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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

050001-EI

In re: Fuel & Purchased Power Cost Recovery and Capacity Cost Recovery
_____________________________________/

Docket No. 030001-EI

Filed: October 2, 2003

DIRECT TESTIMONY AND EXHIBITS

OF

SHEREE L. BROWN

ON BEHALF OF

THE FLORIDA INDUSTRIAL POWER USERS GROUP

AND

THE FLORIDA RETAIL FEDERATION

(CONFIDENTIAL VERSION)

5-10-05

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DOCUMENT NUMBER-DATE
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Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Sheree L. Brown and I am a Managing Principal of Alliant Energy Integrated Services, located at 710 N. Orange Ave., Suite 710, Orlando, Florida 32801.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A: I graduated Magna Cum Laude from the University of West Florida with a B. A. in Accounting and later received a Masters in Business Administration degree from the University of Central Florida. I am a Certified Public Accountant in the State of Florida and am a member of the American Institute of Certified Public Accountants and the Florida Institute of Certified Public Accountants. Since 1981, I have provided utility consulting services in matters pertaining to electric, water, wastewater, natural gas, steam heat and chilled water utilities. My work has focused in the areas of regulatory affairs, revenue requirements and cost of service, rates and rate design, deregulation and stranded costs, valuation and acquisition, feasibility studies and contract negotiations. A more detailed description of my experience is included in my resume that is attached hereto as Exhibit No.____ (SLB-1).

Q: ON WHOSE BEHALF ARE YOU SPONSORING THIS TESTIMONY?

A: I am sponsoring this testimony on behalf of the Florida Industrial Power Users Group ("FIPUG") and the Florida Retail Federation ("FRF").

Q: WHAT ARE THE INTERESTS OF FIPUG AND FRF IN THIS PROCEEDING?

A: FIPUG and FRF are made up of numerous large utility consumers that take power from Tampa Electric Company ("Tampa Electric"). Unexpected electric rate increases have a significant impact on the operating costs of these companies. The extraordinary increase in fuel costs Tampa Electric has requested has triggered FIPUG's and FRF's concern. Typical residential and small business consumers will not be aware of changes in their fuel costs until such changes have already occurred. FIPUG and FRF felt obliged to express their concern to the Commission in this proceeding.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to address Tampa Electric's extraordinary increase in fuel costs. I recommend that the Florida Public Service Commission ("Commission" or "FPSC") take steps to protect Tampa Electric's ratepayers from subsidizing TECO Energy's financially stressed affiliates. This will protect the credit worthiness of Tampa Electric by limiting the free flow of cash from the healthy regulated utility to its affiliates.

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony reviews the distressed financial condition of TECO Energy and its unregulated companies and the effect the financial problems have on Tampa Electric and its ratepayers. I explain how:

(i) contractual relationships between Tampa Electric and TECO Energy's other subsidiaries have resulted in subsidies of those subsidiaries from Tampa Electric ratepayers;

(ii) dissimilar ratemaking concepts between base rates and cost recovery clauses have afforded an opportunity for the holding company to generate additional cash flow from Tampa Electric at ratepayer expense; and

(iii) the timing of the Tampa Electric's decision to accelerate the closure of the Gannon Power station was concurrent with TECO Energy's desperate need for cash.

I then recommend that the Commission reduce Tampa Electric's $100 million requested rate increase to cover anticipated fuel expenses by $63.7 million of Gannon O&M savings, recognizing that the ratepayers would continue to pay for the discontinued operations through base rates at the same time they would be forced to bear the extraordinary fuel cost increases.

I further recommend that the Commission review Tampa Electric's remaining O&M expenditures for 2003 and 2004 and determine the extent of the expenditures that is attributable to dismantlement activities that ratepayers have already paid for through dismantlement accruals. If a portion of the 2003 and 2004 O&M activities are related to dismantlement, I recommend that the Commission provide an additional offset to the increased fuel expenses for the amount of such dismantlement activities.

With respect to Tampa Electric's dealings with its TECO Energy affiliates, I recommend that the Commission review the HPP contract costs in light of the gain on the sale of HPS to assure that costs are reasonable and reflect HPP's actual investment in the facility and to assure that the change of ownership will not affect ratepayer costs. I also recommend that the Commission evaluate the impact of the Company's decisions to purchase contract rights for the acquisition of turbines from General Electric and the subsequent cancellation and write-off of those contract rights.

Q: PLEASE DESCRIBE THE FINANCIAL STRUGGLES TECO ENERGY FACED

DURING 2002 AND 2003.

A: In 2002, TECO Energy suffered downgrades in its ratings. The downgrades reflected rating agency concerns over TPS investments and the negative impact on TECO Energy's earnings and cash flow as a result of weakness in the wholesale power market. TPS has made substantial investments in generating facilities and rating agencies are concerned with TPS' ability to sell the output. TECO Energy has provided corporate guarantees on TPS projects, including a $500 million equity bridge, additional equity guarantees, and a guarantee of contractors' obligations.

As a result of the downgradings by Fitch, Standard & Poors, and Moodys, TECO Energy developed a business plan to decrease capital expenses by deferring generating projects, selling assets, arranging additional financing, and selling additional common equity. Despite TECO Energy's efforts to increase capital through these measures, the TECO Energy's financial predicament has continued. Ratings were downgraded again, with negative rating outlooks. The reasons for the downgrades included higher-than-expected debt leverage on a cash flow basis, the negative impact on earnings and cash flow measures from increased interest expense, weaker projected earnings, and higher-than-anticipated capital expenditures, in addition to continued concerns over the ability of TPS to recover the significant investments it has made in unregulated generating facilities. TECO Energy also announced a 46% dividend cut.

In April, 2003, Moody's cut TECO Energy's long-term debt rating to junk status, forcing the Company to take additional actions. On July 10, 2003, the TECO Energy was placed on CreditWatch by Standard & Poor's Rating Services due to uncertainties regarding TECO Energy's ability to raise cash by the sale of its synfuel production facilities.

Q: HOW DO THE FINANCIAL DIFFICULTIES FACED BY TECO ENERGY AFFECT TAMPA ELECTRIC?

A: Although Tampa Electric's earnings remain strong, the rating agencies have downgraded Tampa Electric, citing the increase in leverage and business risk at the parent. As noted in a September 15, 2003 report by William Ferara, an analyst from Standard & Poor's:

> TECO's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise and recognizes a free flow of funds throughout the organization and the absence of sufficient regulatory insulation. Thus, the ratings on Tampa Electric are expected to mirror those of TECO, given the absence of proscriptive authority by the regulators in Florida. Any *regulatory insulation or structural separation* imposed to legally ring-fence Tampa Electric would be favorable for the utility's ratings. However, this action would drastically hinder TECO's ability to access the utility's strong cash flows and use its overall financial health to its benefit, which would result in significantly lower ratings at the parent. (emphasis added)

Exhibit No. ____(SLB-2) provides a copy of the September 15, 2003 report from Mr. Ferara, along with a report from the two Moody's analysts and an article from the Saint Petersburg Times. These articles and reports succinctly explain TECO Energy's financial situation. As shown above, the Standard & Poor's article explains how the free flow of funds throughout the organization and the absence of sufficient regulatory insulation has driven down Tampa Electric's credit ratings. This will adversely affect consumers and demonstrates the need for protection of the ratepayers' interests to limit the impact of unfortunate management decisions by TECO Energy and its unregulated subsidiaries.

Q: HOW COULD TECO ENERGY'S FINANCIAL SITUATION AFFECT DECISIONS MADE BY TAMPA ELECTRIC?

A: Under traditional ratemaking practices, a utility has the incentive to decrease non-fuel expenses, and thereby increase earnings, during years between rate cases. Utilities also have the incentive to maximize earnings by the use of contractual relationships between affiliates and the utility. Maximizing the utility's income also provides TECO Energy with the ability to take advantage of tax losses incurred by the non-regulated affiliates. These incentives are increased when a company faces financial struggles such as those faced by TECO Energy.

Q: HOW DOES TRADITIONAL RATEMAKING PROVIDE A UTILITY WITH THE INCENTIVE TO DECREASE NON-FUEL EXPENSES DURING YEARS BETWEEN RATE CASES?

A: Under traditional ratemaking, a utility's base rates are set based on estimated revenue requirements for a particular test year. Once rates are set, the utility's earnings can fluctuate based on actual revenues, expenses, and capital investments. The utility, therefore, has the incentive to maximize revenues and minimize expenses between rate proceedings.

Under current practice, Tampa Electric recovers a large portion of its revenue from the Fuel Cost Recovery Clause, the Capacity Cost Recovery Clause, and the Environmental

Cost Recovery Clause. The use of fuel adjustment clauses has been the practice around the country to protect the utilities and the ratepayers from volatile fuel costs over which the utility does not generally have control. Unlike base rates that give the utility the "opportunity to earn a return," cost recovery clauses essentially guarantee full cost recovery of the targeted costs and investments.

When a portion of a utility's revenue requirement is collected through adjustment clauses, which allow the "pass-through" of costs, a utility has the further incentive of shifting costs from base rate expenses into expenses that are recoverable through the pass-through clauses. While regulated utilities typically have this incentive between rate cases, the incentive is even stronger when a utility is facing financial difficulties. This was the situation faced by Tampa Electric at the time it made its decision to shut down the Gannon Units early. That decision allowed Tampa Electric to decrease its operating and maintenance expenses and increase earnings to the holding company, which can be used to support the cash flow needs of the affiliated companies, while increasing fuel costs, which are a pass-through to ratepayers.

Q: DID TAMPA ELECTRIC RECOGNIZE THIS TILT IN BENEFITS AND COSTS BETWEEN THE HOLDING COMPANY AND RATEPAYERS WHEN MAKING ITS DECISION TO SHUT DOWN THE GANNON UNITS EARLY?

A: Yes. Numerous data responses indicate Tampa Electric's knowledge and concern over the impact of the decisions. In addition, many of the analyses clearly show ratepayer costs and holding company savings. The following are just a few excerpts from data responses provided by the Company:

Bates Stamp	Excerpt
3049	Why these changes are necessary: In support of and to contribute to the challenges being faced by our Company.
3534	With the original December 2004 Gannon shut down date, there were no pending layoffs projected. However, now with the Base Case (#9) dates, significant reclassifications and layoffs are projected.
4814	Reduction to Achieve 2003 & 2004 Plug…Gannon – Accelerated Shutdown
4814	Gannon – Accelerated Shutdown (Implementation) • Units 1 & 2 – Shutdown with Bayside 1 Start-up • Units 3 & 4 – Shutdown September 1, 2003 (Anticipates depletion of available funding)
203	Under the Gannon early closure look, what are the impacts to earnings and ROE….what are ratepayer impacts? What are the components that will impact the fuel clause?
15	Rate base removal/Gannon base rate adj? -What would be potential impact? Earnings ROE -Argue immediate replacement of asset (BS1) * - Needs to be linked dates - must run argument -Lead to ratecase? Ratepayer impact – what goes thru fuel clause? Filing of 2003 rates on Sept. 20
797/812	Cons…1994 test year of Gannon Station included in base rates. Strong potential for base rate reduction in 2003.
2239	Since Gannon was required to reduce the 2003 budget by $1.3 M in order to meet the TEFIS assumption, the reduction has to come from these units.
200	PPA Strategy Meeting… Issues and Points to Consider… ROE and revenue requirements without Gannon… Prepare to justify the PPA as low-cost option?... Clause impacts… Shutting down Gannon units should coincide with the beginning of the PPA term and with the first Bayside unit beginning service… Prepare for affiliate discovery requests…

Q: DO TAMPA ELECTRIC'S CONTRACTUAL RELATIONSHIPS WITH TECO ENERGY AFFILIATES AFFECT RATEPAYER COSTS?

