BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2003 THROUGH DECEMBER 2003

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 2003 - December 2003." Document No. 2 is a summary of the GPIF targets for the 2003 period.

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

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

Gannon Station Units 5 and 6, Big Bend Station Units 1, 2, 3, and 4, and Polk Power Station Unit 1. Due to environmental compliance requirements, Gannon Units 5 and 6 are expected to stop operating in February 2003 and September 2003 respectively, however the data for these units are included in the GPIF calculations until the units are shut down for repowering.

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

A. The documents I prepared 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 implementation of the final phases of repowering Gannon units 5 and 6 from coal to natural gas fired generation, 2003 will be a transition year for Tampa Electric. Since the company is repowering Gannon Units 5 and 6 to Bayside Units 1 and 2, its remaining

GPIF units will not represent 80 percent of projected system net generation. Although the first Bayside unit will begin operation in 2003, the repowered unit cannot be immediately included in the GPIF calculations because Tampa Electric will not have the historical operational data required by the GPIF Implementation manual to set GPIF targets. In addition, Tampa Electric has no other base load generating units to substitute for Gannon Units 5 and 6. Therefore, Tampa Electric requests approval of its calculation of the 2003 GPIF 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. 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 2003 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 seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2003 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 24.35% and the Planned Outage Factor is 5.75%. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 69.9% or:

$$100\% - [(24.35\% + 5.75\%)] = 69.9\%$$

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:

$$EAF_{MAX} = 100\% - [0.8\ (24.35\%) + 0.95\ (5.75\%)] = 75.1\%$$

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,

$$EAF_{MIN} = 100\% - [1.4 \ (24.35\%) + 1.1 \ (5.75\%)] = 59.6\%$$

The equivalent availability MAX and MIN for the other six 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 2003 through December 2003 are shown on page 21 of Document No. 1. Also, a Critical Path Method (C.P.M.) for each major planned outage, which affects GPIF, is shown on pages 22 and 23 of Document No. 1. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage February 15 through March 7, 2003. There are 504 planned outage hours scheduled for the 2003 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 5.75% or:

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

The factor for each unit is shown on pages 5 and 14 of Document No. 1. Big Bend Unit 2 has a Planned Outage Factor of 3.84%. Big Bend Unit 3 has a Planned Outage Factor of 3.84%. Big Bend 4 has a Planned Outage Factor of 9.59%. Gannon Unit 5 has a Planned Outage Factor of 0%. Gannon Unit 6 has a Planned Outage Factor of 0%. Polk Unit 1 has a Planned Outage Factor of 12.05%.

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 2002, 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 24.35% for Big Bend Unit 1. The Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 14, 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

$$EUOF = \frac{(1416 + 717)}{8,760} \times 100 = 24.35\%$$

Relative to Big Bend Unit 1, the EUOF of 24.35% 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 24.35%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 5.75%. Therefore, the target equivalent availability for this unit is 69.9%.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 33.16%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 3.84%. Therefore, the target equivalent availability for this unit is 63%.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 28.9%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 3.84%. Therefore, the target equivalent availability for this unit is 67.3%.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 12.68%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 9.59%. Therefore, the target equivalent availability for this unit is 77.7%.

Gannon Unit 5

The projected Equivalent Unplanned Outage Factor for this unit is 28.07%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 71.9%.

Gannon Unit 6

The projected Equivalent Unplanned Outage Factor for this unit is 24.05%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 75.9%.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 13.39%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 12.05%. Therefore, the target equivalent availability for this unit is 74.6%.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 69.3% is shown on Page 5 of Document No. 1 This target compares favorably to the July 2001 - June 2002 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 14 of Document No. 1. During the months of January and April through December, 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 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, along with the PROMOD IV program, formed the basis of the target development. Projections of unit performance were made with the aid of PROMOD IV. 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 do you plan to 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, but the operational history is short of GPIF guidelines. Therefore, targets for Big Bend Units 1 and 2 have been developed in the standard fashion using data without scrubber power. In order to assure compatibility with the targets, scrubber power will be removed prior to calculating Units 1 and 2 heat rates for the subsequent true-up process. This method was approved by the Commission for Big Bend Unit 3 when it began scrubbing operation. The company will utilize the aforementioned method until there is sufficient history to meet target preparation guidelines.

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 31 through 37 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 2003 period.

A. The heat rate target for Big Bend Unit 1 is 10,533 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±622 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10111 Btu/Net kWh with a range of ±537 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,132 Btu/Net kWh, with a range of ±677 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,028 Btu/Net kWh with a range of ±463 Btu/Net kWh. The heat rate target for Gannon Unit 5 is 10,862 Btu/Net kWh with a range of ±728 Btu/Net kWh. The heat rate target for Gannon Unit 6 is 10,775 Btu/Net kWh with a range of ±767 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,382 Btu/Net kWh with a range of ±767 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 13 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 13. The PROMOD IV cost simulation model was used 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 $546,407,900 is shown on page 6, column 2.

The PROMOD IV output was then used 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 $29,158,500, 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 10.36% as shown in the right-hand column on page 6. Pages 7 through 13 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 75.1% equivalent availability, fuel savings would equal $3,021,700 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 13. 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, $29,158,500. 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 2003 through December 2003 is $1,751,599,709. This produces the maximum allowed jurisdictional incentive dollars of $6,960,923 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):

$$
\begin{aligned}
GPIP: = (\ & 0.1036\ EAP_{BB1} + 0.1461\ EAP_{BB2} \\
& + 0.1041\ EAP_{BB3} + 0.0696\ EAP_{BB4} \\
& + 0.0034\ EAP_{GN5} + 0.0441\ EAP_{GN6} \\
& + 0.0306\ EAP_{PK1} + 0.0895\ HRP_{BB1} \\
& + 0.0740\ HRP_{BB2} + 0.1001\ HRP_{BB3} \\
& + 0.0850\ HRP_{BB4} + 0.0050\ HRP_{GN5} \\
& + 0.0660\ HRP_{GN6} + 0.0781\ HRP_{PK1}\ )
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

HRP = Average Net Heat Rate Points awarded/deducted for

Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2003 - December 2003 period?

A. Yes. Document No. 2 entitled "Tampa Electric Company, Summary of GPIF Targets, January 2003 - December 2003" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO.________
DOCKET NO. 020001-EI
TAMPA ELECTRIC COMPANY
(WAS-2)
FILED: SEPTEMBER 20, 2002

INDEX

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 020001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2003 - DECEMBER 2003
TARGETS
TABLE OF CONTENTS

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2003 - DECEMBER 2003**

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,158.5	6,960.9
+9	26,242.6	6,264.8
+8	23,326.8	5,568.7
+7	20,410.9	4,872.6
+6	17,495.1	4,176.6
+5	14,579.2	3,480.5
+4	11,663.4	2,784.4
+3	8,747.5	2,088.3
+2	5,831.7	1,392.2
+1	2,915.8	696.1
0	0.0	0.0
-1	(3,520.2)	(696.1)
-2	(7,040.4)	(1,392.2)
-3	(10,560.7)	(2,088.3)
-4	(14,080.9)	(2,784.4)
-5	(17,601.1)	(3,480.5)
-6	(21,121.3)	(4,176.6)
-7	(24,641.5)	(4,872.6)
-8	(28,161.8)	(5,568.7)
-9	(31,682.0)	(6,264.8)
-10	(35,202.2)	(6,960.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2003 - DECEMBER 2003

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,621,303,807
Line 2	Month of January	2003	$	1,593,621,777
Line 3	Month of February	2003	$	1,607,355,782
Line 4	Month of March	2003	$	1,621,224,265
Line 5	Month of April	2003	$	1,635,308,086
Line 6	Month of May	2003	$	1,649,450,269
Line 7	Month of June	2003	$	1,856,730,928
Line 8	Month of July	2003	$	1,828,644,756
Line 9	Month of August	2003	$	1,842,790,236
Line 10	Month of September	2003	$	1,857,074,223
Line 11	Month of October	2003	$	1,871,154,780
Line 12	Month of November	2003	$	1,885,716,504
Line 13	Month of December	2003	$	1,900,420,811
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,751,599,709
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)		$	7,134,152
Line 18	Jurisdictional Sales			18,037,201 MWH
Line 19	Total Sales			18,486,071 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.57%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**6,960,923**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2003 - DECEMBER 2003

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	10.36%	69.9	75.1	59.6	3,021.7	(1,669.5)
BIG BEND 2	14.61%	63.0	69.9	49.4	4,261.3	(5,768.6)
BIG BEND 3	10.41%	67.3	73.2	55.3	3,034.2	(4,512.7)
BIG BEND 4	6.96%	77.7	80.7	71.7	2,030.2	(3,893.4)
GANNON 5	0.34%	71.9	77.5	60.7	100.5	(274.6)
GANNON 6	4.41%	75.9	80.8	66.3	1,287.1	(2,883.1)
POLK 1	3.06%	74.6	77.8	68.0	892.7	(1,669.5)
GPIF SYSTEM	**50.17%**					

