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TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2005 THROUGH DECEMBER 2005

TESTIMONY AND EXHIBIT

OF

DAVID R. KNAPP

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

A. My name is David R. Knapp. 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 a Senior Engineer in the Resource Planning Department.

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department where I provide engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities.

Q. What is the purpose of your testimony?

A. My testimony 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. _____ (DRK-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 2005 period.

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, 2, 3, and 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 2003 and 2004 projected GPIF. Therefore, Tampa Electric requests approval of its 2005 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 2005 period. A range of potential improvements and degradations was 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 2005 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 4 is 17.48 percent, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability factor for Big Bend Unit 4 equals 78.68 percent or:

$$100\% - [(17.48\% + 3.84\%)] = 78.68\%$$

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:

$$EAF_{MAX} = 100\% - [0.8\ (17.48\%) + 0.95\ (3.48\%)] = 82.4\%$$

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,

$$EAF_{MIN} = 100\% - [1.4\ (17.48\%) + 1.10\ (3.84\%)] = 71.31\%$$

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 2005 through December 2005 are shown on page 17 of Document No. 1. Since only one GPIF unit has a major outage (28 days or greater) in 2005, one Critical Path Method diagram is provided in this testimony. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for a planned outage from February 27, 2005 to March 12, 2005. There are 336 planned outage hours scheduled for the 2005 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 4 at Big Bend is 3.84 percent or:

$$\frac{336}{8,760} \times 100\% = 3.84\%$$

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 3.84 percent. Polk Unit 1 has a Planned Outage Factor of 3.77 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 2004, was used as a basis for the projection. This value was adjusted by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 17.48 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

$$EUOF = \frac{(994.1 + 537.1)}{8{,}760} \times 100 = 17.48\%$$

Relative to Big Bend Unit 4, the EUOF of 17.48 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

<u>Big Bend Unit 1</u>

The projected Equivalent Unplanned Outage Factor for this unit is 32.03 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 15.34 percent. Therefore, the target equivalent availability for this unit is 52.63 percent.

<u>Big Bend Unit 2</u>

The projected Equivalent Unplanned Outage Factor for this unit is 34.52 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 61.64 percent.

<u>Big Bend Unit 3</u>

The projected Equivalent Unplanned Outage Factor for this unit is 35.61 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 60.55 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 17.48 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 78.68 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 16.41 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.77 percent. Therefore, the target equivalent availability for this unit is 79.76 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 68.54 percent is shown on Page 5 of Document No. 1. This target is approximately ten percent higher than the July 2003 through June 2004 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 loaded, 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 January and the months April 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 February and March, 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 2005 period.

A. The heat rate target for Big Bend Unit 1 is 10,853 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±529 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,672 Btu/Net kWh with a range of ±421 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,663 Btu/Net kWh, with a range of ±657 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,350 Btu/Net kWh with a range of ±483 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,342 Btu/Net kWh with a range of ±718 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 $781,574,600 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 $35,060,860 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 15.68 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 82.4 percent equivalent availability, fuel savings would equal $4,096,800, 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, $35,060,860. 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 2005 is $1,464,070,542. This produces the maximum allowed jurisdictional incentive of $5,807,604 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):

$$\begin{aligned} GPIP: = (\ & 0.1568\ EAP_{BB1} + 0.1744\ EAP_{BB2} \\ & + 0.1830\ EAP_{BB3} + 0.1168\ EAP_{BB4} \\ & + 0.0544\ EAP_{PK1} + 0.0527\ HRP_{BB1} \\ & + 0.0472\ HRP_{BB2} + 0.0740\ HRP_{BB3} \\ & + 0.0774\ HRP_{BB4} + 0.0634\ HRP_{PK1}\ ) \end{aligned}$$

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 2005 - December 2005 period?

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

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2005 - DECEMBER 2005

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2005 - DECEMBER 2005
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2005 - DECEMBER 2005

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	35,060.9	5,807.6
+9	31,554.8	5,226.9
+8	28,048.7	4,646.1
+7	24,542.6	4,065.4
+6	21,036.5	3,484.6
+5	17,530.4	2,903.8
+4	14,024.3	2,323.1
+3	10,518.3	1,742.3
+2	7,012.2	1,161.5
+1	3,506.1	580.8
0	0.0	0.0
-1	(6,036.0)	(580.8)
-2	(12,072.0)	(1,161.5)
-3	(18,108.0)	(1,742.3)
-4	(24,144.0)	(2,323.1)
-5	(30,180.0)	(2,903.8)
-6	(36,216.0)	(3,484.6)
-7	(42,252.0)	(4,065.4)
-8	(48,288.0)	(4,646.1)
-9	(54,324.0)	(5,226.9)
-10	(60,360.0)	(5,807.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2005 - DECEMBER 2005

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,404,189,000
Line 2	Month of January	2005	$	1,448,158,351
Line 3	Month of February	2005	$	1,462,338,234
Line 4	Month of March	2005	$	1,476,656,963
Line 5	Month of April	2005	$	1,418,647,933
Line 6	Month of May	2005	$	1,432,538,860
Line 7	Month of June	2005	$	1,446,565,803
Line 8	Month of July	2005	$	1,490,821,253
Line 9	Month of August	2005	$	1,505,418,878
Line 10	Month of September	2005	$	1,520,159,438
Line 11	Month of October	2005	$	1,461,450,698
Line 12	Month of November	2005	$	1,475,760,736
Line 13	Month of December	2005	$	1,490,210,893
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,464,070,542
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)		$	5,963,066
Line 18	Jurisdictional Sales			19,176,209 MWH
Line 19	Total Sales			19,689,398 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.39%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,807,644**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2005 - DECEMBER 2005

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	15.68%	52.6	59.8	38.3	5,498.6	(12,805.0)
BIG BEND 2	17.44%	61.6	68.7	47.5	6,112.9	(12,376.3)
BIG BEND 3	18.30%	60.6	67.9	45.9	6,414.7	(13,384.7)
BIG BEND 4	11.68%	78.7	82.4	71.3	4,096.8	(6,982.3)
POLK 1	5.44%	79.8	76.9	65.5	1,906.3	(3,780.1)
GPIF SYSTEM	**68.54%**					

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	5.27%	10,853	76.8	10,324	11,382	1,848.1	(1,848.1)
BIG BEND 2	4.72%	10,672	77.2	10,251	11,093	1,656.1	(1,656.1)
BIG BEND 3	7.40%	10,663	72.0	10,006	11,319	2,593.2	(2,593.2)
BIG BEND 4	7.74%	10,350	85.7	9,868	10,833	2,712.8	(2,712.8)
POLK 1	6.34%	10,342	89.1	9,624	11,060	2,221.4	(2,221.4)
GPIF SYSTEM	**31.46%**					**11,031.6**	**(11,031.6)**

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 05 - DEC 05			TARGET PERIOD JUL 03 - JUN 04			TARGET PERIOD JUL 02 - JUN 03			TARGET PERIOD JUL 01 - JUN 02		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	15.68%	22.9%	15.3	32.0	37.8	7.9	33.8	36.7	0.0	28.9	28.9	4.5	24.8	26.0
BIG BEND 2	17.44%	25.4%	3.8	34.5	35.9	0.0	37.8	37.8	23.3	24.4	31.8	0.0	28.2	28.2
BIG BEND 3	18.30%	26.7%	3.8	35.6	37.0	0.0	37.4	37.4	0.0	28.6	28.6	16.2	27.7	33.0
BIG BEND 4	11.68%	17.0%	3.8	17.5	18.2	10.6	15.8	17.7	6.1	16.0	17.1	0.0	12.4	12.4
POLK 1	5.44%	7.9%	3.8	16.5	17.1	3.3	18.7	19.3	11.1	7.1	8.0	0.7	14.3	14.4
GPIF SYSTEM	**68.54%**	**100.0%**	**6.5**	**29.9**	**32.1**	**3.9**	**31.5**	**32.5**	**7.8**	**23.7**	**25.9**	**5.4**	**23.5**	**25.2**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**63.6**			**64.6**			**68.4**			**71.1**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
5.7	**26.3**	**27.9**	**68.0**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 05 - DEC 05	ADJUSTED PRIOR HEAT RATE JUL 03 - JUN 04	ADJUSTED PRIOR HEAT RATE JUL 02 - JUN 03	ADJUSTED PRIOR HEAT RATE JUL 01 - JUN 02
BIG BEND 1	5.27%	16.8%	10,853	10,748	10,920	10,693
BIG BEND 2	4.72%	15.0%	10,672	10,658	10,803	10,426
BIG BEND 3	7.40%	23.5%	10,663	10,831	10,752	10,395
BIG BEND 4	7.74%	24.6%	10,350	10,356	10,293	10,331
POLK 1	6.34%	20.1%	10,342	10,024	10,039	10,373
GPIF SYSTEM	**31.46%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,555**	**10,512**	**10,531**	**10,429**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2005 - DECEMBER 2005
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	781,574	776,075	5,499	15.68%
EA_2 BIG BEND 2	781,574	775,461	6,113	17.44%
EA_3 BIG BEND 3	781,574	775,159	6,415	18.30%
EA_4 BIG BEND 4	781,574	777,477	4,097	11.68%
EA_7 POLK 1	781,574	779,667	1,906	5.44%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	781,574	779,726	1,848	5.27%
AHR_2 BIG BEND 2	781,574	779,918	1,656	4.72%
AHR_3 BIG BEND 3	781,574	778,980	2,593	7.40%
AHR_4 BIG BEND 4	781,574	778,861	2,713	7.74%
AHR_7 POLK 1	781,574	779,352	2,221	6.34%
TOTAL SAVINGS			**35,061**	**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 2005 - DECEMBER 2005