A: Yes. As pointed out by the rating agencies, Tampa Electric has several special contractual relationships with affiliates that affect ratepayers' costs. For example, TECO Energy has an affiliate that sells coal to Tampa Electric and TECO Transport provides Tampa Electric's coal transportation. The cost of the coal and its transportation is run through the fuel cost recovery clause. In addition, Tampa Electric has power purchase agreements with Hardee Power Partners Limited ("HPP"). To the extent that such arrangements are made at above-market costs, TECO Energy benefits by increasing the profitability of the non-regulated affiliates, while passing-through such higher costs to Tampa Electric's captive ratepayers.

Q: TECO ENERGY HAS BEEN ATTEMPTING TO RAISE CASH BY SELLING ASSETS. HOW DO THESE CONTRACTUAL RELATIONSHIPS AFFECT THE VALUE OF ASSETS FOR SALE?

A: This strategy has the additional benefit to the holding company of making certain assets more valuable for sale while avoiding the sharing of any gains on disposition. For example, in part of its efforts to increase cash flow, TPS recently announced the sale of its interest in the HPS, noting that it "expects to record a $60-million book gain (pre-tax) on the sale and net incremental cash of approximately $110 million." (Exhibit No.____ (SLB-3)). Thus, while Tampa Electric's power purchase agreement supported the sale, Tampa Electric's ratepayers will not see any of the gain. If this facility had been owned by Tampa Electric, normally the Commission would require the utility to share the gain on the sale with ratepayers.

Q: HOW DID TAMPA ELECTRIC'S POWER PURCHASE AGREEMENT WITH HARDEE SUPPORT THE SALE?

A: The power purchase agreement is simply assigned to the new owner of the facility. Therefore, the value of the facility is directly related to the expected cash flows provided by Tampa Electric ratepayers under the agreement. Tampa Electric's witness, J. Denise Jordan, estimated that the fuel portion of the purchased power from HPP will cost $16.1 million at an average rate of approximately $.05813 per kilowatt hour. (J. Denise Jordan Document No. 2, Schedule E7). In addition to the fuel costs, Tampa Electric is paying HPP almost $20 million a year for capacity payments. Ms. Jordan's Document No. 1 does not specify the level of capacity payments to HPP; however, as shown in document Bates Stamp 11603, the capacity charge is $19,624,800. With capacity payments of $19.6 million a year, the anticipated cost of power from HPP jumps from $.05813 per kilowatthour to $.1291 per kilowatthour. While I do not have sufficient information to evaluate the reasonableness of these charges, the HPP costs are among the highest purchased power costs paid by Tampa Electric.

Q: HAS THE COMMISSION APPROVED THE HPP COSTS?

A: The original HPP contract was approved by the Commission in the early 1990's. In 1999, the Commission addressed the Hardee 2000 amendment and allowed recovery of the HPP costs in the fuel clause, but "left the door open" for future review and consideration. As explained in Order No. PSC-99-2513:

> At the present time, we find that these costs should be recovered through the fuel clause. However, if information indicating that these costs were not prudently incurred is discovered, the prudence of these costs may be raised as an issue for our consideration in a future fuel

hearing.

Q: SHOULD THE COMMISSION INVESTIGATE THE HPP POWER COSTS DUE TO THE SALE OF HPS?

A: Yes. It is my understanding that the HPP is a "cost-based" contract. In light of the gain on the sale of HPS, the Commission should review the amounts paid under the contract to assure that the costs are reasonable and reflect HPP's actual investment in the facility. The Commission should also assure that the change of ownership will not affect ratepayer costs by increasing the owner's cost, which may then be recoverable from Tampa Electric and its ratepayers.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH AFFILIATE TRANSACTIONS?

A: Yes. In 2002, Tampa Electric purchased TECO-Panda Generating Company's rights to four combustion turbines being purchased from General Electric. Tampa Electric paid $62.5 million for these rights. This transaction allowed TECO Energy to shift cash from Tampa Electric to TECO-Panda Generating Company. (Exhibit No.____ (SLB-4)). Just one year later, in 2003, Tampa Electric recorded a before tax charge of $79.6 million ($48.9 million after tax) related to the cancellation of the turbine purchases. The Company expects to receive a refund of approximately $13 million from General Electric. To the extent the Company receives this refund and to the extent TECO Energy can utilize tax benefits from the write-off, the additional cash flow would be available to meet the cash needs of TECO Energy and its unregulated subsidiaries. Yet, given Tampa Electric's plans to add seven combustion turbines over the next nine years, the decision to cancel the rights to the four combustion turbines may result in higher costs to ratepayers as the additional capacity is added. The Commission should evaluate the impact of these decisions on Tampa Electric's costs to assure that short-term decisions to alleviate the TECO Energy's financial problems do not result in higher ratepayer costs.

Q: PLEASE DESCRIBE THE EVENTS LEADING TO THE REQUIREMENT TO SHUT DOWN THE GANNON UNITS.

A: The Gannon plant consisted of six coal-fired steam generating boilers and associated systems located in Hillsborough County, Florida with a total nameplate generating capacity of 1301.88 MWs. On November 3, 1999, the United States Environmental Protection Agency filed a Notice of Violation alleging that Tampa Electric had violated certain requirements of the Clean Air Act ("CAA") by making modifications to the Gannon Station without obtaining the appropriate permits and that these modifications resulted in a net significant increase in emissions from Gannon Station. As explained in the Notice of Violation, the modifications, included, but were not limited to, replacement of the furnace floor of Unit 3 in 1996; replacement of the cyclone burners of Unit 4 in 1994; and replacement of the second radiant superheater of Unit 6 in 1992. The Notice of Violation also included violations at Tampa Electric's Big Bend coal facility.

On December 6, 1999, a Consent Final Judgment ("CFJ") was entered into with the Florida Department of Environmental Protection ("DEP"). The CFJ called for shutting down the Gannon Station three years before the previously expected retirement date. Company witness, Mr. Whale, indicated that the CFJ incorporated the same requirements as the

Consent Decree negotiated between Tampa Electric and the United States Environmental Protection Agency.

On February 29, 2000, the United Stated District Court, Middle District of Florida, approved the Consent Decree negotiated between Tampa Electric and the United States Environmental Protection Agency. (Exhibit No. ____(SLB-5). The Consent Decree required, among other things, that (i) Tampa Electric repower 550 MW of Gannon coal-fired capacity with 200 MW being repowered on or before May 1, 2003 and the remainder being repowered on or before December 31, 2004 and (ii) Tampa Electric shut down and cease any and all operation of all six Gannon coal-fired boilers with a combined capacity of not less than 1194 MW on or before December 31, 2004.

Q: WHAT IMPACT DOES THE COMPANY'S DECISION TO SHUT DOWN THE GANNON UNITS EARLY HAVE ON THE COMPANY'S REQUESTED FUEL COST RECOVERY IN THIS CASE?

A: As noted by the Commission in Order No. PSC-03-0400-PCO-EI, the decision to shut down the Gannon units early resulted in a decrease in coal-fired generation. At that time, the Commission estimated the cost of replacement power costs for 2003 to be approximately $26 million. The Commission stated:

> ...we find that the reasons for, and the cost effectiveness of, Tampa Electric's decision to cease operations early at Gannon Units 1-4 should be fully explored before we can authorize Tampa Electric to recover the $26 million in associated replacement power costs. (Order No. PSC-03-

0400-PCO-EI at page 6).

The Commission further noted that the decision to cease operations early at Gannon Units 1 through 4 was a decision within the utility's control and recognized that this decision might enhance Tampa Electric base rate earnings. The Commission explained:

> We believe that the total economic effect on both base rate earnings as well as fuel costs should be evaluated in determining the prudence of the early shutdowns of Gannon Units 1-4. (Order No. PSC-03-0400-PCO-EI at page 7).

Q: WHAT REASONS DID TAMPA ELECTRIC GIVE FOR ITS DECISION TO SHUT DOWN THE GANNON UNITS PRIOR TO THE REQUIRED DATE OF DECEMBER 31, 2004?

A: First, to meet the May 1, 2003 in-service date for Bayside Unit 1, Gannon Unit 5 had to be shut down. Given that the repowering of Unit 5 to Bayside Unit 1 met the requirements of the Consent Decree and the Consent Final Judgment, the remainder of the units were not required to be shut down prior to December 31, 2004. Tampa Electric, however, determined that the planned in-service date for Bayside Unit 2 would be January 15, 2004, requiring an earlier shutdown of Gannon Unit 6. The decision was also made to shut down Units 1 through 3 earlier than the required date of December 31, 2004. According to Company witness, Mr. Whale, Tampa Electric evaluated various conditions to determine when to shut down the units, including the timing of Bayside construction activities, reliability and safety of units 1 through 4, maintenance costs and planned outage times, employee issues, reserve margin requirements, and transmission constraints. Mr. Whale also noted that Tampa Electric made a determination that it would attempt to keep the units running as long as possible without incurring significant expenditures for preventive maintenance work. Mr. Whale also explained that Tampa Electric ran multiple scenarios to evaluate ratepayer impacts, operation and maintenance impacts, and wholesale sales opportunities for off-system sales.

Q: DID THE COMPANY PRESENT SUFFICIENT EVIDENCE IN ITS FILING TO ALLOW THE COMMISSION TO DETERMINE THE TOTAL ECONOMIC EFFECT ON BASE RATE EARNINGS AND FUEL COSTS?

A: No. Company witness, Mr. Benjamin F. Smith, argued that it is neither feasible nor appropriate to isolate and then attribute costs to a single variable, such as the shutdown of the Gannon units. While he makes the argument that the costs cannot be isolated, he still concludes that the energy purchases to supplement generation due to the shutdown of Gannon Units 1 through 4 are reasonable. He also notes that Tampa Electric will have to make a 50MW firm capacity commitment for the summer of 2004, but does not provide the cost of that commitment. Neither Mr. Smith, nor any other Tampa Electric witness, provided any calculations of the replacement costs actually incurred or anticipated as a result of the early shutdown of the units.

Tampa Electric's witness, Mr. Whale, provides the only testimony regarding O&M savings, noting that Tampa Electric would need to incur "additional" O&M expenses of approximately $57 million to try to keep Units 1 through 4 operating somewhat reliably.

Q: HAS TAMPA ELECTRIC PROVIDED COPIES OF ANY ANALYSES PERFORMED?

Q: HAS TAMPA ELECTRIC PROVIDED COPIES OF ANY ANALYSES PERFORMED?

A: Yes. In response to OPC Requests for Production of Documents, Tampa Electric provided numerous analyses of various operating and shutdown scenarios. None of the scenarios represented the actual shutdown plan currently contemplated by Tampa Electric. In the initial "round" of evaluations, there were 11 scenarios. A review of the assumptions under those scenarios shows that Scenario 9 was the closest scenario to the final shutdown dates described by Witnesses Jordan and Whale. In the next round of evaluations, Tampa Electric evaluated 5 options. A review of the assumptions under those options shows that Option 5 was the closest to the final shutdown dates.

Q: WHAT WERE THE 2003 AND 2004 OPERATING AND MAINTENANCE COST PROJECTIONS FOR GANNON?

A: **As shown in the response to OPC Request for Production of Documents, Bates Stamp 2082 and 2083, the projected O&M costs for 2003 were $26.645 million, exclusive of fuel. The projected costs for 2004 were $8.75 million, exclusive of fuel. These costs were calculated under Scenario 9, which incorporated shutdown of Unit 5 in February, 2003; shutdown of Units 1 and 2 on March 15, 2003; shutdown of Unit 6 on September 1, 2003; and shutdown of Units 3 and 4 at September 1, 2003 or until "O&M dollars are gone." (Bates Stamp 2082 and 2083).**

Q: DID TAMPA ELECTRIC DETERMINE THE COST TO KEEP THE UNITS RUNNING THROUGH THE REQUIRED SHUTDOWN DATE OF DECEMBER 31, 2004?