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	8.95%	10533	70.7	9912	11155	2,610.9	(2,610.9)
BIG BEND 2	7.40%	10111	79.7	9574	10649	2,158.4	(2,158.4)
BIG BEND 3	10.01%	10132	75.5	9455	10810	2,917.7	(2,917.7)
BIG BEND 4	8.50%	10028	88.2	9565	10491	2,477.8	(2,477.8)
GANNON 5	0.50%	10862	64.9	10134	11589	145.8	(145.8)
GANNON 6	6.66%	10775	69.5	10007	11542	1,942.0	(1,942.0)
POLK 1	7.81%	10382	96.0	9615	11148	2,278.3	(2,278.3)
GPIF SYSTEM	**49.83%**					**14,530.8**	**(14,530.8)**

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 POF	EUOF	EUOR	TARGET PERIOD JUL 01 - JUN 02 POF	EUOF	EUOR	TARGET PERIOD JUL 00 - JUN 01 POF	EUOF	EUOR	TARGET PERIOD JUL 99 - JUN 00 POF	EUOF	EUOR
BIG BEND 1	10.36%	20.7%	5.8	24.4	25.8	4.5	24.8	26.0	14.3	23.7	27.7	5.7	16.0	17.0
BIG BEND 2	14.61%	29.1%	3.8	33.2	34.5	0.0	28.2	28.2	6.1	18.5	19.7	5.6	10.4	11.0
BIG BEND 3	10.41%	20.7%	3.8	28.9	30.1	16.2	27.7	33.1	0.0	16.7	16.7	11.2	18.0	20.3
BIG BEND 4	6.96%	13.9%	9.6	12.7	14.0	0.0	12.4	12.4	8.5	12.6	13.8	10.9	9.5	10.7
GANNON 5	0.34%	0.7%	0.0	28.1	28.1	14.0	26.9	31.3	12.2	39.1	44.5	6.3	26.5	28.3
GANNON 6	4.41%	8.8%	0.0	24.1	24.1	0.0	23.4	23.4	8.3	23.3	25.4	9.1	30.0	33.0
POLK 1	3.06%	6.1%	12.1	13.4	15.2	0.7	14.3	14.4	4.3	8.7	9.1	4.9	13.3	14.0
GPIF SYSTEM	**50.17%**	**100.0%**	**5.2**	**25.6**	**26.8**	**4.4**	**23.9**	**25.3**	**7.0**	**18.3**	**19.9**	**7.8**	**15.0**	**16.4**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**69.3**			**71.6**			**74.7**			**77.2**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
6.4	19.1	20.5	74.5

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	8.95%	18.0%	10,533	10,806	10,572	10,225
BIG BEND 2	7.40%	14.9%	10,111	10,390	10,062	9,883
BIG BEND 3	10.01%	20 1%	10,132	10,209	10,149	10,039
BIG BEND 4	8.50%	17.1%	10,028	10,277	9,949	9,835
GANNON 5	0.50%	1.0%	10,862	10,770	10,716	11,072
GANNON 6	6.66%	13.4%	10,775	10,971	10,235	10,938
POLK 1	7.81%	15.7%	10,382	10,623	10,268	10,242
GPIF SYSTEM	**49.83%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,316**	**10,527**	**10,214**	**10,177**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2003 - DECEMBER 2003
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	546407.9	543386.2	3022	10.36%
EA_2 BIG BEND 2	546407.9	542146.6	4261	14.61%
EA_3 BIG BEND 3	546407.9	543373.7	3034.2	10.41%
EA_4 BIG BEND 4	546407.9	544377.7	2030	6.96%
EA_5 GANNON 5	546407.9	546307.4	101	0.34%
EA_6 GANNON 6	546407.9	545120.8	1287	4.41%
EA_7 POLK 1	546407.9	545515.2	892.7	3.06%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	546407.9	543797.0	2610.9	8.95%
AHR_2 BIG BEND 2	546407.9	544249.5	2158.4	7.40%
AHR_3 BIG BEND 3	546407.9	543490.2	2917.7	10.01%
AHR_4 BIG BEND 4	546407.9	543930.1	2477.8	8.50%
AHR_5 GANNON 5	546407.9	546262.1	145.8	0.50%
AHR_6 GANNON 6	546407.9	544465.9	1942.0	6.66%
AHR_7 POLK 1	546407.9	544129.6	2278.3	7.81%
TOTAL SAVINGS			**29,158.5**	**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 2003 - DECEMBER 2003

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	3,021.7	75.1	+10	2,610.9	9,912
+9	2,719.5	74.6	+9	2,349.9	9,966
+8	2,417.4	74.1	+8	2,088.8	10,021
+7	2,115.2	73.5	+7	1,827.7	10,076
+6	1,813.0	73.0	+6	1,566.6	10,130
+5	1,510.9	72.5	+5	1,305.5	10,185
+4	1,208.7	72.0	+4	1,044.4	10,240
+3	906.5	71.5	+3	783.3	10,294
+2	604.3	70.9	+2	522.2	10,349
+1	302.2	70.4	+1	261.1	10,404
					10,458
0	0.0	69.9	0	0.0	10,533
					10,608
-1	(167.0)	68.9	-1	(261.1)	10,663
-2	(333.9)	67.8	-2	(522.2)	10,718
-3	(500.9)	66.8	-3	(783.3)	10,772
-4	(667.8)	65.8	-4	(1,044.4)	10,827
-5	(834.8)	64.7	-5	(1,305.5)	10,882
-6	(1,001.7)	63.7	-6	(1,566.6)	10,936
-7	(1,168.7)	62.7	-7	(1,827.7)	10,991
-8	(1,335.6)	61.6	-8	(2,088.8)	11,046
-9	(1,502.6)	60.6	-9	(2,349.9)	11,100
-10	(1,669.5)	59.6	-10	(2,610.9)	11,155
	Weighting Factor =	10.36%		Weighting Factor =	8.95%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

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	4,261.3	69.9	+10	2,158.4	9,574
+9	3,835.2	69.2	+9	1,942.5	9,620
+8	3,409.0	68.5	+8	1,726.7	9,666
+7	2,982.9	67.8	+7	1,510.9	9,713
+6	2,556.8	67.1	+6	1,295.0	9,759
+5	2,130.7	66.5	+5	1,079.2	9,805
+4	1,704.5	65.8	+4	863.4	9,851
+3	1,278.4	65.1	+3	647.5	9,898
+2	852.3	64.4	+2	431.7	9,944
+1	426.1	63.7	+1	215.8	9,990
					10,036
0	0.0	63.0	0	0.0	10,111
					10,186
-1	(576.9)	61.6	-1	(215.8)	10,233
-2	(1,153.7)	60.3	-2	(431.7)	10,279
-3	(1,730.6)	58.9	-3	(647.5)	10,325
-4	(2,307.4)	57.6	-4	(863.4)	10,371
-5	(2,884.3)	56.2	-5	(1,079.2)	10,418
-6	(3,461.2)	54.8	-6	(1,295.0)	10,464
-7	(4,038.0)	53.5	-7	(1,510.9)	10,510
-8	(4,614.9)	52.1	-8	(1,726.7)	10,556
-9	(5,191.7)	50.8	-9	(1,942.5)	10,603
-10	(5,768.6)	49.4	-10	(2,158.4)	10,649
	Weighting Factor =	14.61%		Weighting Factor =	7.40%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

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	3,034.2	73.2	+10	2,917.7	9,455
+9	2,730.8	72.6	+9	2,625.9	9,515
+8	2,427.4	72.0	+8	2,334.1	9,575
+7	2,123.9	71.4	+7	2,042.4	9,635
+6	1,820.5	70.8	+6	1,750.6	9,696
+5	1,517.1	70.2	+5	1,458.8	9,756
+4	1,213.7	69.6	+4	1,167.1	9,816
+3	910.3	69.0	+3	875.3	9,876
+2	606.8	68.5	+2	583.5	9,937
+1	303.4	67.9	+1	291.8	9,997
					10,057
0	0.0	67.3	0	0.0	10,132
					10,207
-1	(451.3)	66.1	-1	(291.8)	10,267
-2	(902.5)	64.9	-2	(583.5)	10,328
-3	(1,353.8)	63.7	-3	(875.3)	10,388
-4	(1,805.1)	62.5	-4	(1,167.1)	10,448
-5	(2,256.3)	61.3	-5	(1,458.8)	10,508
-6	(2,707.6)	60.1	-6	(1,750.6)	10,569
-7	(3,158.9)	58.9	-7	(2,042.4)	10,629
-8	(3,610.2)	57.7	-8	(2,334.1)	10,689
-9	(4,061.4)	56.5	-9	(2,625.9)	10,749
-10	(4,512.7)	55.3	-10	(2,917.7)	10,810
	Weighting Factor =	10.41%		Weighting Factor =	10.01%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

