TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2006 THROUGH DECEMBER 2006

TESTIMONY AND EXHIBIT

OF

WILLIAM A. SMOTHERMAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (WAS-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2006 period.

GPIF Calculations

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units and one integrated gasification combined cycle unit are included. These are

Big Bend Station Units 1 through 4 and Polk Power Station Unit 1.

Q. Do the exhibits you have prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission, with the exception of the criterion that the company shall include generating units that will represent not less than 80 percent of projected system net generation.

Q. Why does Tampa Electric not include units that represent 80 percent of projected system net generation?

A. Due to the repowering of Gannon Units 5 and 6 to H. L. Culbreath Bayside ("Bayside") Units 1 and 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside Units 1 and 2 began commercial operation in 2003 and 2004, respectively, the repowered units are not included in the GPIF calculations because the company does not have the historical operational data required by the GPIF Implementation Manual to set GPIF targets. Tampa Electric has no other base load generating units to substitute for Gannon Units 5 and 6. Section 3.2 of the GPIF Implementation Manual states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis, and the Commission approved this exception for Tampa Electric's 2005 projected GPIF. Similarly, Tampa Electric requests approval of its 2006 GPIF calculation excluding the repowered units.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2006 period. A range of potential improvements and degradations were determined for each of these parameters.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor or POF and the Equivalent Unplanned Outage Factor or EUOF were subtracted from 100 percent to determine the target Equivalent Availability Factor or EAF. The factors for each of the five units included within the GPIF are shown on page 5 of Document

No. 1.

To give an example for the 2006 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 4 is 22.37 percent, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability factor for Big Bend Unit 4 equals 71.88 percent or:

$$100\% - [(22.37 + 5.75\%)] = 71.88\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 100\% - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 4 example:

$$EAF_{MAX} = 100\% - [0.8\ (22.37\%) + 0.95\ (5.75\%)] = 76.64\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 100\% - [1.4\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Big Bend Unit 4 example,

$$EAF_{MIN} = 100\% - [1.4\ (22.37\%) + 1.10\ (5.75\%)] = 62.36\%$$

The equivalent availability maximum and minimum for the other four units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January 2006 through December 2006 are shown on page 17 of Document No. 1. Two GPIF units have a major outage (28 days or greater) in 2006; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for a planned outage from March 20, 2006 to April 9, 2006. There are 504 planned outage hours scheduled for the 2006 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend Unit 4 is 5.75 percent or:

$$\frac{504}{8,760} \times 100\% = 5.75\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Big Bend Unit 1 has a Planned Outage Factor of 15.34 percent. Big Bend Unit 2 has a Planned Outage Factor of 3.84 percent. Big Bend 3 has a Planned Outage Factor of 9.59 percent. Polk Unit 1 has a Planned Outage Factor of 4.38 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Graphs for both factors, adjusted for planned outages, versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2005, was used as a basis for the projection. All projected factors are based upon historical unit performance. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 22.37 percent for Big Bend Unit 4. The Equivalent Unplanned Outage Factor for Big Bend Unit 4 is verified by the data shown on page 15, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{\text{Period Hours}} \times 100$$

Or

$$EUOF = \frac{(1{,}931 + 29.0)}{8{,}760} \times 100 = 22.37\%$$

Relative to Big Bend Unit 4, the EUOF of 22.37 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 21.03 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 15.34 percent. Therefore, the target equivalent availability for this unit is 63.63 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 18.89 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 77.27 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 34.21 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 9.59 percent. Therefore, the target equivalent availability for this unit is 56.20 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 22.37 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability for this unit is 71.88 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 35.28 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 4.38 percent. Therefore, the target equivalent availability for this unit is 60.33 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 65.0 percent is shown on Page 5 of Document No. 1. This target is similar to the July 2004 through June 2005 GPIF period.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since the units in the GPIF are usually base load units, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 4 on page 15 of Document No. 1. During the months of January, February, and May through December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of March and April, the Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit parameters, which are subsequently converted to factors. Therefore,

$$FOF + MOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates as well as ranges of potential operation have been developed as required.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 25 through 29 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2006 period.

A. The heat rate target for Big Bend Unit 1 is 10,848 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±514 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,518 Btu/Net kWh with a range of ±436 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,904 Btu/Net kWh, with a range of ±718 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,672 Btu/Net kWh with a range of ±595 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,497 Btu/Net kWh with a range of ±1,167 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 11. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $959,068,300 is shown on page 6, column 2.

Multiple production costing simulations were then performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $47,304,788 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit 1, the weighting factor for equivalent availability is 12.33 percent as shown in the right-hand column on page 6. Pages 7 through 11 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 4, page 10, if the unit operates at 76.6 percent equivalent availability, fuel savings would equal $6,443,000, and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 11. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $47,304,788. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2006 is $1,461,702,488. This produces the maximum allowed jurisdictional incentive of $5,802,787 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony on the GPIF.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP: = (\ & 0.1233\ EAP_{BB1} + 0.1147\ EAP_{BB2} \\ & + 0.1905\ EAP_{BB3} + 0.1362\ EAP_{BB4} \\ & + 0.1020\ EAP_{PK1} + 0.0549\ HRP_{BB1} \\ & + 0.0589\ HRP_{BB2} + 0.0645\ HRP_{BB3} \\ & + 0.0849\ HRP_{BB4} + 0.0700\ HRP_{PK} \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3, and 4 and Polk Unit 1.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4 and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2006 - December 2006 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Maintenance Planning

Q. What does Tampa Electric do to complete planned maintenance outages on schedule and within budget?

A. To complete planned maintenance outages on schedule and within budget Tampa Electric: (1) develops a comprehensive scope of work before every planned outage that identifies time, material and manpower requirements; (2) procures materials and contractor labor; (3) assigns outage coordinators, project managers and business plan managers to manage and coordinate the various aspects of the outage; and (4) holds regular meetings with the appropriate personnel prior to and during the planned outage to ensure that the outage schedule is being met, issues are resolved, and costs are being appropriately managed.

Q. What actions does Tampa Electric take to minimize the occurrence, duration and magnitude of unplanned outages?

A. To minimize the occurrence, duration and magnitude of unplanned outages Tampa Electric: (1) uses a Preventative Maintenance ("PM") program that incorporates the Original Equipment Manufacturer's maintenance specifications, vibration analysis, oil sampling, temperature monitoring, and thermograph equipment; (2) reviews historical equipment unplanned outages; (3) assigns project managers and outage coordinators to manage outages; and (4) schedules planned outages on equipment incorporating a review of the outages during the prior year that result in the largest reduction in unit generation. These tools allow Tampa Electric to determine appropriate actions needed to develop equipment repair strategies, predict future maintenance requirements, appropriately manage the impact of unplanned outages, and return units to service as soon as practicable.

Q. How does Tampa Electric optimize the equivalent availability factors and heat rates of its GPIF units?

A. Above I described actions to complete planned maintenance on time and to minimize the occurrence and duration of unplanned maintenance that directly affect the unit equivalent availability factors. While planned maintenance decreases equivalent availability factors in the short-term, in the long run, maintenance work helps Tampa Electric manage unit performance and availability by decreasing the likelihood of future unplanned outages due to the failure of equipment repaired during the planned maintenance. Tampa Electric optimizes the equivalent availability factors of its units by predicting future maintenance requirements and developing advantageous equipment repair and unit operating strategies using the tools, processes and procedures outlined above.

Tampa Electric optimizes GPIF unit heat rates by: (1) running these units at relatively higher load levels for long periods of time, as the system allows, to avoid the inefficiencies associated with starting and cycling a unit and operating a unit at minimum load levels that are less efficient; and (2) incorporating a review of the largest unit heat rate impacts in the outage planning process.

Polk Unit 1 Outage

Q. What is the status of Tampa Electric's investigation of the failure that caused an extended unplanned outage at Polk Unit 1?

A. Tampa Electric consulted with its service provider, General Electric International ("GE"), with regard to the Polk Unit 1 unplanned outage that began on January 18, 2005. Tampa Electric has been advised that the outage was the result of a physical failure that resulted in extensive damage to the unit's air compressor. The investigation determined the compressor discharge case experienced higher than designed creep, which is high temperature progressive deformation of a material at constant stress. The higher than designed creep resulted in reduced clearances between fixed and rotating air compressor components. When the design limits of the fixed components were exceeded, the fixed vane and rotating blades made contact, causing extensive compressor damage.

Q. Has Tampa Electric evaluated all avenues of redress for replacement fuel and purchased power costs for the air compressor failure at Polk Unit 1?

A. Yes, Tampa Electric has been and continues to be in communication with insurers and GE, who is both the manufacturer and service provider for the air compressor. However, under the company's insurance policy and the contract for purchase of the equipment, Tampa Electric is not entitled to recovery for consequential damages such as replacement fuel and purchased power costs. In my experience at Tampa Electric, indirect damages of these sorts are not typically covered by insurance, construction contracts, or service agreements because covering the risk of indirect damages would be cost-prohibitive or impracticable.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO._________
DOCKET NO. 050001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)
FILED: 9/9/05

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GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

EXHIBIT TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2006 - DECEMBER 2006
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2006 - DECEMBER 2006

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	47,304.8	5,802.8
+9	42,574.3	5,222.5
+8	37,843.8	4,642.2
+7	33,113.4	4,062.0
+6	28,382.9	3,481.7
+5	23,652.4	2,901.4
+4	18,921.9	2,321.1
+3	14,191.4	1,740.8
+2	9,461.0	1,160.6
+1	4,730.5	580.3
0	0.0	0.0
-1	(7,868.1)	(580.3)
-2	(15,736.3)	(1,160.6)
-3	(23,604.4)	(1,740.8)
-4	(31,472.6)	(2,321.1)
-5	(39,340.7)	(2,901.4)
-6	(47,208.9)	(3,481.7)
-7	(55,077.0)	(4,062.0)
-8	(62,945.2)	(4,642.2)
-9	(70,813.3)	(5,222.5)
-10	(78,681.5)	(5,802.8)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2006 - DECEMBER 2006

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,400,505,000	
Line 2	Month of January	2006	$	1,447,442,278	
Line 3	Month of February	2006	$	1,461,615,150	
Line 4	Month of March	2006	$	1,475,926,799	
Line 5	Month of April	2006	$	1,414,956,783	
Line 6	Month of May	2006	$	1,428,811,568	
Line 7	Month of June	2006	$	1,442,802,015	
Line 8	Month of July	2006	$	1,490,054,235	
Line 9	Month of August	2006	$	1,504,644,350	
Line 10	Month of September	2006	$	1,519,377,325	
Line 11	Month of October	2006	$	1,457,679,251	
Line 12	Month of November	2006	$	1,471,952,361	
Line 13	Month of December	2006	$	1,486,365,228	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,461,702,488	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.38%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,953,422	
Line 18	Jurisdictional Sales			19,670,497	MWH
Line 19	Total Sales			20,181,122	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.47%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,802,787**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2006 - DECEMBER 2006