A: **Tampa Electric provided numerous documents showing analyses of various shutdown** scenarios. In a later "Gannon Early Shutdown Issues Paper," Tampa Electric determined that it did not need to run the Gannon Units 1-4 through September 4, 2004 as originally planned. Tampa Electric evaluated five possible scenarios for early shutdown in 2003. Of those scenarios, Scenario 5 appears to be the closest to the plan addressed in Tampa Electric's testimony in this proceeding. As shown in the response to OPC Request for Production of Documents, Bates Stamp 1187, implementation of Scenario 5 was expected to result in 2003 impacts to the customers through the fuel clause of $31.8 million, while Tampa Electric would achieve savings of $10.5 million in operating and maintenance expenses.

Q: DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S ESTIMATE OF O&M SAVINGS AS SHOWN ON BATES STAMP 1187?

A: Yes. A review of the average O&M for the Gannon station, as reported in Tampa Electric's 2002 Federal Energy Regulatory Commission Form 1, over the last 5 years shows that O&M, excluding fuel costs, were as follows:

FIVE YEAR HISTORY OF GANNON OPERATING AND MAINTENANCE EXPENSES (EXCLUDING FUEL)			
Year	Operating	Maintenance	Total O&M
1998	$10,031,664	$23,508,659	$33,540,323
1999	$9,822,080	$22,141,702	$31,963,782
2000	$11,145,091	$24,435,680	$35,580,771
2001	$10,667,859	$24,148,779	$34,816,638
2002	$10,103,336	$29,910,813	$40,014,149
Average	$10,354,006	$24,829,127	$35,183,133

Tampa Electric has provided several documents showing that the projected 2003 O&M expenses for Gannon are **$26.645 million**. Based on a simple comparison of the historical O&M costs and the projected 2003 O&M, Tampa Electric's estimate of **$10.5 million** in

O&M savings appears reasonable. However, based on the testimony of Tampa Electric's witness, Mr. Whale, it would appear that Tampa Electric expected much higher-than-normal O&M costs if it were to keep Units 1 through 4 operational through December 31, 2004. Mr. Whale indicated that Tampa Electric would need to incur additional maintenance expenses of $57 million to keep the Gannon Units 1 through 4 operating "somewhat reliably" through 2004. If it is assumed that (i) the expected maintenance expense in 2003 for Units 1 through 4 was at the $57 million level (which does not include any maintenance expenses for Units 5 and 6), (ii) the maintenance expense for Unit 6 is held at the average of $4.13 million per unit, and (iii) Tampa Electric would have incurred normal operating expenses for Units 1 through 4 and Unit 6 of approximately $8.67 million (5/6 of the historical average of $10.4 million), then the actual savings for 2003 would be in the magnitude of **$43.155** million ($69.8 million less the 2003 projection of **$26.6 million**).

Q: WHAT IS THE LEVEL OF O&M SAVINGS EXPECTED FOR 2004?

A: **As shown on the response to OPC's Request for Production of Documents, Bates Stamp 2083, Tampa Electric estimates that Gannon O&M expenses in 2004 will be $8.75 million. When compared to average historical O&M expenses, this will provide Tampa Electric savings of $20.569 million for Units 1 through 4 and 6. When compared to 2002 O&M expenses, Tampa Electric savings will be $24.595 million.**

Q: WHAT ARE THE TOTAL O&M SAVINGS THAT WILL ACCRUE TO THE COMPANY FOR 2003 AND 2004 DUE TO THE GANNON SHUTDOWN?

A: Assuming the $57 million level of avoided O&M costs for 2003, the total O&M savings that will accrue to Tampa Electric for 2003 and 2004 due to the Gannon shutdown will be **$63.7** million. This consists of **$43.155** million in 2003 savings and **$20.569** million in 2004 savings. These savings exclude any savings associated with Unit 5.

Q: WHAT ARE THE SAVINGS IF IT IS ASSUMED THAT THE $57 MILLION IN O&M COSTS ON UNITS 1 THROUGH 4 IS INCURRED OVER THE TWO-YEAR PERIOD?

A: Assuming the average level of maintenance expenses of $24.8 million was equally divided among the six Gannon units, an average level of O&M per unit would be approximately $4.133 million. Thus, over the two-year period, the total avoided O&M would be $57 million on Units 1 through 4 and $8.27 million on Unit 6, for a total of $65.27 million. When added to average operating costs of $17.33 million ($8.67 million a year on 5 units), the total avoided O&M would be approximately $82.6 million. The savings would thus be approximately **$47.2** million ($82.6 million less Tampa Electric's estimated 2003 and 2004 O&M expenses of **$35.4 million**).

Q: DO YOU HAVE ANY CONCERNS WITH THE FUEL COST IMPACTS ESTIMATED BY THE COMPANY ON THE RESPONSE LABELED AS BATES STAMP 1187?

A: Yes. **Tampa Electric's estimate of $31.83 million in fuel clause impacts included $17.605 million in fuel and purchased power, $6.555 million in coal contract penalties, and $7.67 million in dead freight charges. The fuel and purchased power estimate of $17.605 million appears low when compared with historical generation from the Gannon units.**

Q: PLEASE EXPLAIN.

A: Exhibit No. ____(SLB-6) is a calculation of the estimated replacement power costs associated with the Gannon shutdown. In 2002, the Gannon Units had net generation of 4,814,986 MWhs. Using this level of generation as a base and applying the Gannon shutdown dates results in replacement energy of 1,926,049 MWhs. On Schedule E4, the average cost of generation from Bayside is estimated to be $.046 per kWh, while the average cost of generation from Gannon is approximately $.0214 per kWh, based on 2002 actual expenses. Fuel costs, then, more than double when Gannon generation is replaced by gas-fired generation. At the differential of $.0246 per kWh, the replacement fuel costs for 2003 would be approximately $47.4 million. When added to Tampa Electric's estimate of **$6.555 million** in coal contract penalties and **$7.67 million** in dead freight charges, the cost to ratepayers will be approximately **$61.625 million**. Although Tampa Electric did not include the coal contract penalties and dead freight charges in its current cost recovery calculations, it has indicated that these costs would be included in the subsequent true-up calculations.

Q: WHAT IS THE EXPECTED REPLACEMENT COST OF ENERGY IN 2004?

A: Assuming replacement of 100% of Gannon generation in 2004, the expected replacement cost of energy would be $118,604,917 (4,814,986 MWhs X $24.60) before any dead freight costs and coal contract penalties.

Q: HAVE YOU CALCULATED THE REPLACEMENT COST OF ENERGY FOR UNITS 1 THROUGH 4 AND UNIT 6 ONLY?

A: Yes. Since Tampa Electric was required to shut down one unit by May 31, 2003 and chose to shut down Unit 5 to repower to Bayside 1, I determined the cost associated with replacement energy on Units 1 through 4 and Unit 6 to isolate the costs associated with the shutdown of these units. The replacement costs for Units 1 through 4 would be $24.5 million and $56.5 million for 2003 and 2004, respectively. The replacement costs for Unit 6 would be $2.4 million for 2003 and $39.7 million for 2004.

Q: WHAT OTHER COSTS HAVE BEEN INCURRED BY THE EARLY SHUTDOWN OF UNITS 1 THROUGH 4?

A: As explained by Tampa Electric witness Mr. Smith, Tampa Electric is projecting that it will purchase 50 MW of firm capacity for its summer 2004 reserve margin requirement. If Gannon Units 1 through 4 were kept operational until the required December 31, 2004 date, then this purchase would not be required.

In addition, as shown in Tampa Electric's 2004 Fuel Procurement and Wholesale Power Purchases Risk management Plan, Tampa Electric has incurred additional hedging costs due to its implementation of a hedging plan in 2003 in response to the need for an increase amount of natural gas due to repowering of Gannon. In accordance with the Commission's policy, Tampa Electric's incremental hedging costs are passed through the fuel adjustment clause.

Q: DO YOU HAVE A RECOMMENDATION REGARDING TAMPA ELECTRIC'S REPLACEMENT FUEL COSTS?

A: Yes. I believe it would be just and reasonable for the Commission to require Tampa Electric to offset its replacement power costs by $63.7 million in O&M savings. This would be a fair and equitable result because (i) the decision to shut down the units early was a voluntary decision by the Company within its control; (ii) the requirement to shut down the units by the end of 2004 was a direct result of claimed violations by the United States Environmental Protection Agency, (iii) the ratepayers will suffer continued harm through additional replacement power costs from 2005 through 2007, (iv) the ratepayers have also paid Tampa Electric for the environmental modifications which were challenged by the EPA; and (v) TECO Energy has benefited by contractual relationships between its subsidiaries, including recognition of a gain on the sale of HPS which is not shared with the ratepayers.

Q: HAS THE COMMISSION EVER ALLOWED UTILITIES TO USE COST RECOVERY CLAUSES TO CHARGE CUSTOMERS FOR ITEMS THAT WOULD NORMALLY ONLY BE AUTHORIZED THROUGH A BASE RATE ADJUSTMENT AFTER A "FULL BLOWN" GENERAL RATE CASE?

A: Yes. The Commission has allowed the recovery of security costs and incremental hedging costs through adjustment clauses. In addition, environmental costs are recovered through the Environmental Cost Recovery Clause. In 1998, Tampa Electric was allowed to recover the $90 million cost of a new scrubber at Big Bend 1 & 2 that the Company indicated would solve most of the requirements of Phase II of the Clean Air Act Amendments. In addition, Progress Energy is currently being allowed to recover operating, maintenance, and capital costs associated with its Hines Units 2 to the extent of fuel savings. Using this logic, it would seem appropriate to give customers credit in the fuel clause for associated savings Tampa Electric realizes in O&M expenses.

Q: THE COMPANY RECENTLY REQUESTED ACCELERATION OF DEPRECIATION AND DISMANTLEMENT CHARGES ON GANNON. SHOULD THE COMMISSION

RECOGNIZE THESE CHARGES AS REDUCTIONS IN SAVINGS ACCRUING TO SHAREHOLDERS?

A: No. Annual depreciation charges for Gannon have been $23.2 million. Earlier this year, Tampa Electric was given the authorization to accelerate depreciation to assure full depreciation of the Gannon Units by the end of 2003, subject to a final hearing on the issue in November. As a result, Tampa Electric's earnings for 2003 will be reduced by an additional $22.9 million. Expenses for 2004 will thus be $23.2 million less than 2002 and $46.1 million less than in 2003.

In addition to the annual depreciation charges, Tampa Electric has been accruing $5.8 million a year for dismantlement. Earlier this year, in Docket 030409-EI, the Company requested an increase in the dismantlement accrual of $2.2 million, for a total of $7.987 million. Prior to 2003, the portion of the $5.8 million accrual attributable to Gannon was $711,297; however, Gannon represents $7.4 million of the 2003 accrual. If this accrual is discontinued in 2004, Tampa Electric's dismantlement accrual will decrease to $627,925. This is a reduction of $5.1 million from the pre-2003 accrual.

While Tampa Electric's earnings for 2003 will be suppressed as a result of these additional accruals, the accruals do not affect cash flow. The accruals do, however, affect Tampa Electric's surveillance reporting, allowing Tampa Electric to show a reduced level of earnings. In 2004, this situation will reverse.

Until base rates are modified, customers will continue to pay the charge attributable to Gannon depreciation set in the last general rate case. The net result of the acceleration will be a decrease to Tampa Electric's earnings of $25.1 million in 2003 and an increase of $28.3 million in 2004. Therefore, over the two year period, there is a positive impact of $3.2 million on earnings and zero impact on cash flow.

Q: DO YOU HAVE ANY OTHER ISSUES THAT THE COMMISSION SHOULD CONSIDER IN ITS EVALUATION OF TAMPA ELECTRIC'S FUEL FILING?