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	2,030.2	80.7	+10	2,477.8	9,565
+9	1,827.2	80.4	+9	2,230.0	9,604
+8	1,624.2	80.1	+8	1,982.2	9,643
+7	1,421.1	79.8	+7	1,734.4	9,682
+6	1,218.1	79.5	+6	1,486.7	9,721
+5	1,015.1	79.2	+5	1,238.9	9,759
+4	812.1	78.9	+4	991.1	9,798
+3	609.1	78.6	+3	743.3	9,837
+2	406.0	78.3	+2	495.6	9,876
+1	203.0	78.0	+1	247.8	9,915
					9,953
0	0.0	77.7	0	0.0	10,028
					10,103
-1	(389.3)	77.1	-1	(247.8)	10,142
-2	(778.7)	76.5	-2	(495.6)	10,181
-3	(1,168.0)	75.9	-3	(743.3)	10,220
-4	(1,557.4)	75.3	-4	(991.1)	10,259
-5	(1,946.7)	74.7	-5	(1,238.9)	10,297
-6	(2,336.0)	74.1	-6	(1,486.7)	10,336
-7	(2,725.4)	73.5	-7	(1,734.4)	10,375
-8	(3,114.7)	72.9	-8	(1,982.2)	10,414
-9	(3,504.1)	72.3	-9	(2,230.0)	10,453
-10	(3,893.4)	71.7	-10	(2,477.8)	10,491
	Weighting Factor =	6.96%		Weighting Factor =	8.50%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

GANNON 5

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	100.5	77.5	+10	145.8	10,134
+9	90.5	76.9	+9	131.2	10,199
+8	80.4	76.4	+8	116.6	10,265
+7	70.4	75.8	+7	102.1	10,330
+6	60.3	75.3	+6	87.5	10,395
+5	50.3	74.7	+5	72.9	10,460
+4	40.2	74.2	+4	58.3	10,526
+3	30.2	73.6	+3	43.7	10,591
+2	20.1	73.0	+2	29.2	10,656
+1	10.1	72.5	+1	14.6	10,722
					10,787
0	0.0	71.9	0	0.0	10,862
					10,937
-1	(27.5)	70.8	-1	(14.6)	11,002
-2	(54.9)	69.7	-2	(29.2)	11,067
-3	(82.4)	68.6	-3	(43.7)	11,133
-4	(109.8)	67.4	-4	(58.3)	11,198
-5	(137.3)	66.3	-5	(72.9)	11,263
-6	(164.8)	65.2	-6	(87.5)	11,328
-7	(192.2)	64.1	-7	(102.1)	11,394
-8	(219.7)	63.0	-8	(116.6)	11,459
-9	(247.1)	61.8	-9	(131.2)	11,524
-10	(274.6)	60.7	-10	(145.8)	11,589
	Weighting Factor =	0.34%		Weighting Factor =	0.50%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

GANNON 6

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	1,287.1	80.8	+10	1,942.0	10,007
+9	1,158.4	80.3	+9	1,747.8	10,077
+8	1,029.7	79.8	+8	1,553.6	10,146
+7	901.0	79.3	+7	1,359.4	10,215
+6	772.3	78.9	+6	1,165.2	10,284
+5	643.5	78.4	+5	971.0	10,354
+4	514.8	77.9	+4	776.8	10,423
+3	386.1	77.4	+3	582.6	10,492
+2	257.4	76.9	+2	388.4	10,561
+1	128.7	76.4	+1	194.2	10,630
					10,700
0	0.0	75.9	0	0.0	10,775
					10,850
-1	(288.3)	75.0	-1	(194.2)	10,919
-2	(576.6)	74.0	-2	(388.4)	10,988
-3	(864.9)	73.1	-3	(582.6)	11,057
-4	(1,153.2)	72.1	-4	(776.8)	11,126
-5	(1,441.5)	71.1	-5	(971.0)	11,196
-6	(1,729.9)	70.2	-6	(1,165.2)	11,265
-7	(2,018.2)	69.2	-7	(1,359.4)	11,334
-8	(2,306.5)	68.3	-8	(1,553.6)	11,403
-9	(2,594.8)	67.3	-9	(1,747.8)	11,472
-10	(2,883.1)	66.3	-10	(1,942.0)	11,542
	Weighting Factor =	4.41%		Weighting Factor =	6.66%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2003 - DECEMBER 2003

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	892.7	77.8	+10	2,278.3	9,615
+9	803.4	77.5	+9	2,050.4	9,684
+8	714.2	77.2	+8	1,822.6	9,753
+7	624.9	76.8	+7	1,594.8	9,822
+6	535.6	76.5	+6	1,367.0	9,891
+5	446.4	76.2	+5	1,139.1	9,961
+4	357.1	75.9	+4	911.3	10,030
+3	267.8	75.5	+3	683.5	10,099
+2	178.5	75.2	+2	455.7	10,168
+1	89.3	74.9	+1	227.8	10,237
					10,307
0	0.0	74.6	0	0.0	10,382
					10,457
-1	(167.0)	73.9	-1	(227.8)	10,526
-2	(333.9)	73.2	-2	(455.7)	10,595
-3	(500.9)	72.6	-3	(683.5)	10,664
-4	(667.8)	71.9	-4	(911.3)	10,733
-5	(834.8)	71.3	-5	(1,139.1)	10,802
-6	(1,001.7)	70.6	-6	(1,367.0)	10,872
-7	(1,168.7)	70.0	-7	(1,594.8)	10,941
-8	(1,335.6)	69.3	-8	(1,822.6)	11,010
-9	(1,502.6)	68.6	-9	(2,050.4)	11,079
-10	(1,669.5)	68.0	-10	(2,278.3)	11,148
	Weighting Factor =	3.06%		Weighting Factor =	7.81%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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 GPIF (w/o FGD)	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	74.2	37.1	57.4	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	69.9
2. POF	0.0	50.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.75
3. EUOF	25.8	12.9	20 0	25.8	25.8	25.8	25.8	25.8	25.8	25 8	25.8	25.8	24.35
4. EUOR	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	638	288	494	617	638	617	638	638	617	638	617	638	7078
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	106	384	250	103	106	103	106	106	103	106	103	106	1682
9. POH	0	336	168	0	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	128	58	99	124	128	124	128	128	124	128	124	128	1416
11. MOH & EMOH	65	29	50	63	65	63	65	65	63	65	63	65	717
12. OPER BTU (GBTU)	1886	912	1639	1901	1956	1926	2023	2029	1983	2127	1940	2025	22354
13. NET GEN (MWH)	176,693	86,348	156,473	179,939	185,049	182,762	192,406	193,065	189,080	204,142	184,323	191,901	2,122,181
14. ANOHR (Btu/kwh)	10,672	10,557	10,472	10,563	10,571	10,540	10,512	10,507	10,487	10,418	10,527	10,552	10,533
15. NOF (%)	64.3	69.6	73.5	69.3	68.9	70.4	71.6	71.9	72.8	76.0	71.0	69.8	70.7
16. NPC (MW)	431	431	431	421	421	421	421	421	421	421	421	431	424
17. ANOHR EQUATION	ANOHR = NOF(	-21.583	) +		12058								

37

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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 GPIF (w/o FGD)	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	61.2	40.2	63.0
2. POF	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0 0	0 0	6.7	38.7	3.84
3. EUOF	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	32.2	21.1	33.16
4. EUOR	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	622	562	622	602	622	602	622	622	602	622	562	381	7043
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	122	110	122	118	122	118	122	122	118	122	158	363	1717
9. POH	0	0	0	0	0	0	0	0	0	0	48	288	336
10. FOH & EFOH	171	154	171	165	171	165	171	171	165	171	154	105	1932
11. MOH & EMOH	86	78	86	83	86	83	86	86	83	86	78	53	972
12. OPER BTU (GBTU)	2039	1907	2186	2036	2053	2057	2153	2154	2099	2163	1926	1306	24083
13. NET GEN (MWH)	200,361	188,168	216,519	201,316	202,447	203,582	213,426	213,480	208,281	214,566	190,740	128,926	2,381,812
14. ANOHR (Btu/kwh)	10,175	10,137	10,098	10,115	10,142	10,103	10,088	10,088	10,080	10,083	10,100	10,127	10,111
15. NOF (%)	74.7	77.7	80.8	79.4	77.3	80.3	81.5	81.5	82.2	81.9	80 6	78.5	79.7
16. NPC (MW)	431	431	431	421	421	421	421	421	421	421	421	431	424