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	12.33%	63.6	68.6	53.7	5,832.8	(12,556.3)
BIG BEND 2	11.47%	77.3	81.2	69.3	5,426.4	(11,122.1)
BIG BEND 3	19.05%	56.2	63.5	41.6	9,010.8	(16,752.4)
BIG BEND 4	13.62%	71.9	76.6	62.4	6,443.0	(12,663.9)
POLK 1	10.20%	60.3	67.6	45.8	4,825.5	(9,820.5)
GPIF SYSTEM	**66.67%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	5.49%	10,841	75.9	10,327	11,355	2,597.3	(2,597.3)
BIG BEND 2	5.89%	10,510	84.2	10,074	10,947	2,786.9	(2,786.9)
BIG BEND 3	6.45%	10,923	69.1	10,205	11,641	3,053.2	(3,053.2)
BIG BEND 4	8.49%	10,672	81.6	10,077	11,267	4,018.3	(4,018.3)
POLK 1	7.00%	10,497	88.9	9,330	11,664	3,310.5	(3,310.5)
GPIF SYSTEM	**33.33%**					**15,766.3**	**(15,766.3)**

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 06 - DEC 06			TARGET PERIOD JUL 04 - JUN 05			TARGET PERIOD JUL 03 - JUN 04			TARGET PERIOD JUL 02 - JUN 03		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	12.33%	18.5%	15.3	21.0	24.8	0.0	24.8	24.8	7.9	33.8	36.7	0.0	28.9	28.9
BIG BEND 2	11.47%	17.2%	3.8	18.9	19.6	7.3	18.9	20.4	0.0	37.8	37.8	23.3	24.4	31.8
BIG BEND 3	19.05%	28.6%	9.6	34.2	37.8	15.1	30.8	36.3	0.0	37.4	37.4	0.0	28.6	28.6
BIG BEND 4	13.62%	20.4%	5.8	22.4	23.7	8.2	20.1	21.8	10.6	15.8	17.7	6.1	16.0	17.1
POLK 1	10.20%	15.3%	4.4	35.3	36.9	0.0	33.5	33.5	3.3	18.7	19.3	11.1	7.1	8.0
GPIF SYSTEM	**66.67%**	**100.0%**	**8.1**	**26.9**	**29.3**	**7.2**	**25.9**	**28.0**	**4.1**	**29.5**	**30.5**	**6.9**	**22.1**	**23.7**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%				**65.0**			**66.9**			**66.4**			**71.0**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
6.1	**25.8**	**27.4**	**68.1**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 06 - DEC 06	ADJUSTED PRIOR HEAT RATE JUL 04 - JUN 05	ADJUSTED PRIOR HEAT RATE JUL 03 - JUN 04	ADJUSTED PRIOR HEAT RATE JUL 02 - JUN 03
BIG BEND 1	5.49%	16.5%	10,841	10,828	10,752	10,929
BIG BEND 2	5.89%	17.7%	10,510	10,468	10,470	10,647
BIG BEND 3	6.45%	19.4%	10,923	10,923	10,886	10,951
BIG BEND 4	8.49%	25.5%	10,672	10,722	10,638	10,574
POLK 1	7.00%	21.0%	10,497	10,180	10,254	10,361
GPIF SYSTEM	**33.33%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,683**	**10,620**	**10,594**	**10,674**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2006 - DECEMBER 2006
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	959,068.3	953,235.5	5,833	12.33%
EA_2 BIG BEND 2	959,068.3	953,641.9	5,426	11.47%
EA_3 BIG BEND 3	959,068.3	950,057.5	9,011	19.05%
EA_4 BIG BEND 4	959,068.3	952,625.3	6,443	13.62%
EA_7 POLK 1	959,068.3	954,242.8	4,826	10.20%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	959,068.3	956,471.0	2,597	5.49%
AHR_2 BIG BEND 2	959,068.3	956,281.4	2,787	5.89%
AHR_3 BIG BEND 3	959,068.3	956,015.1	3,053	6.45%
AHR_4 BIG BEND 4	959,068.3	955,050.0	4,018	8.49%
AHR_7 POLK 1	959,068.3	955,757.8	3,311	7.00%
TOTAL SAVINGS			**47,304.788**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2006 - DECEMBER 2006

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,832.8	68.6	+10	2,597.3	10,327
+9	5,249.5	68.1	+9	2,337.6	10,371
+8	4,666.2	67.6	+8	2,077.9	10,415
+7	4,083.0	67.1	+7	1,818.1	10,459
+6	3,499.7	66.6	+6	1,558.4	10,502
+5	2,916.4	66.1	+5	1,298.7	10,546
+4	2,333.1	65.6	+4	1,038.9	10,590
+3	1,749.8	65.1	+3	779.2	10,634
+2	1,166.6	64.6	+2	519.5	10,678
+1	583.3	64.1	+1	259.7	10,722
					10,766
0	0.0	63.6	0	0.0	10,841
					10,916
-1	(1,255.6)	62.6	-1	(259.7)	10,960
-2	(2,511.3)	61.6	-2	(519.5)	11,004
-3	(3,766.9)	60.6	-3	(779.2)	11,048
-4	(5,022.5)	59.7	-4	(1,038.9)	11,091
-5	(6,278.1)	58.7	-5	(1,298.7)	11,135
-6	(7,533.8)	57.7	-6	(1,558.4)	11,179
-7	(8,789.4)	56.7	-7	(1,818.1)	11,223
-8	(10,045.0)	55.7	-8	(2,077.9)	11,267
-9	(11,300.7)	54.7	-9	(2,337.6)	11,311
-10	(12,556.3)	53.7	-10	(2,597.3)	11,355
	Weighting Factor =	12.33%		Weighting Factor =	5.49%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2006 - DECEMBER 2006

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,426.4	81.2	+10	2,786.9	10,074
+9	4,883.8	80.8	+9	2,508.2	10,110
+8	4,341.1	80.4	+8	2,229.5	10,146
+7	3,798.5	80.1	+7	1,950.9	10,182
+6	3,255.8	79.7	+6	1,672.2	10,218
+5	2,713.2	79.3	+5	1,393.5	10,254
+4	2,170.6	78.9	+4	1,114.8	10,291
+3	1,627.9	78.5	+3	836.1	10,327
+2	1,085.3	78.1	+2	557.4	10,363
+1	542.6	77.7	+1	278.7	10,399
					10,435
0	0.0	77.3	0	0.0	10,510
					10,585
-1	(1,112.2)	76.5	-1	(278.7)	10,621
-2	(2,224.4)	75.7	-2	(557.4)	10,658
-3	(3,336.6)	74.9	-3	(836.1)	10,694
-4	(4,448.8)	74.1	-4	(1,114.8)	10,730
-5	(5,561.0)	73.3	-5	(1,393.5)	10,766
-6	(6,673.3)	72.5	-6	(1,672.2)	10,802
-7	(7,785.5)	71.7	-7	(1,950.9)	10,838
-8	(8,897.7)	70.9	-8	(2,229.5)	10,874
-9	(10,009.9)	70.1	-9	(2,508.2)	10,911
-10	(11,122.1)	69.3	-10	(2,786.9)	10,947
	Weighting Factor =	11.47%		Weighting Factor =	5.89%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2006 - DECEMBER 2006

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	9,010.8	63.5	+10	3,053.2	10,205
+9	8,109.7	62.8	+9	2,747.8	10,270
+8	7,208.6	62.1	+8	2,442.5	10,334
+7	6,307.6	61.3	+7	2,137.2	10,398
+6	5,406.5	60.6	+6	1,831.9	10,463
+5	4,505.4	59.9	+5	1,526.6	10,527
+4	3,604.3	59.1	+4	1,221.3	10,591
+3	2,703.2	58.4	+3	915.9	10,656
+2	1,802.2	57.7	+2	610.6	10,720
+1	901.1	56.9	+1	305.3	10,784
					10,848
0	0.0	56.2	0	0.0	10,923
					10,998
-1	(1,675.2)	54.7	-1	(305.3)	11,063
-2	(3,350.5)	53.3	-2	(610.6)	11,127
-3	(5,025.7)	51.8	-3	(915.9)	11,191
-4	(6,701.0)	50.3	-4	(1,221.3)	11,256
-5	(8,376.2)	48.9	-5	(1,526.6)	11,320
-6	(10,051.4)	47.4	-6	(1,831.9)	11,384
-7	(11,726.7)	45.9	-7	(2,137.2)	11,448
-8	(13,401.9)	44.5	-8	(2,442.5)	11,513
-9	(15,077.2)	43.0	-9	(2,747.8)	11,577
-10	(16,752.4)	41.6	-10	(3,053.2)	11,641
	Weighting Factor =	19.05%		Weighting Factor =	6.45%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2006 - DECEMBER 2006

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	6,443.0	76.6	+10	4,018.3	10,077
+9	5,798.7	76.2	+9	3,616.5	10,129
+8	5,154.4	75.7	+8	3,214.7	10,181
+7	4,510.1	75.2	+7	2,812.8	10,233
+6	3,865.8	74.7	+6	2,411.0	10,285
+5	3,221.5	74.3	+5	2,009.2	10,337
+4	2,577.2	73.8	+4	1,607.3	10,389
+3	1,932.9	73.3	+3	1,205.5	10,441
+2	1,288.6	72.8	+2	803.7	10,493
+1	644.3	72.3	+1	401.8	10,545
					10,597
0	0.0	71.9	0	0.0	10,672
					10,747
-1	(1,266.4)	70.9	-1	(401.8)	10,799
-2	(2,532.8)	70.0	-2	(803.7)	10,851
-3	(3,799.2)	69.0	-3	(1,205.5)	10,903
-4	(5,065.6)	68.1	-4	(1,607.3)	10,955
-5	(6,331.9)	67.1	-5	(2,009.2)	11,007
-6	(7,598.3)	66.2	-6	(2,411.0)	11,059
-7	(8,864.7)	65.2	-7	(2,812.8)	11,111
-8	(10,131.1)	64.3	-8	(3,214.7)	11,163
-9	(11,397.5)	63.3	-9	(3,616.5)	11,215
-10	(12,663.9)	62.4	-10	(4,018.3)	11,267
	Weighting Factor =	13.62%		Weighting Factor =	8.49%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2006 - DECEMBER 2006