A: Yes. The Commission should review the balance in the dismantlement accrual account for Gannon and determine whether it would be appropriate to utilize a portion of this regulatory liability to cover a portion of the expenses associated with early shutdown. In the FPSC Staff Recommendation filed on May 22, 2003 in Docket No. 030409-EI, Staff noted that the Company's current estimate of dismantlement base costs is $40.7 million. A Tampa Electric document in that docket shows total dismantlement costs of $32.12 million. (Exhibit No. ____(SLB-7)). The **$63.7** million in O&M savings calculated earlier in my testimony was based on the Company's estimate of **$26.645** million and **$8.75** million in 2003 and 2004 O&M costs, respectively. To the extent any of these costs are associated with dismantlement activities, those costs should be covered by Tampa Electric from the dismantlement account. The savings and the fuel cost offset should then be adjusted accordingly.

Q: SHOULD THE COMMISSION REFLECT BAYSIDE COSTS IN THE CALCULATION OF SAVINGS?

A: No. The issue of the Bayside addition is more complex than can, or should, be handled in the context of this proceeding. While the Bayside units are utilizing portions of the Gannon 5 and 6 facilities, the addition of the Bayside units is not intended as simply a replacement for the Gannon units. Even without the retirement of the Gannon Units, the Company would need additional capacity to meet its 20% reserve margin requirement. The addition of the Bayside units provides 515 MW of additional capacity over the amount retired at Gannon. Tampa Electric shows generation from Bayside Units 1 and 2 at approximately 7,874,000 kWh's a year, which is significantly higher than the generation from the Gannon Units.

Further, Tampa Electric laid off approximately 7% of its work force in 2002. (Exhibit No. ___(SLB-8). In addition, a full-blown rate case would include the elimination of the Gannon rate base, depreciation, and dismantlement accruals that were included since the last base rate case. Other issues that would be addressed would include the numerous dealings with TECO Energy affiliates.

The Gannon O&M savings are, however, directly attributable to the early shutdown of the units and the imposition of replacement energy costs on Tampa Electric's ratepayers.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A: I recommend that the Commission offset Tampa Electric's requested fuel cost increase by the O&M savings from the shutdown of the Gannon Units. Assuming Tampa Electric avoided $57 million in extraordinary maintenance expenses in 2003 and average maintenance costs in 2004, the total savings to Tampa Electric would be **$63.7** million which should be used to offset the replacement fuel costs. The recommended Fuel and Purchased Power Cost Recovery Factor would then be calculated as follows:

Calculation of Recommended Recovery Factor		
Savings	$	63,700,000
Jurisdictional %		97.34%
Retail Jurisdiction	$	62,003,032
Jurisdictional Loss Multiplier		1.00114
Total Adjusted for Line Losses	$	62,073,715
Retail kWh Sales		18,768,886,000
Savings per kWh Sold	$	0.0033
Revenue Tax Factor		1.00072
Savings Adj for Taxes	$	0.0033
Total Recovery Factor Requested	$	0.03967
Less Savings	$	0.00350
Recommended Recovery Factor	$	0.03617

I also believe the concerns I have expressed in this testimony support additional Commission investigation of:

(i) amounts paid to HPP under the power purchase agreement to assure that the costs were cost-based due to the recognition of a gain on the sale of HPS which was supported by the power purchase arrangement;

(ii) the HPP agreement to assure that the change of ownership will not affect ratepayer costs due to the revised costs of the new owner;

(iii) Tampa Electric's acquisition and subsequent cancellation of turbine purchase rights from TECO-Panda Generating Company to assure that Tampa Electric's decisions are cost-effective for ratepayers and are not simply a means of generating additional cash to meet TECO Energy's short-term cash needs.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

Sheree L. Brown

Managing Principal

Professional Registration	Certified Public Accountant
Education	B.S. in Accounting University of West Florida Pensacola, Florida M.B.A. University of Central Florida Orlando, Florida
Professional and Business History	AEIS/SVBK CONSULTING GROUP 1985 - Present R.W. Beck & Associates 1981 - 1985

Professional Experience

Ms. Brown has extensive experience in the emerging deregulation of the electric industry. She has provided expert testimony on behalf of clients on such issues as stranded cost calculation and recovery, market pricing, and public policy. In participating in deregulation proceedings, Ms. Brown has been responsible for the preparation of comments to regulatory commissions regarding policy issues on restructuring. She has participated in technical conferences held to set policy issues and assisted legal counsel in the preparation of legal positions regarding previous rate agreements and other agreements entered into relevant to the proceedings. In her experience, Ms. Brown has been responsible for the development of methodologies for determining and recovering interim stranded costs. Ms. Brown has also been called on to participate in panel discussions before the regulators regarding the many issues relative to the deregulation of the electric industry.

Ms. Brown served as a member of the Association of Higher Education Facilities Managers' Energy Task Force on deregulation issues. Further, she has been responsible for positioning clients to actively and successfully participate in a Retail Wheeling Pilot Program. In her capacity as lead financial consultant, Ms. Brown assisted in public information campaigns to encourage volunteers, filed comments with regulators to influence the selection process, and developed an aggregation program for eligible Pilot Program participants.

Sheree L. Brown
Managing Principal

Ms. Brown has developed qualified aggregation programs and participated in public workshops to encourage eligible businesses and residents to participate in municipal aggregation programs. Ms. Brown has negotiated and evaluated power supply arrangements for municipal electric systems, universities, and retail aggregation programs. Such negotiations have included joint ownership arrangements, block power purchases combined with supplemental partial requirements, formula rate contracts, economy purchases, full requirements and partial requirements combined with self-generation. She has evaluated the economic feasibility of peaking generating facilities and has negotiated terms and conditions with the electric supplier to enhance the economic benefits of peaking operations.

Ms. Brown has extensive experience in wholesale and retail ratemaking and has represented numerous municipal, cooperative, university, and regulatory clients in proceedings before the Federal Energy Regulatory Commission and various state and local commissions. She has negotiated the settlement of rate cases and has presented expert testimony as a witness in litigated proceedings. As an expert witness, Ms. Brown has presented testimony on revenue requirement issues, cost-of-service studies and allocation methodologies, rate design, utility valuations, and terms and conditions of service.

Ms. Brown has also developed cost recovery methodologies for least cost integrated resource programs, including the effects of demand side management programs on interim recovery of fixed costs. She has additionally developed innovative rate structures designed to provide performance based incentives for demand side management performance.

Ms. Brown has evaluated the effects of capacity and transmission equalization under combined utility operations and the allocation of costs under joint dispatch arrangements. She has provided expert testimony on the effects of a proposed merger on individual utility operations.

Ms. Brown has performed numerous retail rate studies, including the development of revenue requirements, allocated cost-of-service studies, and rate design. She has developed load forecasts using econometric modeling and has developed proforma operating results for rate phase in plans. She has additionally reviewed transfer policies and interdepartmental service contracts.

Ms. Brown has performed feasibility studies for the installation and operation of cogeneration facilities. She has evaluated the benefits of retaining cogeneration to offset retail electric requirements. She has also evaluated the requirements for standby service or reserves. Ms. Brown has successfully challenged the development of standby rates and terms and conditions of service, resulting in enhanced cogeneration project value. She has performed avoided cost calculations and has negotiated arrangements to sell cogeneration capacity and energy to the electric supplier. In addition, she has reviewed market alternatives to selling cogeneration capacity and energy for resale, including the effect of transmission arrangements on project viability.

Ms. Brown has negotiated the sale or purchase of utility systems or facilities, including the purchase or sale agreements; management, operating, and maintenance agreements, and design/construction agreements. She has enhanced project value by negotiating contractual guarantees, including operational efficiency and price guarantees. She has additionally negotiated long term gas supply contracts and financial hedging instruments, including SWAP agreements. She has negotiated transportation contracts, including banking arrangements, whereby excess contract gas is sold back to the transporter at market rates.

Ms. Brown has served on municipal strategic planning committees and has provided capital budgeting analyses for the evaluation of long-term planning alternatives. She has been extensively involved in the development of utility system management studies, including the review of labor costs and efficiencies, organization structure and financial condition. She has additionally performed billing audits.

Sheree L. Brown
Managing Principal

Regulatory/Legal Appearances	Federal Energy Regulatory Commission ("FERC") Council of the City of New Orleans ("CCNO") Florida Public Service Commission ("FPSC") Illinois Commerce Commission ("ICC") Louisiana Public Service Commission ("LPSC") Massachusetts Department of Telecommunications & Energy ("DTI Minnesota Public Utilities Commission ("MPUC") New Hampshire Public Utilities Commission ("NHPUC") North Carolina Utilities Commission ("NCUC") Texas Public Utilities Commission ("TPUC") Circuit Court, Ninth Judicial Circuit, Orange County, Florida Circuit Court, Eighteenth Judicial Circuit, Seminole County, Florida
Papers, Publications, and Presentations	"Determining the Value of Your Municipal Utility" – Presented to the Florida Municipal Electric Association and Florida Municipal Power Agency Annual Conference, 2003. "Municipalization/Franchise Evaluation" - Presented to the Tri-County League of Cities, Casselberry, Florida, January 2001. "Opportunities and Challenges: Managing Energy Costs in a Deregulated Environment" - Presented to the Dallas Chapter of the National Association of Purchasing Managers, Dallas, Texas, October, 2000. "Unbundling - Identifying Strategies for a Smooth Transition to Competition" - Presented at the South Carolina Association of Municipal Power Systems Annual Conference, Hilton Head, South Carolina, June, 1999. "Preparing for Deregulation - Understanding Electric Restructuring Issues Affecting Local Government" - Presented at the Taking Control of Your Destiny: Assessing the Impact of Electric Utility Industry Deregulation on Local Government Conference, Minneapolis, Minnesota, June, 1999. "Electric Restructuring and Utilities Deregulation: A Facility Manager's Guide" - Coauthor with the APPA Energy Task Force, The Association of Higher Education Facilities Managers,

Alexandria, Virginia, 1998.

"Utilities and You: A New Playing Field" - Presented at the U.S. Department of Energy Rebuild America 1998 Annual Conference, San Antonio, Texas, March 1998.

"Preparing for Deregulation in the Electric Utility Industry" - Presented at the Municipal Association of South Carolina 1998 Winter Meeting, Columbia, South Carolina, February, 1998.

"Electric Utility Deregulation" - Presented at the South Carolina Association of Municipal Power Systems Annual Event, Columbia, South Carolina, April 1997.

"Problems & Solutions in Retail Implementation: An Overview of Issues in Electric Utility Restructuring" - Presented at the Energy Awareness: Competition in Electricity in South Carolina Conference, Columbia, South Carolina, March 1997.

"Municipalization of Electric Utility Systems Seminar" - Presented to the Municipal Association of South Carolina, Columbia, South Carolina, August 1996.

Professional and Business Affiliations

American Institute of Certified Public Accountants
Florida Institute of Certified Public Accountants
American Public Power Association ("APPA")
Florida Government Finance Officers' Association ("FGFOA")

September 15: Credit FAQ - TECO Energy Inc.

Location: **New York**
Author: **William Ferara, Standard & Poor''s Analyst**
Date: **Monday, September 15, 2003**

Print Article
Email Article

TECO Energy Inc (BBB-/Watch Neg/A-3) derives about 70% of its cash flow from its regulated utility operations, Tampa Electric Co and Peoples Gas System.

The remaining portion is provided by nonregulatedbusinesses, including independent power generation, water bulk transportation, and coal operations. The company's ratings were placed on CreditWatch with negative implications on July 10, 2003.

Frequently Asked Questions

Why were TECO's ratings placed on CreditWatch?

Standard & Poor's Ratings Services placed its ratings on TECO Energy and affiliates on CreditWatch with negative implications as a result of an IRS announcement creating potential complications related to the company's sale of interests in its synthetic fuel production facilities. The IRS stated it will suspend issuing new private

letter rulings (PLR) for plants producing synthetic fuels. The CreditWatch listing for the TECO family reflects the uncertainties regarding the company's ability to sell interests in its synfuel production facilities to raise cash to halt the erosion of the company's weakened financial profile. TECO has a pending transaction with a PLR as a condition of sale for a 49% interest in its synfuel production facilities and had anticipatedselling an additional 40% interest in its facilities. The sale of these interests is expectedto contribute about $70 million in cash flow in 2003 and $90 million to cash flow annually in 2004 through 2007. An unfavorable outcome, which either halts or significantly delays the sales or ultimately affects cash flow, could lead to lower credit ratings.

