TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2004 THROUGH DECEMBER 2004

TESTIMONY AND EXHIBITS

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 the 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 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-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 is titled "Generating Performance Incentive Factor January 2004 - December 2004." Document No. 2 is a summary of the GPIF targets for the 2004 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. Please explain.

A. Due to the repowering of Gannon Units 5 and 6 to Bayside Units 1 and 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside Unit 1 began operation in 2003, the repowered unit is 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. For the same reason, Bayside Unit 2, which is expected to be in service in January 2004, is not included in the GPIF calculations. Tampa Electric has no other base load generating units to substitute for Gannon Units

5 and 6. Therefore, Tampa Electric requests approval of its 2004 GPIF calculation excluding the repowered units, as provided for by Section 3.2 of the GPIF Implementation Manual, which states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis.

Q. Did the shutdown of Gannon Units 1 through 4 in 2003 affect the calculation of Tampa Electric's GPIF targets and ranges?

A. No. First, these Gannon Units have never been included in the GPIF calculation. Second, the GPIF units are base load units that are all economically dispatched prior to Gannon Units 1 through 4. Therefore, as the GPIF units' availabilities vary, the absolute system fuel cost numerical value may be different, but the relative penalty or savings for each of the GPIF units is not affected.

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 2004 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 ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100% to determine the target Equivalent Availability Factor ("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 2004 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 27.11% and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 67.15% or:

$$100\% - [(27.11\% + 5.74\%)] = 67.15\%$$

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% reduction in Equivalent Forced Outage Factor ("EUOF") and Equivalent Maintenance Outage Factor ("EMOF"), plus a 5% reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 100\% - [0.8 \ (27.11\%) + 0.95 \ (5.74\%)] = 72.90\%$$

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 and approved in earlier hearings before the Commission. 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 1 example,

$$EAF_{MIN} = 100\% - [1.4 \ (27.11\%) + 1.1 \ (5.74\%)] = 55.73\%$$

The equivalent availability MAX and MIN for the other four units is 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 2004 through December 2004 are shown on page 17 of Document No. 1. Since no GPIF units have a major outage (greater than 28 days) in 2004 no Critical Path Method diagrams are provided in this testimony. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage November 13, 2004 through December 3, 2004. There are 504 planned outage hours scheduled for the 2004 period, and a total of 8,784 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 5.74% or:

$$\frac{504}{8{,}784} \times 100\% = 5.74\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Big Bend Unit 2 has a Planned Outage Factor of 5.74%. Big Bend Unit 3 has a Planned Outage Factor of 5.74%. Big Bend 4 has a Planned Outage Factor of 5.74%. Polk Unit 1 has a Planned Outage Factor of 4.37%.

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 2003, 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 27.11% for Big Bend Unit 1. The

Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 12, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(1{,}875.1 + 506.4)}{8{,}784} \times 100 = 27.11\%$$

Relative to Big Bend Unit 1, the EUOF of 27.11% 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 27.11%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 67.15%.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 27.57%. This unit will have a planned outage in

2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 66.69%.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 26.66%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 67.60%.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 16.09%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 78.18%.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 10.03%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 4.37%. Therefore, the target equivalent availability for this unit is 85.60%.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 69.8% is shown on Page 5 of Document No. 1. This target compares favorably to the July 2002 - June 2003 GPIF period.

Q. When graphing and monitoring Forced and Maintenance Outage Factors, why are they 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 1 on page 12 of Document No. 1. During the months of January through October, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of November and December, 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. The accomplishment of scrubbing the flue gas from Big Bend Units 1 and 2 requires an additional amount of station service power. How did you address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for these units resulting from utilization of the new scrubber can be quantified. In past filings, the operational history with the scrubber was short of GPIF guidelines; and therefore, targets for Big Bend Units 1 and 2 were developed using data without scrubber power. This method was approved by the Commission for Big Bend Unit 3 when it began scrubbing operation. Tampa Electric has previously stated that it would utilize the aforementioned method until there was sufficient history to meet target preparation guidelines. There now exists sufficient history with the scrubber operating to meet the GPIF target preparation guidelines. Therefore, Tampa Electric calculated the 2004 heat rate targets for these units with scrubber power included and will calculate it in the same way for the 2004 period true-up filing to ensure compatibility of data for all GPIF calculations.

Q. Have you developed the heat rate targets in accordance with GPIF guidelines?

A. Yes.

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 24 through 28 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 2004 period.

A. The heat rate target for Big Bend Unit 1 is 10,708 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±504 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,384 Btu/Net kWh with a range of ±563 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,278 Btu/Net kWh, with a range of ±656 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,272 Btu/Net kWh with a range of ±505 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,569 Btu/Net kWh with a range of ±434 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 a 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 $665,093 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 $27,344,800, 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 14.90% 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 1, page 7, if the unit operates at 72.9% equivalent availability, fuel savings would equal $4,074,500 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, $27,344,800. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2004 is $1,450,831,850. This produces the maximum allowed jurisdictional incentive dollars of $5,752,609 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 our determination of GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$GPIP: = (\ 0.1490\ EAP_{BB1} + 0.1604\ EAP_{BB2} + 0.1398\ EAP_{BB3} + 0.1047\ EAP_{BB4} + 0.0209\ EAP_{PK1} + 0.0758\ HRP_{BB1} + 0.0885\ HRP_{BB2} + 0.1033\ HRP_{BB3} + 0.1030\ HRP_{BB4} + 0.0546\ HRP_{PK1}\ )$$

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 2004 - December 2004 period?

A. Yes. Document No. 2 entitled "Tampa Electric Company, Summary of GPIF Targets, January 2004 - December 2004" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO._________
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WAS-2)
FILED: 9/12/03

INDEX

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 030001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2004 - DECEMBER 2004
TARGETS
TABLE OF CONTENTS

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2004 - DECEMBER 2004**

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	27,344.8	5,752.6
+9	24,610.4	5,177.3
+8	21,875.9	4,602.1
+7	19,141.4	4,026.8
+6	16,406.9	3,451.6
+5	13,672.4	2,876.3
+4	10,937.9	2,301.0
+3	8,203.5	1,725.8
+2	5,469.0	1,150 5
+1	2,734.5	575.3
0	0.0	0.0
-1	(4,295 9)	(575.3)
-2	(8,591.8)	(1,150.5)
-3	(12,887.7)	(1,725.8)
-4	(17,183.6)	(2,301.0)
-5	(21,479.5)	(2,876.3)
-6	(25,775.4)	(3,451.6)
-7	(30,071.3)	(4,026.8)
-8	(34,367.2)	(4,602.1)
-9	(38,663.0)	(5,177.3)
-10	(42,958.9)	(5,752.6)

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2004 - DECEMBER 2004**

Line 1	Beginning of period balance of common equity: End of month common equity.		$	1,395,385,000	
Line 2	Month of January	2004	$	1,430,582,145	
Line 3	Month of February	2004	$	1,444,589,928	
Line 4	Month of March	2004	$	1,458,734,871	
Line 5	Month of April	2004	$	1,409,668,446	
Line 6	Month of May	2004	$	1,423,471,449	
Line 7	Month of June	2004	$	1,437,409,607	
Line 8	Month of July	2004	$	1,472,809,507	
Line 9	Month of August	2004	$	1,487,230,767	
Line 10	Month of September	2004	$	1,501,793,235	
Line 11	Month of October	2004	$	1,452,114,666	
Line 12	Month of November	2004	$	1,466,333,289	
Line 13	Month of December	2004	$	1,480,691,135	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,450,831,850	
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)		$	5,909,146	
Line 18	Jurisdictional Sales			18,768,886	MWH
Line 19	Total Sales			19,279,615	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.35%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,752,609**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

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	14.90%	67.2	72 9	55.7	4,074.5	(8,083.0)
BIG BEND 2	16.04%	66.7	72.5	55.1	4,386 4	(8,770.2)
BIG BEND 3	13 98%	67.6	73.2	56.4	3,822.1	(7,513 0)
BIG BEND 4	10 47%	78 2	81.7	71.2	2,862.2	(5,826.8)
POLK 1	2.09%	85.6	87.8	81.2	571.1	(1,137.4)
GPIF SYSTEM	**57.47%**					

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	7 58%	10,708	77.9	10,204	11,212	2,073.1	(2,073.1)
BIG BEND 2	8.85%	10,384	82 2	9,821	10,948	2,421.0	(2,421.0)
BIG BEND 3	10.33%	10,278	78.5	9,622	10,935	2,825.9	(2,825.9)
BIG BEND 4	10 30%	10,272	83.9	9,767	10,777	2,815.9	(2,815.9)
POLK 1	5.46%	10,569	89.3	10,135	11,003	1,492.6	(1,492.6)
GPIF SYSTEM	**42.53%**					**11,628.5**	**(11,628.5)**

28

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 03 - DEC 03			TARGET PERIOD JUL 01 - JUN 02			TARGET PERIOD JUL 00 - JUN 01			TARGET PERIOD JUL 99 - JUN 00		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	14.90%	25.9%	5.7	27.1	28 8	0 0	28.9	28.9	4.5	24.8	26.0	14.3	23.7	27 7
BIG BEND 2	16.04%	27.9%	5.7	27.6	29.3	23.3	24 4	31.8	0.0	28.2	28.2	6.1	18 5	19.7
BIG BEND 3	13.98%	24.3%	5.7	26 7	28.3	0.0	28.6	28 6	16.2	27.7	33 1	0 0	16.7	16 7
BIG BEND 4	10.47%	18.2%	5.7	16.1	17.1	6.1	16.0	17.1	0.0	12.4	12.4	8.5	12.6	13.8
POLK 1	2.09%	3.6%	4.4	10.0	10.5	11.1	7.1	8.0	0.7	14.3	14.4	4.3	8 7	9.1
GPIF SYSTEM	**57.47%**	**100.0%**	**5.7**	**24.5**	**26.0**	**8.0**	**24.4**	**26.7**	**5.1**	**23.8**	**25.4**	**7.1**	**18.0**	**19.6**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**69.8**			**67.6**			**71.1**			**74.9**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
6.8	22.1	23.9	71.2