17. ANOHR EQUATION ANOHR = NOF(-12.783) + 11130

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

ORIGINAL SHEET NO. 8.401.03E
PAGE 15 OF 40

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	69.9	69.9	38.4	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	67.3
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.84
3. EUOF	30.1	30.1	16.5	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	28.90
4. EUOR	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	597	539	327	578	597	578	597	597	578	597	578	597	6760
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	147	133	417	142	147	142	147	147	142	147	142	147	2000
9. POH	0	0	336	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	136	123	74	131	136	131	136	136	131	136	131	136	1536
11. MOH & EMOH	88	79	48	85	88	85	88	88	85	88	85	88	996
12. OPER BTU (GBTU)	1969	1805	1019	1918	1969	1913	1993	2001	1951	1911	1931	2017	22400
13. NET GEN (MWH)	193,848	178,983	98,013	189,482	193,899	188,652	197,340	198,493	194,204	185,755	191,281	200,870	2,210,820
14 ANOHR (Btu/kwh)	10,155	10,083	10,398	10,125	10,154	10,139	10,098	10,079	10,045	10,287	10,094	10,040	10,132
15. NOF (%)	75.0	76.7	69.2	75.7	75.0	75.4	76.3	76.8	77.6	71.9	76.4	77.7	75.5
16. NPC (MW)	433	433	433	433	433	433	433	433	433	433	433	433	433
17. ANOHR EQUATION	ANOHR = NOF(		-42.211	) +	13320								

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	86 0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	47.1	25.8	86.0	77.7
2 POF	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.2	70.0	0.0	9.59
3. EUOF	14.0	14 0	14.0	14.0	14 0	14.0	14.0	14.0	14.0	7.7	4.2	14.0	12 68
4 EUOR	14.0	14.0	14 0	14 0	14 0	14 0	14 0	14 0	14.0	14.0	14.0	14.0	14.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	658	595	658	637	658	637	658	658	637	361	191	658	7006
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	86	77	86	83	86	83	86	86	83	383	529	86	1754
9. POH	0	0	0	0	0	0	0	0	0	336	504	0	840
10. FOH & EFOH	72	65	72	70	72	70	72	72	70	39	21	72	766
11. MOH & EMOH	32	29	32	31	32	31	32	32	31	18	9	32	345
12. OPER BTU (GBTU)	2554.951	2352.685	2610 856	2514 136	2555.776	2445.295	2563.987	2569.815	2519.294	1431.958	749.068	2626.980	27493.324
13. NET GEN (MWH)	252,964	234,609	260,720	251,672	254,191	242,090	255,333	256,146	252,402	143,641	74,789	262,992	2,741,549
14. ANOHR (Btu/kwh)	10,100	10,028	10,014	9,990	10,055	10,101	10,042	10,033	9,981	9,969	10,016	9,989	10,028
15. NOF (%)	86 0	88.2	88.6	89.4	87.4	86.0	87.8	88.1	89.6	90.0	88.6	89.4	88.2
16. NPC (MW)	447	447	447	442	442	442	442	442	442	442	442	447	444

17. ANOHR EQUATION ANOHR = NOF(-32.62558703) + 12906.02976

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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
GANNON 5	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1 EAF (%)	71.9	71.9											71.9
2. POF	0.0	0 0											0.00
3. EUOF	28.1	28.1											28.07
4 EUOR	28.1	28.1											28.1
5. PH	744	168											912
6. SH	562	125											687
7. RSH	0	0											0
8. UH	182	43											225
9. POH	0	0											0
10. FOH & EFOH	143	32											176
11. MOH & EMOH	65	15											80
12. OPER BTU (GBTU)	844.655	206.435											1051.108
13. NET GEN (MWH)	77,748	19,023											96,771
14. ANOHR (Btu/kwh)	10,864	10,852											10,862
15. NOF (%)	63.7	70.1											64.9
16. NPC (MW)	217	217											217

17. ANOHR EQUATION ANOHR = NOF(-1.899627385) + 10985.08063

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

ORIGINAL SHEET NO. 8.401.03E

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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
GANNON 6	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9					75.9
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					0.00
3. EUOF	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1					24.05
4. EUOR	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1					24.1
5 PH	744	672	744	720	744	720	744	744					5832
6. SH	617	557	617	597	617	597	617	617					4837
7. RSH	0	0	0	0	0	0	0	0					0
8. UH	127	115	127	123	127	123	127	127					995
9. POH	0	0	0	0	0	0	0	0					0
10 FOH & EFOH	103	93	103	100	103	100	103	103					806
11. MOH & EMOH	76	69	76	74	76	74	76	76					596
12. OPER BTU (GBTU)	1569.141	1536.134	1795.428	1661.188	1738.703	1730.081	1840.396	1862.661					13736.851
13 NET GEN (MWH)	144,712	142,157	166,569	154,170	161,464	160,885	171,398	173,581					1,274,936
14. ANOHR (Btu/kwh)	10,843	10,806	10,779	10,775	10,768	10,754	10,738	10,731					10,775
15. NOF (%)	59.8	65.1	68.9	69.4	70.3	72.4	74.7	75.6					69.5
16. NPC (MW)	392	392	392	372	372	372	372	372					379

17. ANOHR EQUATION ANOHR = NOF(-7.118328179) + 11269.01914

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO: 020001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

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-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	2003
1. EAF (%)	84.8	84 8	19.1	28 3	84 8	84.8	84 8	84.8	84.8	84.8	84.8	84.8	74.6
2 POF	0.0	0.0	77.4	66.7	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	12.05
3. EUOF	15.2	15.2	3.4	5.1	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	13.39
4. EUOR	15.2	15 2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15 2	15.2	15.2
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	584	527	132	226	584	565	584	584	565	584	565	584	6084
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	160	145	612	494	160	155	160	160	155	160	155	160	2676
9. POH	0	0	576	480	0	0	0	0	0	0	0	0	1056
10. FOH & EFOH	72	65	16	23	72	69	72	72	69	72	69	72	741
11. MOH & EMOH	42	38	9	13	42	40	42	42	40	42	40	42	432
12. OPER BTU (GBTU)	1512.416	1368.560	348.341	572.583	1387.749	1342.951	1387.749	1387.749	1342.951	1516.220	1467.275	1516.202	15153.516
13. NET GEN (MWH)	146,198	132,326	33,732	55,238	133,138	128,843	133,138	133,138	128,843	146,600	141,871	146,598	1,459,663
14. ANOHR (Btu/kwh)	10,345	10,342	10,327	10,366	10,423	10,423	10,423	10,423	10,423	10,343	10,342	10,343	10,382
15. NOF (%)	100.1	100.4	102.2	97.8	91 2	91.2	91.2	91.2	91.2	100.4	100.4	100.4	96.0
16. NPC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250

17. ANOHR EQUATION ANOHR = NOF(-8.76500931) + 11222.67106

FILED:
SUSPENDED:
EFFECTIVE: 09/20/02
DOCKET NO· 020001-EI

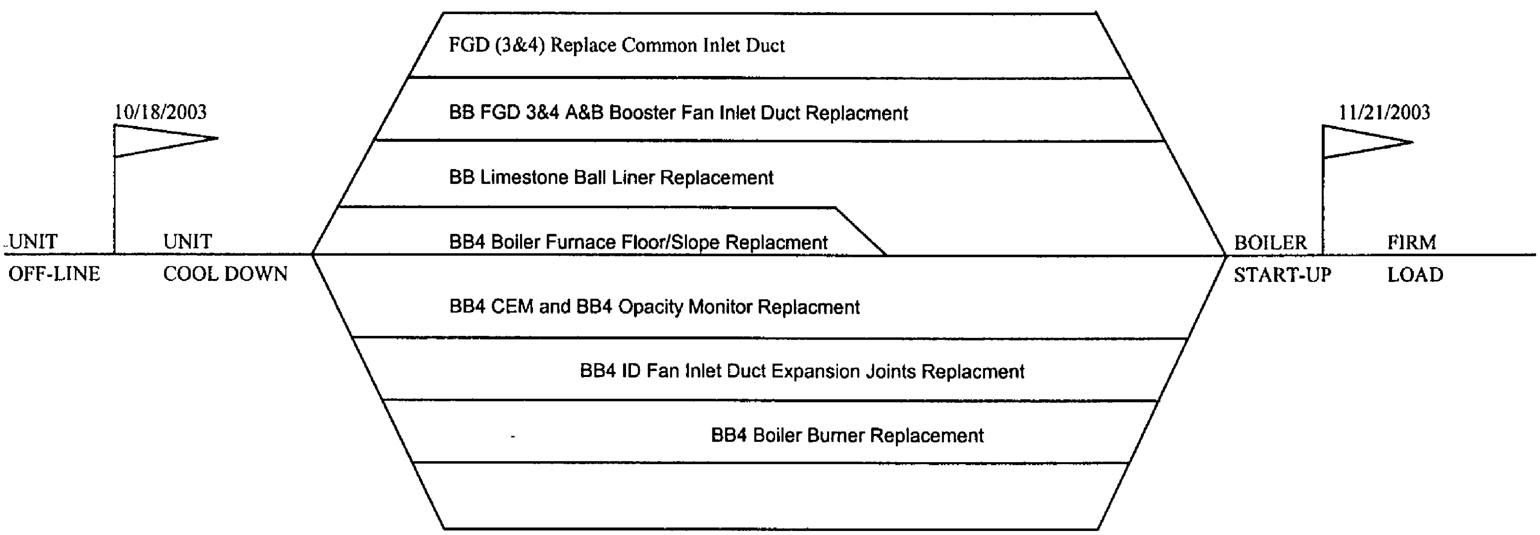
ORIGINAL SHEET NO. 8.401.03E
PAGE 20 OF 40