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	5,498.6	59.8	+10	1,848.1	10,324
+9	4,948.7	59.1	+9	1,663.3	10,369
+8	4,398.9	58.4	+8	1,478.5	10,415
+7	3,849.0	57.6	+7	1,293.6	10,460
+6	3,299.2	56.9	+6	1,108.8	10,506
+5	2,749.3	56.2	+5	924.0	10,551
+4	2,199.4	55.5	+4	739.2	10,596
+3	1,649.6	54.8	+3	554.4	10,642
+2	1,099.7	54.1	+2	369.6	10,687
+1	549.9	53.3	+1	184.8	10,733
					10,778
0	0.0	52.6	0	0.0	10,853
					10,928
-1	(1,280.5)	51.2	-1	(184.8)	10,973
-2	(2,561.0)	49.8	-2	(369.6)	11,019
-3	(3,841.5)	48.3	-3	(554.4)	11,064
-4	(5,122.0)	46.9	-4	(739.2)	11,109
-5	(6,402.5)	45.5	-5	(924.0)	11,155
-6	(7,683.0)	44.0	-6	(1,108.8)	11,200
-7	(8,963.5)	42.6	-7	(1,293.6)	11,246
-8	(10,244.0)	41.2	-8	(1,478.5)	11,291
-9	(11,524.5)	39.7	-9	(1,663.3)	11,336
-10	(12,805.0)	38.3	-10	(1,848.1)	11,382
	Weighting Factor =	15.68%		Weighting Factor =	5.27%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

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	6,112.9	68.7	+10	1,656.1	10,251
+9	5,501.6	68.0	+9	1,490.5	10,286
+8	4,890.3	67.3	+8	1,324.9	10,320
+7	4,279.0	66.6	+7	1,159.2	10,355
+6	3,667.7	65.9	+6	993.6	10,389
+5	3,056.5	65.2	+5	828.0	10,424
+4	2,445.2	64.5	+4	662.4	10,459
+3	1,833.9	63.8	+3	496.8	10,493
+2	1,222.6	63.1	+2	331.2	10,528
+1	611.3	62.4	+1	165.6	10,562
					10,597
0	0.0	61.6	0	0.0	10,672
					10,747
-1	(1,237.6)	60.2	-1	(165.6)	10,782
-2	(2,475.3)	58.8	-2	(331.2)	10,816
-3	(3,712.9)	57.4	-3	(496.8)	10,851
-4	(4,950.5)	56.0	-4	(662.4)	10,886
-5	(6,188.2)	54.5	-5	(828.0)	10,920
-6	(7,425.8)	53.1	-6	(993.6)	10,955
-7	(8,663.4)	51.7	-7	(1,159.2)	10,989
-8	(9,901.0)	50.3	-8	(1,324.9)	11,024
-9	(11,138.7)	48.9	-9	(1,490.5)	11,059
-10	(12,376.3)	47.5	-10	(1,656.1)	11,093
	Weighting Factor =	17.44%		Weighting Factor =	4.72%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

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	6,414.7	67.9	+10	2,593.2	10,006
+9	5,773.2	67.2	+9	2,333.9	10,064
+8	5,131.8	66.4	+8	2,074.6	10,122
+7	4,490.3	65.7	+7	1,815.3	10,181
+6	3,848.8	65.0	+6	1,555.9	10,239
+5	3,207.3	64.2	+5	1,296.6	10,297
+4	2,565.9	63.5	+4	1,037.3	10,355
+3	1,924.4	62.8	+3	778.0	10,413
+2	1,282.9	62.0	+2	518.6	10,471
+1	641.5	61.3	+1	259.3	10,530
					10,588
0	0.0	60.6	0	0.0	10,663
					10,738
-1	(1,338.5)	59.1	-1	(259.3)	10,796
-2	(2,676.9)	57.6	-2	(518.6)	10,854
-3	(4,015.4)	56.2	-3	(778.0)	10,912
-4	(5,353.9)	54.7	-4	(1,037.3)	10,970
-5	(6,692.4)	53.2	-5	(1,296.6)	11,028
-6	(8,030.8)	51.8	-6	(1,555.9)	11,087
-7	(9,369.3)	50.3	-7	(1,815.3)	11,145
-8	(10,707.8)	48.9	-8	(2,074.6)	11,203
-9	(12,046.2)	47.4	-9	(2,333.9)	11,261
-10	(13,384.7)	45.9	-10	(2,593.2)	11,319
	Weighting Factor =	18.30%		Weighting Factor =	7.40%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

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	4,096.8	82.4	+10	2,712.8	9,868
+9	3,687.1	82.0	+9	2,441.6	9,908
+8	3,277.4	81.7	+8	2,170.3	9,949
+7	2,867.8	81.3	+7	1,899.0	9,990
+6	2,458.1	80.9	+6	1,627.7	10,031
+5	2,048.4	80.5	+5	1,356.4	10,071
+4	1,638.7	80.2	+4	1,085.1	10,112
+3	1,229.0	79.8	+3	813.9	10,153
+2	819.4	79.4	+2	542.6	10,194
+1	409.7	79.1	+1	271.3	10,235
					10,275
0	0.0	78.7	0	0.0	10,350
					10,425
-1	(698.2)	77.9	-1	(271.3)	10,466
-2	(1,396.5)	77.2	-2	(542.6)	10,507
-3	(2,094.7)	76.5	-3	(813.9)	10,548
-4	(2,792.9)	75.7	-4	(1,085.1)	10,589
-5	(3,491.2)	75.0	-5	(1,356.4)	10,629
-6	(4,189.4)	74.3	-6	(1,627.7)	10,670
-7	(4,887.6)	73.5	-7	(1,899.0)	10,711
-8	(5,585.8)	72.8	-8	(2,170.3)	10,752
-9	(6,284.1)	72.0	-9	(2,441.6)	10,793
-10	(6,982.3)	71.3	-10	(2,712.8)	10,833
	Weighting Factor =	11.68%		Weighting Factor =	7.74%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

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	1,906.3	76.9	+10	2,221.4	9,624
+9	1,715.7	77.2	+9	1,999.2	9,688
+8	1,525.0	77.5	+8	1,777.1	9,753
+7	1,334.4	77.8	+7	1,555.0	9,817
+6	1,143.8	78.0	+6	1,332.8	9,881
+5	953.1	78.3	+5	1,110.7	9,945
+4	762.5	78.6	+4	888.5	10,010
+3	571.9	78.9	+3	666.4	10,074
+2	381.3	79.2	+2	444.3	10,138
+1	190.6	79.5	+1	222.1	10,203
					10,267
0	0.0	79.8	0	0.0	10,342
					10,417
-1	(378.0)	78.3	-1	(222.1)	10,481
-2	(756.0)	76.9	-2	(444.3)	10,546
-3	(1,134.0)	75.5	-3	(666.4)	10,610
-4	(1,512.0)	74.1	-4	(888.5)	10,674
-5	(1,890.0)	72.6	-5	(1,110.7)	10,739
-6	(2,268.1)	71.2	-6	(1,332.8)	10,803
-7	(2,646.1)	69.8	-7	(1,555.0)	10,867
-8	(3,024.1)	68.4	-8	(1,777.1)	10,931
-9	(3,402.1)	66.9	-9	(1,999.2)	10,996
-10	(3,780.1)	65.5	-10	(2,221.4)	11,060
	Weighting Factor =	5.44%		Weighting Factor =	6.34%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

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-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct):	Nov-05	Dec-05	2005
1. EAF (%)	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	0.0	10.4	62.2	52.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	83.3	0.0	15.34
3. EUOF	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	0.0	6.3	37.8	32.03
4. EUOR	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	0.0	37.8	37.8	37.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	503	454	503	486	503	486	498	503	486	0	81	491	4,993
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	241	218	241	234	241	234	246	241	234	744	639	253	3,767
9. POH	0	0	0	0	0	0	0	0	0	744	600	0	1,344
10. FOH & EFOH	201	181	201	194	201	194	201	201	194	0	32	201	2,001
11. MOH & EMOH	81	73	81	78	81	78	81	81	78	0	13	81	804
12. OPER BTU (GBTU)	1,769	1,601	1,778	1,715	1,771	1,717	1,753	1,775	1,716	0	286	1,732	17,612
13. NET GEN (MWH)	162,706	147,304	163,593	158,191	163,292	158,331	161,642	163,676	158,300	0	26,428	159,316	1,622,779
14. ANOHR (Btu/kwh)	10,874	10,871	10,867	10,844	10,845	10,843	10,846	10,842	10,843	0	10,840	10,870	10,853
15. NOF (%)	75.6	75.8	76.1	77.3	77.2	77.3	77.1	77.4	77.3	0.0	77.4	75.9	76.8
16. NPC (MW)	428	428	428	421	421	421	421	421	421	421	421	428	423
17. ANOHR EQUATION	ANOHR = NOF(	-18.920	) +		12,306								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 200:

PLANT/UNIT	MONTH OF:	MONTH OF:	IONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	35.2	64.1	64.1	61.6
2. POF	0.0	0.0	0.0	0.0	.0	0.0	0.0	0.0	0.0	5.2	0.0	0.0	3.84
3. EUOF	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	19.7	35.9	35.9	34.52
4. EUOR	35.9	35.9	35.9	35.9	35.9	35.9	5.9	35.9	35.9	[illegible]	35.9	35.9	35.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	512	459	515	498	398	499	508	515	499	[illegible]	499	393	5,575
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	232	213	229	222	346	221	236	229	221	462	221	351	3,185
9. POH	0	0	0	0	0	0	0	0	0	336	0	0	336
10. FOH & EFOH	192	173	192	186	192	186	192	192	186	105	186	192	2,171
11. MOH & EMOH	75	68	75	73	75	73	75	75	73	41	73	75	853
12. OPER BTU (GBTU	1,740	1,567	1,792	1,702	1,326	1,732	1,770	1,797	1,731	987	1,742	1,317	19,205
13. NET GEN (MWH)	162,435	146,301	167,531	159,571	124,053	162,710	166,275	168,837	162,599	92,788	.63,679	122,729	1,799,508
14. ANOHR (Btu/kwh)	10,714	10,710	10,695	10,664	10,686	10,648	10,644	10,644	10,648	[illegible]	10,642	10,727	10,672
15. NOF (%)	73.3	73.7	75.1	77.9	75.9	79.4	79.7	79.7	79.4	79.9	79.9	72.1	77.2
16. NPC (MW)	433	433	433	411	411	411	411	411	411	1	411	433	418
17. ANOHR EQUATIC	ANOHR = NOF(		-10.937	) +	11,516								

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ORIGINAL SHEET NO. 8.401.05E