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 03 - DEC 03	ADJUSTED PRIOR HEAT RATE JUL 01 - JUN 02	ADJUSTED PRIOR HEAT RATE JUL 00 - JUN 01	ADJUSTED PRIOR HEAT RATE JUL 99 - JUN 00
BIG BEND 1	7.58%	17.8%	10,708	10,805	10,559	10,419
BIG BEND 2	8.85%	20.8%	10,384	10,658	10,300	9,985
BIG BEND 3	10.33%	24.3%	10,278	10,563	10,205	10,056
BIG BEND 4	10.30%	24.2%	10,272	10,283	10,378	10,070
POLK 1	5.46%	12.8%	10,569	10,226	10,539	10,206
GPIF SYSTEM	**42.53%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,413**	**10,515**	**10,372**	**10,129**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2004 - DECEMBER 2004
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	665,093	661,018	4,075	14 90%
EA_2 BIG BEND 2	665,093	660,706	4,386	16 04%
EA_3 BIG BEND 3	665,093	661,271	3,822	13.98%
EA_4 BIG BEND 4	665,093	662,230	2,862	10.47%
EA_7 POLK 1	665,093	664,522	571	2.09%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	665,093	663,020	2,073	7.58%
AHR_2 BIG BEND 2	665,093	662,672	2,421	8.85%
AHR_3 BIG BEND 3	665,093	662,267	2,826	10.33%
AHR_4 BIG BEND 4	665,093	662,277	2,816	10 30%
AHR_7 POLK 1	665,093	663,600	1,493	5.46%
TOTAL SAVINGS			**27,345**	**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 2004 - DECEMBER 2004

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	4,074 5	72.9	+10	2,073.1	10,204
+9	3,667.1	72.3	+9	1,865.8	10,247
+8	3,259 6	71 8	+8	1,658.5	10,290
+7	2,852.2	71 2	+7	1,451.2	10,333
+6	2,444 7	70.6	+6	1,243.9	10,375
+5	2,037.3	70.0	+5	1,036 5	10,418
+4	1,629 8	69.5	+4	829.2	10,461
+3	1,222.4	68.9	+3	621.9	10,504
+2	814.9	68 3	+2	414 6	10,547
+1	407.5	67.7	+1	207.3	10,590
					10,633
0	0 0	67.2	0	0.0	10,708
					10,783
-1	(808 3)	66.0	-1	(207.3)	10,826
-2	(1,616.6)	64.9	-2	(414.6)	10,869
-3	(2,424.9)	63.7	-3	(621.9)	10,911
-4	(3,233.2)	62.6	-4	(829.2)	10,954
-5	(4,041.5)	61.4	-5	(1,036.5)	10,997
-6	(4,849.8)	60.3	-6	(1,243.9)	11,040
-7	(5,658.1)	59.2	-7	(1,451.2)	11,083
-8	(6,466 4)	58.0	-8	(1,658.5)	11,126
-9	(7,274.7)	56.9	-9	(1,865.8)	11,169
-10	(8,083.0)	55.7	-10	(2,073.1)	11,212
	Weighting Factor =	14.90%		Weighting Factor =	7.58%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

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	4,386.4	72.5	+10	2,421.0	9,821
+9	3,947.8	71.9	+9	2,178.9	9,870
+8	3,509.1	71.3	+8	1,936.8	9,919
+7	3,070.5	70.8	+7	1,694.7	9,968
+6	2,631.8	70.2	+6	1,452.6	10,017
+5	2,193.2	69.6	+5	1,210.5	10,065
+4	1,754.6	69.0	+4	968.4	10,114
+3	1,315.9	68.4	+3	726.3	10,163
+2	877.3	67.9	+2	484.2	10,212
+1	438.6	67.3	+1	242.1	10,261
					10,309
0	0.0	66.7	0	0.0	10,384
					10,459
-1	(877.0)	65.5	-1	(242.1)	10,508
-2	(1,754.0)	64.4	-2	(484.2)	10,557
-3	(2,631.1)	63.2	-3	(726.3)	10,606
-4	(3,508.1)	62.1	-4	(968.4)	10,655
-5	(4,385.1)	60.9	-5	(1,210.5)	10,704
-6	(5,262.1)	59.7	-6	(1,452.6)	10,752
-7	(6,139.1)	58.6	-7	(1,694.7)	10,801
-8	(7,016.2)	57.4	-8	(1,936.8)	10,850
-9	(7,893.2)	56.3	-9	(2,178.9)	10,899
-10	(8,770.2)	55.1	-10	(2,421.0)	10,948

Weighting Factor = 16.04% Weighting Factor = 8.85%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

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	3,822.1	73.2	+10	2,825.9	9,622
+9	3,439.9	72 6	+9	2,543.3	9,680
+8	3,057.7	72 1	+8	2,260.7	9,738
+7	2,675.5	71.5	+7	1,978.1	9,796
+6	2,293.3	71.0	+6	1,695.5	9,854
+5	1,911.0	70 4	+5	1,413.0	9,913
+4	1,528.8	69.8	+4	1,130 4	9,971
+3	1,146 6	69.3	+3	847.8	10,029
+2	764.4	68.7	+2	565.2	10,087
+1	382 2	68 2	+1	282.6	10,145
					10,203
0	0 0	67.6	0	0.0	10,278
					10,353
-1	(751.3)	66.5	-1	(282.6)	10,411
-2	(1,502.6)	65.4	-2	(565.2)	10,470
-3	(2,253.9)	64.2	-3	(847.8)	10,528
-4	(3,005.2)	63.1	-4	(1,130.4)	10,586
-5	(3,756.5)	62.0	-5	(1,413.0)	10,644
-6	(4,507.8)	60.9	-6	(1,695.5)	10,702
-7	(5,259.1)	59.7	-7	(1,978.1)	10,760
-8	(6,010 4)	58.6	-8	(2,260.7)	10,818
-9	(6,761.7)	57.5	-9	(2,543.3)	10,877
-10	(7,513.0)	56.4	-10	(2,825.9)	10,935
	Weighting Factor =	13.98%		Weighting Factor =	10.33%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

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	2,862.2	81.7	+10	2,815.9	9,767
+9	2,576.0	81.3	+9	2,534 3	9,810
+8	2,289.8	81.0	+8	2,252.7	9,853
+7	2,003.5	80.6	+7	1,971.1	9,896
+6	1,717.3	80.3	+6	1,689.6	9,939
+5	1,431.1	79.9	+5	1,408.0	9,982
+4	1,144.9	79.6	+4	1,126.4	10,025
+3	858.7	79.2	+3	844.8	10,068
+2	572.4	78 9	+2	563.2	10,111
+1	286 2	78.5	+1	281.6	10,154
					10,197
0	0 0	78.2	0	0.0	10,272
					10,347
-1	(582.7)	77.5	-1	(281.6)	10,390
-2	(1,165.4)	76.8	-2	(563.2)	10,433
-3	(1,748.0)	76.1	-3	(844.8)	10,476
-4	(2,330.7)	75.4	-4	(1,126.4)	10,519
-5	(2,913.4)	74.7	-5	(1,408.0)	10,562
-6	(3,496.1)	74.0	-6	(1,689.6)	10,605
-7	(4,078.8)	73.3	-7	(1,971.1)	10,648
-8	(4,661 4)	72.6	-8	(2,252.7)	10,691
-9	(5,244.1)	71.9	-9	(2,534.3)	10,734
-10	(5,826.8)	71.2	-10	(2,815.9)	10,777
	Weighting Factor =	10.47%		Weighting Factor =	10.30%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

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	571.1	87.8	+10	1,492.6	10,135
+9	514.0	87.6	+9	1,343.4	10,171
+8	456.9	87 4	+8	1,194 1	10,207
+7	399.8	87.1	+7	1,044.8	10,243
+6	342.7	86.9	+6	895.6	10,279
+5	285.5	86.7	+5	746.3	10,315
+4	228.4	86.5	+4	597.0	10,351
+3	171.3	86.3	+3	447.8	10,387
+2	114.2	86.0	+2	298.5	10,423
+1	57.1	85.8	+1	149.3	10,458
					10,494
0	0.0	85.6	0	0.0	10,569
					10,644
-1	(113.7)	85.2	-1	(149.3)	10,680
-2	(227.5)	84.7	-2	(298.5)	10,716
-3	(341.2)	84.3	-3	(447.8)	10,752
-4	(455.0)	83.8	-4	(597.0)	10,788
-5	(568.7)	83.4	-5	(746.3)	10,824
-6	(682.4)	82.9	-6	(895.6)	10,860
-7	(796.2)	82.5	-7	(1,044.8)	10,896
-8	(909.9)	82.0	-8	(1,194.1)	10,932
-9	(1,023.7)	81.6	-9	(1,343.4)	10,967
-10	(1,137.4)	81.2	-10	(1,492.6)	11,003
	Weighting Factor =	2.09%		Weighting Factor =	5.46%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

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-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1 EAF (%)	71 2	71 2	71 2	71.2	71 2	71 2	71 2	71 2	71 2	71 2	28 5	64 3	67 2
2 POF	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	60 0	9 7	5 74
3 EUOF	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	11 5	26 0	27 11
4. EUOR	28.8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8	28 8
5 PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6 SH	590	550	598	565	578	556	582	585	575	602	223	515	6519
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	154	146	146	155	166	164	162	159	145	142	497	229	2265
9 POH	0	0	0	0	0	0	0	0	0	0	432	72	504
10 FOH & EFOH	168	158	168	163	168	163	168	168	163	168	65	152	1,875
11. MOH & EMOH	46	43	46	44	46	44	46	46	44	46	18	41	506
12 OPER BTU (GBTU)	2,098	1,966	2,135	1,971	1,973	1,949	2,038	2,061	2,028	2,147	804	1,844	23,014
13 NET GEN (MWH)	195,710	183,649	199,411	183,674	182,742	182,012	190,141	192,675	189,663	201,524	75,731	172,317	2,149,249
14. ANOHR (Btu/kwh)	10,718	10,705	10,709	10,728	10,799	10,711	10,717	10,697	10,690	10,653	10,620	10,700	10,708
15. NOF (%)	77 6	78 0	77 9	77 3	75 1	77 8	77 6	78 2	78 4	79 5	80 5	78 1	77 9
16 NPC (MW)	428	428	428	421	421	421	421	421	421	421	421	428	423

17 ANOHR EQUATION ANOHR = NOF (-32 945) + 13,274

FILED·
SUSPENDED
EFFECTIVE· 09/12/03
DOCKET NO 030001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

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-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	70 7	31 7	59.3	70 7	70 7	70 7	70 7	70 7	70 7	70 7	70.7	70 7	66 7
2 POF	0 0	55 2	16 1	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	5 74
3. EUOF	29.3	13 1	24 5	29 3	29 3	29 3	29 3	29 3	29 3	29 3	29 3	29 3	27 57
4 EUOR	29 3	29 3	29 3	29 3	29 3	29 3	29.3	29 3	29.3	29 3	29 3	29.3	29.3
5 PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	599	250	502	580	596	577	593	594	580	599	577	599	6,647
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	145	446	242	140	148	143	151	150	140	145	143	145	2137
9. POH	0	384	120	0	0	0	0	0	0	0	0	0	504
10 FOH & EFOH	173	73	145	168	173	168	173	173	168	173	168	173	1,927
11 MOH & EMOH	45	19	37	43	45	43	45	45	43	45	43	45	495
12 OPER BTU (GBTU)	2,199	920	1,844	2,050	2,091	2,054	2,094	2,103	2,056	2,134	2,034	2,159	23,748
13. NET GEN (MWH)	211,471	88,502	177,342	197,723	201,336	198,366	201,942	202,874	198,387	206,066	196,046	206,850	2,286,905
14 ANOHR (Btu/kwh)	10,400	10,397	10,397	10,369	10,387	10,354	10,371	10,366	10,364	10,355	10,377	10,437	10,384
15 NOF (%)	81 5	81 7	81.6	83.0	82.1	83 7	82.9	83 1	83 2	83 7	82 6	79 7	82 2
16 NPC (MW)	433	433	433	411	411	411	411	411	411	411	411	433	418