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,825.5	67.6	+10	3,310.5	9,330
+9	4,343.0	66.9	+9	2,979.5	9,439
+8	3,860.4	66.2	+8	2,648.4	9,549
+7	3,377.9	65.4	+7	2,317.4	9,658
+6	2,895.3	64.7	+6	1,986.3	9,767
+5	2,412.8	64.0	+5	1,655.3	9,876
+4	1,930.2	63.2	+4	1,324.2	9,985
+3	1,447.7	62.5	+3	993.2	10,095
+2	965.1	61.8	+2	662.1	10,204
+1	482.6	61.1	+1	331.1	10,313
					10,422
0	0.0	60.3	0	0.0	10,497
					10,572
-1	(982.1)	58.9	-1	(331.1)	10,681
-2	(1,964.1)	57.4	-2	(662.1)	10,791
-3	(2,946.2)	56.0	-3	(993.2)	10,900
-4	(3,928.2)	54.5	-4	(1,324.2)	11,009
-5	(4,910.3)	53.1	-5	(1,655.3)	11,118
-6	(5,892.3)	51.6	-6	(1,986.3)	11,227
-7	(6,874.4)	50.2	-7	(2,317.4)	11,336
-8	(7,856.4)	48.7	-8	(2,648.4)	11,446
-9	(8,838.5)	47.2	-9	(2,979.5)	11,555
-10	(9,820.5)	45.8	-10	(3,310.5)	11,664
	Weighting Factor =	10.20%		Weighting Factor =	7.00%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
1. EAF (%)	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	37.6	0.0	50.1	75.2	63.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	100.0	33.3	0.0	15.3
3. EUOF	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	12.4	0.0	16.6	24.8	21.0
4. EUOR	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	0.0	24.8	24.8	24.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	632	570	595	611	632	611	632	632	307	0	406	611	6,239
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	112	102	149	109	112	109	112	112	413	744	314	133	2,521
9. POH	0	0	0	0	0	0	0	0	360	744	240	0	1,344
10. FOH & EFOH	146	132	146	141	146	141	146	146	71	0	94	146	1,452
11. MOH & EMOH	39	35	39	38	39	38	39	39	19	0	25	39	390
12. OPER BTU (GBTU)	2,175	2,018	2,058	2,155	2,221	2,150	2,161	2,166	1,046	0	1,437	2,180	21,766
13. NET GEN (MWH)	199,822	186,354	189,304	199,384	205,381	198,846	198,912	199,427	96,180	0	132,635	201,539	2,007,784
14. ANOHR (Btu/kwh)	10,883	10,831	10,873	10,808	10,815	10,812	10,865	10,861	10,872	0	10,832	10,817	10,841
15. NOF (%)	73.9	76.4	74.3	77.5	77.2	77.3	74.8	75.0	74.4	0.0	76.3	77.1	75.9
16. NPC (MW)	428	428	428	421	421	421	421	421	421	421	428	428	424
17. ANOHR EQUATION	ANOHR = NOF(		-20.606	) +	12,405								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
1. EAF (%)	80.4	80.4	80.4	80.4	80.4	80.4	80.4	80.4	80.4	80.4	80.4	44.1	77.3
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.2	3.8
3. EUOF	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	10.8	18.9
4. EUOR	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	673	612	635	649	673	653	673	673	653	666	653	379	7,592
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	71	60	109	71	71	67	71	71	67	78	67	365	1,168
9. POH	0	0	0	0	0	0	0	0	0	0	0	336	336
10. FOH & EFOH	114	103	114	110	114	110	114	114	110	114	110	62	1,286
11. MOH & EMOH	33	29	33	32	33	32	33	33	32	33	32	18	369
12. OPER BTU (GBTU)	2,438	2,221	2,285	2,348	2,437	2,358	2,340	2,340	2,247	2,418	2,378	1,329	27,146
13. NET GEN (MWH)	231,373	210,844	216,597	224,694	233,171	225,552	222,336	222,395	213,105	231,554	225,834	125,409	2,582,864
14. ANOHR (Btu/kwh)	10,538	10,535	10,550	10,451	10,449	10,454	10,523	10,523	10,542	10,444	10,529	10,594	10,510
15. NOF (%)	82.6	82.8	82.0	87.4	87.5	87.2	83.4	83.4	82.4	87.8	83.1	79.5	84.2
16. NPC (MW)	416	416	416	396	396	396	396	396	396	396	416	416	404
17. ANOHR EQUATION	ANOHR = NOF(	-18.218	) +		12,043								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
1. EAF (%)	62.2	22.2	28.1	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	56.2
2. POF	0.0	64.3	54.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6
3. EUOF	37.8	13.5	17.1	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	34.2
4. EUOR	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	520	186	207	493	512	497	513	513	493	504	488	504	5,430
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	224	486	537	227	232	223	231	231	227	240	232	240	3,330
9. POH	0	432	408	0	0	0	0	0	0	0	0	0	840
10. FOH & EFOH	240	78	109	233	240	233	240	240	233	240	233	240	2,559
11. MOH & EMOH	41	13	19	40	41	40	41	41	40	41	40	41	438
12. OPER BTU (GBTU)	1,406	546	664	1,611	1,655	1,614	1,659	1,670	1,604	1,703	1,609	1,690	17,496
13. NET GEN (MWH)	117,757	47,263	60,134	149,823	152,757	149,470	153,167	154,868	148,660	162,319	148,106	157,416	1,601,740
14. ANOHR (Btu/kwh)	11,943	11,555	11,043	10,754	10,834	10,799	10,831	10,783	10,788	10,493	10,861	10,736	10,923
15. NOF (%)	52.3	58.7	67.1	71.8	70.5	71.1	70.6	71.4	71.3	76.1	70.1	72.1	69.1
16. NPC (MW)	433	433	433	423	423	423	423	423	423	423	433	433	427
17. ANOHR EQUATION	ANOHR = NOF(	-60.836	) +		15,125								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
1. EAF (%)	76.3	76.3	46.7	53.4	76.3	76.3	76.3	76.3	76.3	76.3	76.3	76.3	71.9
2. POF	0.0	0.0	38.7	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.75
3. EUOF	23.7	23.7	14.6	16.6	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	22.4
4. EUOR	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	674	583	340	440	639	612	630	628	602	623	608	633	7,012
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	70	89	404	280	105	108	114	116	118	121	112	111	1,748
9. POH	0	0	288	216	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	174	157	107	118	174	168	174	174	168	174	168	174	1,931
11. MOH & EMOH	3	2	2	2	3	3	3	3	3	3	3	3	29
12. OPER BTU (GBTU)	2,347	2,329	1,421	1,771	2,577	2,476	2,424	2,440	2,344	2,617	2,491	2,552	27,802
13. NET GEN (MWH)	216,021	218,162	133,949	166,510	242,292	232,985	226,442	228,255	219,320	247,607	234,216	239,361	2,605,120
14. ANOHR (Btu/kwh)	10,866	10,676	10,606	10,637	10,635	10,629	10,706	10,691	10,688	10,569	10,637	10,662	10,672
15. NOF (%)	69.7	81.3	85.6	83.7	83.9	84.2	79.5	80.4	80.6	87.9	83.7	82.2	81.6
16. NPC (MW)	460	460	460	452	452	452	452	452	452	452	460	460	455
17. ANOHR EQUATION	ANOHR = NOF(		-16.290	) +	12,001								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
1. EAF (%)	63.1	63.1	63.1	33.6	60.5	63.1	63.1	63.1	63.1	62.5	62.3	63.1	60.3
2. POF	0.0	0.0	0.0	46.7	4.2	0.0	0.0	0.0	0.0	1.0	1.3	0.0	4.4
3. EUOF	36.9	36.9	36.9	19.7	35.4	36.9	36.9	36.9	36.9	36.5	36.4	36.9	35.3
4. EUOR	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	492	444	491	238	286	476	492	492	476	444	254	492	5,077
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	252	228	253	482	458	244	252	252	244	300	466	252	3,683
9. POH	0	0	0	336.1	31.2	0	0	0	0	7	10	0	384
10. FOH & EFOH	265	239	265	137	254	257	265	265	257	263	253	265	2,985
11. MOH & EMOH	9	9	9	5	9	9	9	9	9	9	9	9	106
12. OPER BTU (GBTU)	1,231	1,114	1,218	564	650	1,084	1,120	1,120	1,127	1,104	637	1,231	12,201
13. NET GEN (MWH)	117,748	106,600	116,382	53,669	61,580	102,651	106,073	106,073	107,315	105,544	60,917	117,777	1,162,329
14. ANOHR (Btu/kwh)	10,453	10,449	10,465	10,504	10,560	10,558	10,559	10,559	10,504	10,462	10,450	10,453	10,497
15. NOF (%)	92.0	92.3	91.2	88.4	84.4	84.6	84.5	84.5	88.4	91.4	92.2	92.1	88.9
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	257
17. ANOHR EQUATION	ANOHR = NOF(	-14.057	) +		11,747								

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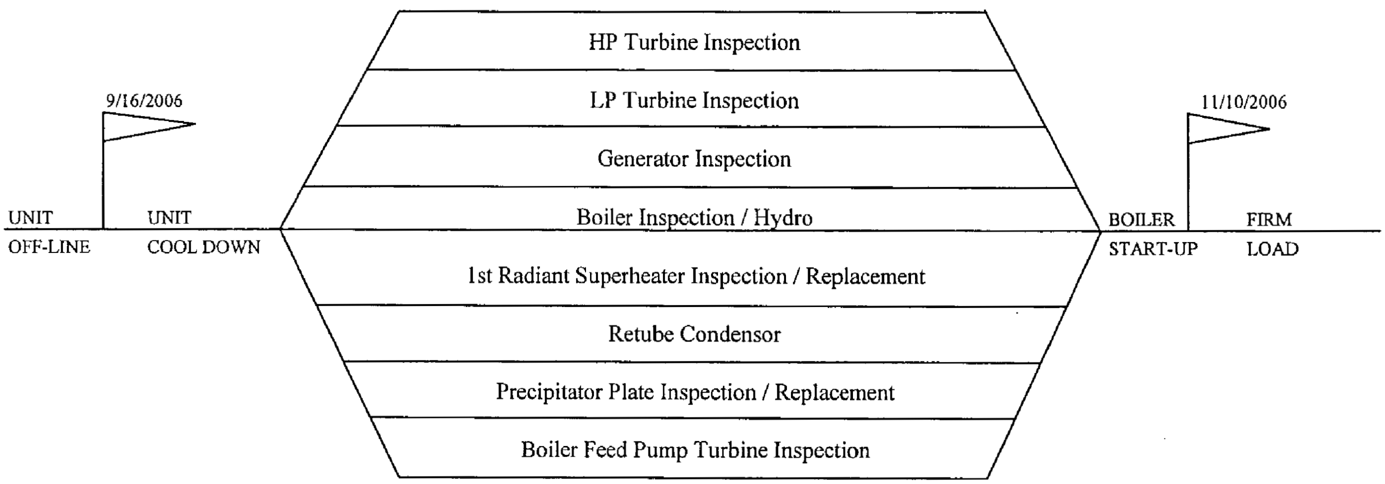
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2006 - DECEMBER 2006

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Sep 16	-	Nov 10	Major Systems Outage
+	BIG BEND 2	Dec 04	-	Dec 17	Fuel System Clean-up
	BIG BEND 3	Feb 11	-	Mar 17	Expanded Fuel Systems Clean-up
+	BIG BEND 4	Mar 20	-	Apr 09	Fuel System Clean -up
+	POLK 1	Apr 16	-	Apr 29	CT Combustion Path

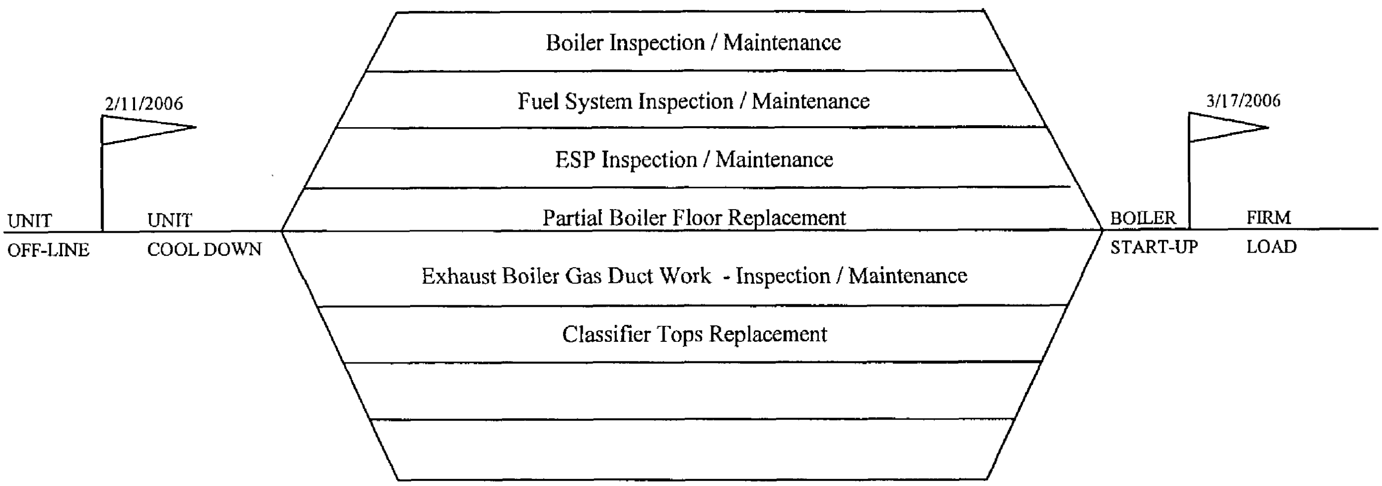
\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006