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

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-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	33.6	63.0	60.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.84
3. EUOF	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	19.7	37.0	35.61
4. EUOR	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	531	479	531	514	531	514	531	531	514	531	274	531	6,010
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	213	193	213	206	213	206	213	213	206	213	446	213	2,750
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. FOH & EFOH	190	171	190	184	190	184	190	190	184	190	98	190	2,148
11. MOH & EMOH	86	78	86	83	86	83	86	86	83	86	44	86	972
12. OPER BTU (GBTU)	1,750	1,587	1,711	1,681	1,742	1,679	1,764	1,774	1,687	1,860	943	1,792	19,973
13. NET GEN (MWH)	163,376	148,282	158,870	157,495	163,327	157,257	165,852	167,114	158,160	176,305	88,982	168,191	1,873,211
14. ANOHR (Btu/kwh)	10,712	10,702	10,767	10,673	10,665	10,676	10,633	10,617	10,664	10,552	10,600	10,652	10,663
15. NOF (%)	70.3	70.6	68.3	71.6	71.9	71.5	73.0	73.6	71.9	75.8	74.1	72.3	72.0
16. NPC (MW)	438	438	438	428	428	428	428	428	428	438	438	438	433
17. ANOHR EQUATION	ANOHR = NOF(		-28.859	) +	12,740								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY [illegible] - DECEMBER [illegible]

PLANT/UN	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	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	81.8	76.0	50.1	8 .8	81.8	81.8	81.8	81.8	81.8	81.8	81.8	81.8	78.7
2. POF	0.0	7.1	38.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.84
3. EUOF	18.2	16.9	11.1	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	17.48
4. EUOR	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	613	514	376	594	[illegible]	[illegible]	603	611	590	613	594	598	6,908
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	131	158	368	126	131	131	141	133	130	131	126	146	1,852
9. POH	0	48	288	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	88	74	54	85	88	85	88	88	85	88	85	88	994
11. MOH & EMOH	47	40	29	46	47	46	47	47	46	47	46	47	537
12. OPER BTU (GBT	2,465	2,083	1,536	2,403	2,460	2,337	2,418	2,455	2,341	2,510	2,412	2,432	27,857
13. NET GEN (MWH	[illegible]	[illegible]	148,540	233,261	237,711	224,607	233,663	237,383	225,031	245,054	234,610	234,589	2,691,339
14. ANOHR (Btu/kwh	10,427	10,390	10,342	10,3[illegible]	10,348	10,403	10,347	10,341	10,402	10,242	10,280	10,367	10,350
15. NOF (%)	83.8	84.7	85.9	6.9	85.7	84.4	85.8	85.9	84.4	88.4	87.4	85.3	85.7
16. NPC (MW)	460	460	460	452	452	452	452	452	452	452	452	460	455
17. ANOHR EQUAT	ANOHR = NOF(	-40.19208525) +			13,794								

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ORIGINAL SHEET NO. 8.401.05E

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

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-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	82.9	82.9	82.9	55.3	82.9	82.9	82.9	82.9	82.9	80.0	75.4	82.9	79.76
2. POF	0.0	0.0	0.0	33.3	0.0	0.0	0.0	0.0	0.0	3.5	9.0	0.0	3.77
3. EUOF	17.1	17.1	17.1	11.4	17.1	17.1	17.1	17.1	17.1	16.5	15.6	17.1	16.47
4. EUOR	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	628	567	628	405	628	607	628	628	607	466	202	628	6,621
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	116	105	116	315	116	113	116	116	113	278	518	116	2,139
9. POH	0	0	0	240	0	0	0	0	0	26	65	0	330
10. FOH & EFOH	24	22	24	16	24	24	24	24	24	24	22	24	277
11. MOH & EMOH	103	93	103	66	103	100	103	103	100	99	91	103	1,166
12. OPER BTU (GBTU)	1,531	1,383	1,531	957	1,445	1,398	1,445	1,445	1,398	1,126	493	1,530	15,711
13. NET GEN (MWH)	153,110	138,375	153,209	93,330	135,391	131,023	135,391	135,391	131,023	110,743	49,283	152,874	1,519,143
14. ANOHR (Btu/kwh)	9,997	9,993	9,992	10,249	10,673	10,673	10,673	10,673	10,673	10,170	10,012	10,008	10,342
15. NOF (%)	93.8	93.9	93.9	90.4	84.6	84.6	84.6	84.6	84.6	91.5	93.6	93.7	89.1
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	257
17. ANOHR EQUATION	ANOHR = NOF(		-73.21622695) +		16,866								

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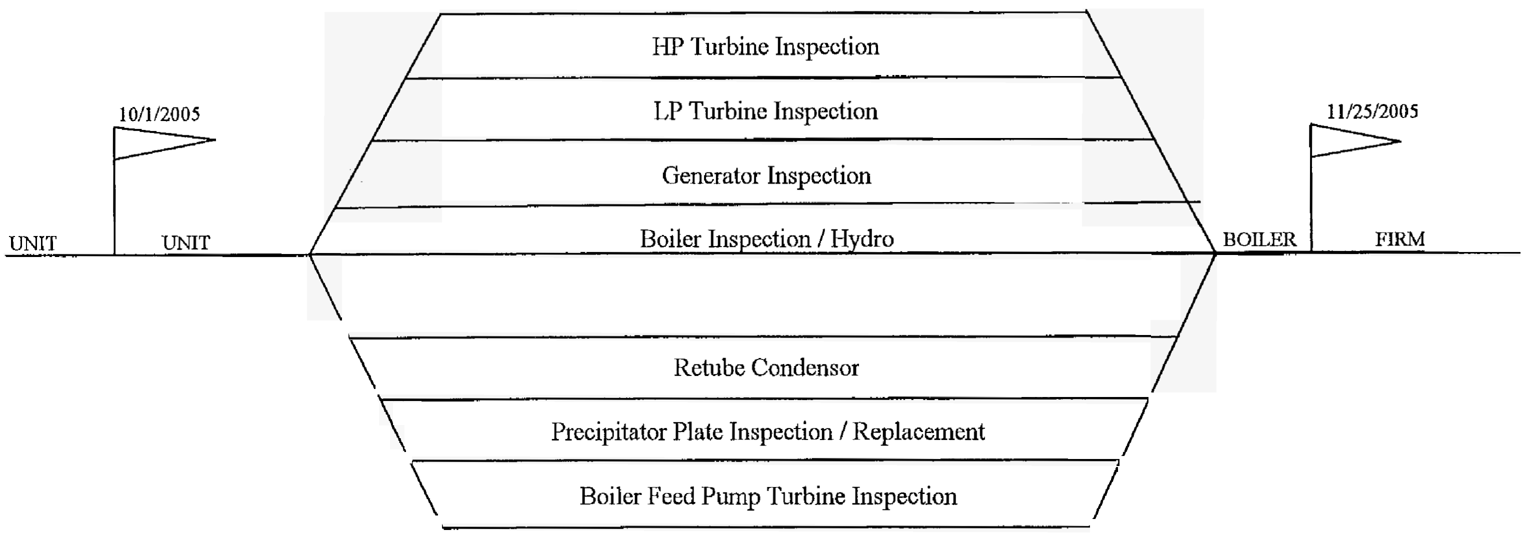
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2005 - DECEMBER 2005

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Oct 01	-	Nov 25	Fuel System Clean-up
+	BIG BEND 2	Oct 15	-	Oct 28	Fuel System Clean-up
+	BIG BEND 3	Nov 05	-	Nov 18	Fuel System Clean-up
+	BIG BEND 4	Feb 27	-	Mar 12	Fuel System Clean -up
+	POLK 1	Apr 09	-	Apr 18	#1CT Combustion Path

\+ Critical Path Method diagrams for units with outages of less than 4 weeks are not included.

**TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAM
GPIF UNITS ≥ FOUR WEEKS
JANUARY 2005 - DECEMBER 2005**



TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 1
PLANNED OUTAGE 2005
PROJECTED CPM
08/24/2004

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAM
GPIF UNITS ≥ FOUR WEEKS
JANUARY 2005 - DECEMBER 2005