17 ANOHR EQUATION ANOHR = NOF (-20 911) + 12,104

FILED
SUSPENDED
EFFECTIVE 09/12/03
DOCKET NO 030001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBLR 2004

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-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1 EAF (%)	71 7	71.7	27 8	66 9	71 7	71 7	71 7	71 7	71 7	71 7	71 7	71 7	67 6
2 POF	0 0	0 0	61 3	6 7	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	5 74
3 EUOF	28 3	28 3	11 0	26 4	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	26 66
4 EUOR	28.3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3	28 3
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6 SH	599	561	232	541	599	577	596	596	580	599	580	599	6,659
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	145	135	512	179	145	143	148	148	140	145	140	145	2125
9 POH	0	0	456	48	0	0	0	0	0	0	0	0	504
10 FOH & EFOH	181	170	70	164	181	175	181	181	175	181	175	181	2,017
11 MOH & EMOH	29	27	11	26	29	28	29	29	28	29	28	29	325
12. OPER BTU (GBTU)	2,161	1,987	809	1,872	2,051	1,982	2,051	2,063	2,013	2,099	2,058	2,119	23,269
13. NET GEN (MWH)	211,498	193,440	78,443	182,173	199,007	192,550	199,416	200,877	196,128	203,740	200,503	206,159	2,263,934
14. ANOHR (Btu/kwh)	10,219	10,271	10,318	10,274	10,305	10,292	10,287	10,271	10,264	10,304	10,266	10,278	10,278
15 NOF (%)	80 6	78.8	77 1	78 6	77 6	78 0	78 2	78 8	79 0	77 6	78 9	78 5	78 5
16. NPC (MW)	438	438	438	428	428	428	428	428	428	438	438	438	433

17 ANOHR EQUATION ANOHR = NOF(-28 979) + 12,553

FILED
SUSPENDED.
EFFECTIVE 09/12/03
DOCKET NO 030001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

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-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	82 9	82.9	82 9	82 9	82 9	82 9	82 9	82 9	82 9	26 8	82 9	82 9	78 2
2 POF	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	67 7	0 0	0 0	5 74
3. EUOF	17.1	17.1	17 1	17 1	17 1	17 1	17 1	17 1	17 1	5 5	17 1	17.1	16 09
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	696	744	720	744	720	744	744	720	744	720	744	8,784
6 SH	660	618	660	639	660	631	656	656	639	213	639	660	7,332
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	84	78	84	81	84	89	88	88	81	531	81	84	1452
9. POH	0	0	0	0	0	0	0	0	0	504	0	0	504
10. FOH & EFOH	102	96	102	99	102	99	102	102	99	33	99	102	1,140
11. MOH & EMOH	24	23	24	24	24	24	24	24	24	8	24	24	273
12 OPER BTU (GBTU)	2,604	2,441	2,607	2,491	2,573	2,447	2,566	2,570	2,497	836	2,507	2,611	28,745
13. NET GEN (MWH)	252,428	236,986	252,968	242,569	250,558	237,213	250,424	251,036	243,544	81,779	245,233	253,610	2,798,348
14. ANOHR (Btu/kwh)	10,314	10,299	10,305	10,269	10,271	10,314	10,247	10,238	10,252	10,220	10,222	10,294	10,272
15 NOF (%)	83.1	83.4	83 3	84 0	84 0	83 1	84 4	84.6	84 3	85 0	84 9	83 5	83.9
16. NPC (MW)	460	460	460	452	452	452	452	452	452	452	452	460	455
17 ANOHR EQUATION	ANOHR = NOF(		-51 316	) +	14,580								

38

FILED
SUSPENDED
EFFECTIVE 09/12/03
DOCKET NO 030001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

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-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	89 5	89 5	89.5	65.6	89 5	89.5	89.5	89 5	89 5	66.4	89 5	89 5	85 6
2 POF	0 0	0 0	0 0	26 7	0 0	0 0	0 0	0 0	0 0	25 8	0 0	0 0	4 37
3. EUOF	10 5	10 5	10.5	7 7	10 5	10 5	10 5	10 5	10 5	7 8	10 5	10 5	10 03
4 EUOR	10 5	10.5	10.5	10 5	10.5	10 5	10 5	10 5	10 5	10 5	10 5	10 5	10 5
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	669	626	669	432	669	648	669	669	648	497	648	669	7,515
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	75	70	75	288	75	72	75	75	72	247	72	75	1269
9. POH	0	0	0	192	0	0	0	0	0	192	0	0	384
10 FOH & EFOH	54	51	54	39	54	53	54	54	53	40	53	54	614
11. MOH & EMOH	24	22	24	17	24	23	24	24	23	18	23	24	267
12 OPER BTU (GBTU)	1,711	1,604	1,715	1,066	1,541	1,491	1,541	1,541	1,491	1,232	1,631	1,692	18,272
13. NET GEN (MWH)	165,102	154,913	165,605	101,976	142,976	138,363	142,976	142,976	138,363	117,169	156,112	162,252	1,728,783
14 ANOHR (Btu/kwh)	10,365	10,355	10,354	10,449	10,776	10,776	10,776	10,776	10,776	10,518	10,446	10,426	10,569
15. NOF (%)	94 9	95 1	95 1	92 6	83 8	83 8	83 8	83 8	83 8	90 7	92 7	93.2	89 3
16 NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	258

17. ANOHR EQUATION ANOHR = NOF(-37 017) + 13,876

FILED
SUSPENDED
EFFECTIVE 09/12/03
DOCKET NO 030001-EI

ORIGINAL SHEET NO. 8.401.04E
PAGE 16 OF 31

39

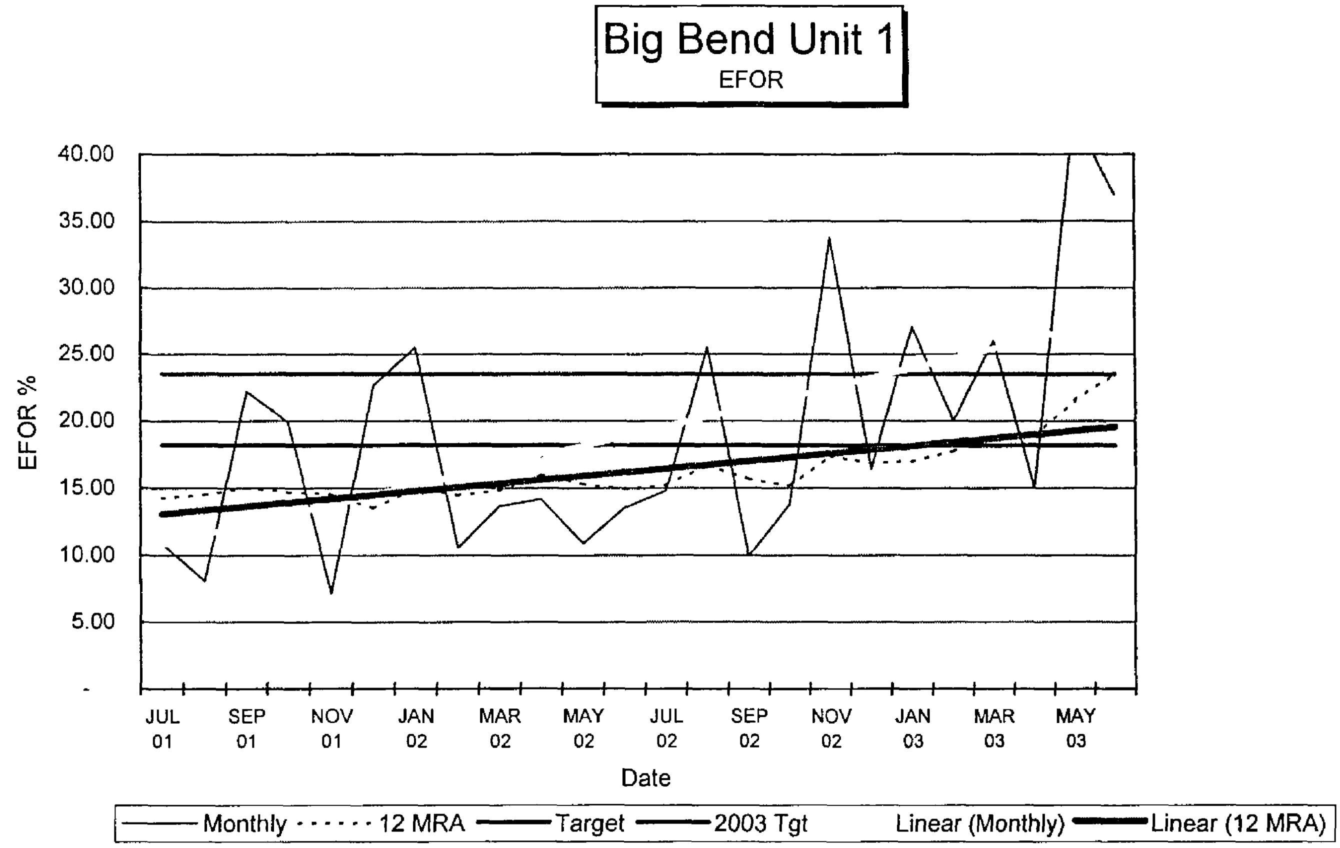
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2004 - DECEMBER 2004