When will the CreditWatch listing be resolved?

The CreditWatch listing will be resolved upon completion, or abandonment of, of the company's pending sale of interests in its synthetic fuel production facilities. However, the timing of the IRS ruling is uncertain and may be prolonged. Because the company has other asset sales that it is expecting to complete in the near term that are crucial to credit quality, the CreditWatch listing will most likely not extend beyond late 2003.

What would cause Standard & Poor's to lower its ratings on TECO?

An unfavorable outcome relatedto the company's sale of interests in its synfuel facilities, which either halts or significantly delays the sales or ultimately affects cash flow, could lead to lower credit ratings. Also, the lack of execution in selling other assets (TECO Transport, Guatemalan assets, and other assets), which are intended to help reduce debt leverage, could affect ratings. The company's ability to rationalize its merchant power exposure and drastically reduce these higher-risk holdings is critical to the company maintaining ratings.

To avoid a ratings downgrade, the company will have to complete planned asset sales to meaningfully reduce debt leverage and rationalize its merchant power investments to reduce exposure to a weak power price environment. The company also needs to maintain an adequate liquidity position and produce a more consistent cash flow stream commensurate with the ratings. Ratings are supported by the expecteddramatic reduction in the company's business risk profile, which will be supported by a lower-risk consolidatedbusiness mix that is expectedto produce a steady cash flow stream, mostly generatedfrom integratedutility operations. Without this reduction in its risk profile, TECO's credit quality would be in the noninvestment-grade 'BB' category.

How successful has TECO been in selling off assets, and what expectations does Standard & Poor's have for future near-term sales?

TECO's active asset sale program was triggered by the company's weakened financial performance and liquidity position. The program has had mixed results and some delays, with the more challenging sales still seemingly difficult to achieve. So far, TECO has been unable to sell Tampa Electric's gasifier unit, and its pending sale of interests in its synfuel facilities is unclear. Regarding TECO Transport, an existing above-market contract between Transport and Tampa Electric, which soon expires, has placed some uncertainty around the unit's ultimate value, which is expectedto delay any potential sale. The potential sale of the company's merchant power assets seems challenging given the projectedlow energy prices in the markets that these plants were expectedto serve. However, TECO has completedthe sale of its coalbed methane assets for $140 million, as planned. Also, TECO recently announced the sale of its Hardee power plant for $115 million, plus the assumption of $103 million of debt, with completion expectedin September 2003. Although these sales provide some minor supportto the company's asset-sale program, the other sales are expectedto be more challenging.

Why does Standard & Poor's assign the same ratings to TECO Energy and Tampa Electric instead of separating them?

Standard & Poor's employs the consolidatedratings methodology for TECO and its subsidiaries. TECO's corporate credit rating is based on the financial and business risk profile analysis of the consolidatedenterprise and recognizes a free flow of funds throughout the organization and the absence of sufficient regulatory insulation. Thus, the ratings on Tampa Electric are expectedto mirror those of TECO, given the absence of proscriptive authority by the regulators in Florida. Any regulatory insulation or structural separation imposed to legally ring-fence Tampa Electric would be favorable for the utility's ratings. However, this action would drastically hinder TECO's ability to access the utility's strong cash flows and use its overall financial health to its benefit, which would result in significantly lower ratings at the parent.

On a stand-alone basis, how is Tampa Electric operating?

Tampa Electric continues to operate adequately on a stand-alone basis. The utility benefits from a solid financial profile and a strong business profile. Tampa Electric's credit metrics are solid with adjustedfunds from operations (FFO) to average total debt of about 25% and adjustedFFO interest coverage of more than 4.5x, respectively.

Debt levels for the regulatedutility is moderate at about 45% of total capitalization.

Tampa Electric's business profile is supported by strong customer growth, minimal reliance on industrial load, competitive rates, expectations of supportive regulation, and a solid regulatedgas local distribution unit, Peoples Gas. The utilities' long-term prospects are buoyed by Florida's vibrant economy and natural gas expansion into the southwest and northeast parts of the state.

What has occurred at TECO Power Services?

Depressed profitability at TECO Power Services (TPS), combined with a weak environment for power prices, has greatly strained the company's financial profile. As such, TECO has decided to rethink its strategy to expand the nonregulatedpower development business and instead is currently rationalizing its investments in this area.

Recent write-downs have affectedthe company's equity layer, with more reductions possible due to asset dispositions and continued low power prices. The large, recently built plants are expectedto be a drag on financials in the future. Importantly, the use of nonrecourse financing at the project level for some investments (including the largest plants, Unionand Gila) and the issuance of equity to raise the necessary capital have buffered any further potential credit deterioration. However, while a large part of the financing is nonrecourse, Standard & Poor's considers stress scenarios with a degree of nonrecourse debt.

In late 2002, TPS decided to defer further investment in two gas-fired power plants (Dell in Arkansas and McAdams in Mississippi; both 599 MW), both of which are about 90% complete, due to projectedlow energy prices in the markets that these plants were expectedto serve. At the time of suspension, about $690 million had been investedin these plants. TPS also has an interest in two merchant power plants with a combined capacity of 4,345 MW in Arkansas(Union, 2,200 MW) and Arizona(Gila, 2,145 MW). TECO has investednearly $700 million, including an equity bridge loan, in these plants. TPS and former partner Panda Energy International Inc. financed the plants with a $2.2 billion power plant financing, which includes $1.7 billion in nonrecourse debt and a $500 million equity bridge loan that was paid by TECO Energy. The nonrecourse debt has a five-year term, through 2006, after which these projects are exposed to refinancing risk. TPS also has an interest in the Odessaand Guadalupe power stations (2,000 MW) through a venture with Panda Energy. These plants have performed poorly due to substantial overcapacity in the Texasmarket.

How is TECO's liquidity position?

TECO's liquidity is expected to improve over the coming months due to the expiration of LOCs posted to complete the Union and Gila power plants, asset sale proceeds such as the Hardee power plant, the upsizing of a credit line in October 2003, and minimal debt maturities over the next few years (assuming the company's $350 million term loan due November 2003 is refinanced). TECO's liquidity position has improved dramatically from an earlier stressed position in which a ratings downgrade triggered an equity bridge guarantee, which totaled $500 million in addition to an earlier contribution. The company has about $350 million of availability on its credit facilities (a $350 million unsecured multiyear facility due November 2004 and an unsecured $150 million facility due April 2004 containing a six-month extension at TECO's option).

Tampa Electric's $300 million credit facility due November 2003, which has minimal borrowings outstanding, provides additional flexibility to the consolidatedenterprise. The company has about $270 million of cash.

What is TECO's consolidated business position on Standard & Poor's business risk scale?

Standard & Poor's has assessed TECO Energy's business position as a '5', in the middle of the risk spectrum ('1' is the lowest risk, '10' is the highest). This assessment largely reflects the relative stability and low operating risk of the regulatedelectric and gas utility operations. However, a higher-risk, poorly performing merchant power business hinders the company's business risk score. The company's attempt to refocus its business strategy to rationalize its merchant power exposure and focus primarily on its utility (about 70% of cash flow) and coal (about 20% of cash flow) businesses will create a lower-risk consolidatedbusiness mix that is expectedto produce a steady cash flow stream.

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Global Credit Research
Rating Action
12 MAR 2003

Rating Action: TECO Energy, Inc.

MOODY'S PLACES THE DEBT RATINGS OF TECO ENERGY, TAMPA ELECTRIC COMPANY, AND
TECO FINANCE ON REVIEW FOR POSSIBLE DOWNGRADE.

Approximately $3.6 Billion of Debt Securities Affected.
New York, March 12, 2003 -- Moody's Investors Service has placed the debt ratings of TECO Energy, Inc. (TECO), Tampa Electric Company, and TECO Finance, Inc. on review for possible downgrade. Ratings under review include TECO Energy's Baa2 senior unsecured debt rating; Tampa Electric Company's A1 senior secured, A2 issuer, senior unsecured and pollution control revenue bond debt, and P-1 commercial paper rating; TECO Finance Inc.'s P-2 commercial paper rating; and the Baa3 rating of the trust preferred securities of TECO Capital Trust I and TECO Capital Trust II.

This review is prompted by Moody's concerns about the pace of the remaining activities associated with the execution of TECO's announced asset sales program, continued poor market conditions in the energy merchant markets that increase the likelihood of writedowns related to some TECO Power Services (TPS) projects; and concerns regarding the amount of cash flow likely to be generated from the TPS power project portfolio in both 2003 and 2004. In addition, Moody's notes the limited progress thus far in extending or otherwise replacing bank credit facilities which are due at both TECO and Tampa Electric in November 2003.

Moody's review will focus on TECO's contingency plans with regard its expiring bank credit facilities; the progress and expected completion dates of previously announced asset sales, including a coal gasification unit at Tampa Electric and synthetic fuel facilities at TECO Coal; additional actions the company may consider to bolster cash flow and increase liquidity during 2003; and the extent to which the TPS merchant generation portfolio may require writedowns in 2003 or early 2004. ***In our review, Moody's will also assess Tampa Electric's traditionally strong operating performance and robust financial measures and the degree to which Tampa Electric may be able to provide support to TECO.***

In addition, Moody's review will include the potential effects of TECO's significant contingent obligations with respect to the Union and Gila projects, which include equity contribution guarantees, equity bridge loan guarantees, letters of credit, and other related guarantees, most of which would be triggered by changes in TECO's credit ratings or by a failure to meet certain financial covenants. Moody's will also examine the impact, if any, that consolidation of $1.5 billion of nonrecourse TECO Panda Generating Company debt would have on TECO if required in the third quarter of 2003 pursuant to FASB Interpretation No. 46, which will become effective in the third quarter. Finally, Moody's will review TECO's obligations related to its partnership with Panda Energy International, which include a $60 million contingent purchase obligation related to the Union and Gila projects and the impact of the recent conversion of a $137 million Panda loan into an equity interest in the Odessa and Guadalupe projects. Moody's intends to meet with TECO senior management shortly to discuss these issues as part of our review process.

TECO Energy is a diversified energy company headquartered in Tampa, Florida.

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TECO debt downgraded to 'junk'

A ratings agency sees risks from the utility's investments in wholesale power plants.

By LOUIS HAU, Times Staff Writer

TAMPA -- Moody's Investors Service cut TECO Energy Inc.'s long-term debt rating by two notches Monday to "junk" status, barely a week after the struggling utility initiated a dividend cut and other financial measures aimed in part at avoiding a downgrade.

Even at junk, or subinvestment, grade, Moody's doesn't deem TECO's debt rating secure. The ratings agency said it was leaving a negative outlook on the rating because of the Tampa company's "limited financial flexibility" for the rest of this year and 2004.

Moody's also reduced the debt rating of Tampa Electric Co., TECO's otherwise healthy flagship unit, which continues to be weighed down by troubles at its parent.

The rating would make it more difficult for TECO to secure new financing because companies issuing junk bonds must pay high yields to make up for the higher risk they pose.

Moody's attributed the downgrades to heightened risks from TECO's heavy investments in wholesale power plants, many of which are in markets that are saturated with generating capacity.

TECO's shares closed Monday at $10.93, down 28 cents on nearly twice the average trading volume. The downgrade came just ahead of TECO's annual shareholders meeting, which is scheduled for today at 11:30 a.m. at the company's headquarters at 702 N Franklin St. in downtown Tampa.

In a statement, TECO chief financial officer Gordon Gillette acknowledged the Moody's downgrades were "a significant change" for the company. But he also asserted, "We have the necessary liquidity available to meet the requirements brought on by this ratings change."