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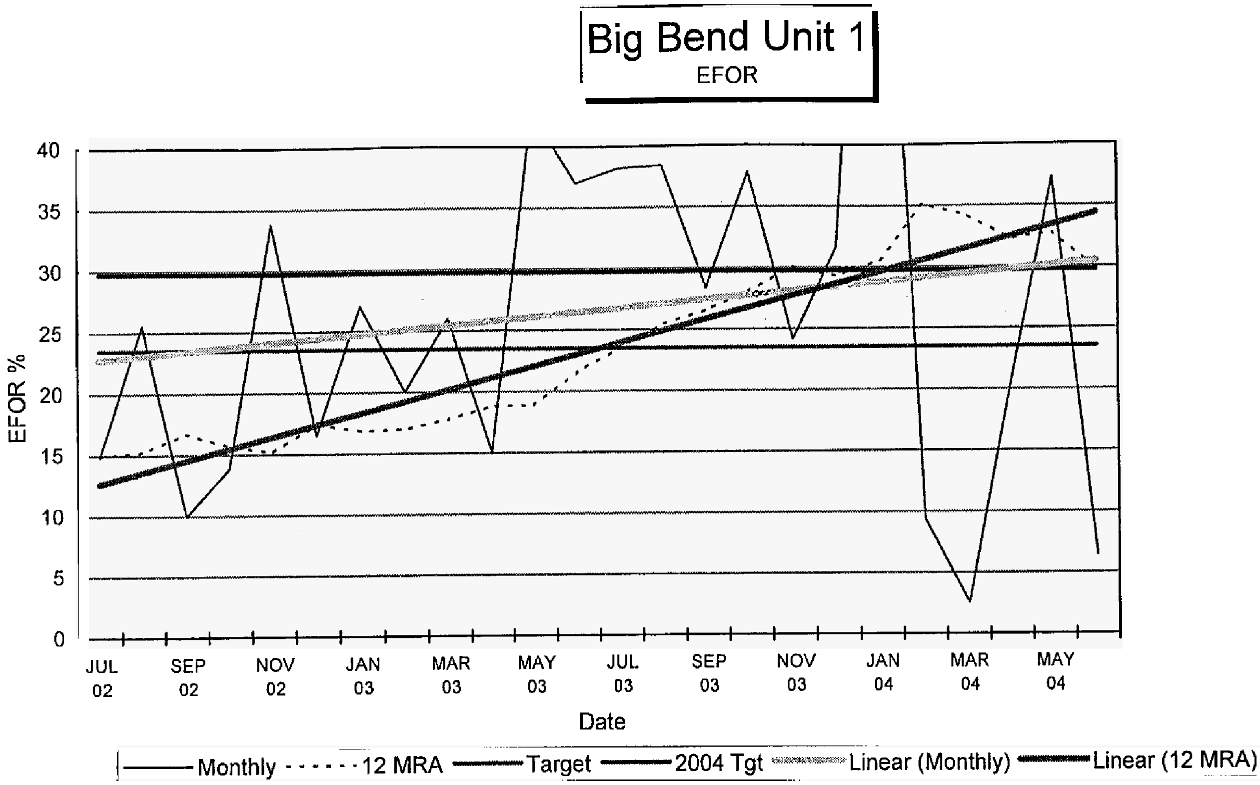
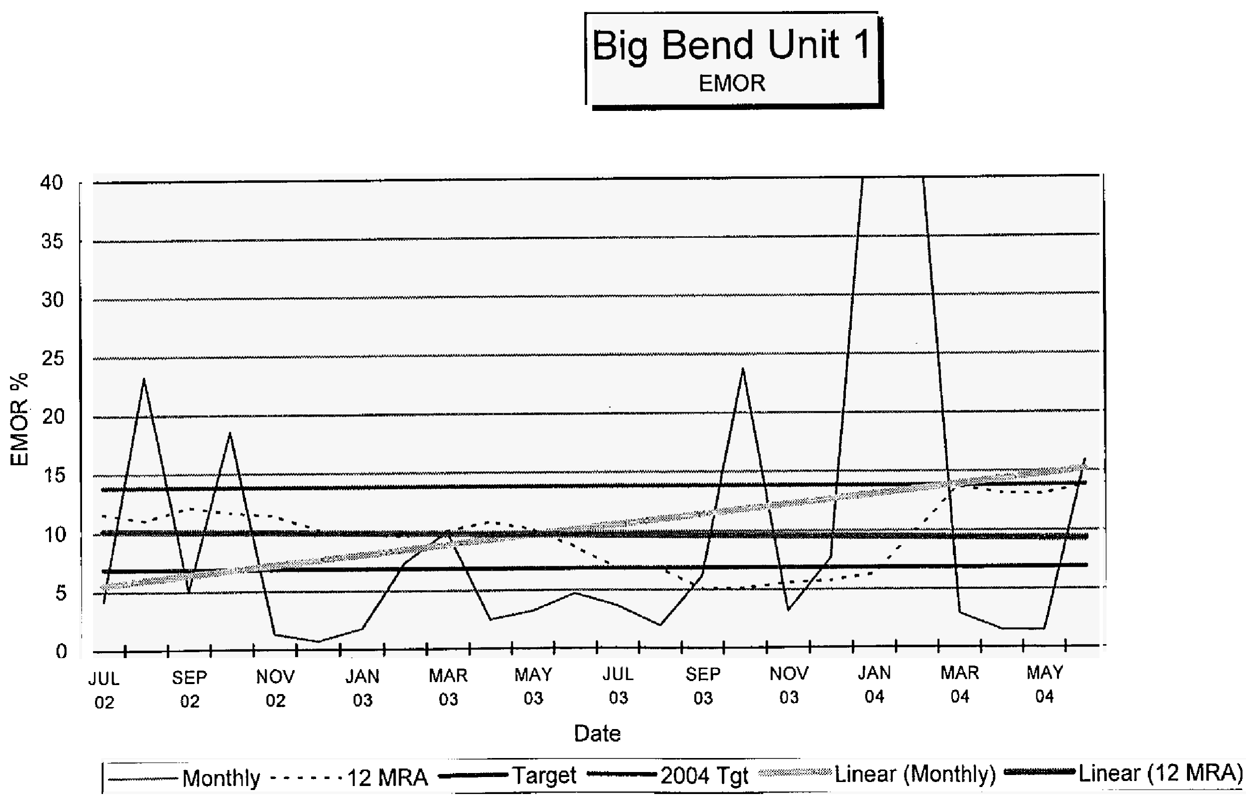
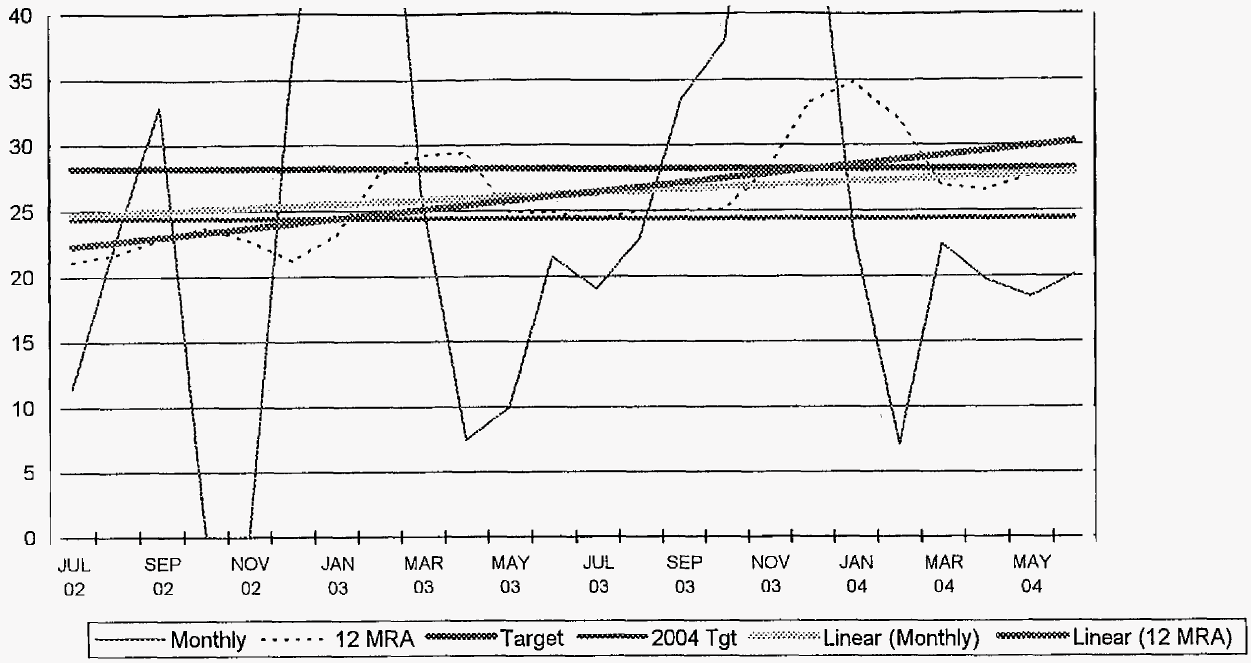