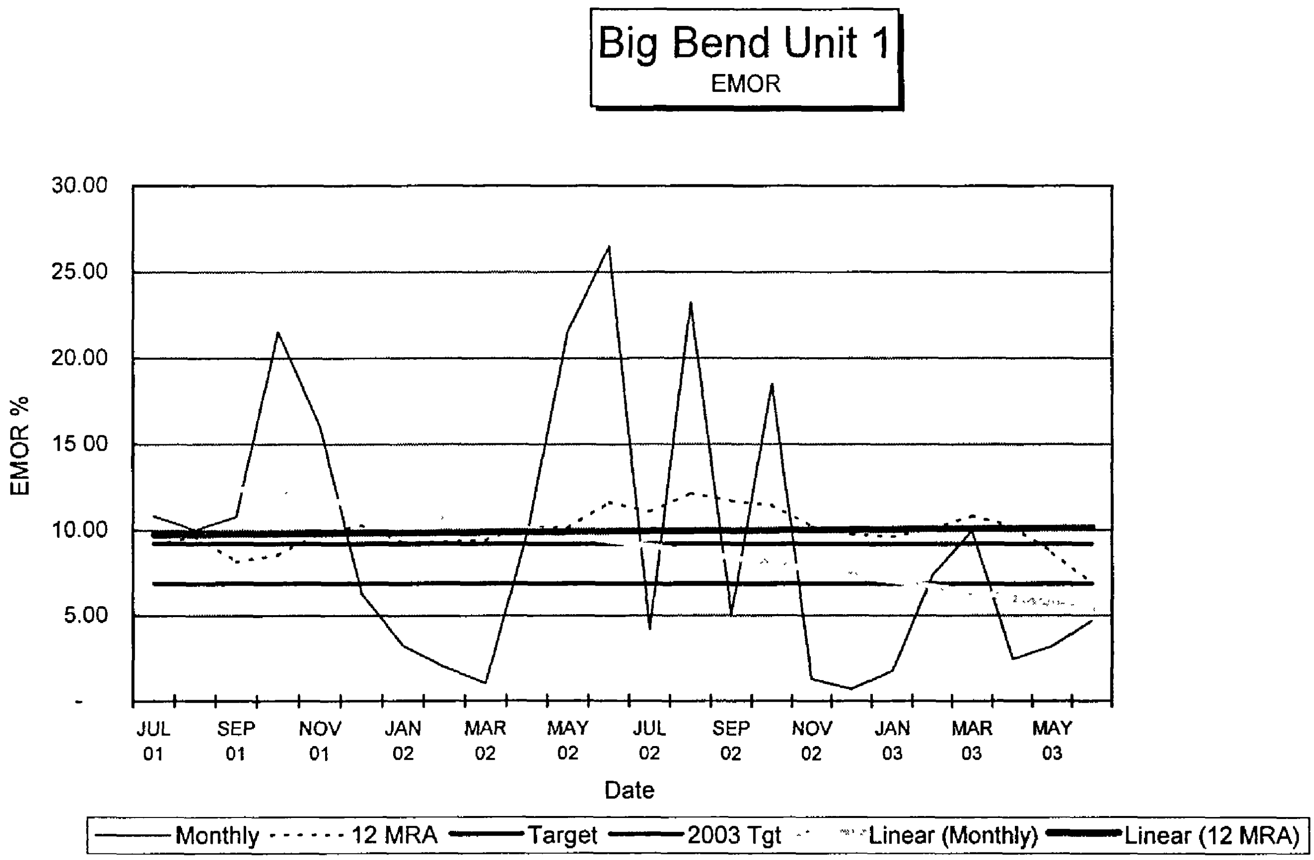
PLANT / UNIT	PLANNED OUTAGE DATES +			OUTAGE DESCRIPTION
BIG BEND 1	Nov 13	-	Dec 03	Fuel System Clean-up
BIG BEND 2	Feb 14	-	Mar 05	Fuel System Clean-up
BIG BEND 3	Mar 13	-	Apr 02	Fuel System Clean-up
BIG BEND 4	Oct 02	-	Oct 22	Fuel System Clean -up
POLK 1	Apr 03	-	Apr 10	#1CT Combustion Path
	Oct 04		Oct 11	Fuel System Clean-up

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

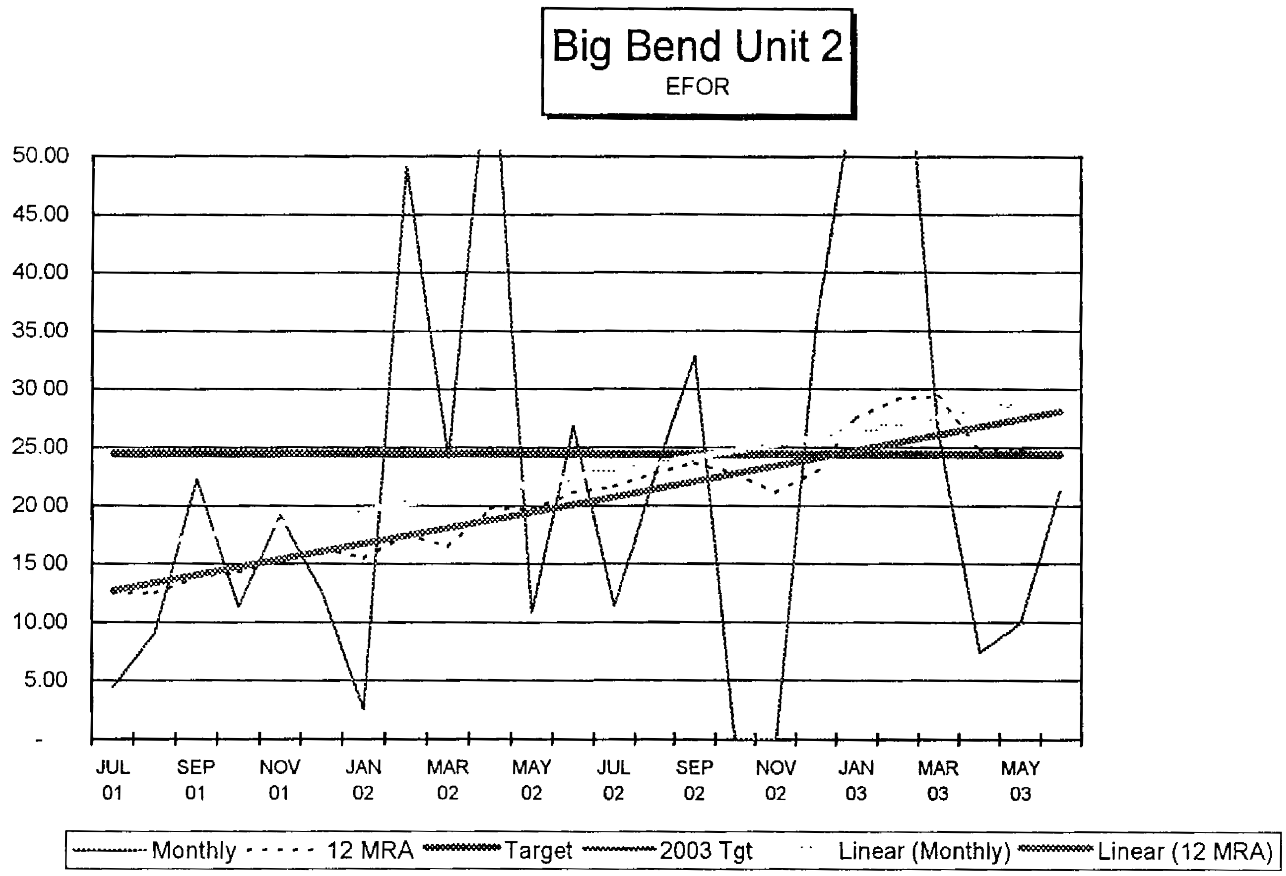
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2004 - DECEMBER 2004

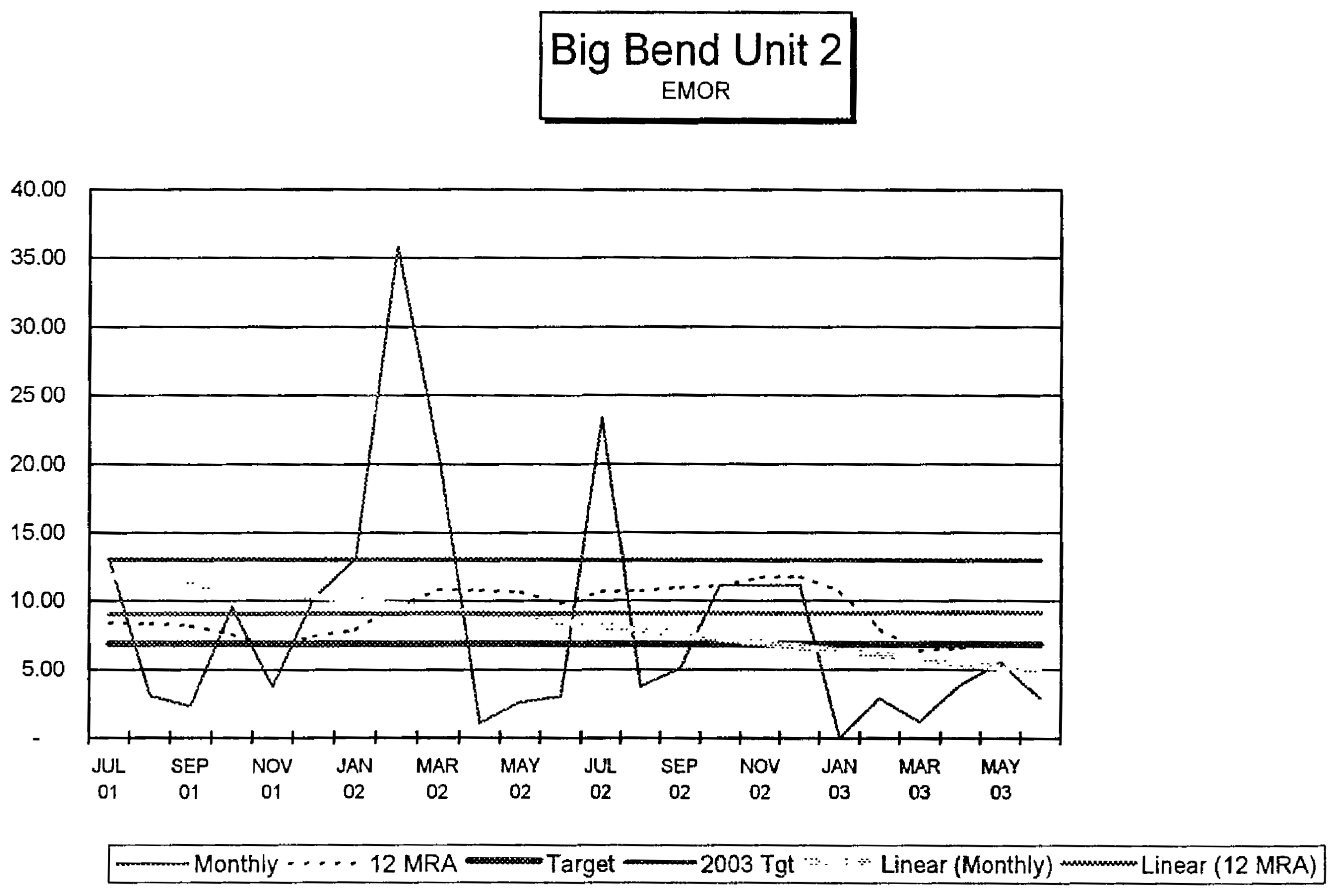
This page was intentionally left blank
because no scheduled outages apply.