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2003 - DECEMBER 2003

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Feb 15	-	Mar 07	Fuel System Clean-up
+	BIG BEND 2	Nov 29	-	Dec 12	Fuel System Clean-up
+	BIG BEND 3	Mar 15	-	Mar 28	Fuel System Clean-up
	BIG BEND 4	Oct 18	-	Nov 21	FGD (3&4) Replace Common Inlet Duct, BB Limestone Ball Liner Replacement, BB FGD 3&4 A&B Booster Fan Inlet Duct Replacment, BB4 Boiler Burner Replacement, BB4 ID Fan Inlet Duct Expansion Joints Replacment, BB4 CEM and BB4 Opacity Monitor Replacment, BB4 B
+	GANNON 5	---	-	---	
+	GANNON 6	---	-	---	
	POLK 1	Mar 08	-	Apr 20	#1CT Major Outage: Tops off Rotor out, Gen. Rotor Rewind/Insul., Steam Turbine Major Outage: Tops off Rotors out, Gen. Rotor Rewind, Gasifier Outage Major Inspection, Syngas Saturator Project, Gasifier Hot Face Brick Replacement, RSC Vessel Shell Repairs

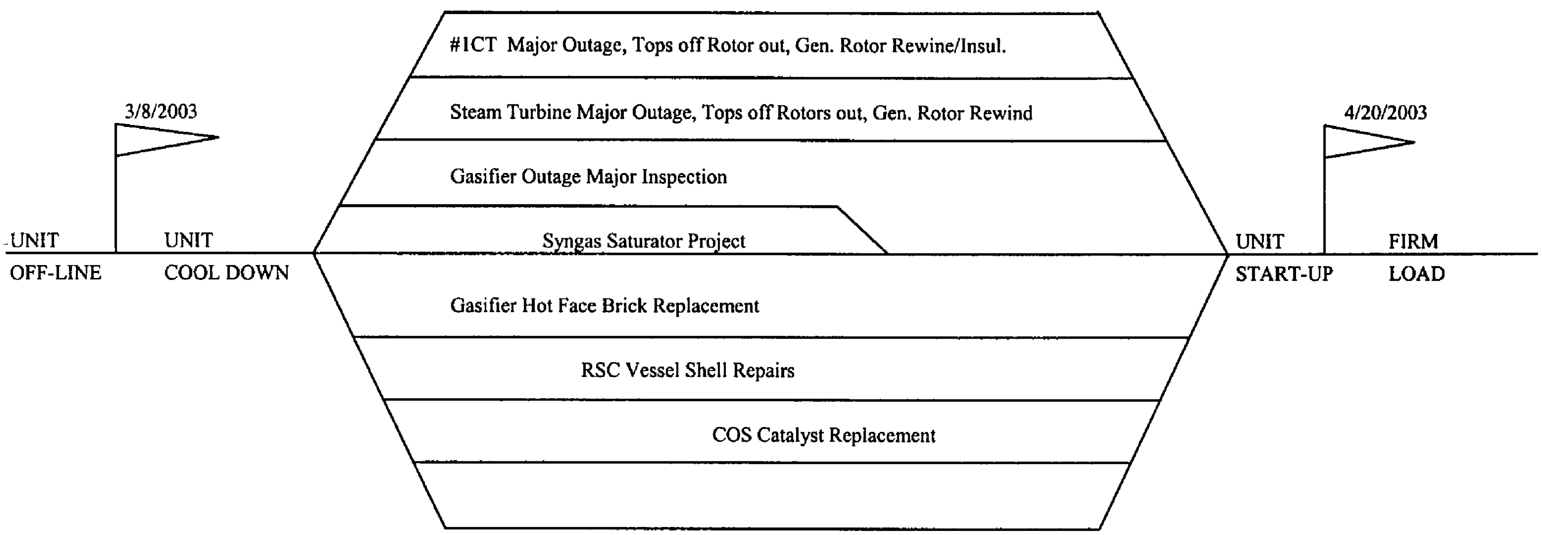
\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2003 - DECEMBER 2003