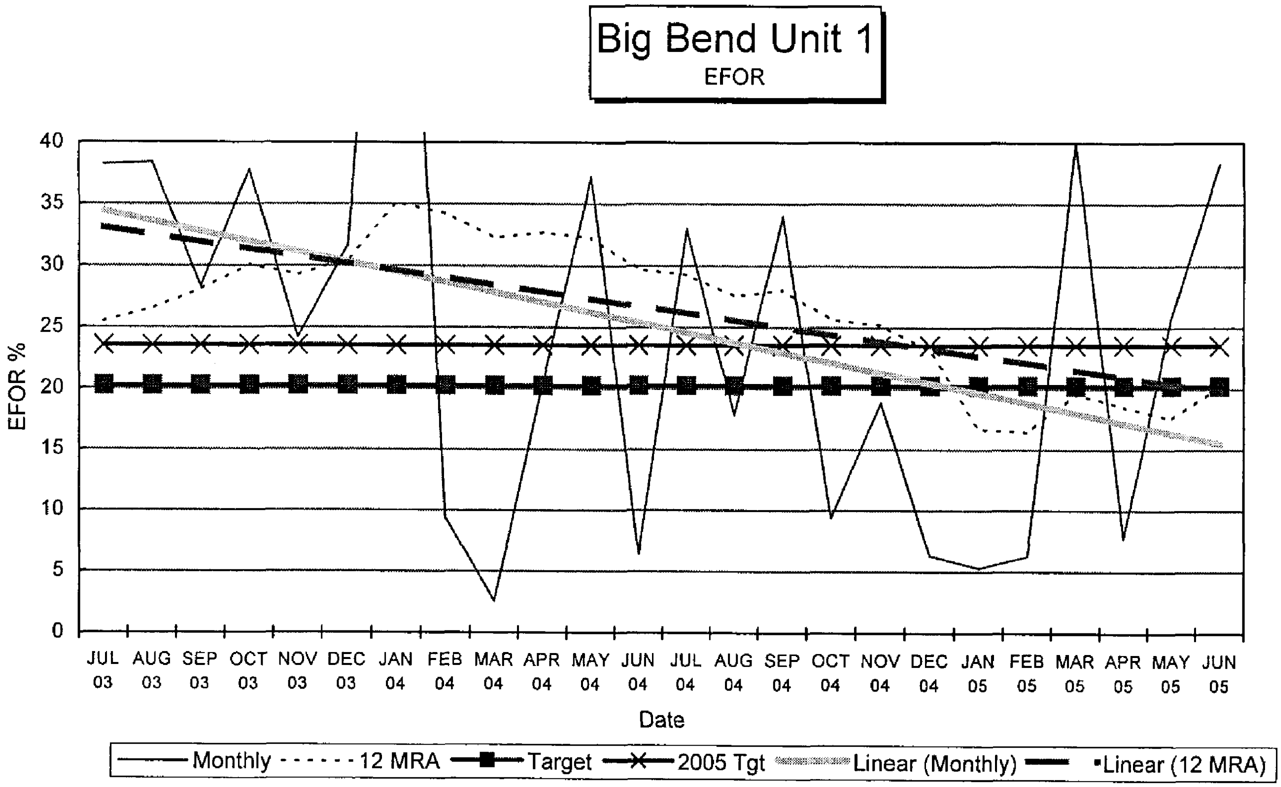


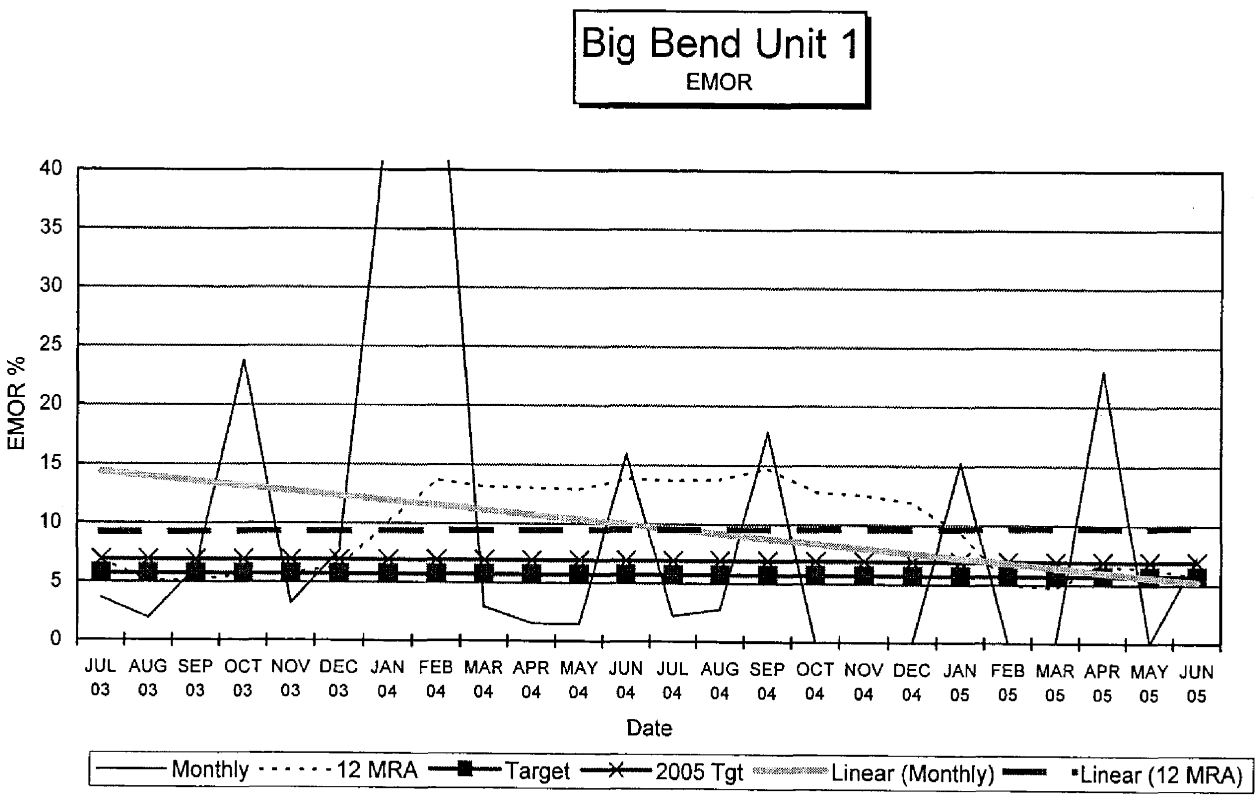
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 1
PLANNED OUTAGE 2006
PROJECTED CPM
08/01/2005