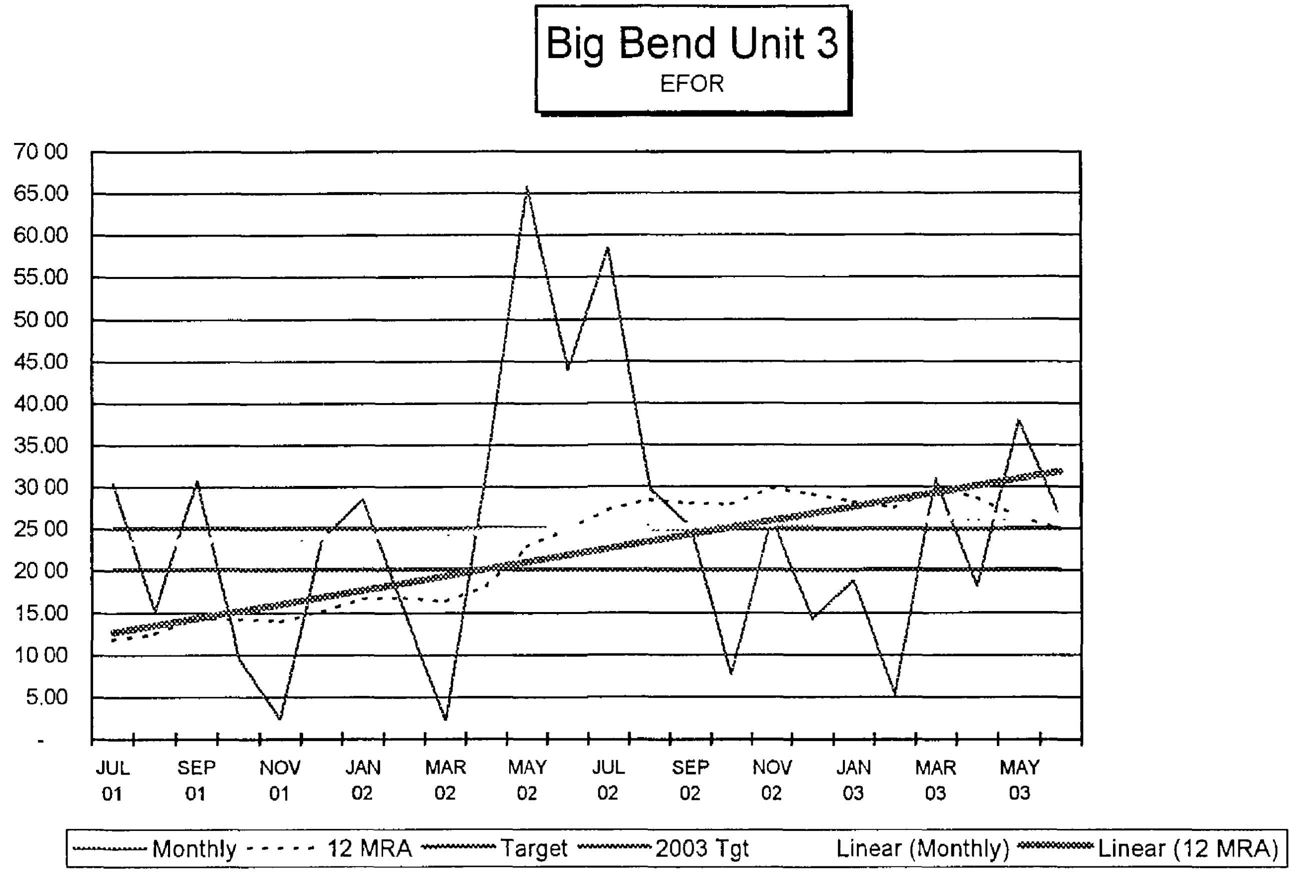


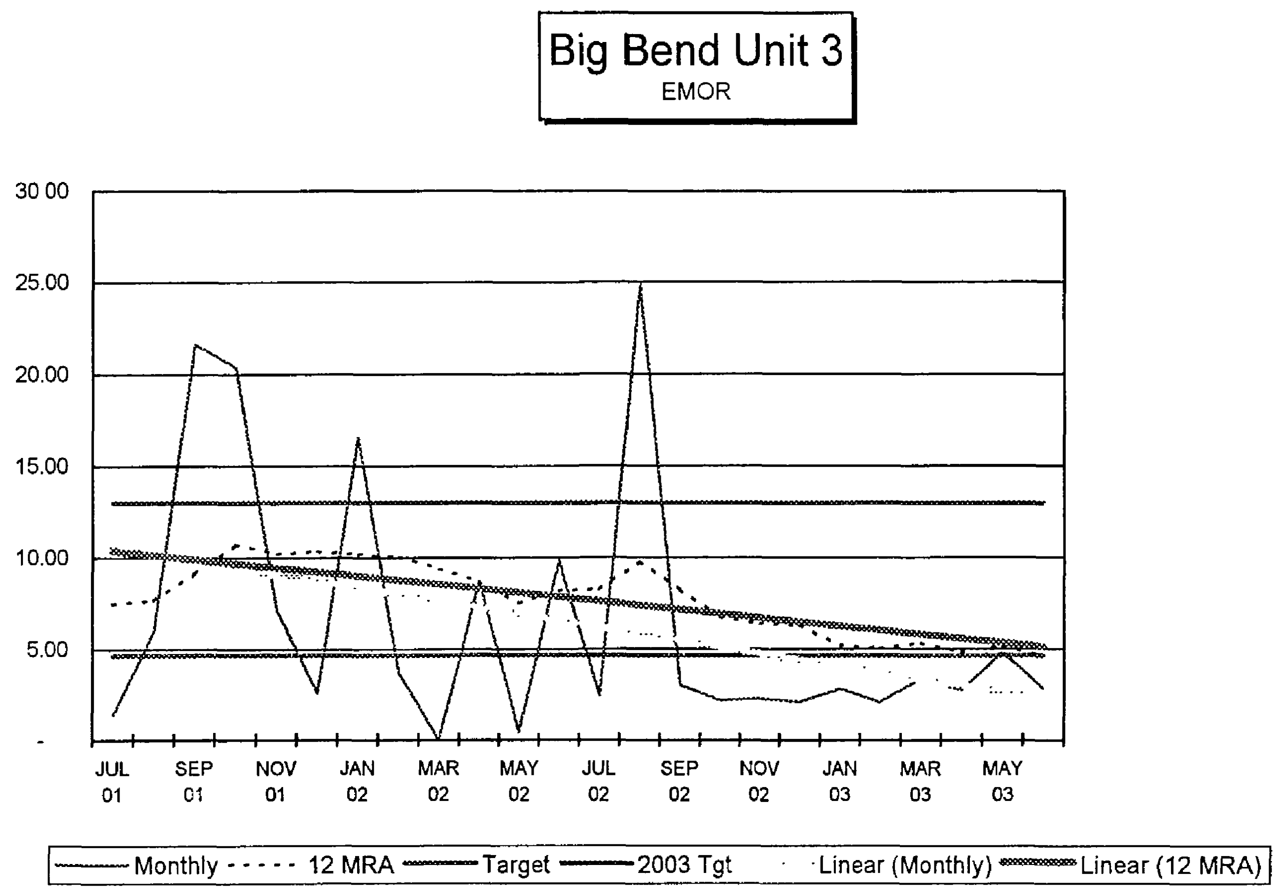
12 MRA = 12 Month Rolling Average



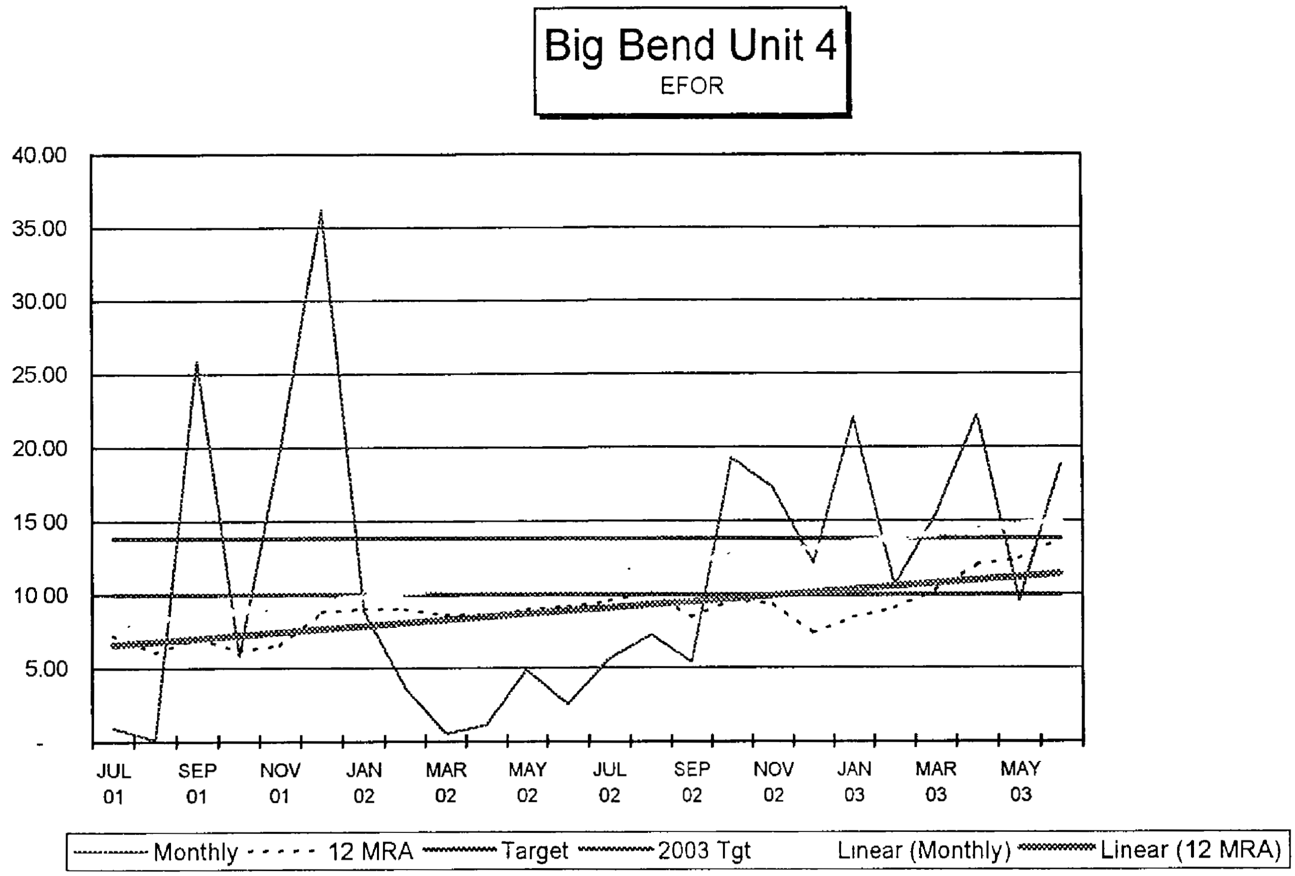


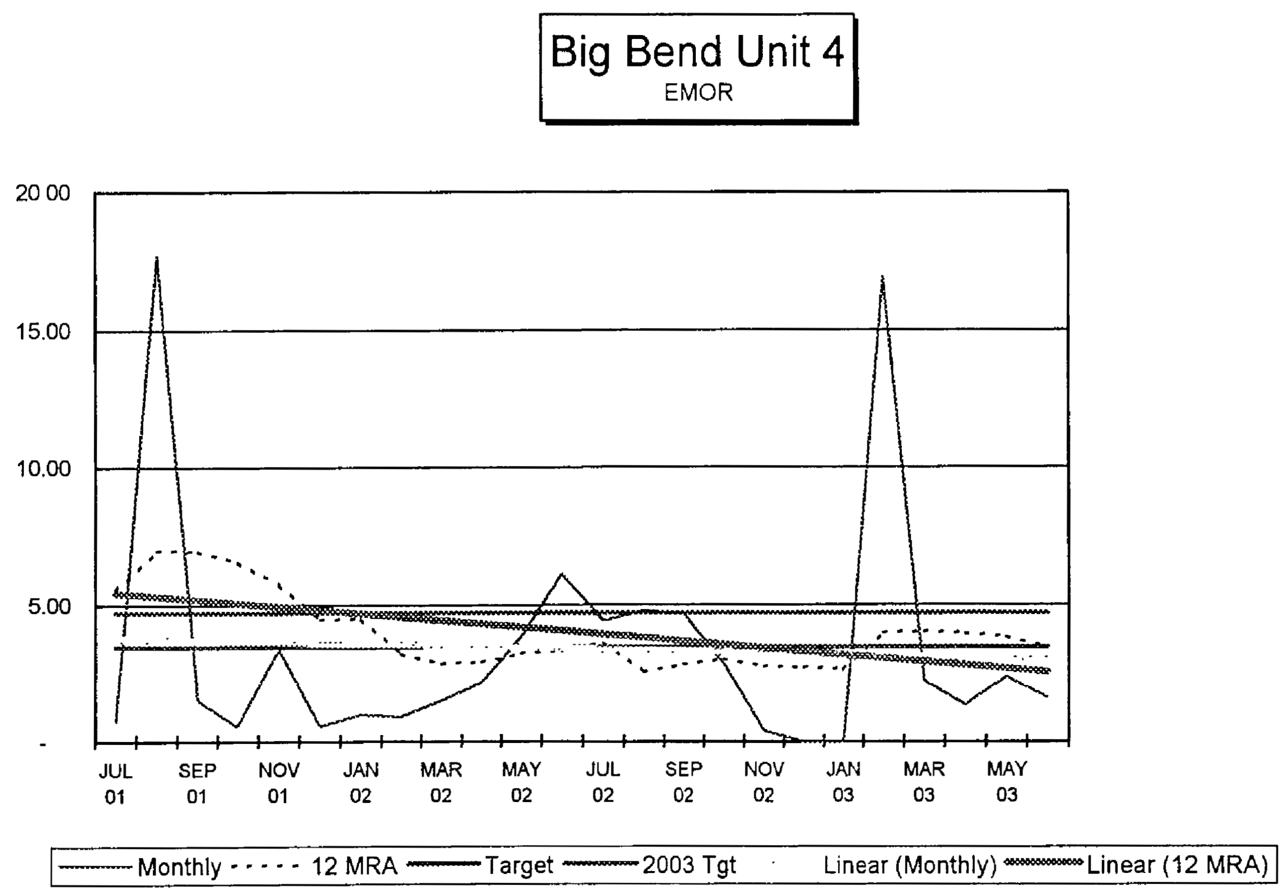