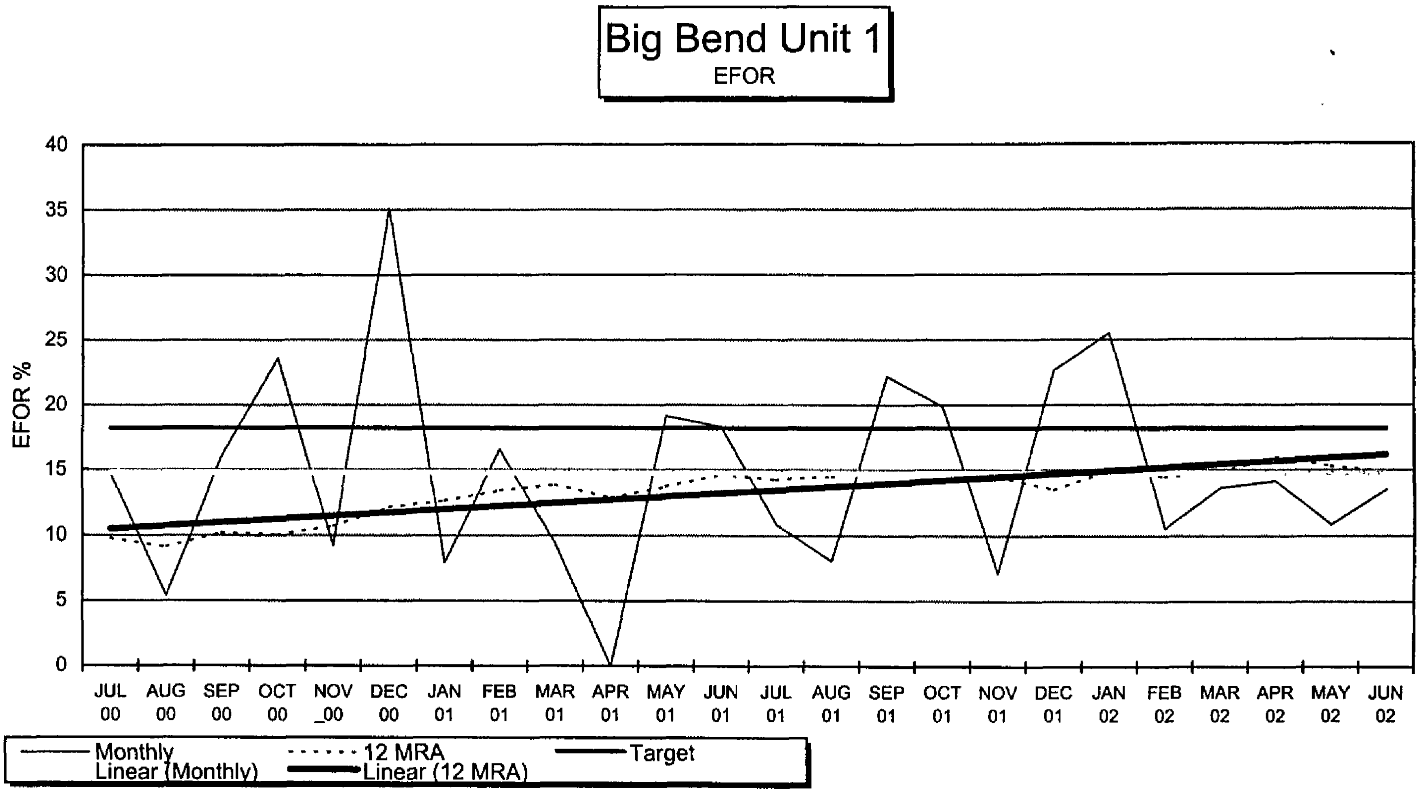


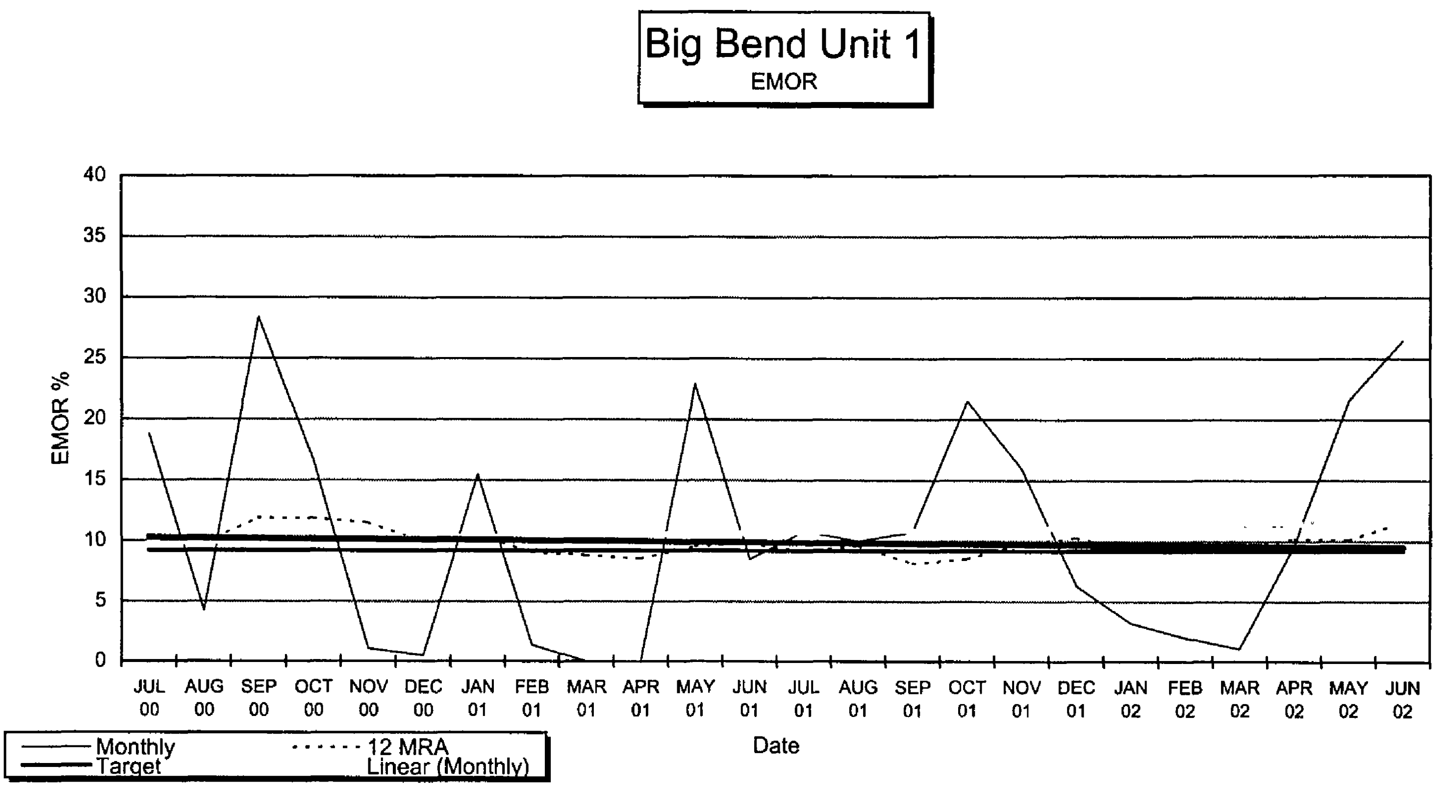
TAMPA ELECTRIC COMPANY
BIG BEND UNT #4
Planned Outage 2003
PROJECTED CPM
08/29/02