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006

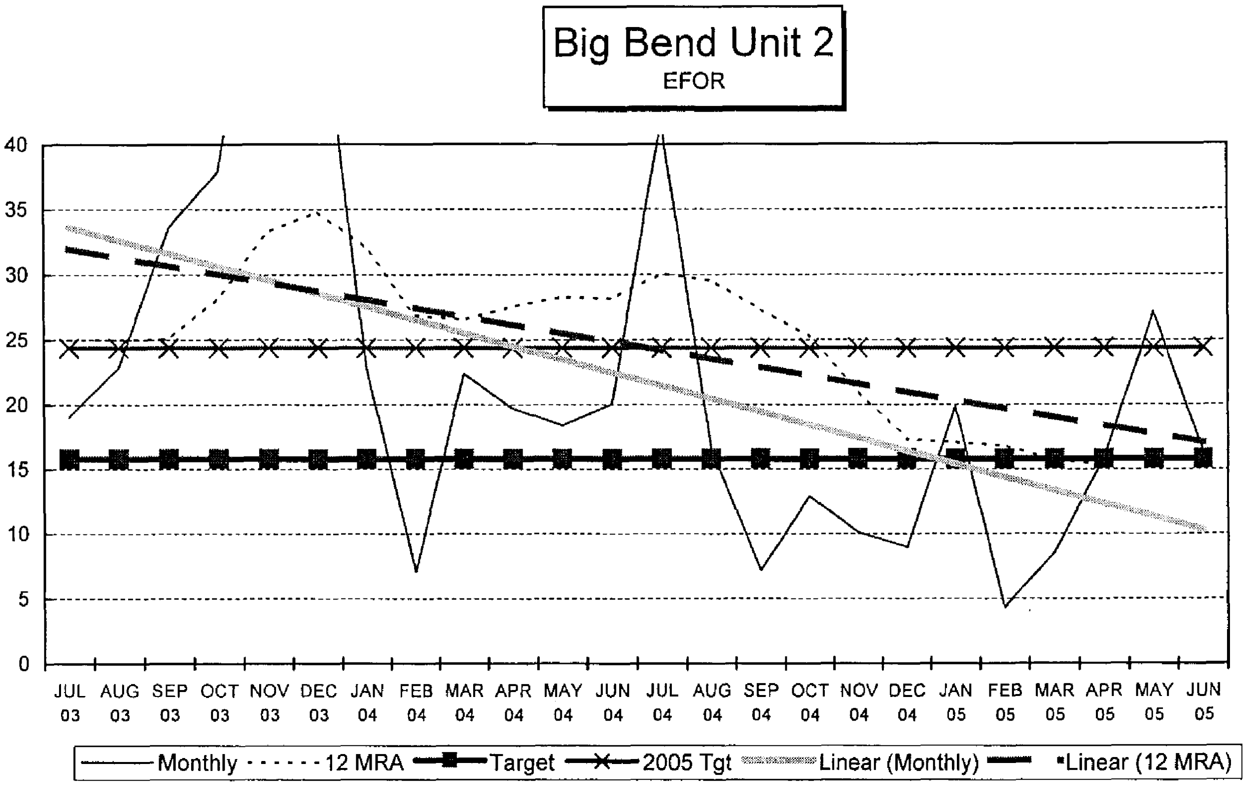


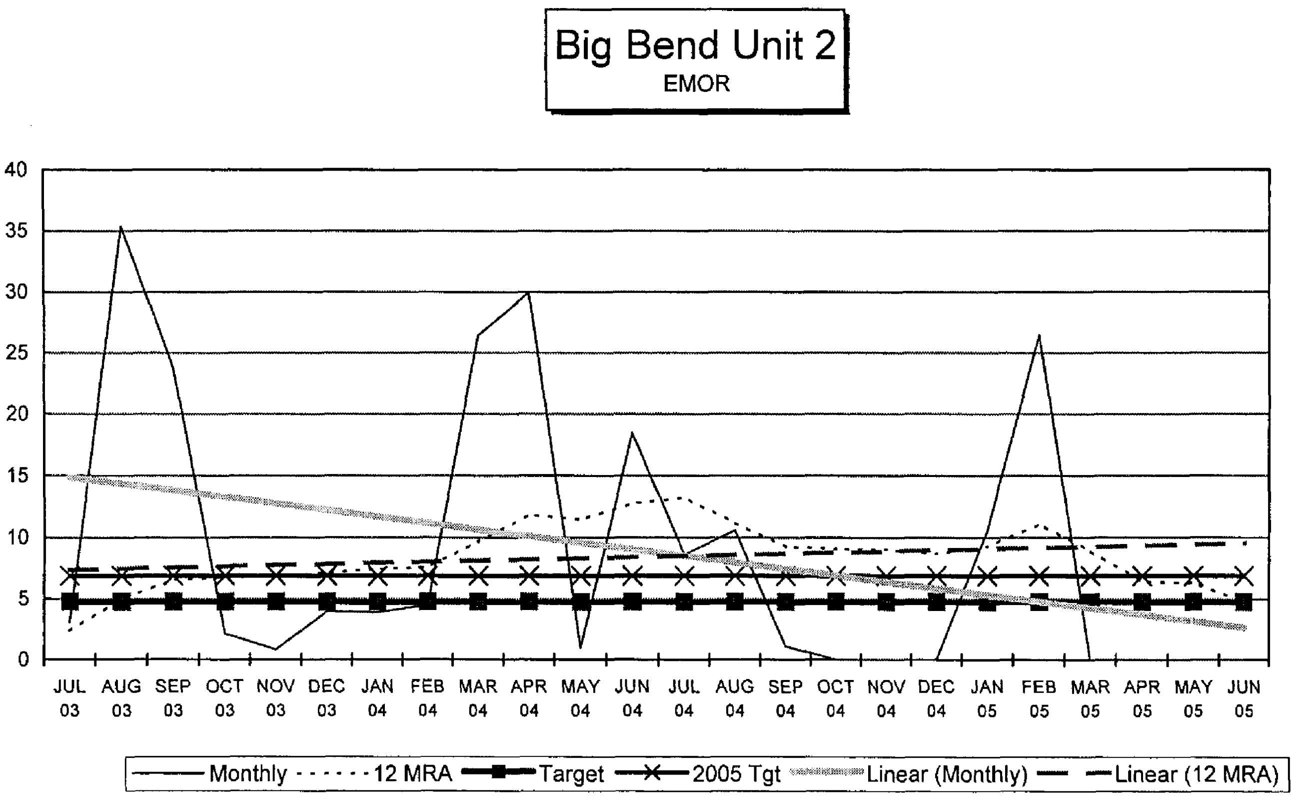
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 3
PLANNED OUTAGE 2006
PROJECTED CPM
08/01/2005