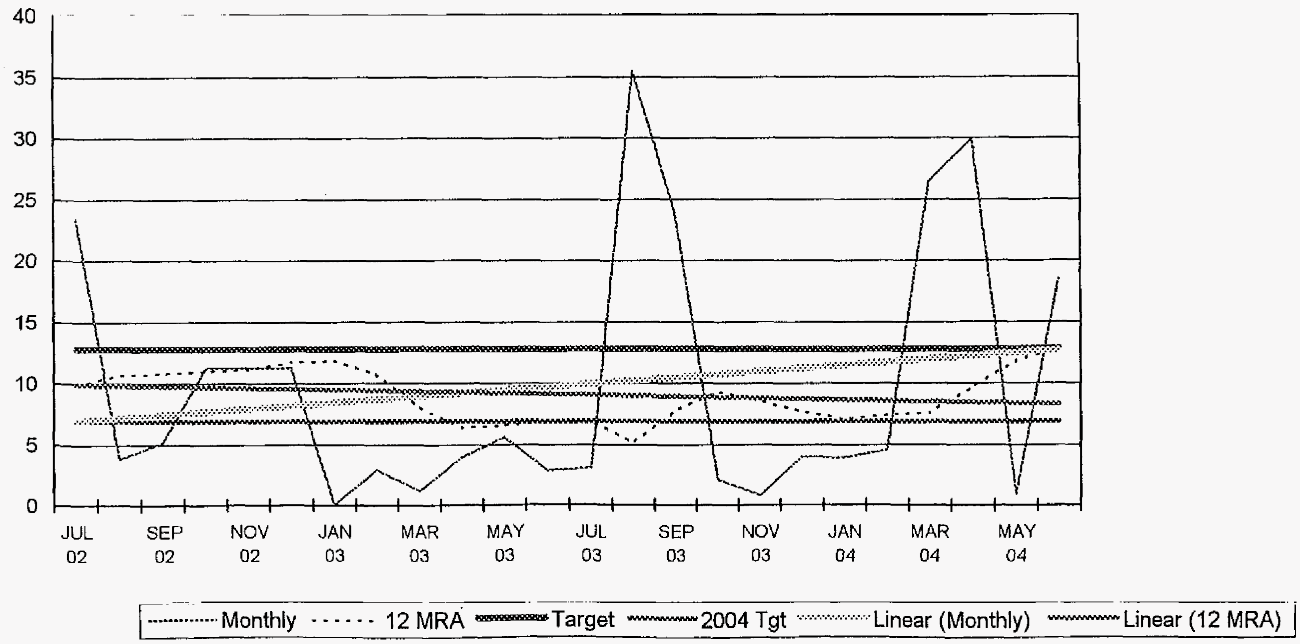
12 MRA = 12 Month Rolling Average

Big Bend Unit 2

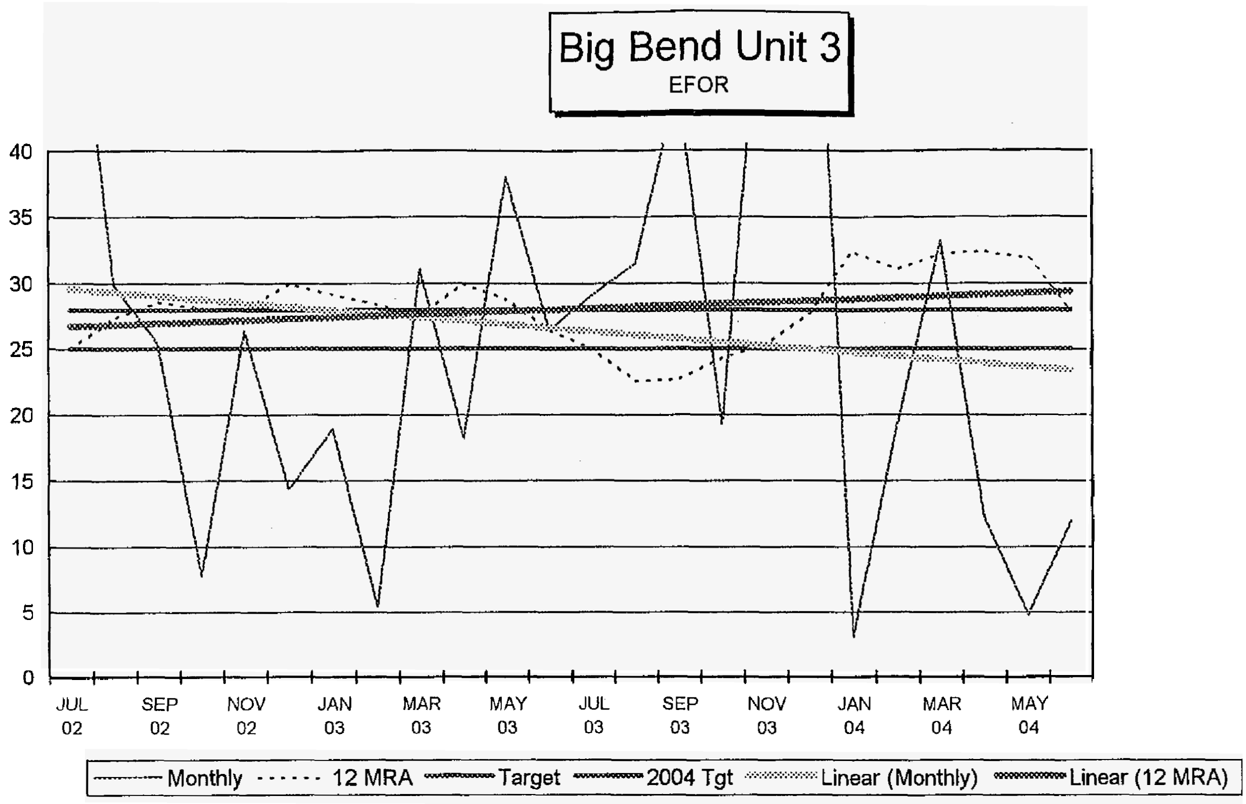


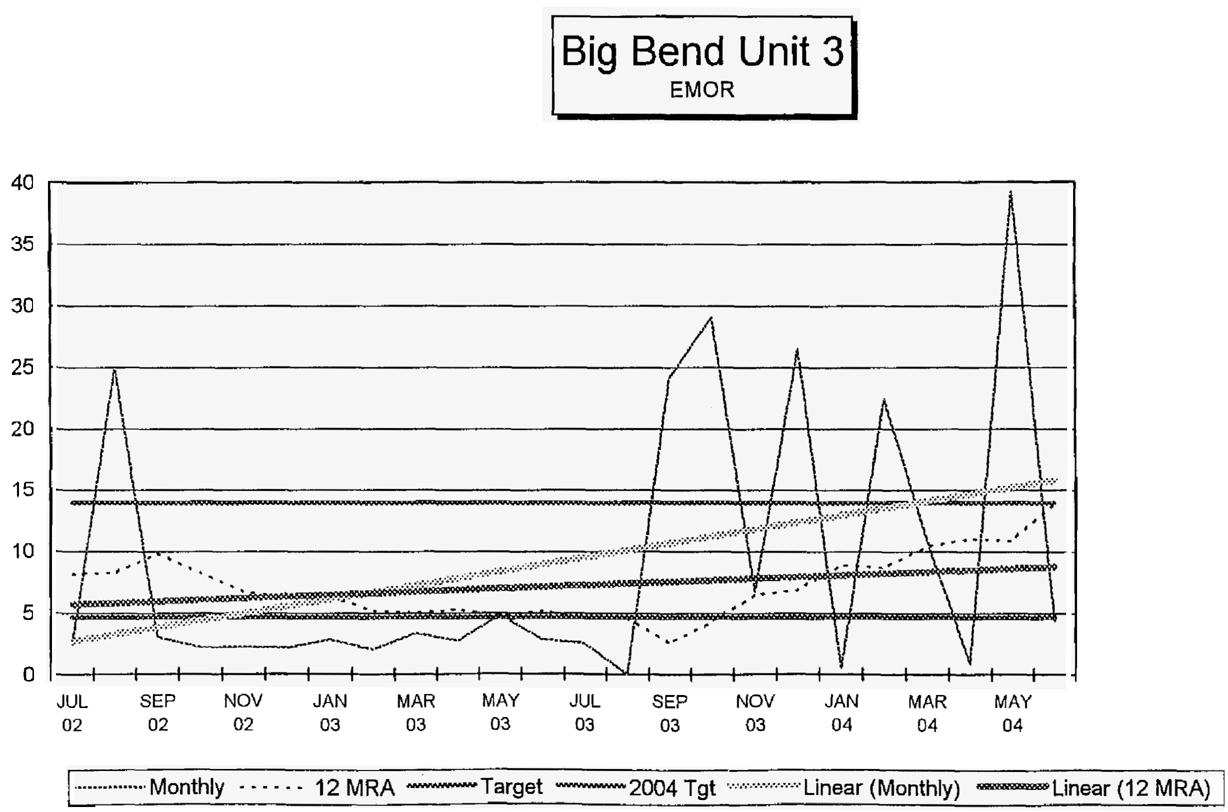
Big Bend Unit 2

EMOR

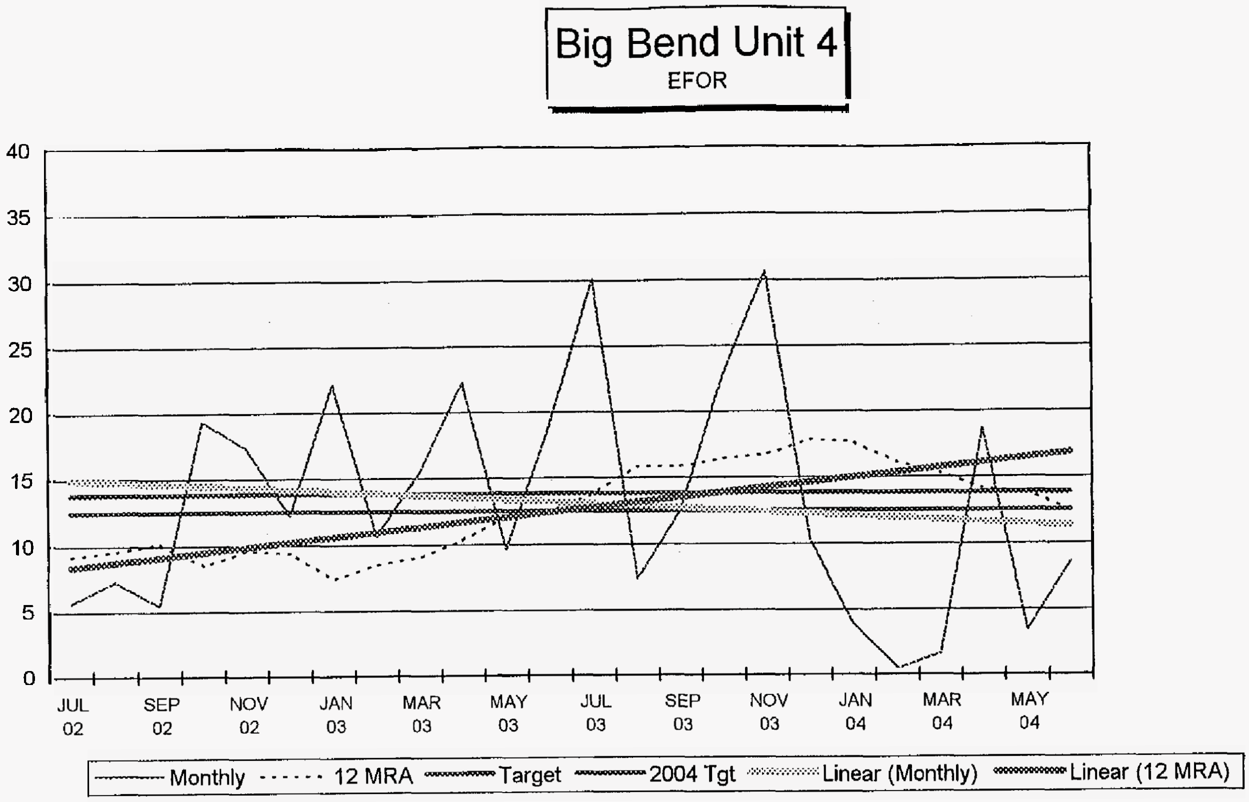


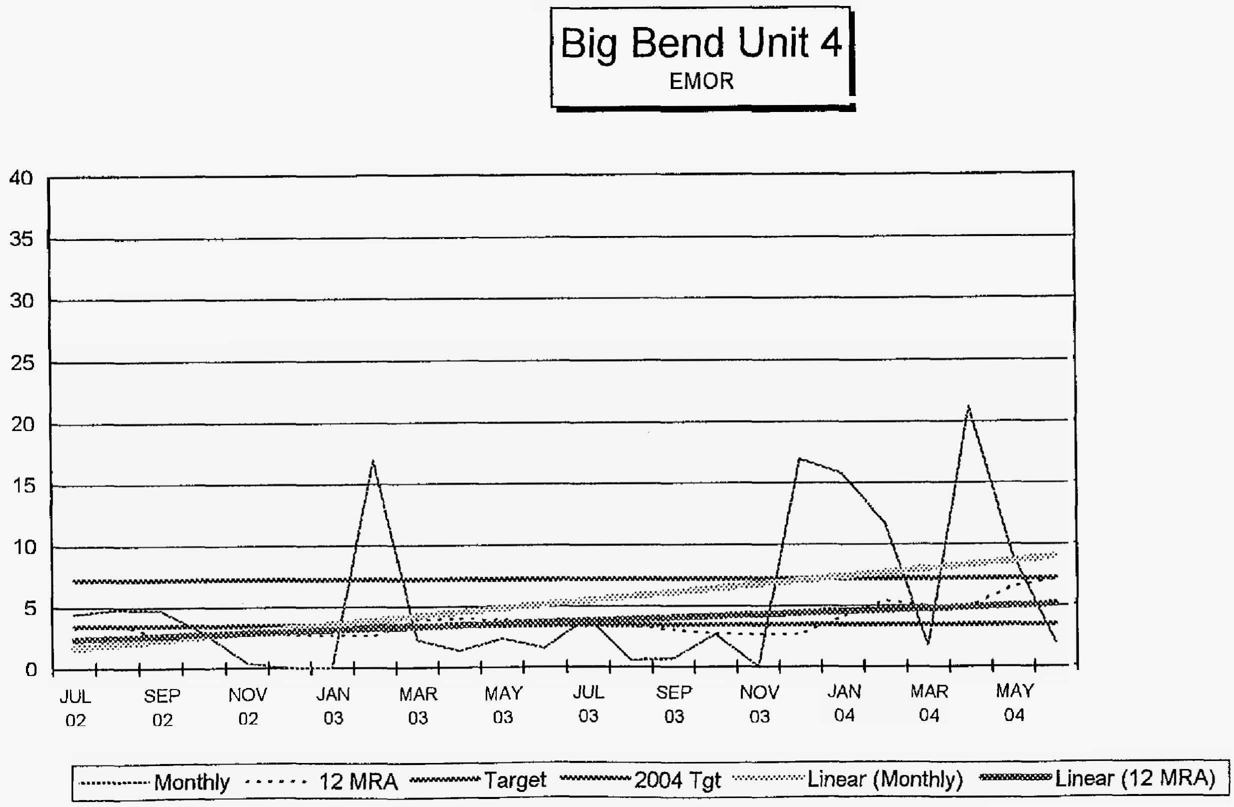
