% was assumed

The timing of these modifications is based upon the complex and intricate nature of the combination of: 1) scheduled major outage maintenance work, 2) current and future selective catalytic reduction ("SCR") installation and related duct modifications, and 3) these FGD system modifications.

The SCRs for Big Bend Units 1 and 2 will be in operation in mid-2010 and mid-2009, respectively. The units' back end ductwork and fans must be redesigned to accommodate the SCR systems. However, in order to maintain the ability to operate un-scrubbed after the SCRs are installed would require additional ductwork and controls over and above what is required for the SCR installations. Tampa Electric analyzed if the cost for these additional ductwork modifications and controls necessary to operate the units un-scrubbed through the end of 2012 would be more cost-effective than relinquishing the un-scrubbed operating days for Big Bend Units 1 and 2. The analysis demonstrated that it was prudent to forego the un-scrubbed operating days available to the units for calendar years 2011 and 2012. Simply stated, maintaining the ability to use these un-scrubbed operating days through the expenditure of additional capital for the two-year period of time could not be economically justified. However, the cost to modify the ductwork necessary to retain the un-scrubbed operating days for Big Bend Unit 3 was justified and the company will retain this operating strategy until the de-integration days expire at the end of 2009.

The FGD system reliability project work is currently scheduled to commence in 2006. The primary focus in 2006 will be the modifications to the Big Bend Unit 3 and 4 FGD system in coordination with the SCR projects currently underway for compliance with NO_x emissions on Big Bend Units 3 and 4. The total cost for the Big Bend Station FGD system reliability modifications is estimated to be $21,651,000 with approximately $2,731,000 of that occurring in 2006.

The economic benefits of these planned FGD system reliability projects is justified and outlined in this report. The net savings is estimated to be almost $34 million.

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 2006, Tampa Electric is projecting a firm retail load of approximately 3,735 MW while maintaining a net electric generating capacity of 4,250 MW located at four different sites: Big Bend Station, H.L. Culbreath Bayside Power Station, Phillips Station, and Polk Power Station.

Historically, coal was 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 to the H.L. Culbreath Bayside Power Station with natural gas-fired combined cycle technology in early 2004. Current 2006 projections for the system's net generation are 40 percent from natural gas, 50 percent from coal and the balance from 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") entered into 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 29, 30 and 40 of the CD require Tampa Electric to operate the flue gas desulfurization ("FGD") system for each of the units at Big Bend Station at all times with exceptions as listed below.

Paragraph 29 states,

> "Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:
>
> A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:
>
> (1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of

the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2

emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit."

Paragraph 30 of the CD discusses the FGD requirements for Big Bend Unit 3. It states,

> "Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1,

2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for

Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4."

Since Tampa Electric elected to continue to burn coal at Big Bend Station, the future requirements for Big Bend Units 1 through 3 are stated in Paragraph 40 of the CD as follows,

"If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. <u>Removal Efficiency or Emission Rate</u>. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control SO_2 emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control SO_2 emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of

NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it."

1.3 Overview of Tampa Electric's Big Bend FGD System Reliability Study

To evaluate the best approach to comply with the Orders, Tampa Electric, with the assistance of Sargent & Lundy, investigated ways to improve the Big Bend FGD system reliability once the allowable un-scrubbed operating days expired. These investigations considered all the requirements of the Orders and future capital and operation and maintenance ("O&M") expenses. The investigation addressed two main questions:

- What FGD system reliability modifications and upgrades were cost effective for improving overall unit availability?
- Should the cost effective FGD reliability improvements be made just prior to the expiration of the allocated un-scrubbed operating days or should they be installed as part of the ongoing SCR construction unit outages?

The major causes of FGD system forced outages and FGD system capacity reductions were identified. Potential future causes of forced outages and capacity reductions were also identified. The time durations and capacity reductions generally associated with each of these conditions were also determined.

A conceptual design of the changes to the boiler draft system and the cost of these modifications was developed to maintain the ability to run un-scrubbed on Big Bend Units 1 through 3 after the SCRs are installed. Also, the SCR construction and major maintenance outage schedules were analyzed to determine the most advantageous time to implement the FGD modifications. The potential additional capital cost associated with the boiler draft system modifications was developed for two cases: 1) maintaining the ability to utilize the allowed un-scrubbed days after the SCR installation, and 2) not maintaining the ability to run un-scrubbed after the SCR installation. Installing some of the FGD system reliability modifications as part of the SCR construction effort would mean that the allowable un-scrubbed operating days would be retired prior to their expiration in some instances. The value of the un-scrubbed operating days for the time period between their expiration and their early retirement was developed and compared to the cost to maintain them until their expiration date.