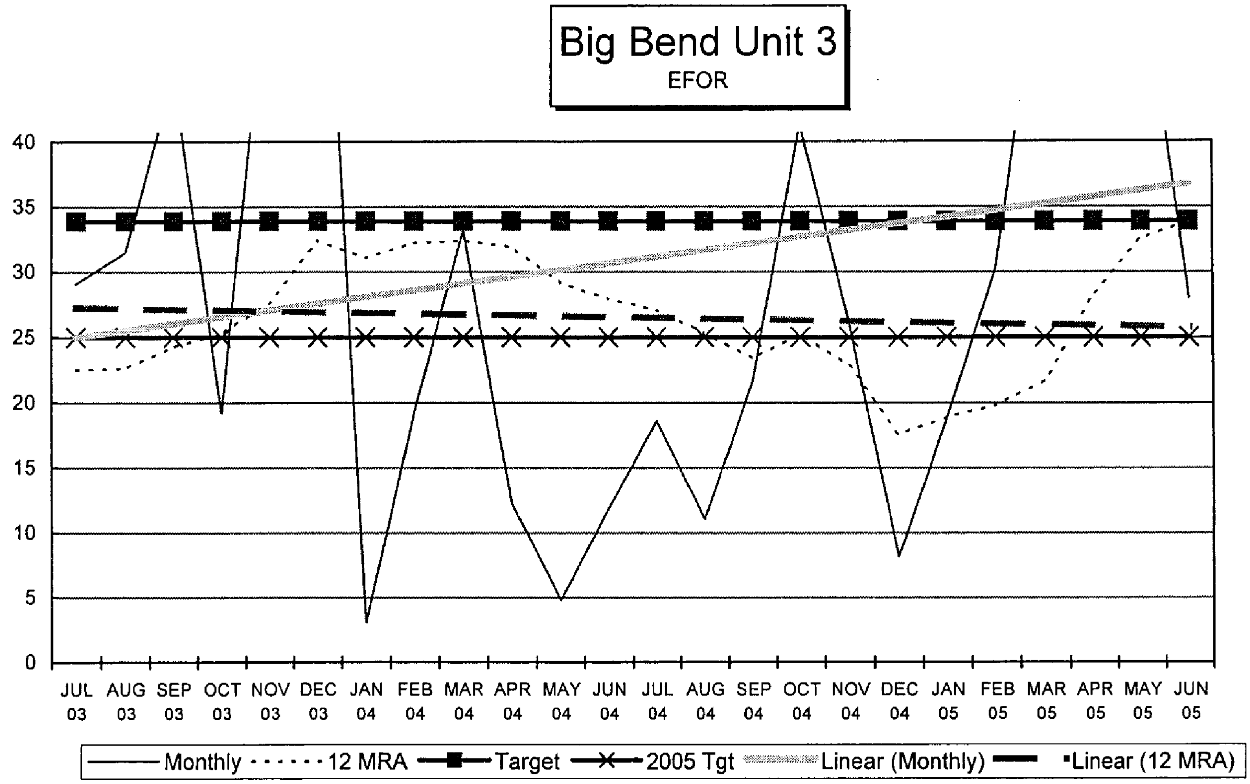


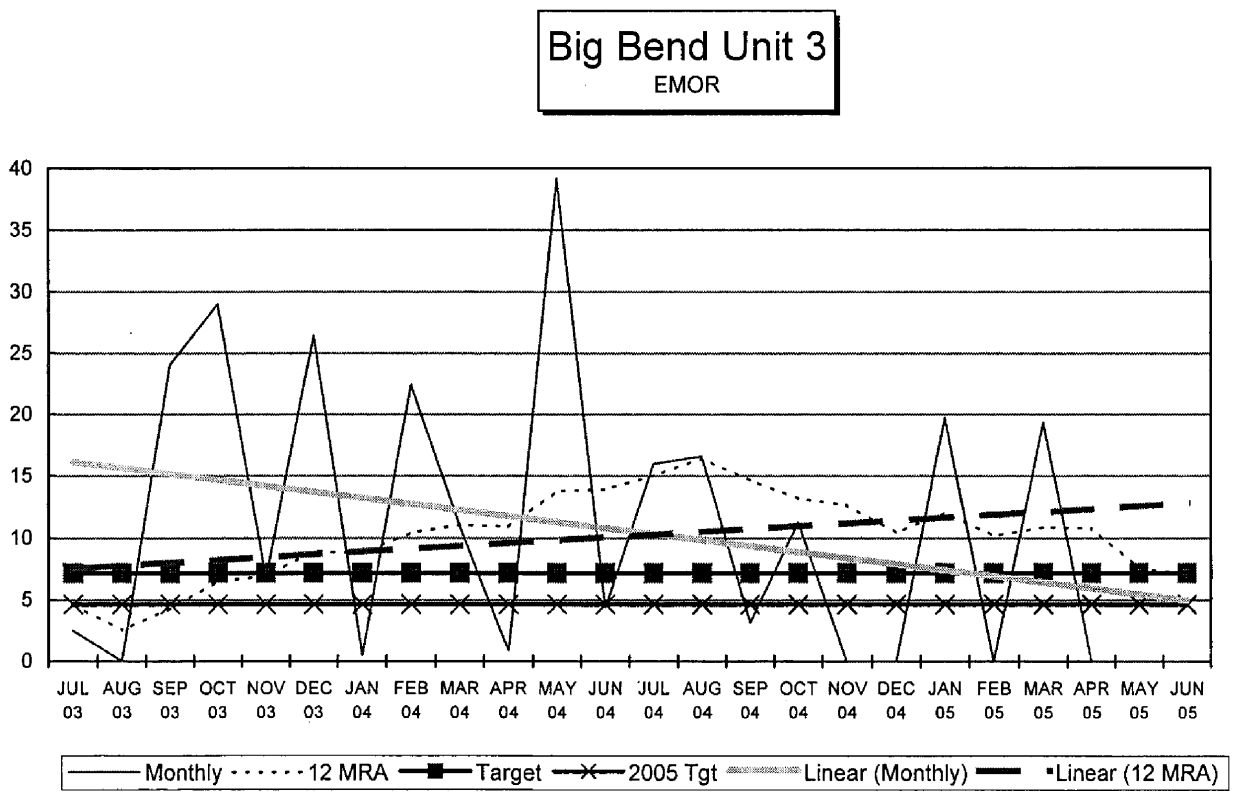
12 MRA = 12 Month Rolling Average



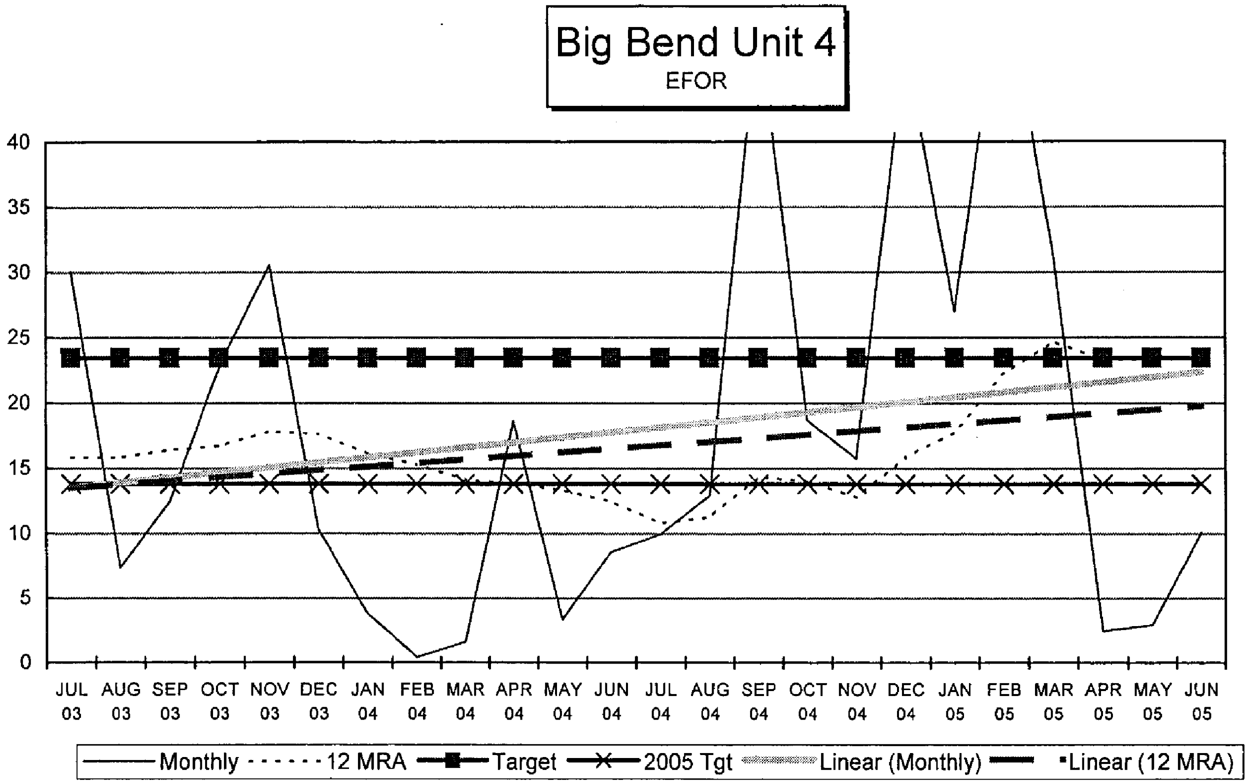


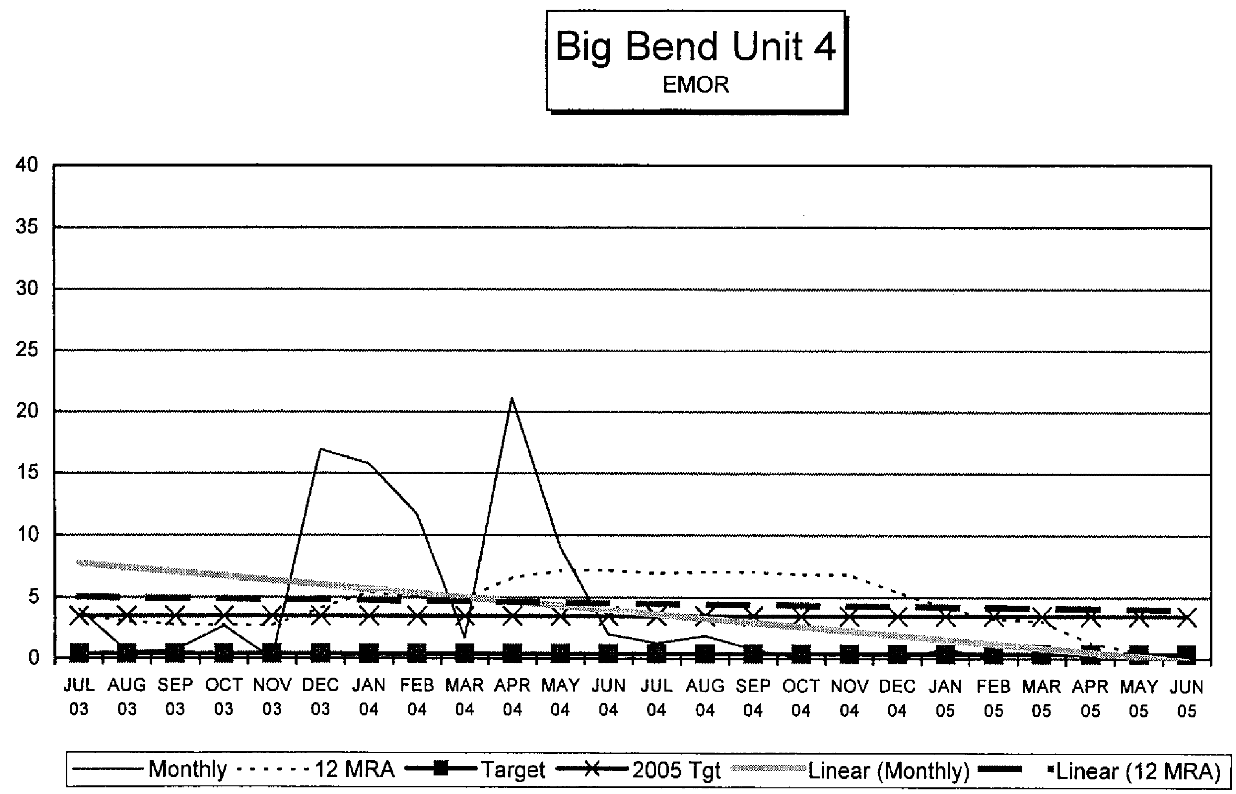
12 MRA = 12 Month Rolling Average



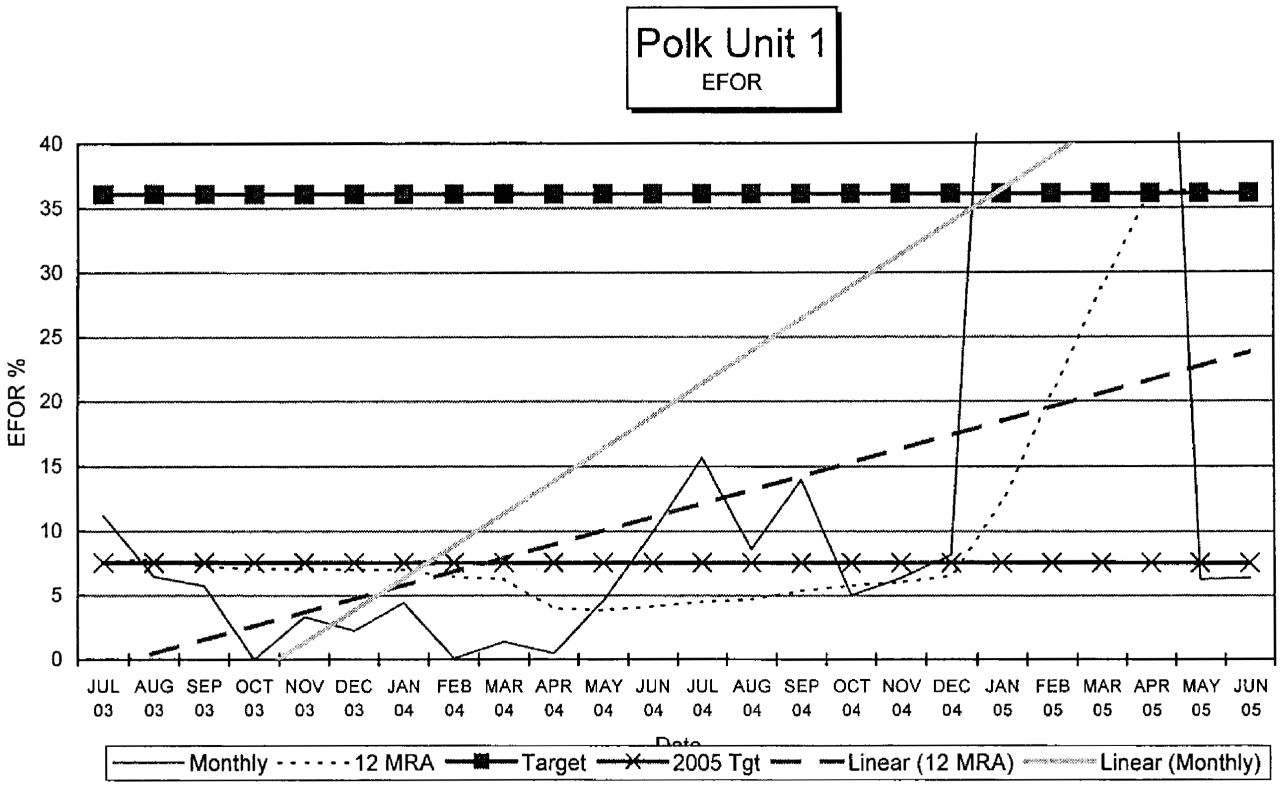


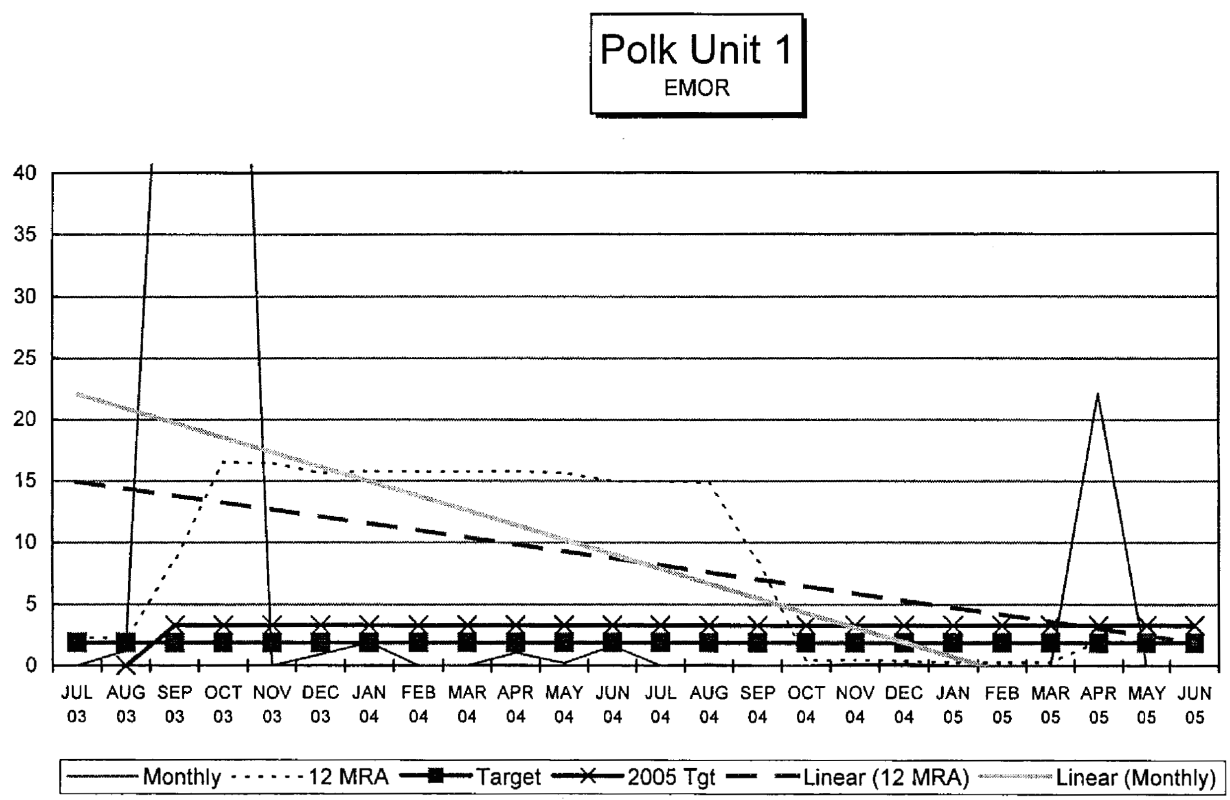
12 MRA = 12 Month Rolling Average