12 MRA = 12 Month Rolling Average



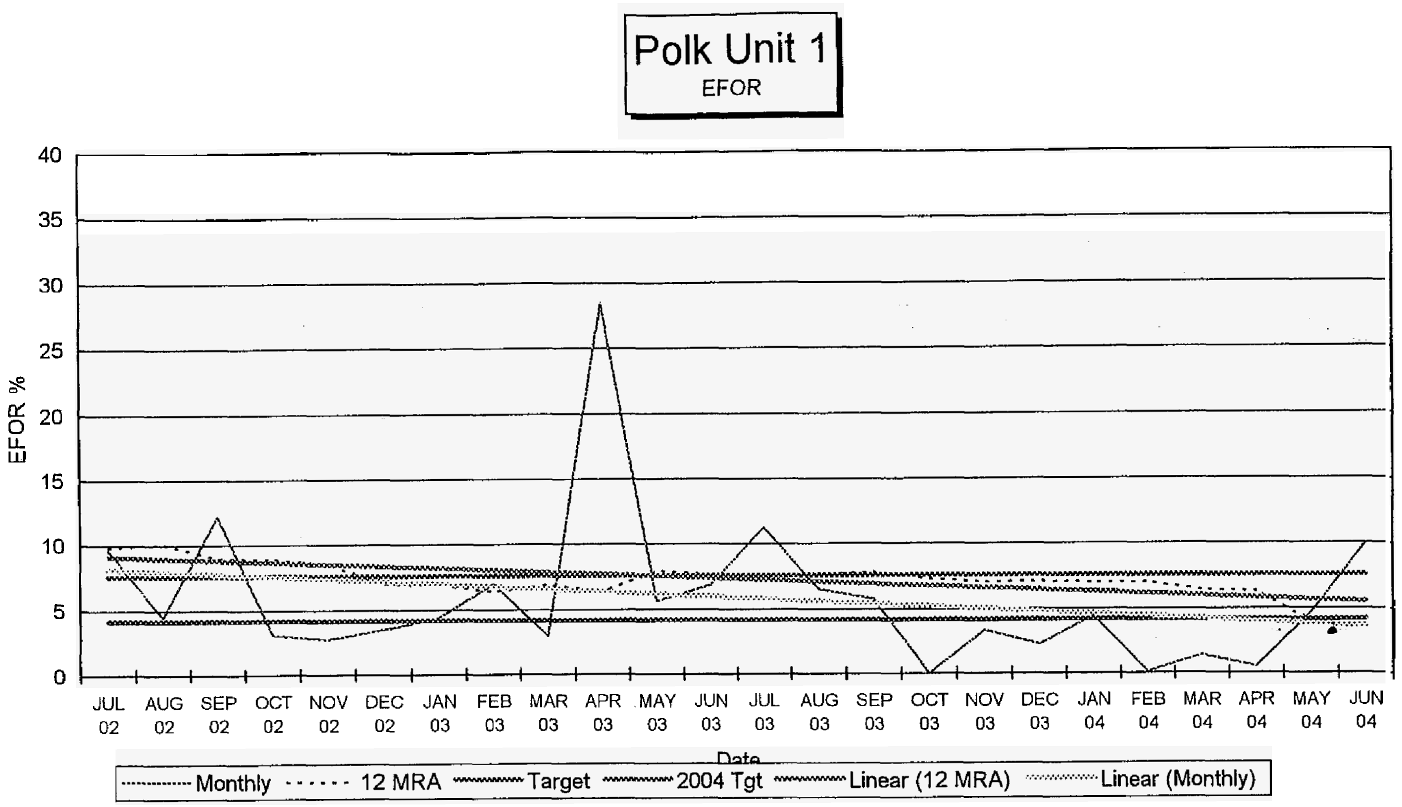


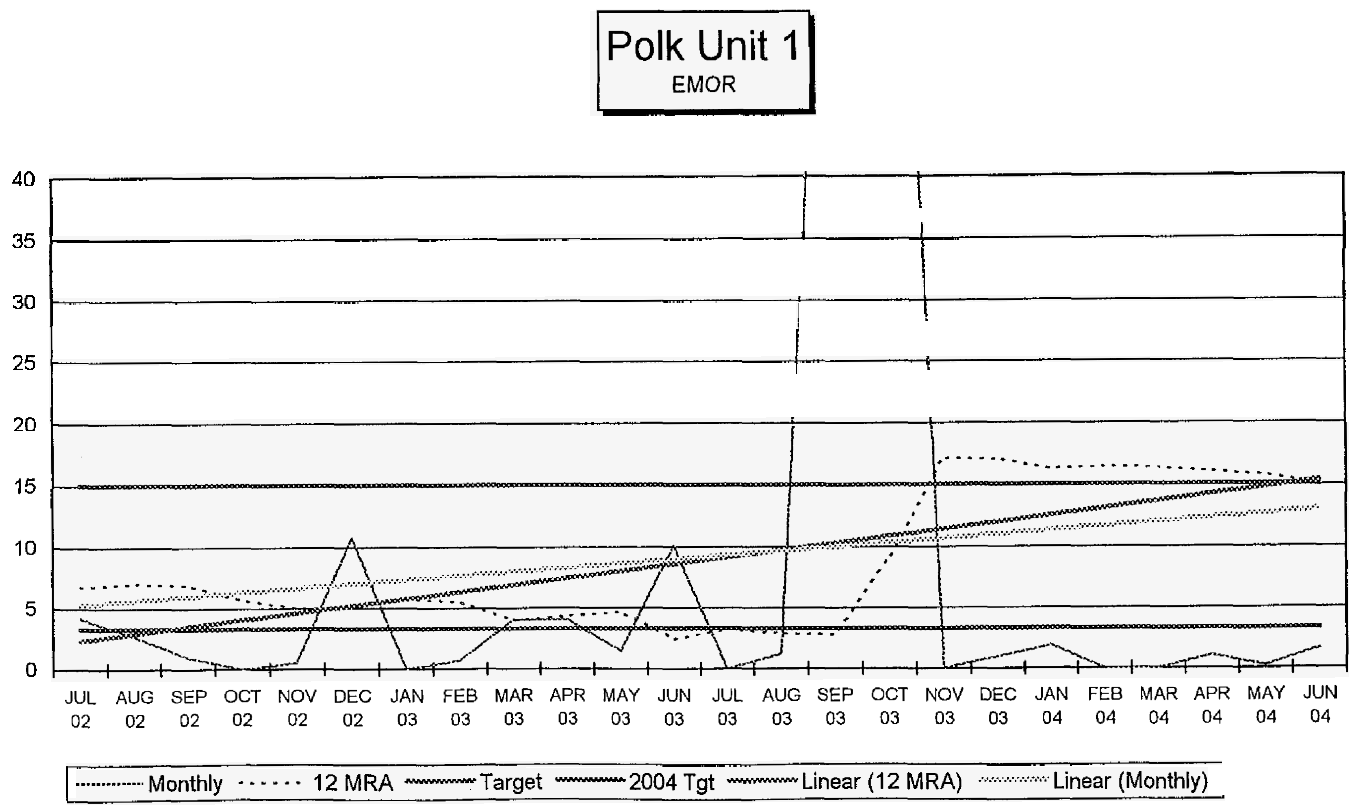
12 MRA = 12 Month Rolling Average





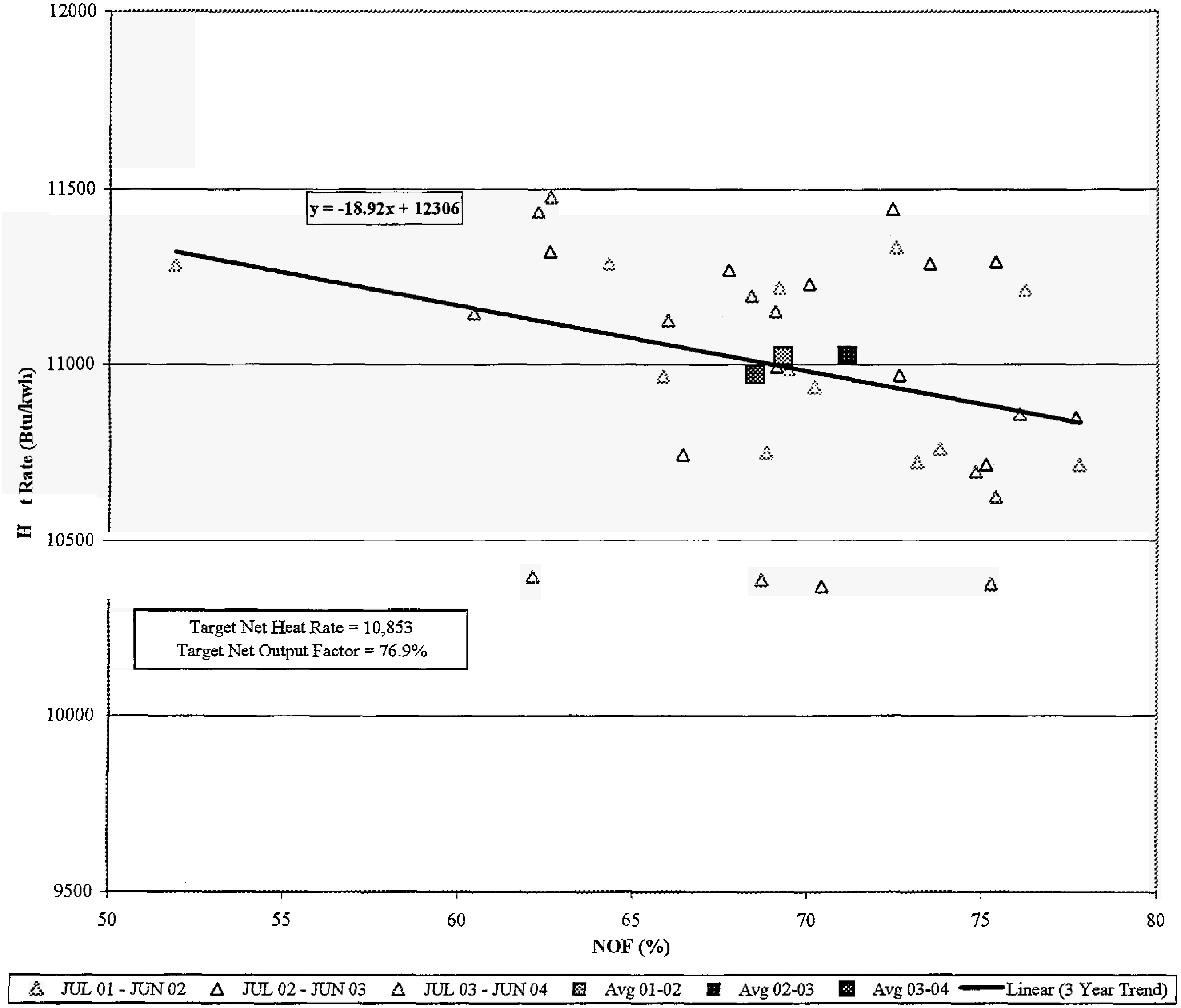
12 MRA = 12 Month Rolling Average



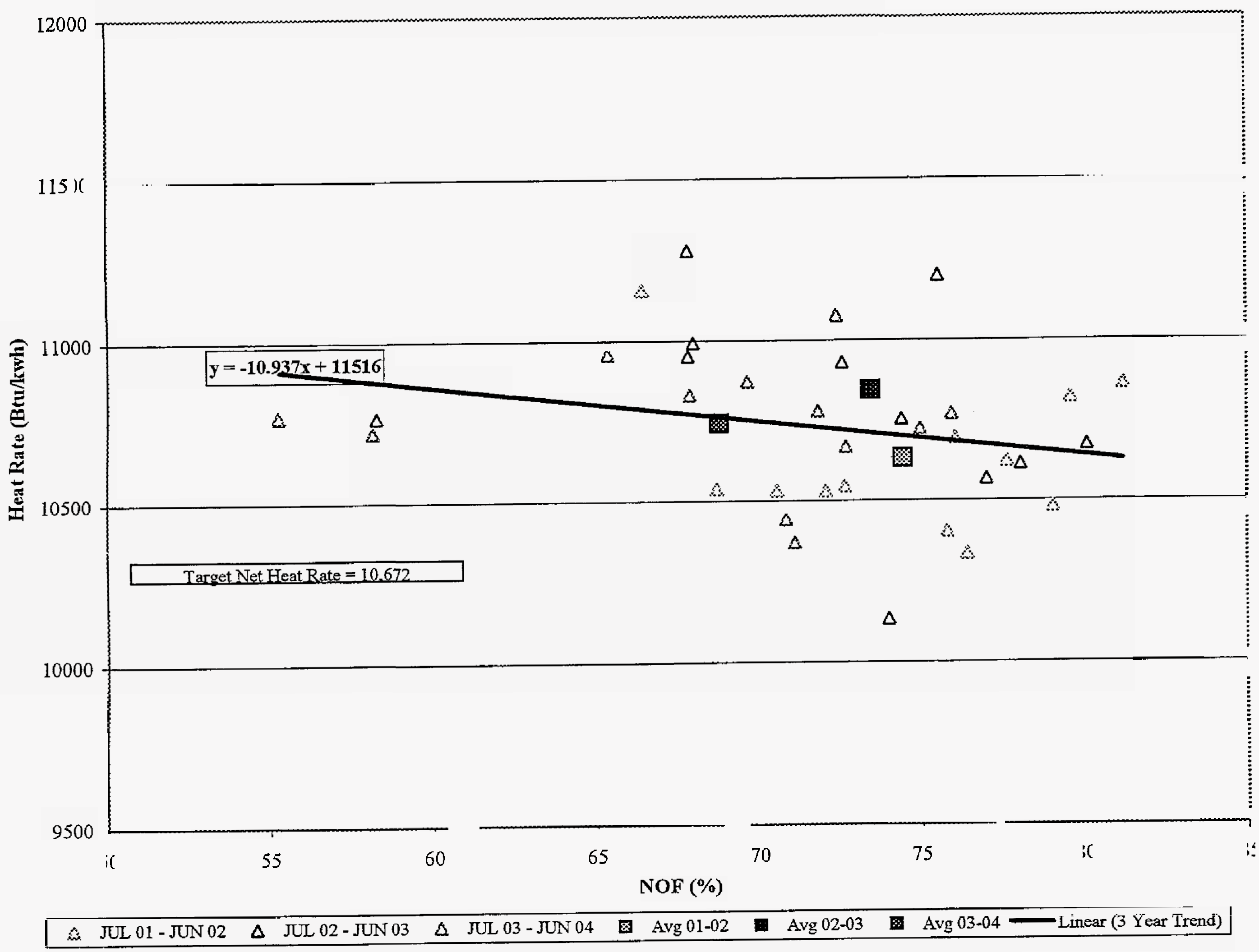