12 MRA = 12 Month Rolling Average





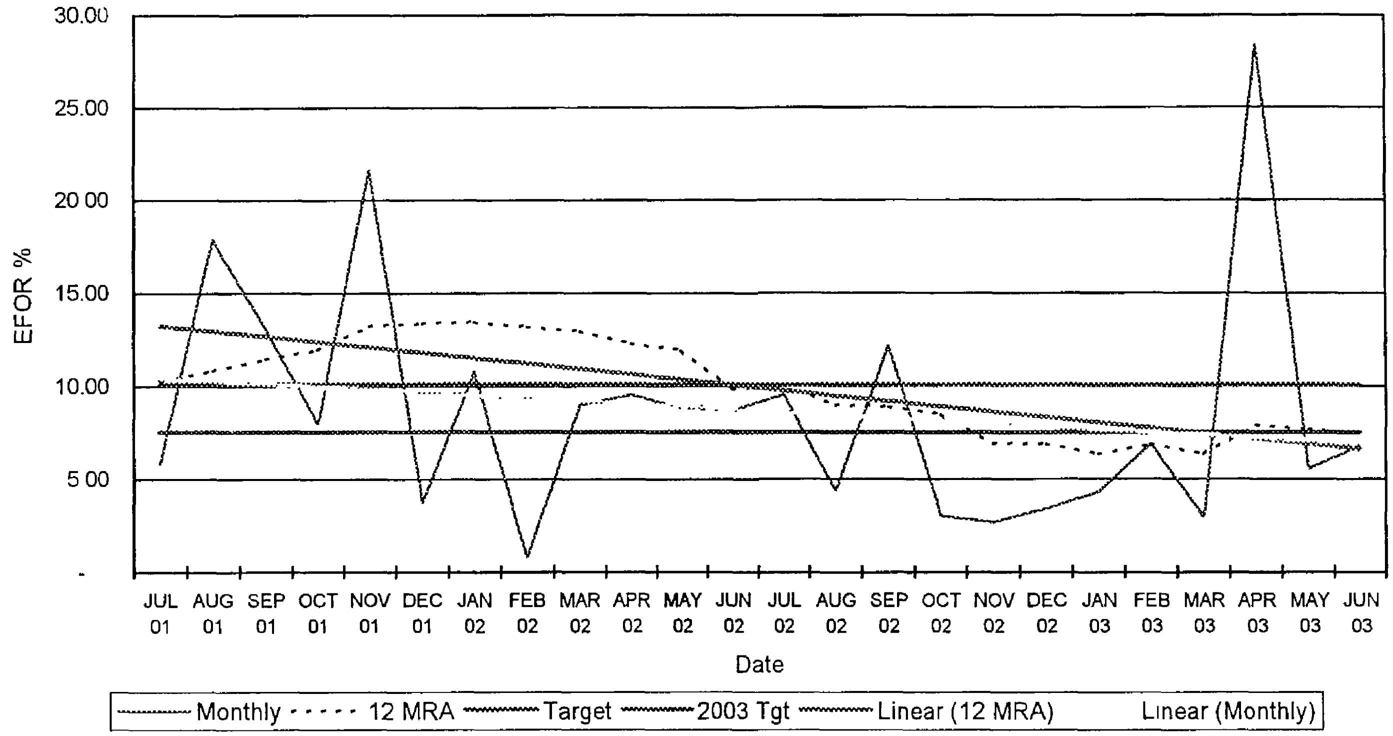
12 MRA = 12 Month Rolling Average



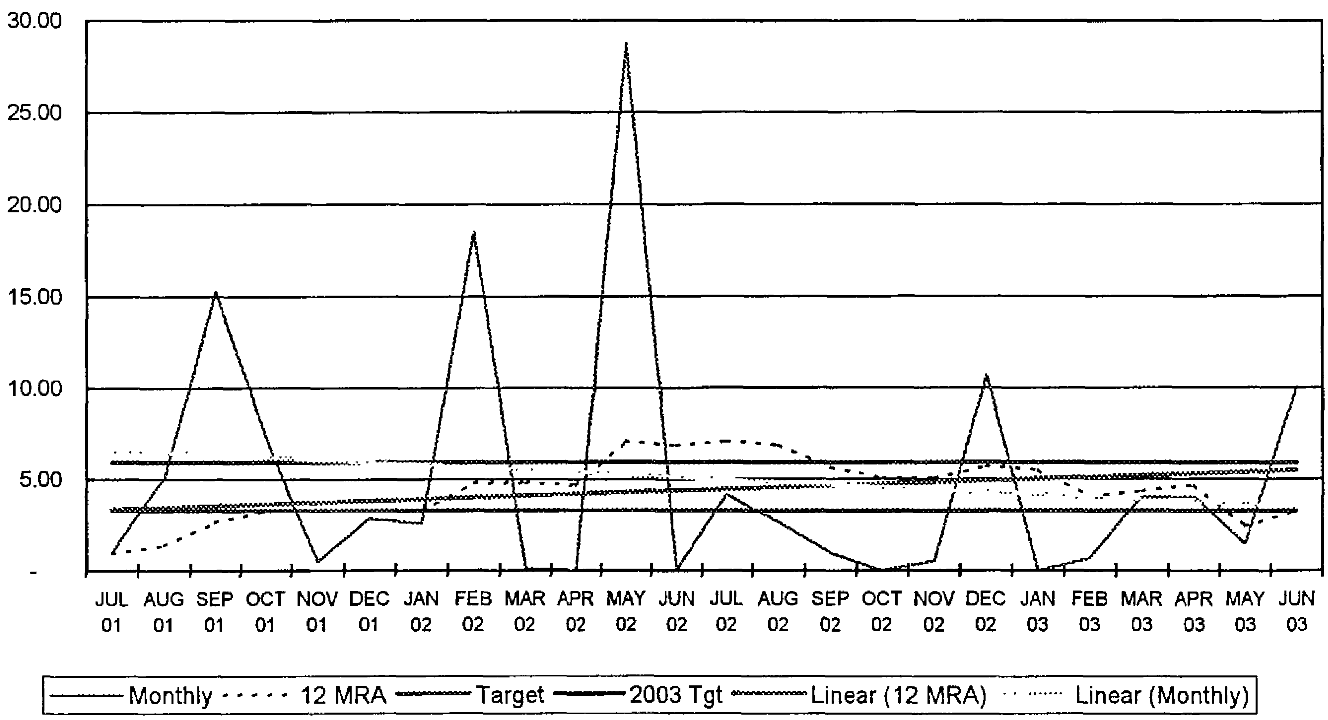


12 MRA = 12 Month Rolling Average

Polk Unit 1
EFOR