Among the requirements, the company has 15 days to repay, or post letters of credit for, $375-million remaining on a loan for construction of two giant gas-

fired power plants in Arizona and Arkansas. TECO also must arrange for an estimated $75-million in letters of credit to guarantee the completion of those two plants.
Also, the company will have to post an estimated $30-million in collateral with companies that purchase its power under contract. Finally, as part of financial covenants related to $380-million in five-year notes TECO issued last November, the company must now meet new accounting and earnings standards.
Moody's isn't certain that TECO's obligations end there. The ratings agency indicated it is worried about "uncertainty surrounding the actual amount" TECO will owe its lenders for the Arizona and Arkansas plants.
Moody's said that it expects TECO to take costly writedowns on its power plant projects and that continued poor conditions in TECO's wholesale power markets will severely limit the cash flow generated by its wholesale plants in 2003 and 2004. That, in turn, will make it "increasingly difficult for TECO to meet ... interest and dividend obligations without relying on additional asset sales or debt financings," Moody's said.
Over the short term, a junk rating on TECO's debt won't leave the company significantly worse off than a lesser downgrade because it doesn't have major loan payments coming due soon that it hasn't already prepared for. But the downgrade does increase pressure on the utility to issue more stock, something that would help improve its battered balance sheet but would also further dilute the value of its existing shares.
-- Louis Hau can be reached at hau@sptimes.com or (813) 226-3404.

TECO Energy earnings slide, liquidity a concern

| TOOLS |

NEW YORK, April 22 (Reuters)

Cash-strapped power company TECO Energy Inc. on Tuesday reported sharply lower first-quarter net earnings a day after its credit ratings were slashed to "junk" status.

Though TECO responded to the action by Moody's Investors Service by saying the downgrade would not jeopardize its liquidity position, investors were skeptical and pushed its stock down.

"They have a difficult road ahead of them," said James Elliot, who helps manage the ELCO Energy Fund. "People are just not comfortable with their liquidity expectations."

TECO's stock was down 25 cents, or 2.3 percent, at $10.68 in midday trade on Tuesday on the New York Stock Exchange after falling as much as 4.3 percent to a session low of $10.46.

TECO's first-quarter net profit of $2.1 million, or 1 cent per share, was weighed down by its loss-making merchant energy business and charges for turbine purchase cancellations, a tax benefit deferral, and an accounting change. The company reported a net profit of $75.4 million, or 54 cents per share, a year ago.

Excluding one-time items, TECO earned 40 cents per share. On that basis, Wall Street analysts had expected the company to report earnings of 37 cents per share, according to research firm Thomson First Call.

TECO, the owner of Tampa Electric Co., is one of many U.S. utilities that have struggled with an industrywide credit crunch in the wake of energy trader Enron Corp.'s collapse.

Like several of its peers, TECO has decided to refocus on its reliable domestic utility business and scale back its exposure to the riskier merchant energy business. Moody's in a statement cited TECO's large exposure to the risky merchant energy business and the diminished value of its assets as reasons for the downgrade, which affected about $3.6 billion of debt.

TECO will have to collateralize or repay the $375 million balance of a bridge loan within the next 15 days as a result of the downgrade. The company earlier this month said it would slash its dividend as part of a plan to improve its financial health.

Going forward, TECO may be forced to take other, more aggressive actions to shore up its finances, according to one analyst. "TECO may have to issue equity and/or pursue additional asset sales to support the anticipated weak performance of its merchant generation fleet," Gerard Klauer Mattison analyst Mike Worms, who rates the stock "underperform" and owns no TECO shares, said in a report. "Unfortunately we do not believe this will be the last negative news in TECO's near-term future."

News Provided By

REUTERS

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported):

AUGUST 26, 2003

TECO ENERGY, INC.
(Exact name of registrant as specified in its charter)

FLORIDA	1-8180	59-2052286
(State or other jurisdiction of incorporation)	(Commission file Number)	(IRS Employer Identification No.)

702 North Franklin Street, Tampa Florida 33602
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (813) 228-4111

Exhibit 99.1

[TECO Energy, Inc. Logo]

FOR IMMEDIATE RELEASE

CONTACT:	Media (Laura Plumb) 813.228.1572	Investors (Mark Kane) 813.228.1772

TECO POWER SERVICES REACHES AGREEMENT TO SELL HARDEE POWER STATION FOR $115 MILLION PLUS ASSUMPTION OF DEBT

Tampa, Florida – August 26, 2003 – TECO Energy's TECO Power Services subsidiary today announced that it has signed an agreement to sell its interest in the 370–megawatt Hardee Power Station in Florida to GTCR and Invenergy for $115 million and the assumption of all outstanding project–related debt. The transaction is expected to close by the end of September, subject to certain regulatory and lender approvals. TECO Energy expects to record an estimated $60–million book gain (pre–tax) on the sale and net incremental cash of approximately $110 million. Merrill Lynch is advising TPS in the transaction.

Chairman and CEO Robert D. Fagan said, "This transaction will further strengthen TECO Energy's financial position. In April, we identified a number of potential assets that could be sold to improve our financial position, including Hardee Power Station. With this agreement, we've demonstrated our commitment to the plan, and our continued refocus on our regulated utility operations."

The Hardee Power Station will continue to serve both Seminole Electric Cooperative and Tampa Electric under established long–term power purchase contracts. A TECO Power Services subsidiary will continue to operate the facility after the change of ownership.

TECO Power Services is a subsidiary of TECO Energy, Inc. (NYSE: TE), a diversified, energy–related holding company headquartered in Tampa, Florida. Other TECO Energy businesses include Tampa Electric, Peoples Gas System, TECO Transport, TECO Coal and TECO Solutions. For more information, visit online: www.tecoenergy.com.

Formed in 2001, Chicago–based Invenergy is a developer, owner and operator of power generation and energy delivery assets. Invenergy is led by Michael Polsky, previously CEO of SkyGen Energy. Partnered with GTCR Golder Rauner LLC, a leading private equity firm, Invenergy is pursuing acquisitions of large–scale power plants currently being divested by utilities, IPPs and financial institutions. For more information, visit www.invenerllc.com.

Founded in 1980, GTCR Golder Rauner is a leading private equity investment firm currently managing more than $6 billion of equity capital invested in a wide range of companies and industries. For more information, visit www.gtcr.com.

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TECO Power Services

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Press Release

TECO Power Services reaches agreement to sell Hardee Power Station for $115 million plus assumption of debt

Tampa, Florida August 26, 2003

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Docket No.: 030001-EI
Witness: Sheree L. Brown
Exhibit No. _____, (SLB-3)

Closing the generation gap.℠

10kWIZARD
SEC POWER SEARCH

Form 10-Q

TECO ENERGY INC - TE

Filed: August 14, 2003 (period: June 30, 2003)

Quarterly report which provides a continuing view of a company's financial position

Docket No.: 030001-EI
Witness: Sheree L. Brown
Exhibit No. ______, (SLB-4)
Page 1 of 2

Pro Forma Disclosure — Stock Options - continued

(millions, except per share amounts)	Three months ended June 30, 2003	Three months ended June 30, 2002	Six months ended June 30, 2003	Six months ended June 30, 2002
Net (loss) income from continuing operations - EPS, basic				
As reported	$ (0.58)	$ 0.56	$ (0.69)	$ 1.06
Pro forma	$ (0.58)	$ 0.55	$ (0.70)	$ 1.04
Net (loss) income from continuing operations - EPS, diluted				
As reported	$ (0.58)	$ 0.56	$ (0.69)	$ 1.06
Pro forma	$ (0.58)	$ 0.55	$ (0.70)	$ 1.04
Net (loss) income - EPS, basic				
As reported	$ (0.58)	$ 0.59	$ (0.56)	$ 1.13
Pro forma	$ (0.58)	$ 0.59	$ (0.57)	$ 1.12
Net (loss) income - EPS, diluted				
As reported	$ (0.58)	$ 0.59	$ (0.56)	$ 1.13
Pro forma	$ (0.58)	$ 0.58	$ (0.58)	$ 1.11
Assumptions				
Risk-free interest rate	4.33%	5.09%	4.33%	5.09%
Expected lives (in years)	6	6	6	6
Expected stock volatility	31.21%	25.92%	31.21%	25.92%
Dividend yield	5.98%	5.47%	5.98%	5.47%

(1) Compensation expense for stock options determined under fair-value based method, after-tax.

10. Asset Impairments

At Mar. 31, 2003, TECO Energy recorded a $64.2 million after-tax charge ($104.1 million pretax) to reflect the impact of the cancellation of turbine purchase commitments. This represented after-tax charges of $15.3 million ($24.5 million pretax) at TPS and $48.9 million ($79.6 million pretax) at Tampa Electric relating to installment payments made and capitalized in prior periods. As reported previously and in Note 15, certain turbine rights had been transferred from TPS to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations for TPS and Tampa Electric.

11. TPGC Joint Venture Termination

In January 2002, TPS agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy guaranteed payment of TPS' obligation under this agreement. Panda Energy obtained bank financing using the purchase obligation and TECO Energy's guarantee as collateral. Under certain circumstances, the purchase obligation could have been accelerated for a reduced price based on the timing of the acceleration. In connection with TPS' purchase obligation, Panda Energy retained a cancellation right, exercisable in 2007 for $20 million by the holder, with early exercise permitted for a reduced price of $8 million.

On April 9, 2003, TECO Energy and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated TPS' purchase obligation to on or before July 1, 2003, and reduced the overall purchase obligation to $58 million. Under the guarantee TECO Energy became obligated to make interest and certain principal payments to or on behalf of Panda related to the collateralized loan obligation of Panda. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see Note 1 for additional details on TECO Energy's ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing could be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on June 16, 2003. TECO Energy's guarantee of TPS' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as an after-tax loss of $21.4 million ($35.0 million pretax), included in the "Loss on joint venture termination" caption in the Statements of Consolidated Income. From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment, giving rise to a receivable from Panda of $9.0 million.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable at that time. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	CIVIL ACTION NO. 99-2524
v.	)	CIV-T-23F
	)	
	)	
TAMPA ELECTRIC COMPANY,	)	
	)	
Defendant.	)	
	)	

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (Plaintiff or the United States), on behalf of the United States Environmental Protection Agency (EPA) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company (Tampa Electric) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration (PSD) requirements at Part C of the Clean Air Act (Act), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV);

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input (lb/mmBTU) or the average concentration of a pollutant in parts per million by volume (ppm), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% O_2.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. S O_2" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. <u>for Gannon</u>: 30,763 tons of NO_x, 64,620 tons of SO_2, and 1,914 tons of PM; and

B. <u>for Big Bend</u>: 36,077 tons of NO_x, 107,334 tons of SO_2, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

A. GANNON

26. <u>Consent Decree-Required Re-Powering of Gannon</u>. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW (Megawatt), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2.

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.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3. 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.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of NO_x at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. 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 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 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. Early Reductions of NO_x from Big Bend Units 1 through 3: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. <u>Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal</u>. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. <u>Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired</u>. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, 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 lb/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. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. 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 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3. If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. <u>Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown.</u> If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. 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. Removal Efficiency or Emission Rate. 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 $S0_2$ 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 $S0_2$ 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.

C. BIG BEND AND GANNON – PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII (Termination), the provisions of Paragraph 44 (Resolution of Future Claims - Covenant Not to Sue) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as Projects) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. <u>Performance of Air Chemistry Work in Tampa Bay Estuary</u>. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. <u>RIGHT OF ENTRY</u>

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. <u>DISPUTE RESOLUTION</u>

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

<u>As to Tampa Electric</u>:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. <u>Modification</u>. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. <u>Continuing Jurisdiction</u>. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF _______________ 2000.