12 MRA = 12 Month Rolling Avreage

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



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2



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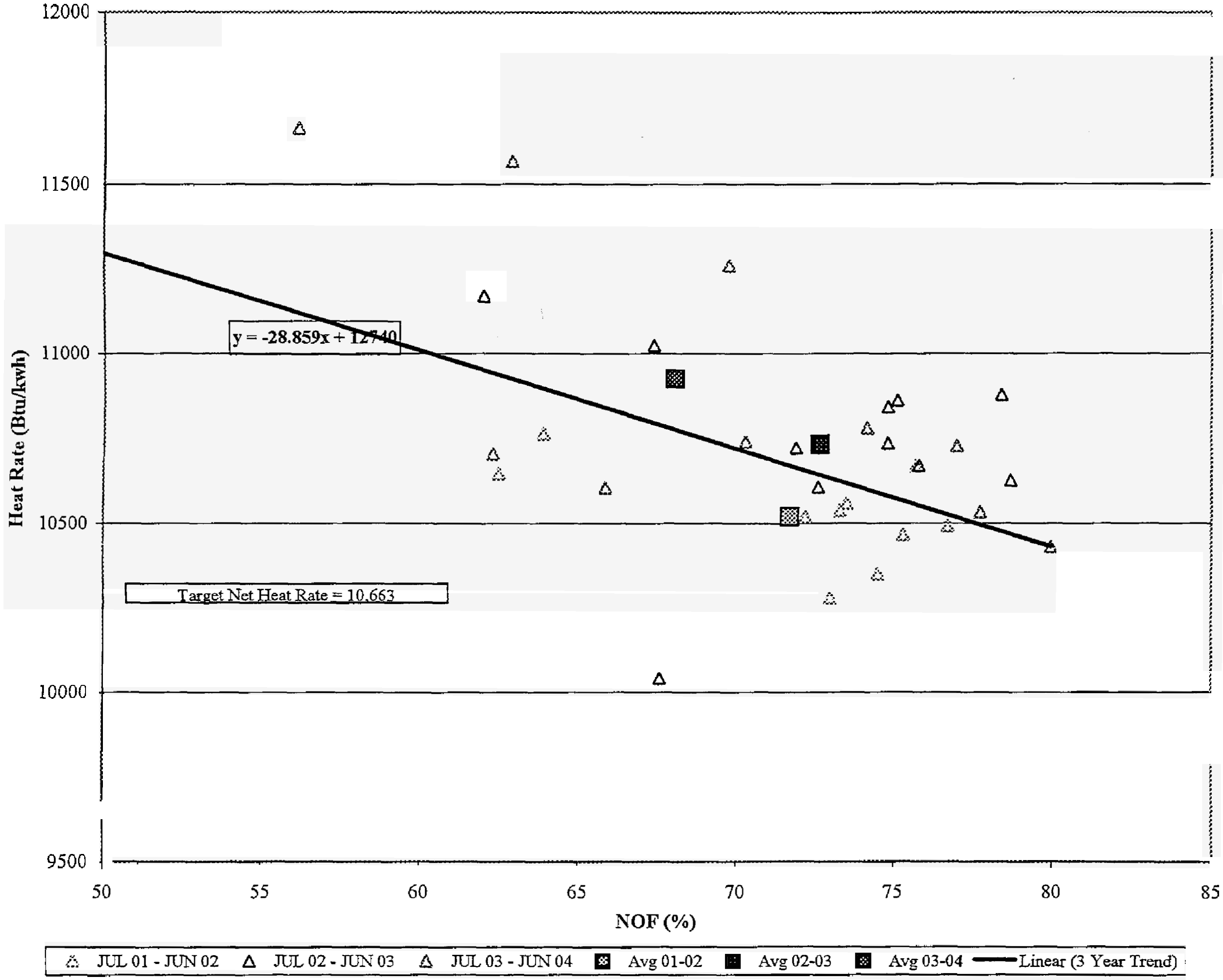
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3