2.0 ASSUMPTIONS

Two analyses were performed. The first analysis determined those projects (or groups of projects) that were cost-effective in maintaining minimal unit outages subsequent to the 2009 and 2012 CD deadlines for the termination of un-scrubbed de-integration unit operation. The result of this analysis is shown in Section 4.1. The second analysis was performed to determine if Tampa Electric should make the modifications concurrent with the installation of SCRs on the generating units. By doing the modifications concurrently and relinquishing the de-integration days allowed by the CD, the company would be able to determine if savings on capital expenditures would occur while taking advantage of the long SCR tie in outages on the units. The result of this analysis is shown in Section 4.2.

In order to evaluate the effects of the loss of the allowed FGD un-scrubbed operating days, certain assumptions were made as to the effects of specific improvement projects upon the FGD systems along with specific economic assumptions.

2.1 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 3.00%
- Income Tax Rate 38.58%
- Other Tax Rate 3.00%
- Debt Ratio 45.00%
- Equity Ratio 55.00%
- Debt Rate 7.50%
- Equity Rate 12.75%
- Discount Rate 9.09%

- AFUDC Rate 7.79%
- It was assumed that all units would have a maximum life of 50 years and would be shutdown or repowered at that time.

2.2 Big Bend FGD System Reliability Study Assumptions

Big Bend Units 1 through 3 would experience an increase in their forced and planned outage rates after the expiration of the un-scrubbed operating days if the FGD systems were left in their present configurations without any modifications or upgrades.

Tampa Electric investigated FGD system reliability improvements with Sargent and Lundy to develop costs for the various modifications being considered for the Big Bend FGD systems. Each option considered capital costs, scheduling, and compatibility with the existing equipment, fuel sources, emissions requirements, generation forecast and O&M costs.

A number of the planned modifications that will provide reliability improvements were combined due to the fact that the FGD system is not a single piece of equipment but a very complex system. Therefore, improving only one part of the system would make an imperceptible change in the whole system. The modifications that were considered together are identified by a group letter (i.e., A, B and C). All of the modifications are improvements that would otherwise occur after the expiration of the un-scrubbed operating days.

2.2.1 Big Bend Units 1 through 4 Electric Isolation

Much of the FGD equipment on the Big Bend Units 1 through 4 FGD systems is fed from common transformers and motor control centers. Therefore the loss of one of these centers or transformers will cause a forced outage of the entire FGD system resulting in the outage of Units 1 and 2 or Units 3 and 4. In order to eliminate the possibility of this occurrence, the equipment feeds will be divided up among separate transformers and control centers to ensure that their loss can only affect a single unit at a time. The estimated cost for this addition is $6,600,000. The benefit to the forced outage and the maintenance outage rates is estimated to be the avoidance of two days per year for each outage rate for any unit.

2.2.2 Big Bend Units 3 and 4 Split Inlet Duct – Group A

The FGD inlet duct for Big Bend Units 3 and 4 is common to both units. In order to perform any maintenance on this duct, both units must be scheduled to be off-line at the same time. To avoid such a large loss of generating capacity, the inlet duct for Unit 3 will be isolated from the inlet duct for Unit 4 by installing a double wall half way between the B and C absorber towers. The estimated cost for this addition is $116,000. The benefit to the forced outage rate and the maintenance outage rate is estimated to be the avoidance of two days per year for each outage rate for Unit 3 or 4. This benefit is included in the Group A projects.

2.2.3 Big Bend Units 3 and 4 Split Outlet Duct – Group A

The FGD outlet duct for Big Bend Units 3 and 4 is common to both units. In order to perform any maintenance on this duct, both units must be scheduled to be off-line at the same time. To avoid such a large loss of generating capacity, the outlet duct for Unit 3 will be isolated from the outlet duct for Unit 4 by installing a new duct for the sole use by A and B absorber towers. The estimated cost for this addition is $4,829,000. The benefit to the forced outage rate and the maintenance outage rate is estimated to be the avoidance of two days per year for each outage rate for Unit 3 or 4. This benefit is included in the Group A projects.