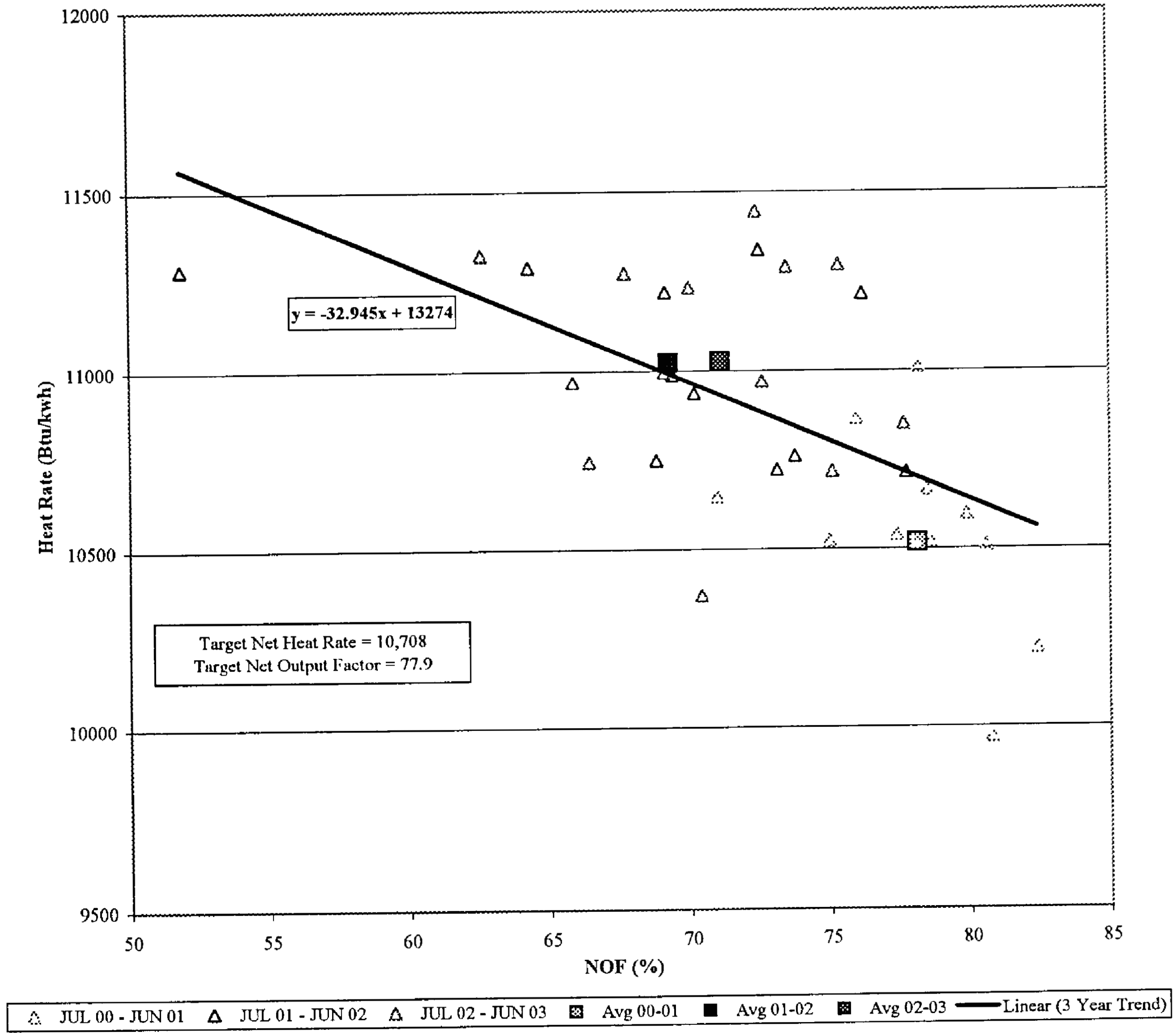


Polk Unit 1
EMOR

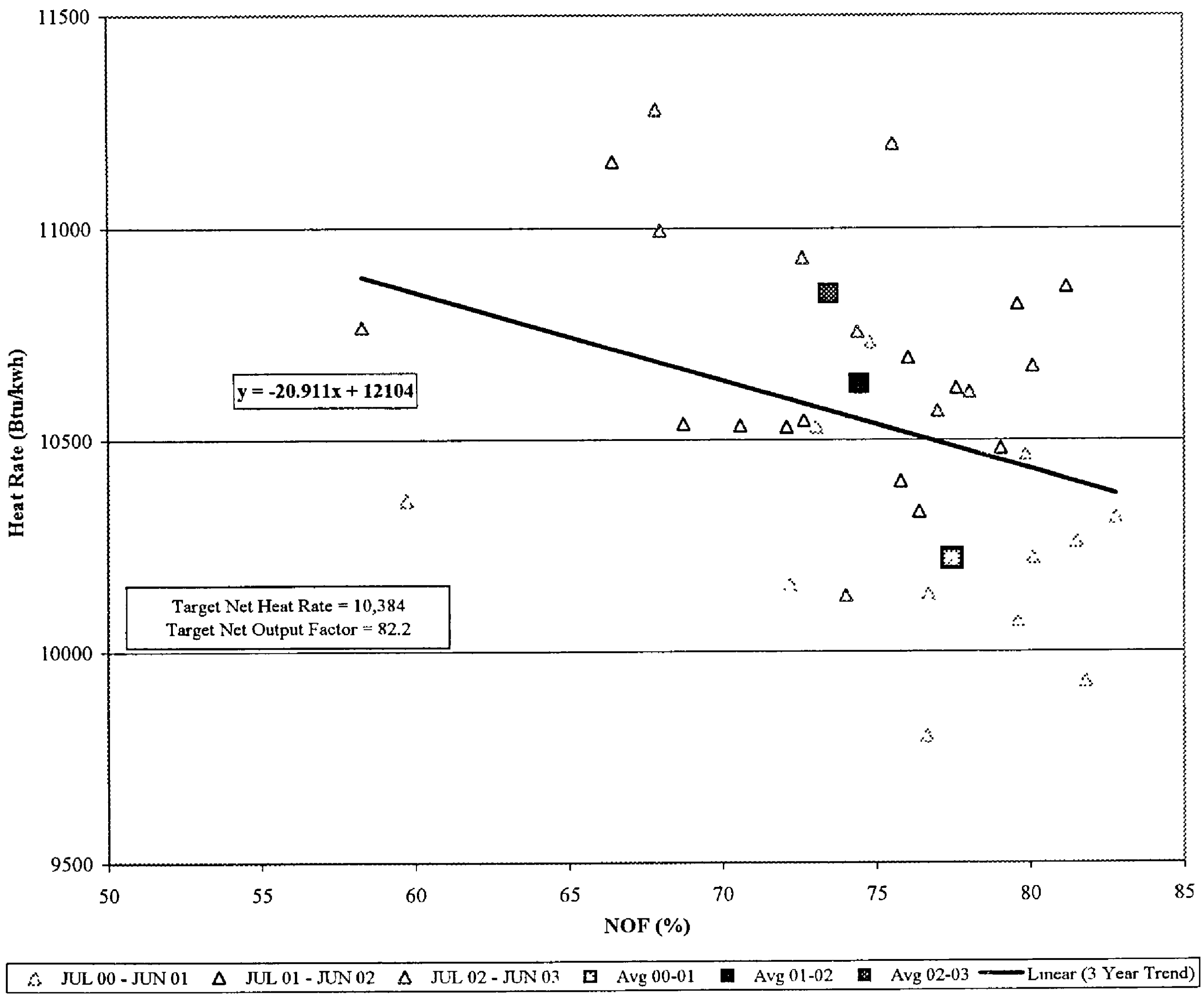


12 MRA = 12 Month Rolling Avreage

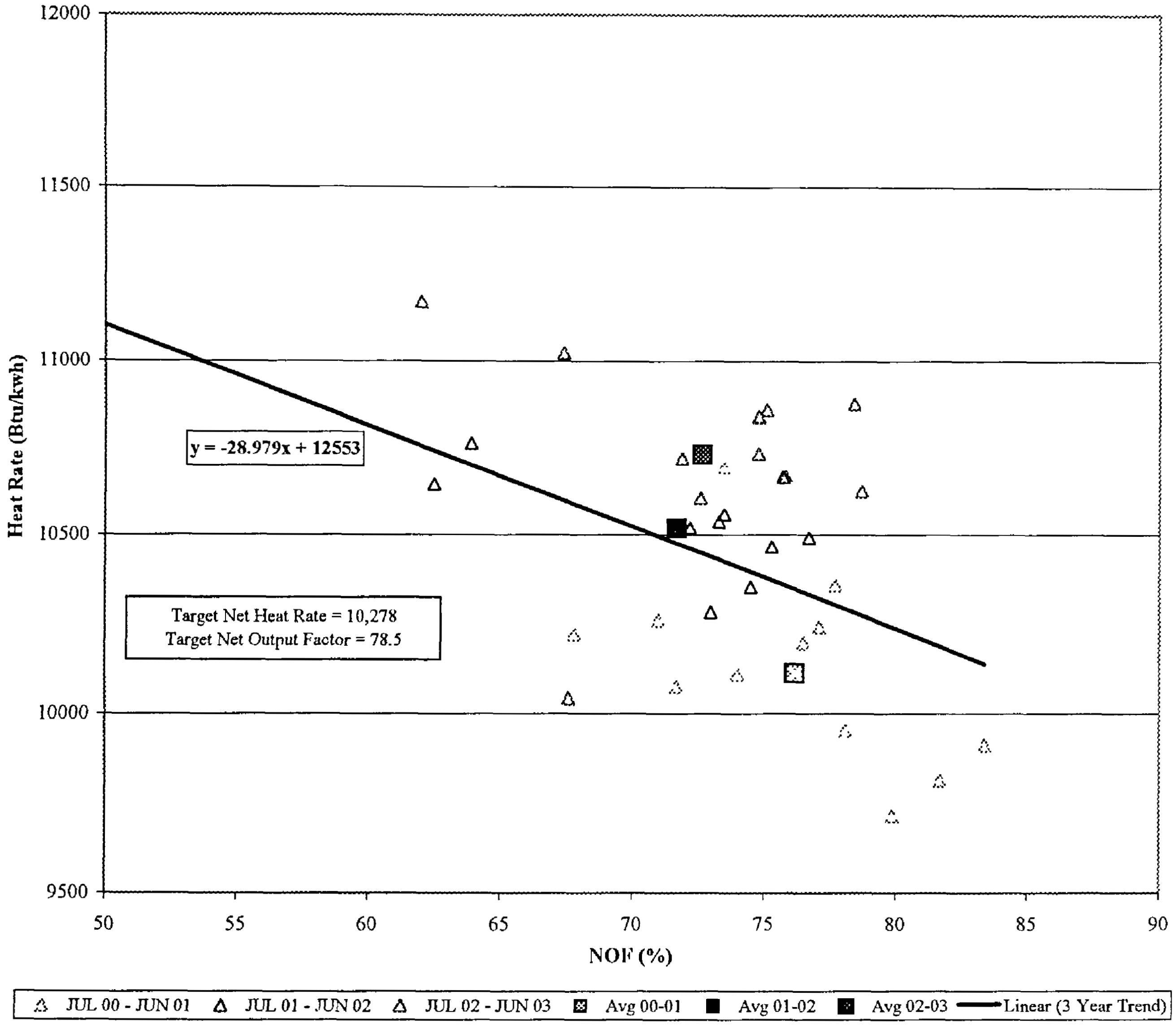
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