____

UNITED STATES DISTRICT JUDGE

Calculation of Replacement Fuel Costs for 2003 and 2004 Based on 2002 Generation

2002 Total Generation (Total Replaced in 2004)

Gannon #1 - Year 2002 Net Capacity - 114 MW			
Month	Net Generation (MWH)	Net Generation (MWH)	Fuel Cost
Jan	35,443	$ 0.0260	921,518
Feb	32,948	$ 0.0178	586,474
March	53,089	$ 0.0199	1,056,471
April	48,902	$ 0.0204	997,601
May	45,994	$ 0.0204	938,278
June	42,306	$ 0.0202	854,581
July	53,279	$ 0.0228	1,214,761
August	44,015	$ 0.0213	937,520
September	40,940	$ 0.0213	872,022
October	51,079	$ 0.0202	1,031,796
November	36,494	$ 0.0186	678,788
December	27,043	$ 0.0209	565,199
Total	511,532	$ 0.0208	10,655,009

Gannon #2 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation (MWH)	Net Generation (MWH)	Fuel Cost
Jan	23,260	$ 0.0270	628,020
Feb	18,304	$ 0.0192	351,437
March	49,384	$ 0.0205	1,012,372
April	43,565	$ 0.0217	945,361
May	45,722	$ 0.0204	932,729
June	41,350	$ 0.0204	843,540
July	48,092	$ 0.0244	1,173,445
August	44,471	$ 0.0218	969,468
September	39,108	$ 0.0214	836,911
October	52,415	$ 0.0216	1,132,164
November	37,407	$ 0.0183	684,548
December	24,678	$ 0.0214	528,109
Total	467,756	$ 0.0215	10,038,103

Generation Replaced in 2003

Gannon #1 - Year 2002 Net Capacity - 114 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	48,902
May	45,994
June	42,306
July	53,279
August	44,015
September	40,940
October	51,079
November	36,494
December	27,043
Total	390,052

Gannon #2 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	43,565
May	45,722
June	41,350
July	48,092
August	44,471
September	39,108
October	52,415
November	37,407
December	24,678
Total	376,808

Calculation of Replacement Fuel Costs
for 2003 and 2004
Based on 2002 Generation

Gannon #3 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation (MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	58,009	$ 0.0330	1,914,297
Feb	47,989	$ 0.0231	1,108,546
March	71,380	$ 0.0240	1,713,120
April	75,890	$ 0.0256	1,942,784
May	71,839	$ 0.0260	1,867,814
June	17,829	$ 0.0291	518,824
July	83,695	$ 0.0282	2,360,199
August	64,750	$ 0.0272	1,761,200
September	65,992	$ 0.0246	1,623,403
October	57,911	$ 0.0264	1,528,850
November	23,448	$ 0.0177	415,030
December	39,051	$ 0.0234	913,793
Total	677,783	$ 0.0261	17,667,860

Gannon #3 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	28,021
November	23,448
December	39,051
Total	90,520

Gannon #4 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	40,730	$ 0.0347	1,413,331
Feb	41,861	$ 0.0223	933,500
March	1,726	$ 0.0296	51,090
April	32,648	$ 0.0252	822,730
May	79,840	$ 0.0266	2,123,744
June	67,869	$ 0.0272	1,846,037
July	75,796	$ 0.0305	2,311,778
August	67,872	$ 0.0269	1,825,757
September	61,896	$ 0.0262	1,621,675
October	60,861	$ 0.0270	1,643,247
November	55,035	$ 0.0215	1,183,253
December	51,249	$ 0.0208	1,065,979
Total	637,383	$ 0.0264	16,842,120

Gannon #4 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	29,449
November	55,035
December	51,249
Total	135,733

Calculation of Replacement Fuel Costs for 2003 and 2004 Based on 2002 Generation

Gannon #5 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation (MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	72,050	$ 0.0240	1,729,200
Feb	34,488	$ 0.0161	555,257
March	0	$ -	0
April	573	$ 0.0388	22,232
May	99,739	$ 0.0180	1,795,302
June	110,417	$ 0.0182	2,009,589
July	94,688	$ 0.0206	1,950,573
August	122,031	$ 0.0187	2,281,980
September	89,300	$ 0.0199	1,777,070
October	83,099	$ 0.0191	1,587,191
November	102,728	$ 0.0169	1,736,103
December	99,138	$ 0.0193	1,913,363
Total	908,251	$ 0.0191	17,357,861

Gannon #5 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	34,488
March	0
April	573
May	99,739
June	110,417
July	94,688
August	122,031
September	89,300
October	83,099
November	102,728
December	99,138
Total	836,201

Gannon #6 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation (MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	153,653	$ 0.0226	3,472,558
Feb	169,401	$ 0.0162	2,744,296
March	153,458	$ 0.0182	2,792,936
April	165,068	$ 0.0190	3,136,292
May	189,537	$ 0.0183	3,468,527
June	171,501	$ 0.0182	3,121,318
July	154,914	$ 0.0199	3,082,789
August	179,658	$ 0.0180	3,233,844
September	178,356	$ 0.0182	3,246,079
October	39,227	$ 0.0179	702,163
November	0	$ -	0
December	57,508	$ 0.0230	1,322,684
Total	1,612,281	$ 0.0188	30,323,486

Gannon #6 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	39,227
November	0
December	57,508
Total	96,735

Calculation of Replacement Fuel Costs for 2003 and 2004 Based on 2002 Generation

Total 2002	4,814,986	$	0.0214	102,884,439	1,926,049			
Calculation of Savings Using BS1 Cost of $.046/kWh								
Total 1-4	2,294,454	$	0.0246	56,518,031	993,113	$	0.0246	24,462,817
Total 6	1,612,281	$	0.0246	39,714,436	96,735	$	0.0246	2,382,820
Total 1-6	4,814,986	$	0.0246	118,604,917	1,926,049	$	0.0246	47,443,320

Tampa Electric Company
Final Dismantling Study
in 2002 Dollars and
includes 15% Contingency

	LABOR	MATERIALS & EQUIPMENT	DISPOSAL	SALVAGE	TOTAL	2003 ACCRUAL
Retiring Coal Related Assets						
Gannon Common	1,827,488	403,767	407,982	(49,974)	2,589,263	3,688,028
Gannon Coal Field	2,603,184	536,322	508,494	(73,000)	3,575,000	N/A
Gannon Unit 3	3,056,977	766,441	487,203	(146,620)	4,164,001	567,820
Gannon Unit 4	3,524,289	894,144	561,585	(166,165)	4,813,853	1,463,847
Gannon Unit 5	3,226,609	813,337	509,543	(145,603)	4,403,886	2,157,925
Gannon Unit 6	2,246,035	1,455,097	16,359	(237,274)	3,480,217	926,621
Retiring Units						
Gannon Unit 1	3,342,563	831,213	540,225	(167,001)	4,547,000	(1,343,882)
Gannon Unit 2	3,342,563	831,213	540,225	(167,001)	4,547,000	(101,038)
	23,169,708	6,531,534	3,571,616	(1,152,638)	32,120,220	7,359,321

NOTE: The 2003 accruals have been calculated to reflect a 2007 start for dismantling. Current dismantling estimates were escalated to 2007 and then reduced to present day cost. The results are the total dismantling estimate less the total accrual as of 12/31/2002.
The accrual for Gannon Coal Field is included with Gannon Common.

Tampa Electric Focuses on Plans for 2002, 2003

TAMPA, Fla., Sep 24, 2002 /PRNewswire-FirstCall via COMTEX/ -- TECO Energy (NYSE: TE) announced Monday that it expects 2002 earnings per share to increase over 2001, and that net income is expected to grow by more than 10 percent. The company also provided its initial 2003 outlook.

Tampa Electric Company, the principal subsidiary of TECO Energy, is projected to complete its third straight year of increased net income. In 1999, Tampa Electric's net income, excluding one-time charges, was $138.8 million. In 2000, it increased net income by 4 percent to $144.5 million. In 2001, it increased net income to $154 million, a 6.6 percent increase over the previous year. For 2002, Tampa Electric expects net income to increase again by more than 6 percent.

Restructuring activity at Tampa Electric is also part of TECO Energy's 2003 business plan. The company will be making personnel reductions of about 5 percent, on top of a 2 percent reduction earlier this year. Personnel reductions at Tampa Electric are not expected to affect service to customers.

President John Ramil said, "Our reductions are largely in line with what others in the industry are doing to as a result of productivity improvements and technology applications. We are primarily eliminating managerial and administrative jobs. It's possible that some of those whose jobs are being eliminated will be placed in our Customer Service area, where we are planning to add employees soon to serve our customers better and improve our operation."

In 2003, Tampa Electric expects continued retail energy sales growth of about 2.5 percent and significant operations and maintenance cost savings from the reduction in the number of coal-fired units at Gannon Station, and the completion of Bayside Unit 1.

"We have made a large financial commitment to construction, including $1 billion for our Bayside project and state-of-the-art emissions control technology at our Big Bend power plant, in order to meet the most stringent environmental requirements," said Ramil.

"With the Bayside conversion to natural gas, we can expect to reduce sulfur dioxide and nitrogen oxide emissions at that plant by over 95 percent each from 1998 levels. The environmental equipment added to our Big Bend Station will achieve a 95 percent sulfur dioxide removal efficiency. By 2010, nitrogen oxide (NOx) emissions from Big Bend will be reduced by over 85 percent from 1998 emission levels. Besides that, we will invest up to $11 million for early NOx reductions and for demonstrating innovative technologies for reducing NOx emissions at Big Bend and our other plants. We are continuing these and other technology and expansion-related investments, because it helps us serve our growing customer base in a way that is highly efficient and that meets modern-day environmental standards," Ramil added.

Long-term, the company feels it is well-positioned with assets that will serve future energy needs. "Though 2003 is going to be a transitional year for us, that is in keeping with the long-term view we have taken about our business and our proven core assets," said Bob Fagan, chairman and CEO of Tampa Electric's parent company, TECO Energy.

TAMPA, Fla., Jan. 22 /PRNewswire-FirstCall/ – TECO Energy, Inc. (NYSE: TE) today reported that its full-year 2002 net income from continuing operations rose 9 percent to $298.2 million, up from $273.8 million in 2001.

Fourth quarter net income from continuing operations decreased 41 percent to $34.6 million, down from $59.1 million in 2001. Full-year 2002 revenues rose 8 percent to almost $2.7 billion, up from $2.5 billion in 2001.

Full-year 2002 earnings per share from continuing operations were $1.95, down 4 percent, compared with 2001 earnings per share of $2.04. Earnings per share from continuing operations for the quarter were $0.20, compared to $0.43 in 2001. The number of common shares outstanding was 14 percent and 23 percent higher for the year and the quarter, respectively, than for the same periods in 2001.

Results from continuing operations for the year and the fourth quarter include a $34-million pre-tax ($20.9 million after-tax) charge related to a debt refinancing transaction executed by TECO Energy in the fourth quarter, and a $5.8-million after-tax charge for an asset valuation adjustment for TECO Power Services' (TPS) proposed sale of generating facilities in the Czech Republic. Absent these charges, net income from continuing operations rose 19 percent to $324.9 million for the year, and earnings per share rose 4 percent to $2.12 per share for the year. Results from continuing operations exclude the results from TECO Coalbed Methane, which was sold in December and is reported as discontinued operations.

Total net income and earnings, including continuing operations and recently discontinued operations were $330.1 million and $2.15 per share, respectively. Total non-GAAP net income and earnings, excluding the $20.9 million debt refinancing and $5.8 million asset valuation charges and the $7.7 million gain on the sale of TECO Coalbed Methane, were $349.1 million and $2.28 per share, respectively.

TECO Energy Chairman and CEO Robert Fagan said, "TECO Energy had another good year for net income in 2002, despite a soft economy and tough energy markets. Except for the two unusual items, we delivered the double-digit net income growth we projected earlier in the year. While earnings per share were diluted by the new shares issued during the year, the share issuance was important to strengthen the balance sheet and improve our cash position.