2.2.4 Big Bend Units 1 and 2 Gypsum Blow Down Line Addition

The gypsum reaction product is removed from the Units 1 and 2 FGD system through a single gypsum blow down pipeline. This pipeline is subject to maintenance and breakage or can become plugged. When this occurs, Units 1 and 2 would be forced off line until repairs could be completed. To avoid this type of loss a new additional gypsum blow down pipeline will be installed. The estimated cost of this addition is $284,000. The benefit to the forced outage rate and the maintenance outage rate is estimated to be the avoidance of two days per year for each outage rate for Unit 1 or 2.

2.2.5 Controls Additions

The Programmable Logic Controllers ("PLC") for the Big Bend Units 1 through 4 FGD systems must be backed up by another system to prevent the FGD systems from tripping due to a single PLC failure. This will require new input/output cabinets and associated controls that will be added to the existing system. The estimated cost for this addition is $406,000. The benefit to the forced outage rate is estimated to be the avoidance of two days per year for Unit 1 or 2 and three-quarters of one day per year for Unit 3 or 4.

2.2.6 Big Bend Units 3 and 4 FGD Booster Fan Capacity Expansion

When the ductwork on Units 3 and 4 is split, the two towers dedicated to Unit 3 will not handle the entire gas flow at full load. The flue gas handling capacity of tower A or B must be increased by 60 percent. A larger fan wheel will be installed to provide the additional fan capacity needed to allow full gas flow with two towers on each unit. Also, a larger motor will also be installed. The estimated cost for this modification is $1,849,000. The benefit derived is from avoiding a five percent reduction in Unit 3 capacity due to flue gas flow restrictions.

2.2.7 Big Bend Units 1 through 4 Mist Eliminator Upgrades – Group B

In order to increase on-line tower availability, the mist eliminators must be maintained in a clean, unplugged state. To accomplish this cleaning, a high pressure water wash system must be added to the absorber towers. However, the current mist eliminators are made of a polypropylene material that will become damaged when washed with high pressure water. Therefore, the polypropylene mist eliminators of all the absorber towers must be changed to alloy materials of construction. The corrosion resistant alloy material will then allow the mist eliminators to be high pressure washed which is essential to maintaining tower availability.

In addition, the alloy material is required for temperature protection on the absorber towers during hurricane operation since the polypropylene also cannot withstand high temperatures. During hurricanes, power plant operations outside the confines of the main buildings are suspended for personnel protection, which results in the inability to maintain the operation of the recycle pumps and other outside equipment that provide the scrubbing slurry inside the absorber. Without the flue gas being contacted by this slurry from the recycle pumps, the flue gas will remain at its tower inlet temperature which is too high for the polypropylene mist eliminators. This is a paramount concern subsequent to SCR installations since the hot flue gas will only be allowed to pass through the tower and past the mist eliminators in hurricane operation mode.

The replacement of the existing mist eliminators includes both upper and lower stages (layers) at an estimated cost of $1,554,000. The mist eliminator internal wash piping on the FGD system for Units 1 and 2 will also be replaced with alloy piping instead of the fiberglass presently used which has suffered repeated failures and breakage. The change to alloy piping will eliminate these failures and the incomplete washing by the standard wash system and premature pluggage of the mist eliminators. The estimated cost for this modification is $833,000. Therefore, the total of the two mist eliminator changes is $2,387,000. The benefit to the forced outage rate is estimated to be the avoidance of four days per year for Unit 1 or 2 and one and one-half days for Unit 3 or 4. The maintenance outage rate benefit is estimated to be the avoidance of two days per year for either Unit 1 or 2.

2.2.8 Big Bend Units 1 through 4 On-line Mist Eliminator Wash System Addition – Group B

The absorber towers are to be fitted with a high pressure mist eliminator wash system. This would involve the installation of an internal rail track to guide a high pressure nozzle underneath the new alloy mist eliminator sections (upper and lower) to wash the undersides of the alloy packing while the tower is still on-line. The system will consist of the track, wash nozzle, high pressure pumps, internal high pressure hose and high pressure supply piping leading up to the towers. The estimated cost for this addition is $669,000. The benefit to the forced outage rate is estimated to be the avoidance of four days per year for Unit 1 or 2 and one and one half-days for Unit 3 or 4. The maintenance outage rate benefit is estimated to be the avoidance of two days per year for Unit 1 or 2. This benefit was included in the Group B projects in the analysis.