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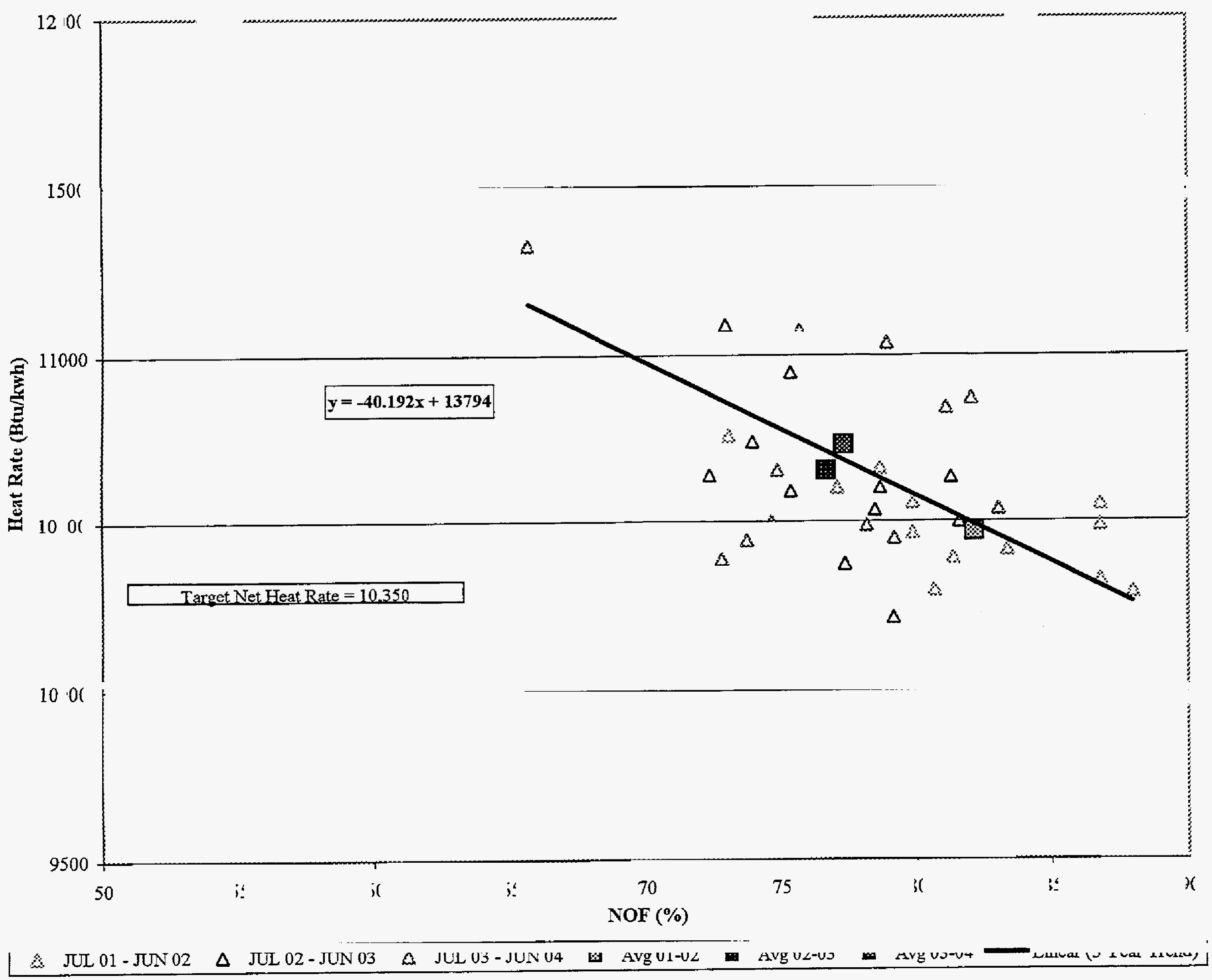
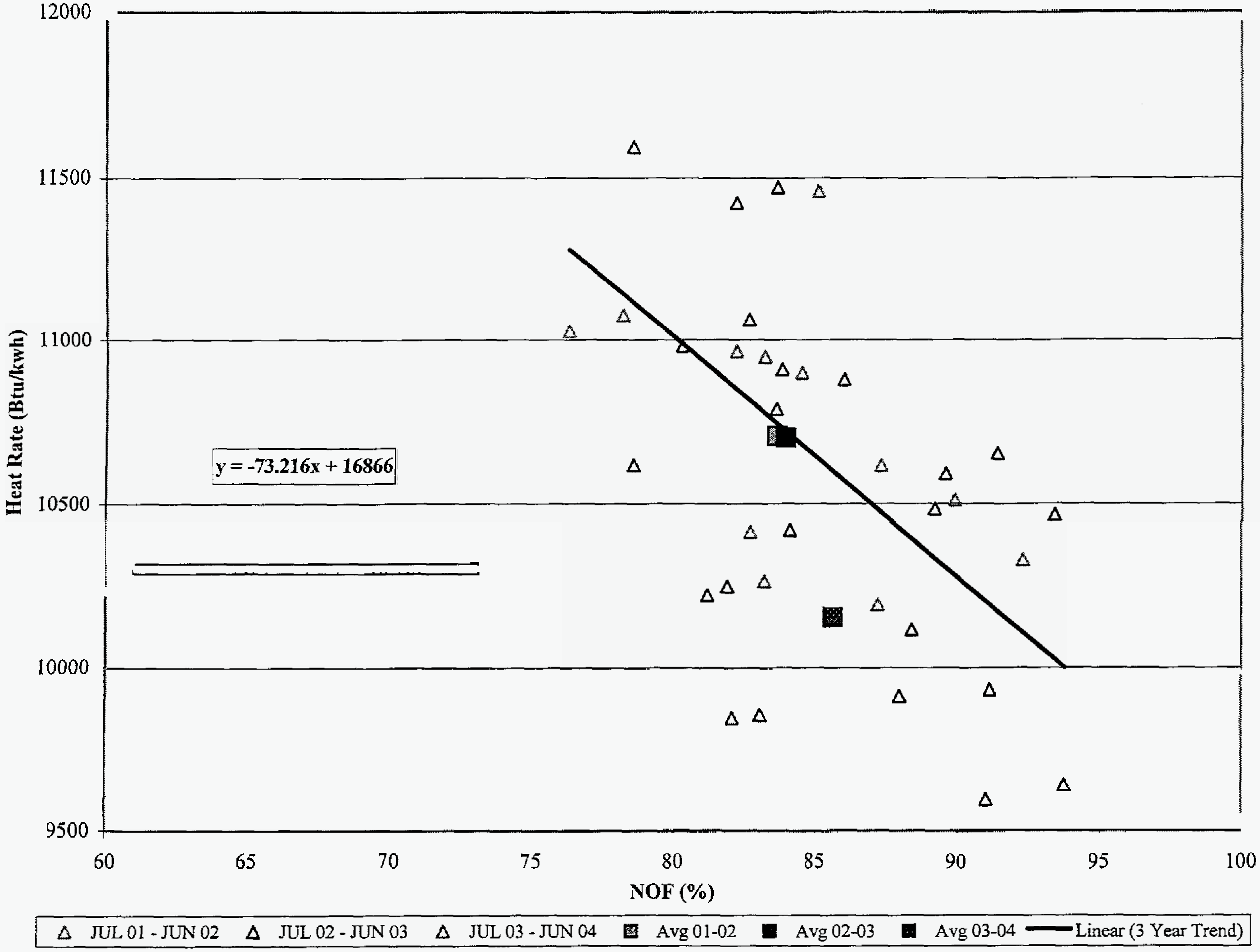
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4



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



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2005 - DECEMBER 2005

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
POLK 1		325	258
	GPIF TOTAL	2,167	1,993
	SYSTEM TOTAL	4,547	4,252
	% OF SYSTEM TOTAL	47.66%	46.88%

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2005 - DECEMBER 2005

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
	BIG BEND TOTAL	1,842	1,736
BIG BEND CT1		15	15
BIG BEND CT2		80	73
BIG BEND CT3		70	65
	CT TOTAL	165	153
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK 1		325	258
POLK 2		180	170
POLK 3		180	173
	POLK TOTAL	685	600
BAYSIDE 1		787	745
BAYSIDE 2		1,032	985
	BAYSIDE TOTAL	1,819	1,730
	SYSTEM TOTAL	**4,547**	**4,252**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2005 - DECEMBER 2005

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,674,230	26.33%	26.33%
BIG BEND	4	2,691,339	15.16%	41.50%
BAYSIDE	1	3,402,421	19.17%	60.67%
BIG BEND	3	1,873,211	10.55%	71.22%
BIG BEND	2	1,799,508	10.14%	81.36%
BIG BEND	1	1,622,779	9.14%	90.50%
POLK	1	1,519,143	8.56%	99.06%
POLK	2	79,166	0.45%	99.51%
PHILLIPS	1	20,010	0.11%	99.62%
PHILLIPS	2	20,068	0.11%	99.73%
POLK	3	41,910	0.24%	99.97%
BIG BEND CT	3	2,162	0.01%	99.98%
BIG BEND CT	1	488	0.00%	99.98%
BIG BEND CT	2	3,061	0.02%	100.00%
TOTAL GENERATION		17,749,496	100.00%	

GENERATION BY COAL UNITS:	9,505,980 MWH	GENERATION BY NATURAL GAS UNITS:	8,197,727 MWH
% GENERATION BY COAL UNITS:	53.56%	% GENERATION BY NATURAL GAS UNITS:	46.19%
GENERATION BY OIL UNITS:	45,789 MWH	GENERATION BY GPIF UNITS:	9,505,980 MWH
% GENERATION BY OIL UNITS:	0.26%	% GENERATION BY GPIF UNITS:	53.56%

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2005 - DECEMBER 2005

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(DRK-1)
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 9/9/04

Tampa Electric Company
Summary of GPIF Targets
January 2005 - December 2005

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	52.6	15.34	32.03	10,853
Big Bend 2[2]	61.6	3.84	34.52	10,672
Big Bend 3[3]	60.6	3.84	35.61	10,663
Big Bend 4[4]	78.7	3.84	17.48	10,350
Polk 1[5]	79.76	3.77	15.47	10,342

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3/ Original Sheet 8.401.05E, Page 14

4/ Original Sheet 8.401.05E, Page 15

5/ Original Sheet 8.401.05E, Page 16