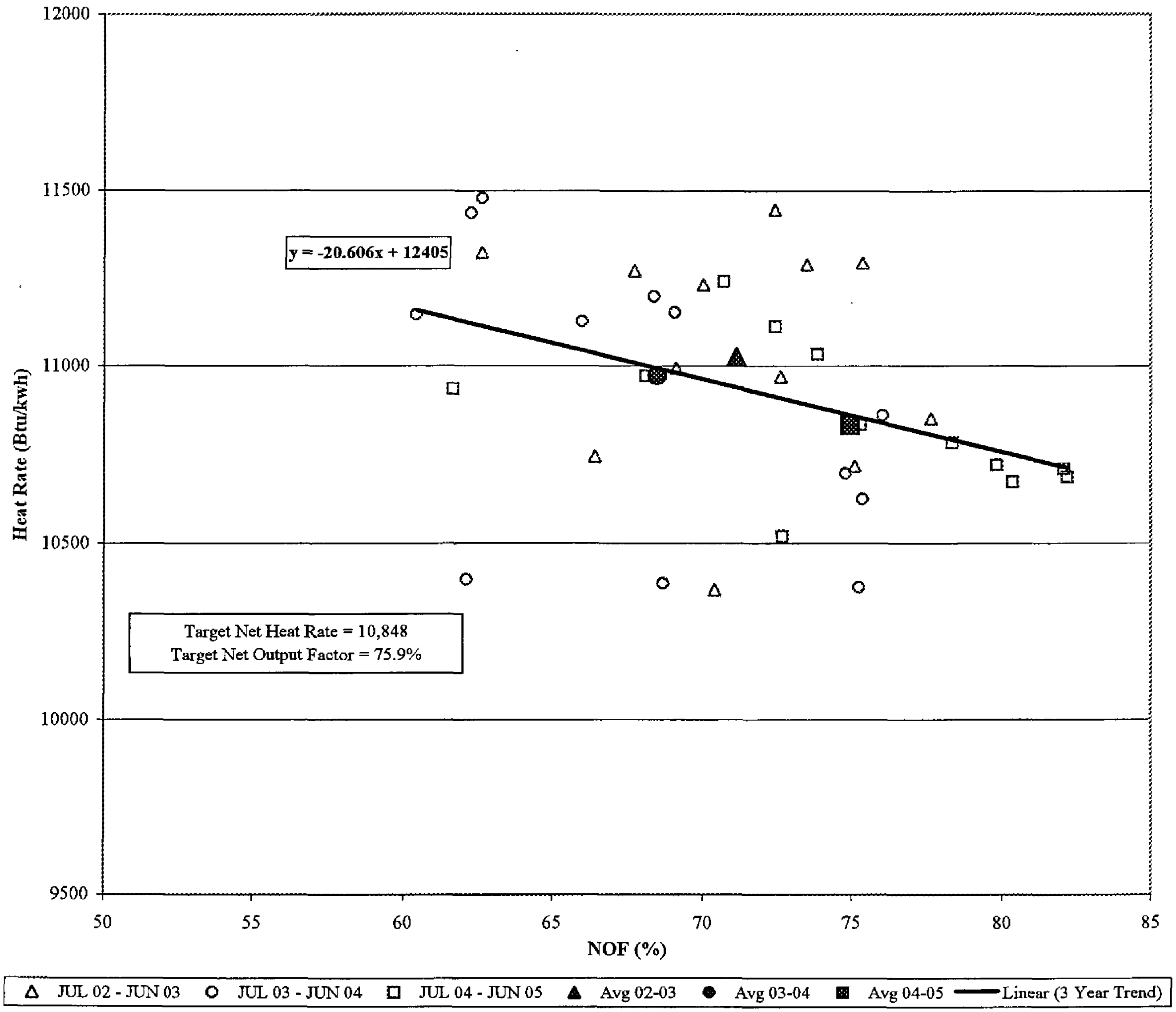
12 MRA = 12 Month Rolling Average





12 MRA = 12 Month Rolling Avreage

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1



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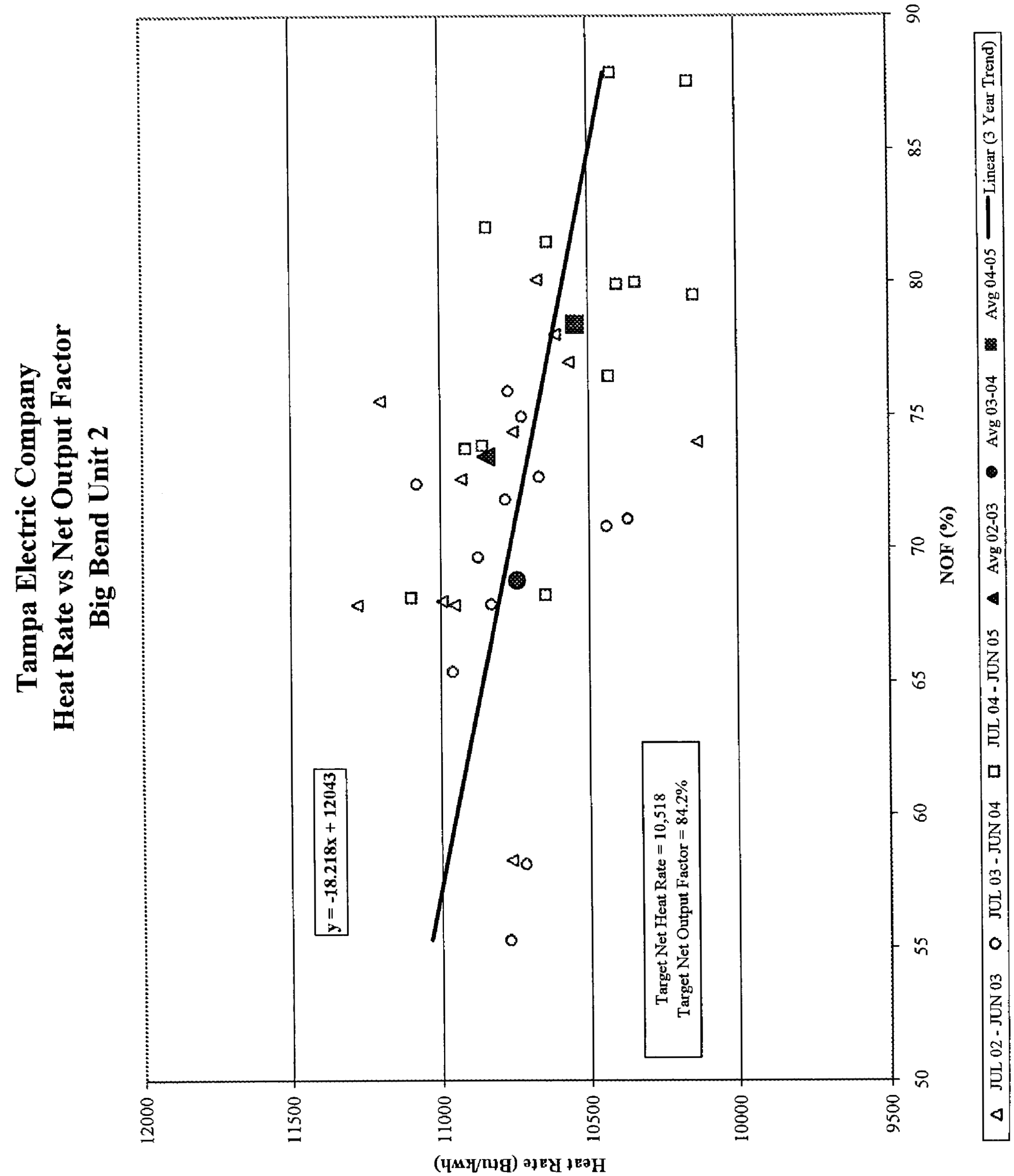
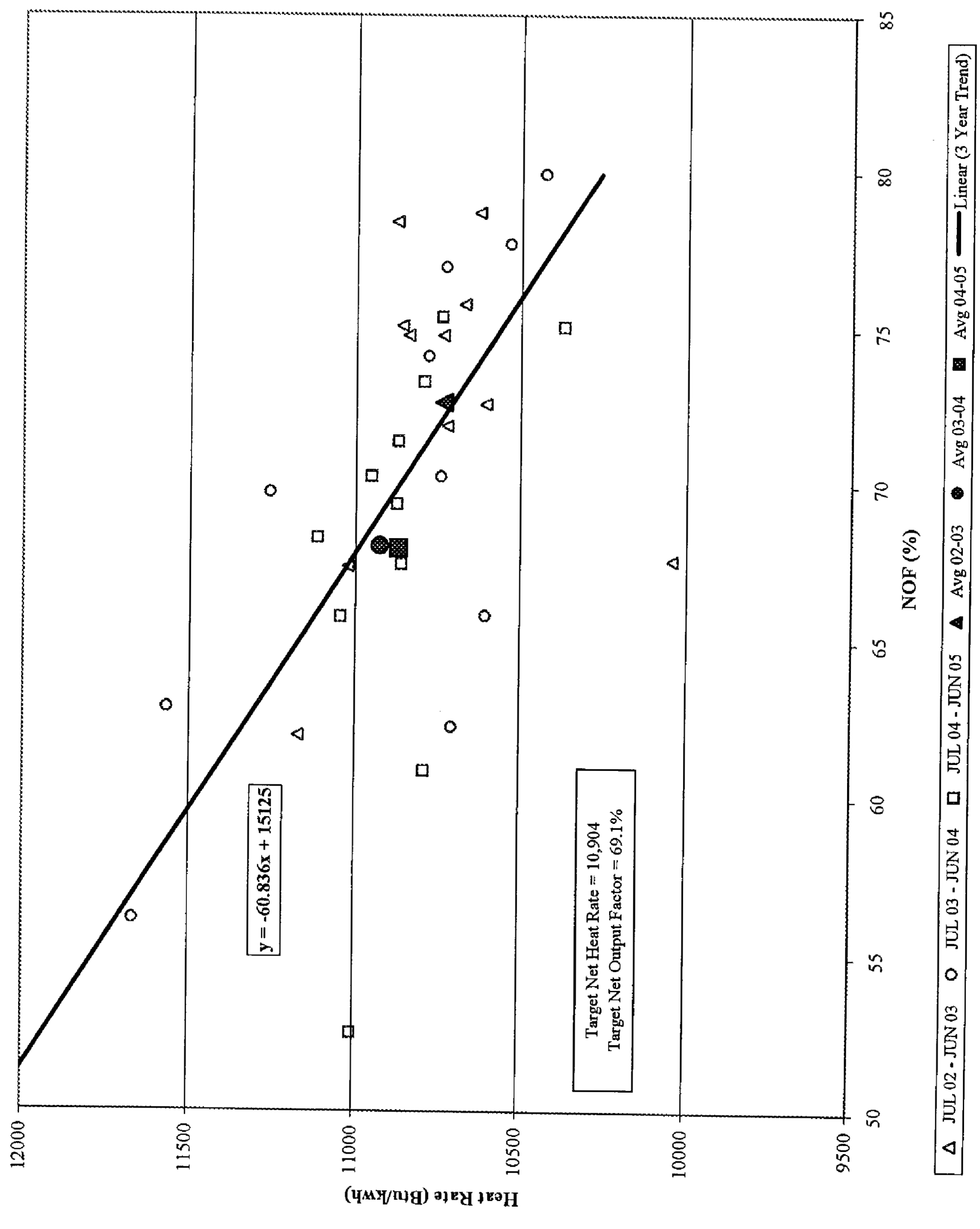
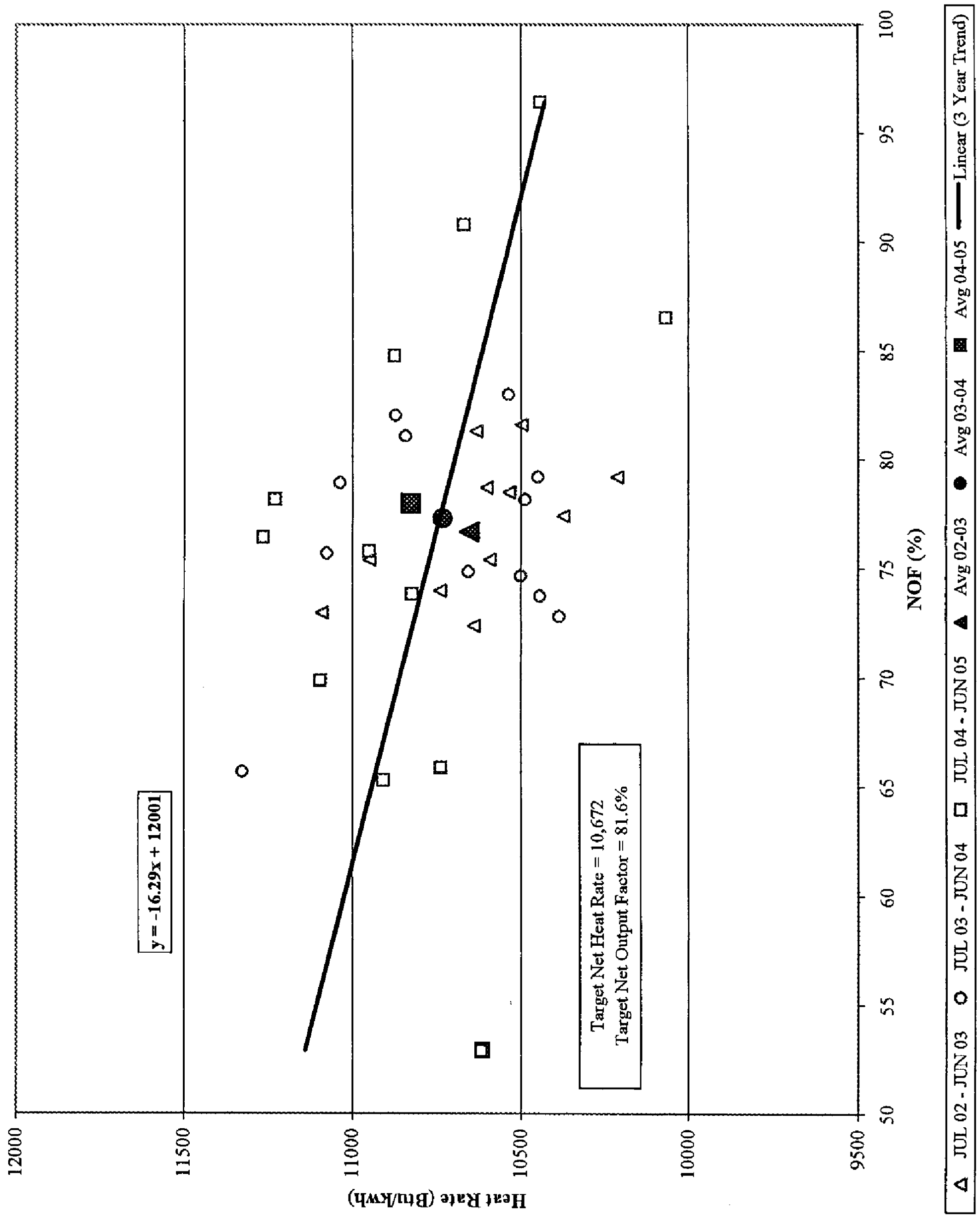