2.2.9 Big Bend Units 1 through 4 On-Line Nozzle Wash System Addition – Group B

The internal spray headers of the absorber towers are to be fitted with valves and packing glands to allow on-line cleaning of the header pipe (internal to the pipe) via a traveling high pressure wash nozzle. This system will facilitate the on-line cleaning of the four spray headers of the Big Bend 1 and 2 tower and the six spray headers of each of the four Big Bend 3 and 4 towers. The estimated cost for this addition is $561,000. The benefit to the forced outage rate is estimated to be the avoidance of four days per year for Unit 1 or 2 and one and one-half days for Unit 3 or 4. The maintenance outage rate benefit is estimated to be the avoidance of two days per year for Unit 1 or 2. This benefit was included in the Group B projects in the analysis.

2.2.10 Big Bend Units 1 and 2 Recycle Pump Discharge Isolation Bladders Addition

The absorber recycle pumps cannot be disconnected from the spray headers while the tower is on-line because flue gas will leak from the tower through the open pipe. These lines are approximately 42 inches in diameter and presently contain no valves of any type. Therefore, each of the four recycle pump discharge lines will be fitted with an inflating bladder which will act as an isolation valve. The bladder will be inserted immediately adjacent to the tower wall so that it is in gas service only (no hydraulic head on the bladder due to standing slurry against it from inside the tower) and will also serve to isolate the recycle pipes. The estimated cost for this addition is $227,000. The benefit to the forced outage rate is estimated to be the avoidance of two days per year for Unit 1 or 2.

2.2.11 Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper Addition

The carbon steel inlet duct to the absorber tower must be wallpapered with C-276 sheets that are 1/16th inch thick for corrosion protection. The area to be covered is the floor and four feet up the sidewalls to 10 feet back from the absorber tower inlet expansion joint. The estimated cost for this addition is $234,000. The benefit to the forced outage rate and the maintenance outage rate is estimated to be the avoidance of one day per year for each outage rate for Unit 1 or 2.

2.2.12 Gypsum Fines Filter Addition – Group C

In order to maintain uninterrupted operation of the gypsum dewatering system, a gypsum fines filter must be installed. The scope is to install a 12 ft. diameter by 20 ft. long precoat filter for gypsum fines filtering service. The filter will be fed 250 – 300 gallons per minute of return water (primary dewatering hydroclone overflow) at approximately six percent solids. The filter will have an automatic precoating system complete with tank, valves and control system for precoating the filter with gypsum from the sludge surge tanks (primary dewatering hydroclone underflow). The filter is to be complete with its own liquid ring vacuum pumps and vacuum receivers. The filter will discharge into an open screw conveyor which will then deliver the material to a location where a front end loader will remove the filter cake. The estimated cost for this addition is $2,866,000. The benefit to the maintenance outage rate is estimated to be the avoidance of two days per year for any unit. This benefit was included in the Group C projects in the analysis.

2.2.13 Gypsum Filter Vacuum Pump Upgrades – Group C

The gypsum dewatering system has two Komline-Sanderson 12 ft.

diameter by 20 ft. long vacuum filters installed as part of the Big Bend Units 1 and 2 FGD project. These filters are equipped with liquid ring vacuum pumps. The gypsum cake dryness can be improved if the capacity of these pumps is increased. With improved cake dryness the capacity and reliability of the filters will be improved. In addition, the materials of construction will be upgraded to a more corrosion resistant material to improve their reliability. The objective is to double the air flow of the vacuum system on each of these filters. This will require the replacement of each vacuum pump with new vacuum pumps and motors and electrical supply equipment. The estimated cost for this modification is $623,000. The benefit to the maintenance outage rate is estimated to be the avoidance of two days per year for any unit. This was included in the Group C projects in the analysis.

2.3 Maintaining Un-scrubbed Operating Days vs. Early Retirement

This analysis looks at the advantages of performing these projects in conjunction with the SCR projects. A significant portion of the FGD reliability projects require construction in and on the same portions of the plants as the SCR project construction. Therefore, the determination of the benefit of simultaneously undertaking the two construction activities must be made. This would result in the FGD reliability projects being implemented early with respect to the dates required by the CD. The assumptions made for the station during the time period that the un-scrubbed operating days are available include:

- The Big Bend units would experience no forced outages due to the loss of the FGD system while the un-scrubbed operating days are still available.
- The units would experience no increase in their planned outage rate while the un-scrubbed operating days are still available.
- The units would consume SO_2 allowances at an accelerated rate of

between 520 and 555 per year while the un-scrubbed operating days are available.