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2003 - DECEMBER 2003

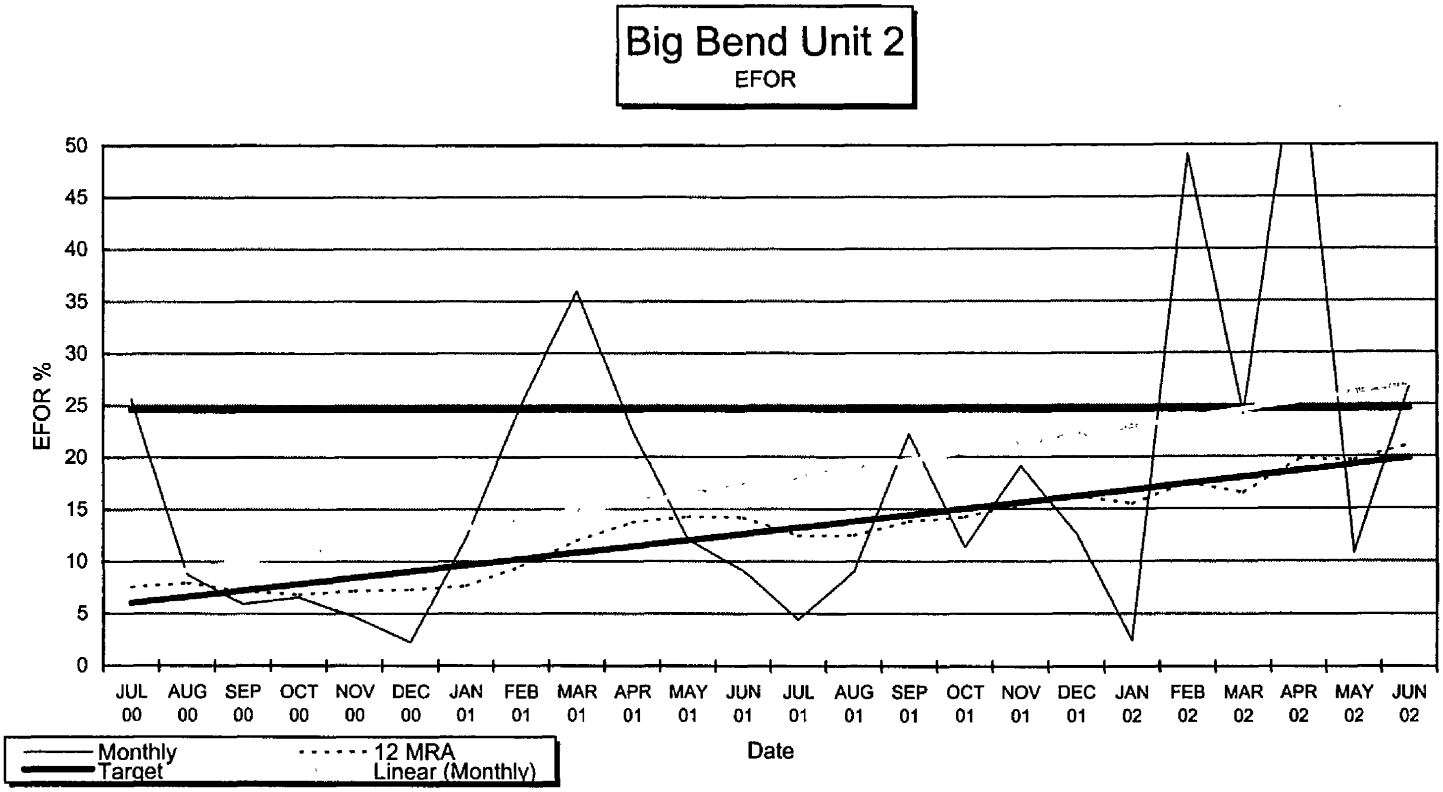


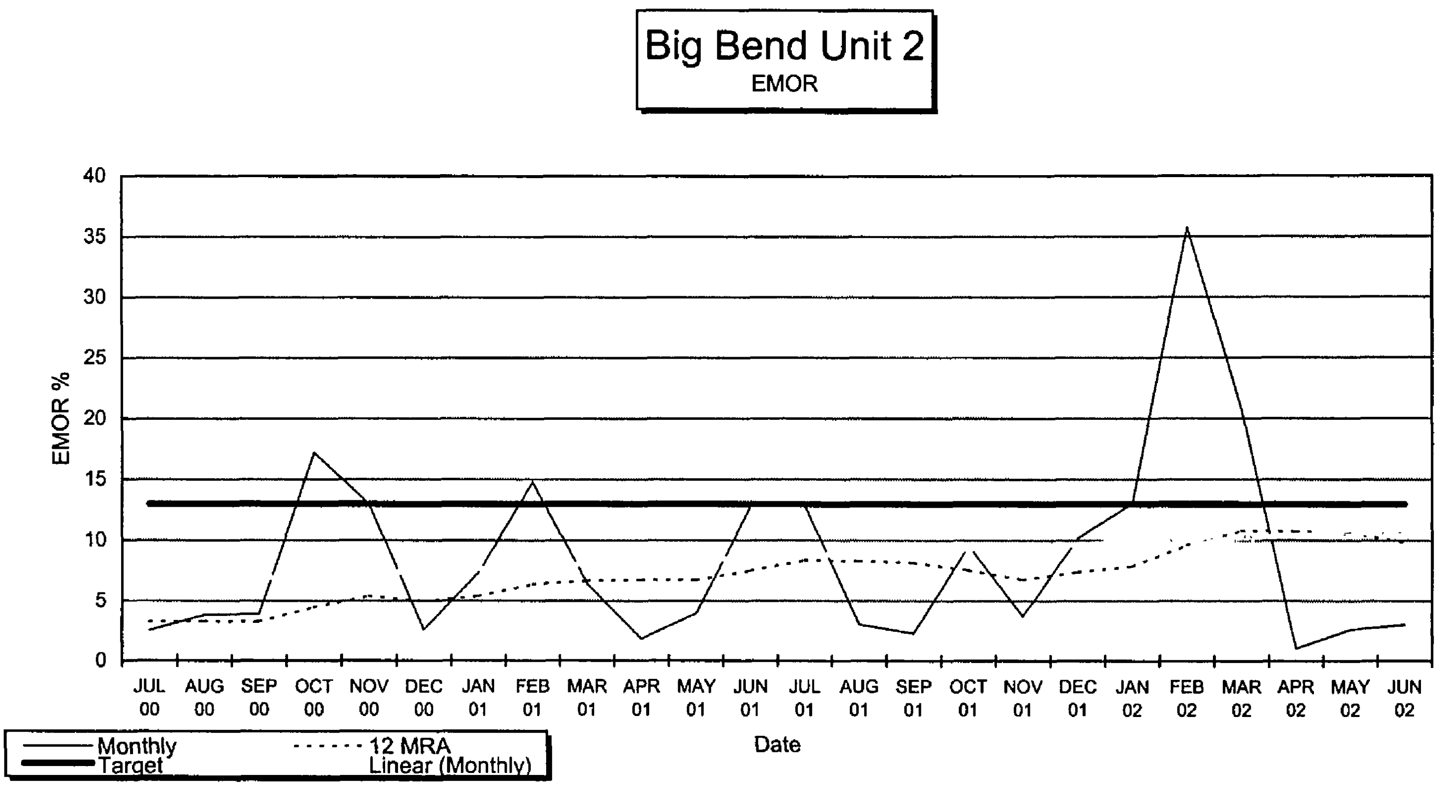
TAMPA ELECTRIC COMPANY
POLK #1
PLANNED OUTAGE 2003
PROJECTED CPM
08/29/02