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

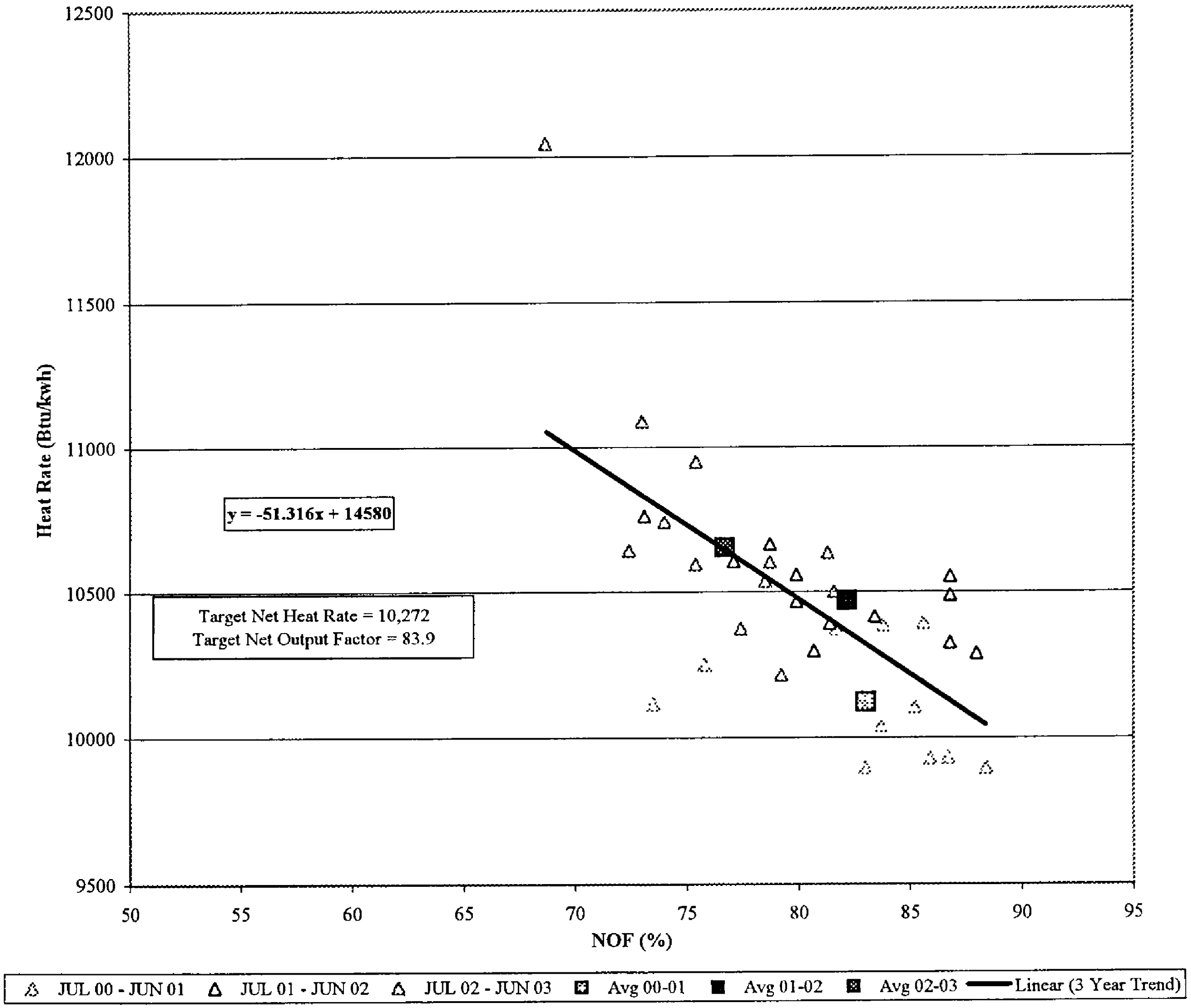


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3

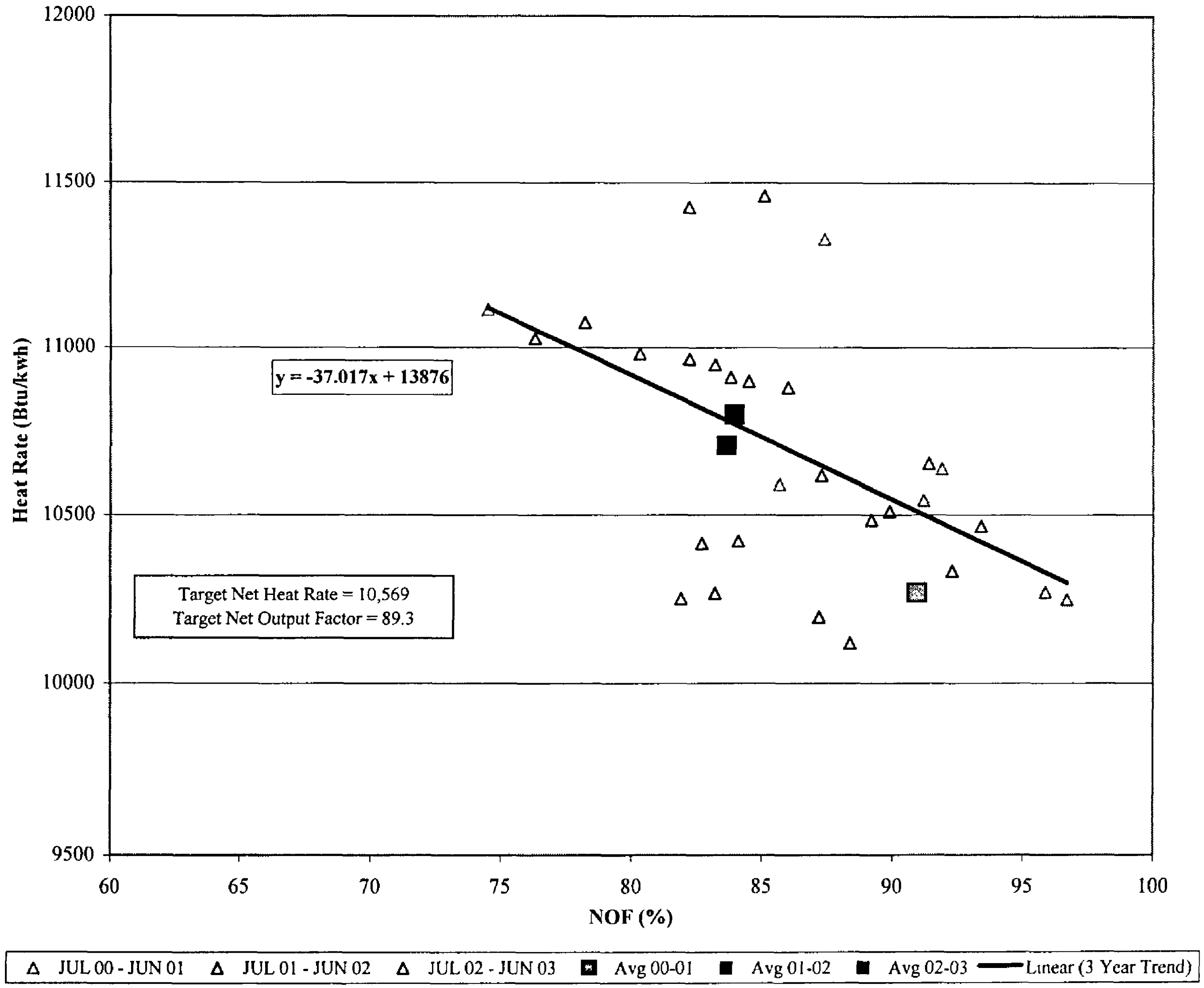


ORIGINAL SHEET NO. 8.401.04E
PAGE 26 OF 31

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 2004 - DECEMBER 2004

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**	**4,222**
	% OF SYSTEM TOTAL	**47.66%**	**47.21%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2004 - DECEMBER 2004

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
GANNON 1		0	0
GANNON 2		0	0
GANNON 3		0	0
GANNON 4		0	0
GANNON 5		0	0
GANNON 6		0	0
	GANNON TOTAL	0	0
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	735
BAYSIDE 2		1,032	965
	BAYSIDE TOTAL	1,819	1,700
	SYSTEM TOTAL	**4,547**	**4,222**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2004 - DECEMBER 2004

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,984,242	25.90%	25.90%
BIG BEND	4	2,798,348	14.54%	40.44%
BAYSIDE	1	2,890,112	15.02%	55.46%
BIG BEND	3	2,263,934	11.76%	67.22%
BIG BEND	2	2,286,905	11.88%	79.11%
BIG BEND	1	2,149,249	11.17%	90.27%
POLK	1	1,728,783	8.98%	99.26%
POLK	2	40,157	0.21%	99.47%
PHILLIPS	1	35,275	0.18%	99.65%
PHILLIPS	2	34,067	0.18%	99.83%
POLK	3	33,156	0.17%	100.00%
BIG BEND CT	3	64	0.00%	100.00%
BIG BEND CT	1	58	0 00%	100.00%
BIG BEND CT	2	-	0 00%	100.00%
GANNON	1	-	0.00%	100.00%
GANNON	2	-	0.00%	100.00%
GANNON	3	-	0.00%	100.00%
GANNON	4	-	0.00%	100.00%
GANNON	5	-	0.00%	100.00%
GANNON	6	-	0.00%	100.00%
TOTAL GENERATION		19,244,350	100.00%	

GENERATION BY COAL UNITS: 14,117,331 MWH

% GENERATION BY COAL UNITS 73.36%

GENERATION BY OIL UNITS: 69,464 MWH

% GENERATION BY OIL UNITS: 0.36%

GENERATION BY NATURAL GAS UNITS: 7,947,667 MWH

% GENERATION BY NATURAL GAS UNITS 41.30%

GENERATION BY GPIF UNITS: 11,227,219 MWH

% GENERATION BY GPIF UNITS: 58.34%

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 030001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WAS-2)
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 9/12/03

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2004 - DECEMBER 2004

Availability				Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1 [1]	67.2	5.74	27.11	10,708
Big Bend 2 [2]	66.7	5.74	27.57	10,384
Big Bend 3 [3]	67.6	5.74	26.66	10,278
Big Bend 4 [4]	78.2	5.74	16.09	10,272
Polk 1 [5]	85.6	4.37	10.03	10,569

1/ Original Sheet 8.401.04E, Page 12

2/ Original Sheet 8.401.04E, Page 13

3/ Original Sheet 8.401.04E, Page 14

4/ Original Sheet 8.401.04E, Page 15

5/ Original Sheet 8.401.04E, Page 16