- SO_2 allowance prices were estimated at \$804 - \$856 each during the years that the un-scrubbed operating days are available.

The assumptions made for the station when the un-scrubbed operating days were retired early in conjunction with the start-up of the SCR projects include:

- Big Bend Units 1 and 2 would retire their un-scrubbed operating days early on May 1, 2010 and May 1, 2009, respectively, to coincide with the expected SCR start-up date for each unit.
- Big Bend Units 1 and 2, without the ability to de-integrate due to the early retirement of un-scrubbed days, would require five additional maintenance outage days per year per unit.

In order to maintain de-integration capability on Big Bend Units 1 and 2 beyond the time of SCR installation and its associated draft modifications would require significant ductwork and equipment additions. The ductwork and isolation damper additions would require an expenditure of approximately \$5,800,000 above what is required for the SCR modifications to that same area. The useful life of these additions would only be from May 1, 2009 and May 1, 2010 for Big Bend Units 1 and 2, respectively, to January 1, 2013 when de-integration operation expires under the CD.

In accordance with the CD, the sulfur content of the fuel burned during the 2010 through 2012 de-integration days is significantly below that allowed by the CD for the current de-integration days. This significantly lower sulfur coal would require the additional expenditure of \$2,830,000 for installing two flue gas conditioning systems on the units to aid electrostatic precipitator performance, conducting a series of low sulfur coal test burns to find an acceptable fuel for the boilers, expanding coal yard operations for segregation and additional handling of low sulfur de-integration coal, fluxing of high ash fusion temperature low sulfur coal and similar related items. By retiring the de-integration days early, the company will avoid this additional expenditure.

The situation for maintaining FGD de-integration days on Big Bend Unit 3 is considerably different. In order to maintain de-integration capability on Big Bend Unit 3 beyond the time of SCR installation and its associated draft modifications would require $200,000 of ductwork and equipment additions. Also, the sulfur content of the coal burned during the time period of Unit 3's de-integration days is not as restrictive as that of Units 1 and 2 and as such does not require any of the capital expenditures to burn it that are required on those units. In summary, maintaining FGD de-integration days on Unit 3 would cost approximately $200,000 compared to $8,630,000 ($5,800,000 for ductwork and isolation dampers plus $2,830,000 for flue gas conditioning) for Units 1 and 2.

3.0 METHODOLOGY

3.1 Big Bend FGD System Reliability

All the projects evaluated in this study increase Big Bend Station's availability by investing capital into various projects. In order to determine the economic viability of each project the following steps were completed:

- Establish a baseline by creating a base case.
- Create a change case by modifying the base case with the project specific improvements to Big Bend Station's availability.
- Subtract the base case from the change case, which provides the total system savings.
- Layer the total system savings into the capital costs of the project.
- Calculate the net present value ("NPV") of each case was calculated.
- If the NPV is positive, then the project is declared beneficial to Tampa Electric customers.

ProMOD version 8.7 was the model used to determine the overall system savings.

Table 2 below summarizes the capital expenditures and the effects on Big Bend Station's availability.

Table 2 Big Bend FGD Reliability Analysis Inputs

	Capital Expenditures					Scheduled Outage		Unit	FOR*	MOR**
Group A	2006	2007	2008	2009	2010	Start	Stop			
Big Bend Units 3-4 Split Inlet Duct	-	$123	-	-	-	2/1/2007	5/1/2007	BB 1	0	0
Big Bend Units 3-4 Split Outlet Duct	$1,061	4,030	-	-	-	2/1/2007	5/1/2007	BB 2	0	0
	$1,061	$4,153	-	-	-			BB 3	24	24
								BB 4	24	24