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
Heat Rate (Btu/kwh)
12000
11500
11000
10500
10000
9500
50
55
60
65
70
75
80
85
90
NOF (%)
y = -18.218x + 12043
Target Net Heat Rate = 10,518
Target Net Output Factor = 84.2%
JUL 02 - JUN 03
JUL 03 - JUN 04
JUL 04 - JUN 05
Avg 02-03
Avg 03-04
Avg 04-05
Linear (3 Year Trend)

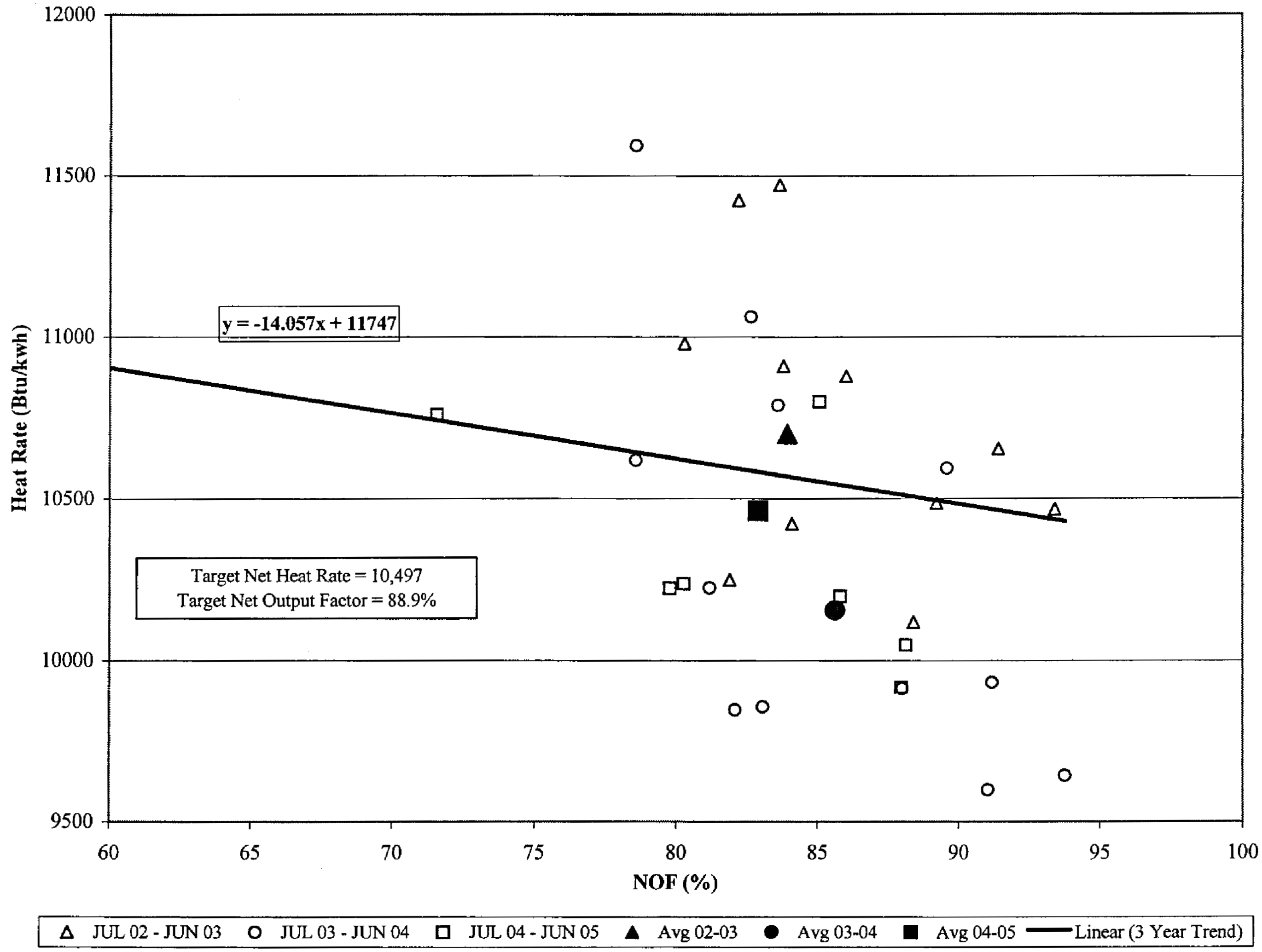
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1



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TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2006 - DECEMBER 2006

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447.0	424.5
BIG BEND 2		435.0	406.0
BIG BEND 3		450.0	428.0
BIG BEND 4		488.0	456.0
POLK 1		325.0	257.5
	GPIF TOTAL	2,145.0	1,972.0
	SYSTEM TOTAL	**4,584.0**	**4,250.5**
	% OF SYSTEM TOTAL	**46.8%**	**46.4%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2006 - DECEMBER 2006

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447.0	424.5
BIG BEND 2		435.0	406.0
BIG BEND 3		450.0	428.0
BIG BEND 4		488.0	456.0
	BIG BEND TOTAL	1,820.0	1,714.5
BIG BEND CT1		15.0	14.5
BIG BEND CT2		80.0	73.0
BIG BEND CT3		80.0	73.0
	CT TOTAL	175.0	160.5
PHILLIPS 1		18.5	17.5
PHILLIPS 2		18.5	17.5
	PHILLIPS TOTAL	37.0	35.0
POLK 1		325.0	257.5
POLK 2		184.0	172.0
POLK 3		184.0	174.5
	POLK TOTAL	693.0	604.0
BAYSIDE 1		801.0	747.5
BAYSIDE 2		1,058.0	989.0
	BAYSIDE TOTAL	1,859.0	1,736.5
	SYSTEM TOTAL	**4,584.0**	**4,250.5**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2006 - DECEMBER 2006

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,103,233	23.903%	23.903%
BAYSIDE	1	2,962,000	17.255%	41.158%
BIG BEND	4	2,605,120	15.176%	56.334%
BIG BEND	2	2,582,864	15.046%	71.381%
BIG BEND	1	2,007,784	11.696%	83.077%
BIG BEND	3	1,601,740	9.331%	92.408%
POLK	1	1,162,329	6.771%	99.179%
POLK	2	65,950	0.384%	99.563%
Polk	3	38,331	0.223%	99.787%
PHILLIPS	1	16,981	0.099%	99.886%
PHILLIPS	2	16,461	0.096%	99.981%
BIG BEND CT	2	1,824	0.011%	99.992%
BIG BEND CT	3	1,132	0.007%	99.999%
BIG BEND CT	1	231	0.001%	100.000%
TOTAL GENERATION		17,165,980	100.000%	

GENERATION BY COAL UNITS:	9,959,837 MWH	GENERATION BY NATURAL GAS UNITS:	7,169,514 MWH
% GENERATION BY COAL UNITS:	58.02%	% GENERATION BY NATURAL GAS UNITS:	41.77%
GENERATION BY OIL UNITS:	36,629 MWH	GENERATION BY GPIF UNITS:	9,959,837 MWH
% GENERATION BY OIL UNITS:	0.21%	% GENERATION BY GPIF UNITS:	58.02%

EXHIBIT TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

Tampa Electric Company
Summary of GPIF Targets
January 2006 - December 2006

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1 [1]	63.6	15.3	21.0	10,841
Big Bend 2 [2]	77.3	3.8	18.9	10,510
Big Bend 3 [3]	56.2	9.6	34.2	10,923
Big Bend 4 [4]	71.9	5.8	22.4	10,672
Polk 1 [5]	60.3	4.4	35.3	10,497

[1] Original Sheet 8.401.06E, Page 12

[2] Original Sheet 8.401.06E, Page 13

[3] Original Sheet 8.401.06E, Page 14

[4] Original Sheet 8.401.06E, Page 15

[5] Original Sheet 8.401.06E, Page 16