"We will have our challenges in 2003, but we are making good progress on our $900 million cash generation plan, which we announced in September to fund the completion of the construction programs at TPS and Tampa Electric without raising incremental debt. We have already accounted for more than 70 percent of the targeted $900 million of cash generation from capital expenditure reductions, non-core asset sales and monetization of Section 29 tax credits, and other financial transactions or asset sales. I expect our Florida utilities to have a good year in 2003, contributing strong earnings and cash flow, thanks to continuing growth in the state's economy. TECO Energy's mix of profitable regulated and unregulated businesses helps mitigate the impact of the weak energy markets that TPS is experiencing," Fagan added.

Operating Segment Results:*

(in millions)	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Net Income Summary	2002	2001	2002	2001
Tampa Electric	$27.3	$28.6	$171.8	$154.0
Peoples Gas System	6.9	5.8	24.2	23.1
Total regulated	$34.2	$34.4	$196.0	$177.1
TECO Power Services	$(5.3)	$2.1	$34.1	$26.9
TECO Transport	5.2	6.0	21.0	27.5
TECO Coal	17.7	18.4	76.5	59.0
Other unregulated companies	3.2	1.6	6.8	4.0

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Parent / other	(20.4)	(3.4)	(36.2)	(20.8)
Total unregulated	$0.4	$24.7	$102.2	$96.7
Net income from continuing operations	$34.6	$59.1	$298.2	$273.8
Discontinued operations	$15.5	$5.7	$31.9	$29.9
Total net income	$50.1	$64.8	$330.1	$303.7

- Segment net income includes internally allocated financing costs.

Tampa Electric's net income for the fourth quarter was $27.3 million, compared with $28.6 million for the same period in 2001. The equity component of allowance for funds used during construction (AFUDC, which represents allowed equity cost capitalized to construction costs), primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $8.0 million for the quarter, from $2.6 million for the same period in 2001. Average customer growth of 2.2 percent for the quarter and more favorable weather increased retail energy sales 14.7 percent in the quarter. Total energy sales, including sales to other utilities, rose 15.8 percent in the fourth quarter due to favorable weather. Higher operating expenses for the quarter reflected higher depreciation from normal electric plant additions to support customer growth and higher non-fuel operations and maintenance expenses relating to generating plant maintenance and costs associated with a workforce reduction.

Tampa Electric's full-year net income was $171.8 million, compared with $154.0 million in 2001. The equity component of AFUDC increased to $24.9 million from $6.7 million in 2001. Full-year retail sales were 5.6 percent above 2001 levels, driven by 2.5 percent average customer growth, and increased usage by residential and commercial customers. Tampa Electric also benefited from lower interest rates on short-term borrowing. Higher operating expenses for the year included increased depreciation from normal plant additions to support customer growth and the addition of the Polk Unit 3 combustion turbine in May 2002, and higher operations and maintenance expenses reflecting increased generating plant maintenance and costs associated with a 7-percent workforce reduction in 2002.

Peoples Gas System reported net income of $6.9 million for the quarter, up 19 percent from the $5.8 million recorded in the same period in 2001. Quarterly results reflected customer growth of 4.0 percent and increased volumes for the residential and commercial customers as a result of early winter weather. Gas sales volumes for electric power generators increased in the quarter as gas prices relative to alternative fuels made gas utilization more attractive.

Full-year results at Peoples Gas System improved almost 5 percent over 2001, with net income increasing to $24.2 million from $23.1 million. Full- year customer growth of more than 4 percent contributed to higher gas sales to residential and commercial customers. Lower gas prices early in the year increased sales to larger interruptible and power generation customers, many of whom have the ability to switch to alternative fuels or alter consumption patterns based on gas prices. Operations and maintenance expenses were lower in 2002, reflecting aggressive cost containment measures taken to offset the impact of lower sales early in the year due to mild weather.

TECO Power Services' (TPS) net loss for the quarter was $5.3 million, compared with net income of $2.1 million in 2001, while full-year net income of $34.1 million was 27 percent higher than the $26.9 million reported in 2001. Results for the fourth quarter reflect the $5.8 million after-tax asset valuation adjustment for the proposed sale of generating assets in the Czech Republic, and additional taxes on the $55 million of cash repatriated from Guatemala. In addition, the results reflect higher allocated interest costs based on increased investment levels in power projects. These factors more than offset improved results in the fourth quarter from the San Jose Power Station in Guatemala and the Frontera Power Station in Texas and increased earnings from construction-related and loan agreements with Panda Energy in 2002.

Full-year results at TPS reflected higher earnings from the Alborada and San Jose generating stations in

Guatemala, increased earnings from construction-related and loan agreements with Panda Energy, increased earnings from sales of ancillary services from the Frontera Power Station in the second and third quarters and a reliability-must-run (RMR) contract in the fourth quarter with the Electric Reliability Council of Texas (ERCOT). The improved operating performance over 2001 was partially offset by the factors described for the fourth quarter as well as higher operating costs associated with a full year of operation of TPS' energy marketing and management operations.

On Jan. 3, 2003, the $137-million loan to Panda Energy related to the Odessa and Guadalupe power stations in Texas converted to a TPS ownership interest in those plants. TPS is evaluating its options relative to its ownership interest in these projects and is targeting to structure its interest in such a manner that it will be cash flow neutral in 2003 and have minimal impact on earnings. Since the Frontera RMR contract was not renewed for the first quarter of 2003, the plant has been taken off-line for planned maintenance. The first quarter has lower opportunities than other quarters for sales to ERCOT, Mexico or other customers due to weather.

TECO Transport reported net income of $5.2 million in the quarter, compared to $6.0 million for the same period in 2001. In the fourth quarter, weak pricing for river shipments and lower northbound river shipments more than offset lower labor and repair costs. For the year, net income was $21.0 million, compared to $27.5 million in 2001. The lack of northbound cargoes on the river system and generally weak pricing for river freight, lower petroleum coke and other product volumes through the transfer terminal, lower Tampa Electric tonnage, and lower spot cargo at TECO Ocean Shipping more than offset increased phosphate shipments and lower repair and fuel costs.

TECO Coal achieved fourth quarter net income of $17.7 million, compared to $18.4 million reported in 2001; full-year net income was $76.5 million, compared with $59.0 million in 2001. Results for the quarter were driven primarily by lower volumes of synthetic fuel and metallurgical and steam coals, offsetting better margins and higher prices across the product line. For the year, results were driven by higher synthetic fuel production and sales, resulting in higher Section 29 tax credits, better synfuel margins and improved pricing for all coal types, which more than offset higher production costs.

TECO Energy's other unregulated companies recorded net income of $3.2 million and $6.8 million for the fourth quarter and full year, respectively, compared to $1.6 million and $4.0 million for the same periods in 2001. These results reflect primarily a full year of results from Prior Energy, TECO Energy's end-use gas marketing company, which was acquired in November 2001, the sale of properties at TECO Properties, and increased distributions from TECO Propane Ventures, more than offsetting a $3.0-million after-tax third quarter write-off of an aircraft leased to US Airways, which has filed for bankruptcy.

Discontinued operations reflect results from TECO Coalbed Methane, which was sold in December for $140 million; $42 million was paid in 2002, with the remainder to be paid in early 2003. For the year, TECO Coalbed Methane produced 14.2 billion cubic feet (Bcf) of gas on lower realized gas prices of about $2.80 per thousand cubic feet (Mcf), compared with production of 15 Bcf on realized gas prices of $3.66 per Mcf in 2001. Fourth quarter results also reflect the $7.7-million after-tax gain on the portion of the sale recognized in 2002.

Non-Operating Items

Interest expense was essentially unchanged for the quarter and lower for the full year due to higher capitalized interest at TPS, increased interest expense credit for AFUDC-borrowed funds at Tampa Electric, and a refund and a reversal of interest expense related to prior year tax deficiencies previously recorded at Tampa Electric and TECO Energy based on an IRS tax settlement, which offset the effect of interest expense on higher overall levels of debt and preferred securities in support of TECO Energy's capital investment program.

Cash from operations was $156.4 million for the quarter, compared with $103.8 million in 2001. Cash used for investing activities was $350.7 million, which was net of proceeds from the sale of TECO Coalbed Methane and $56.2 million of proceeds from a sale-lease-back transaction at TECO Transport, compared with $351.2 million in 2001. Net cash received from financing activities was $418.0 million,

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including $209.7 million from the sale of common equity and $373.9 million from a long-term debt issuance, compared with $279.8 million in 2001. Cash from financing activities is net of dividend payments of $62.4 million in the fourth quarter of 2002, compared with $48.1 million in 2001.

Year-to-date cash from operations was $655.7 million, compared with $502.7 million in 2001. Cash used for investing activities was $1.7 billion, compared with $1.1 billion in 2001. Net cash received from financing activities was $1.3 billion, compared with $613.6 million in 2001, net of dividend payments of $215.8 million in 2002, and $184.2 million in 2001. At Dec. 31, 2002, TECO Energy had $411.1 million of cash on hand compared to $108.5 million in 2001. In addition, there was $460 million of unused capacity available under the bank credit facilities at Tampa Electric and TECO Energy at Dec. 31, 2002.

Outlook

TECO Energy is planning to provide updates on its cash generation plan and 2003 outlook by early March.

Additional financial information related to the company's results through December 31, 2002, including unaudited financial statements, segment information, and electric and gas volumes is available at the Investor Relations section of TECO Energy's web site at www.tecoenergy.com.

LexisNexis

Tampa Tribune (Florida)

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HEADLINE: TECO Layoffs Sending Workers Job Hunting

BYLINE: CHERIE JACOBS , cjacobs@tampatrib.com; Reporter Cherie Jacobs can be reached at (813) 259-7668.

BODY:
COMPANY SAYS CHANGES WON'T HURT CUSTOMERS

TAMPA - Tampa Electric laid off 5 percent of its work force this week as part of the utility's effort to conserve cash.

About 130 employees in a half-dozen offices learned Tuesday that their jobs were cut. They began working with a job placement service Wednesday.

"Times in the energy industry are pretty tough," John Ramil, president of Tampa Electric, said Thursday. "It was the first time in a long time I had an employee cry in front of me."

Those laid-off workers will remain on Tampa Electric's payroll until Dec. 31. Employees who have worked for the utility for more than six years will get a lump-sum payment in January based on their longevity. Some workers also will get incentives to retire early.

The cuts will not affect customers, Ramil said, because no jobs were cut from power plants, repair crews or customer service. Twenty jobs are being added to customer service.

Nor will customer rates be affected, he said.

The layoffs leave the remaining workers - whom Ramil calls "the survivors" - with low morale.

"It's hard for people because this is not a common thing for our company," he said.

The layoffs come after several blows to the work force.

Tampa Electric has been scaling back jobs at its Gannon plant through attrition, preparing for the day when the plant reopens with natural gas as its fuel instead of coal. The plant will require 55 workers then, compared with 196 now.

About 50 employees took voluntary early retirement this spring, to save money.

Tampa Electric employs about 2,500.

Ramil said the cuts were primarily because of Gannon's fuel change to natural gas. The $700 million project will carry an annual debt payment of $70 million.

Tampa Electric also constitutes 60 percent of its parent company, TECO Energy.

But the layoffs are only part of TECO Energy's problems.

Shares of TECO have been hammered on Wall Street because of financial uncertainty. They closed at $11.36 Thursday, down 65 cents or 5 percent, a new 13-year low.

Last month, a handful of analysts and bond-rating agencies downgraded TECO's ratings because of turmoil with its wholesale power subsidiary, TECO Power Services. Investors feared the company would be unable to sell its excess power in an uncertain market, when prices are depressed.

On Sept. 23, the company announced its plan to save cash, which included selling assets and postponing two power plants outside Florida.

This week, TECO said it would sell 15 million shares of stock, but they had not been sold as of Thursday, spokeswoman Laura Plumb said.

Now, the company has hit bottom, Ramil said.

"My job is to pick everybody up from here," Ramil said. "Everybody else who's here [needs to] focus on keeping the lights on, moving ahead."

GRAPHIC: PHOTO (C)
John Ramil

(C) Tampa Electric president: "Times in the energy industry are ... tough," as TECO cuts 130 employees.

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