	Capital Expenditures					Scheduled Outage		Unit	FOR	MOR
Group B	2006	2007	2008	2009	2010	Start	Stop			
Big Bend Units 1-4 Mist Eliminator Upgrades	$834	$789	$66	$870	-	1/2/2009	4/9/2009	BB 1	48	24
Big Bend Units 1-4 On-line Mist Eliminator Wash System	-	-	-	753	-	1/2/2009	4/9/2009	BB 2	48	24
Big Bend Units 1-4 On-line Nozzle Wash System	30	564	-	-	-	1/2/2009	4/9/2009	BB 3	18	0
	$864	$1,354	$66	$1,623	-			BB 4	18	0

	Capital Expenditures					Scheduled Outage		Unit	FOR	MOR
Group C	2006	2007	2008	2009	2010	Start	Stop			
Gypsum Fines Filter	-	-	$1,566	$1,613	-	1/2/2009	4/9/2009	BB 1	0	12
Gypsum Filter Vacuum Pump Upgrades	-	-	340	351	-	1/2/2009	4/9/2009	BB 2	0	12
	-	-	$1,906	$1,964	-			BB 3	0	12
								BB 4	0	12

Stand Alone Projects	Capital Expenditures					Scheduled Outage		Unit	FOR	MOR
	2006	2007	2008	2009	2010	Start	Stop			
Big Bend Units 1-4 Electric Isolation	$288	$5,305	$721	$743	-	2/1/2007	5/1/2007	BB 3	24	6
								BB 4	24	6
Big Bend Units 1-2 Gypsum Blow Down Line	-	-	155	160	-	1/2/2009	4/9/2009	BB 1	6	0
								BB 2	6	0
Controls Additions	103	106	109	119	-	2/1/2007	5/1/2007	BB 3	9	0
								BB 4	9	0
Big Bend Units 3-4 FGD Booster Fan Capacity Expansion	173	990	817	-	-	2/1/2007	5/1/2007	BB 3	0	0
Big Bend Units 1-2 Recycle Pump Discharge Isolation Bladders	-	18	229	-	-	1/2/2009	4/9/2009	BB 1	24	0
								BB 2	24	0
Big Bend Units 1-2 Inlet Duct C-276 Wallpaper	241	-	-	-	-	1/2/2009	4/9/2009	BB 1	12	12
								BB 2	12	12
Grand Total	$2,731	$11,926	$4,004	$4,609	-		$23,269			

Assumptions
1) All dollars in $000
2) All dollars are inflated at 3% from 2005 baseline
3) All projects occur during previously schedule outages and have no net effect on those outages
4) All projects remain beneficial, without degradation, until the end of unit life

* FOR = Forced outage rate in hours
** MOR = Maintenance outage rate in hours

3.2 Maintaining Un-scrubbed Operating Days versus Early Retirement

Tampa Electric performed an analysis to determine if maintaining the un-scrubbed operating days until their expiration, as allowed by the CD, would be cost-effective as compared to performing the reliability projects during the SCR outages when similar construction activities on the same areas of the plant are taking place. ProMOD version 8.7 was used to calculate the net fuel and purchase power cost difference between the cases to account for the five additional days of maintenance outage per unit required with the early retirement of de-integration days. In addition, Tampa Electric accounted for the timing difference of the capital expenditures for the reliability projects and the value of the SO_2 credits that the company would lose by emitting more SO_2 when running the units un-scrubbed. The analysis also included the premium paid for very low sulfur coal as well as the capital cost to modify the ductwork and add dampers to allow continued de-integration operation and capital cost to modify the unit to allow burning of very low sulfur coal.

4.0 RESULTS

4.1 FGD System Reliability Improvements

After compilation of the input assumptions and completion of the modeling phase, the CBRs of the proposed reliability projects were identified. Table 3 below summarizes those CBRs.

Table 3 Big Bend FGD Reliability Analysis Results

Projects	Project Cost	NPV of Capital Expenditure	NPV of Savings	Net Savings	CBR
Group A	$4,945	$4,463	$7,131	$2,668	1.6
Big Bend Units 3-4 Split Inlet Duct					
Big Bend Units 3-4 Split Outlet Duct					
Group B	3,617	3,126	3,882	755	1.2
Big Bend Units 1-4 Mist Eliminator Upgrades					
Big Bend Units 1-4 On-line Mist Eliminator Wash System					
Big Bend Units 1-4 On-line Nozzle Wash System					
Group C	3,489	2,855	5,768	2,913	2.0
Gypsum Fines Filter					
Gypsum Filter Vacuum Pump Upgrades					
Other Projects					
Big Bend Units 1-4 Electric Isolation	6,600	5,802	7,131	1,329	1.2
Big Bend Units 1-2 Gypsum Blow Down Line	284	232	436	203	1.9
Controls Additions	406	352	2,404	2,052	6.8
Big Bend Units 3-4 FGD Booster Fan Capacity Expansion	1,849	1,620	18,205	16,585	11.2
Big Bend Units 1-2 Recycle Pump Discharge Isolation Bladders	227	192	4,023	3,831	21.0
Big Bend Units 1-2 Inlet Duct C-276 Wallpaper	234	221	3,882	3,661	17.6
Grand Total	**$21,651**	**$18,862**	**$52,860**	**$33,998**	

Notes:
1) All Dollars in $000
2) All Capital Expenditures were assumed to be in 2005 dollars
3) An inflation rate of 3.0% was assumed
4) A discount rate of 9.09% was assumed

The analysis indicates that a net savings of $33,998,000 can be achieved by the simultaneous undertaking of the FGD reliability projects and the SCR projects at Big Bend Station.

4.2 Maintaining Un-scrubbed Operating Days versus Early Retirement

After compilation of the input assumptions and completion of the modeling phase, the analysis of performing the proposed reliability projects in conjunction with the SCR construction in lieu of the later time of de-integration day expiration set forth in the CD was conducted. The results of that analysis are found in Table 4 below.

Table 4 Maintain Deintegration Days

	2006	2007	2008	2009	2010	2011	2012	2013	2014
SO_2 Emissions Inc (Dec) (tons)	-	-	-	-	520	555	551	-	-
SO_2 Credit Forward Mkt ($/credit)	$1,465	$1,525	$1,486	$1,488	$856	$849	$804	$752	$692
NF&PP	0	0	0	0	2,287	2,894	5,235	0	0
SO_3 Cond/Test Burn/Low Sulfer Coal O&M	(2,830)	0	0	0	0	0	0	0	0
SO_2 Cash Inc (Dec)	0	0	0	0	(445)	(472)	(443)	0	0
Project Capital Expenditure	0	0	(1,050)	(1,428)	0	(1,100)	(2,235)	0	0
Coal Cost	0	0	0	0	(894)	(977)	(969)	0	0
Total Cash Flow	($2,830)	$0	($1,050)	($1,428)	$949	$346	$1,588	$0	$0
NPV ($000)	($2,729)								

Notes:
1) All dollars in $000
2) The 45 deintegration days of Big Bend Units 1 & 2 would be used after 2010
3) FGD maintenance outage rate is five days every year for each unit

The analysis indicates that maintaining the de-integration days would cost Tampa Electric and additional $2.729 million over the base case. This additional cost clearly demonstrates that the reliability projects should be performed in conjunction with the SCR projects and the de-integration days retired at the appropriate earlier time.

No specific quantitative analysis was conducted on the early retirement of un-scrubbed operating days for Big Bend Unit 3 due to the low cost necessary to retain de-integrated operation of the unit in accordance with the CD. It was readily apparent from quantitative analysis conducted on Big Bend Units 1 and 2 that the accrued benefits from maintaining the de-integration days for Unit 3 would exceed the cost of $200,000 many times over.

5.0 CONCLUSIONS

All of the FGD reliability projects demonstrated a net positive savings to Tampa Electric. The implementation of these reliability projects will minimize additional decreases in availability and reliability of the Big Bend Station units that would otherwise occur after the de-integration days expire in 2009 and 2012. In total, the projects have a cumulative capital cost of $21,651,000 that is offset by a savings of $52,860,000 which provides a net benefit of $33,998,000.

Furthermore, it is prudent for Tampa Electric to retire the de-integration days allowed by the CD for Big Bend Units 1 and 2 prior to the established deadline. The additional capital expenditures described in Section 2.3 of over $8,630,000 for ductwork, isolation dampers and flue gas conditioning equipment required to maintain FGD system de-integration capability beyond the date of the SCR construction and implementation for the units do not provide commensurate savings. It would cost the company an additional $2,729,000. Therefore, it is not prudent. However, the benefit to Big Bend Unit 3 derived from maintaining de-integration days beyond its SCR installation exceeds many times over the modification cost of $200,000.

Tampa Electric anticipates moving forward with implementing the projects described in this study as the most prudent way to ensure generating unit and FGD system reliability at Big Bend Station.