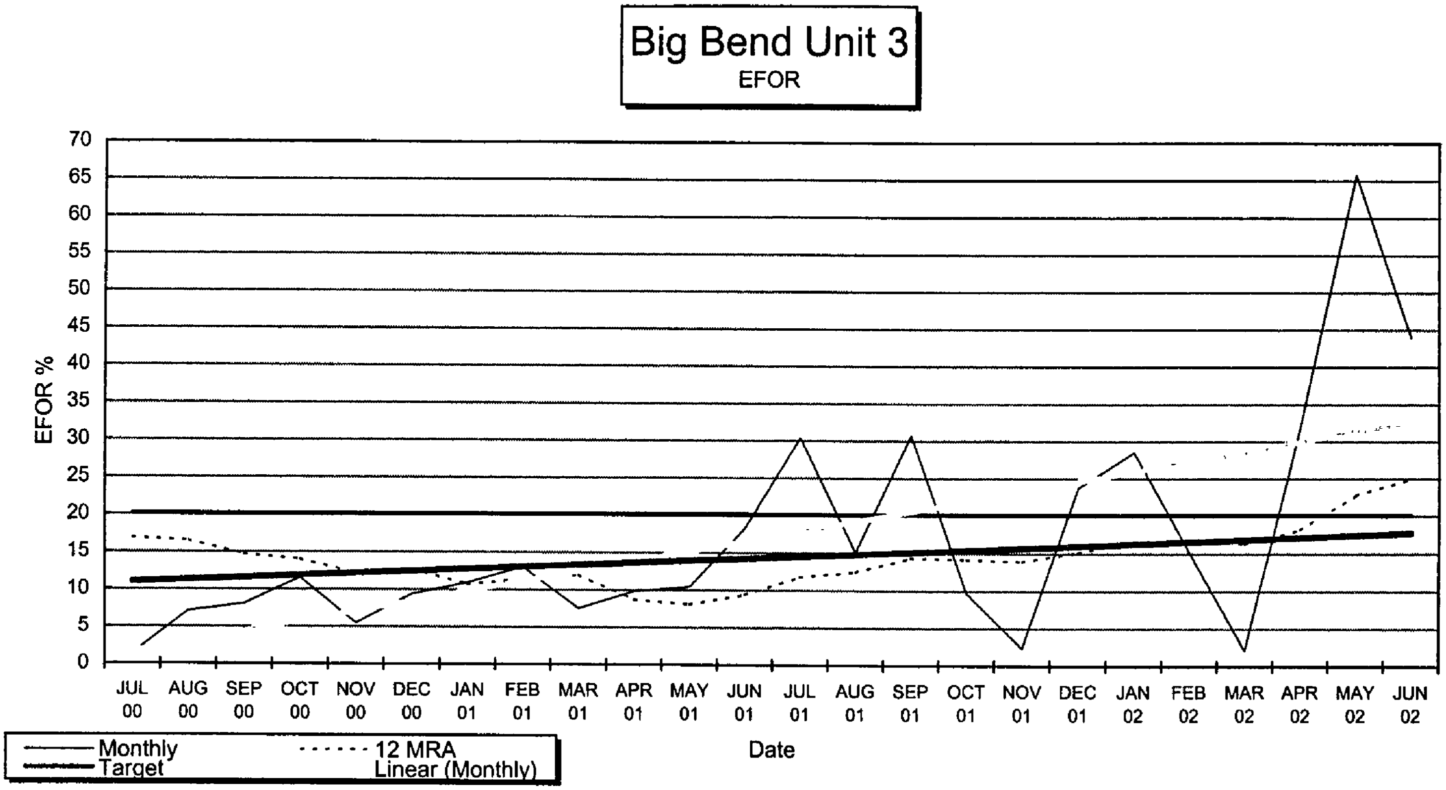


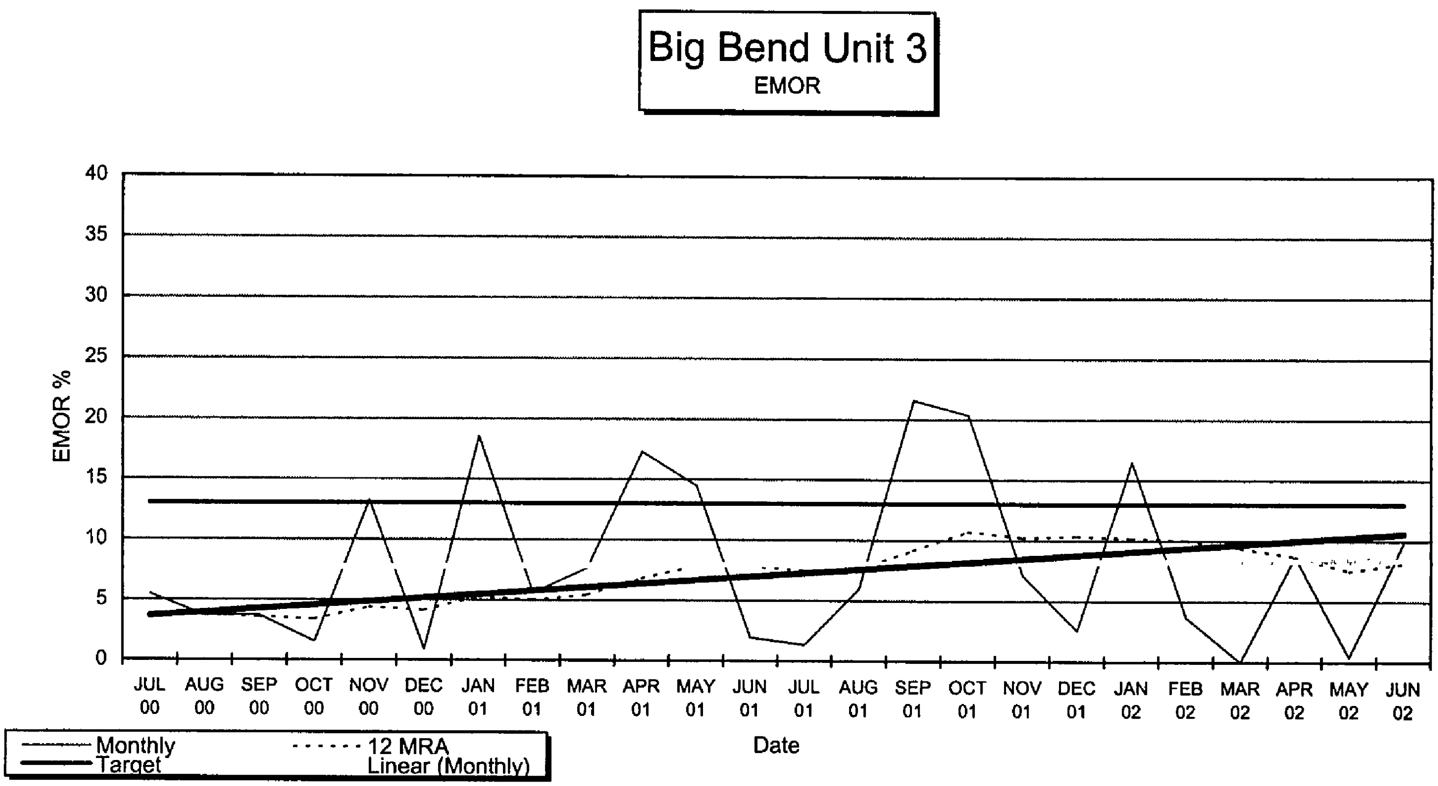
12 MRA = 12 Month Rolling Average



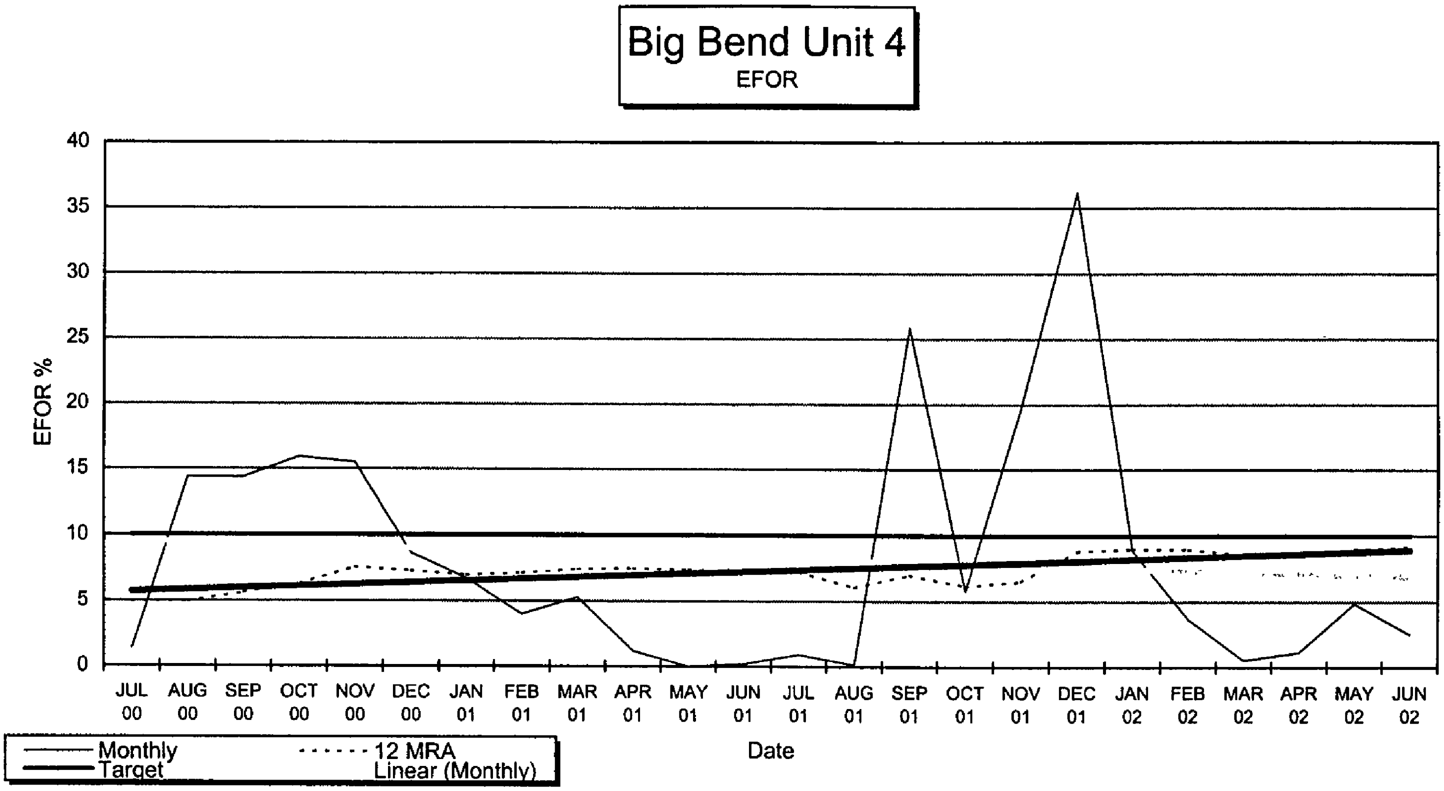


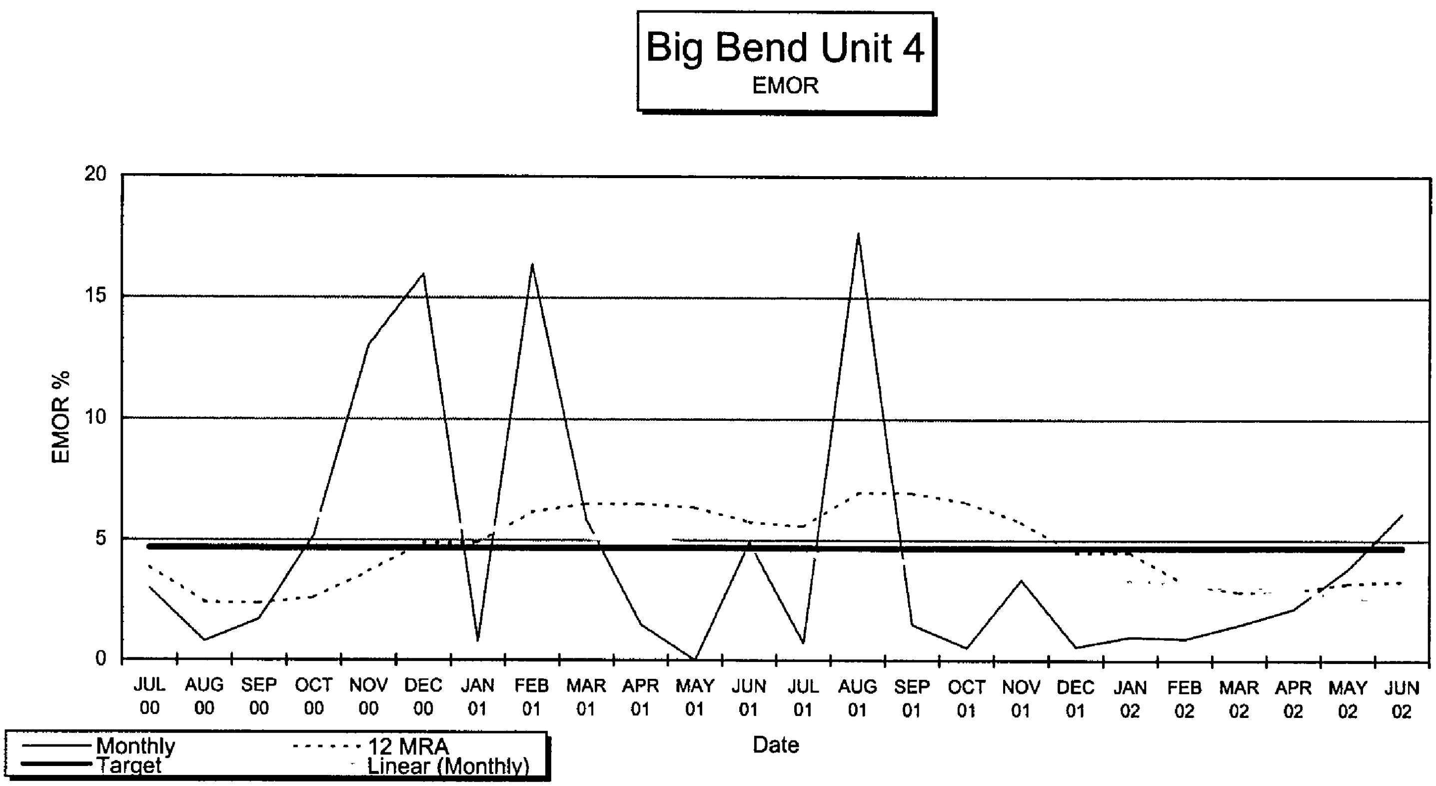
12 MRA = 12 Month Rolling Average



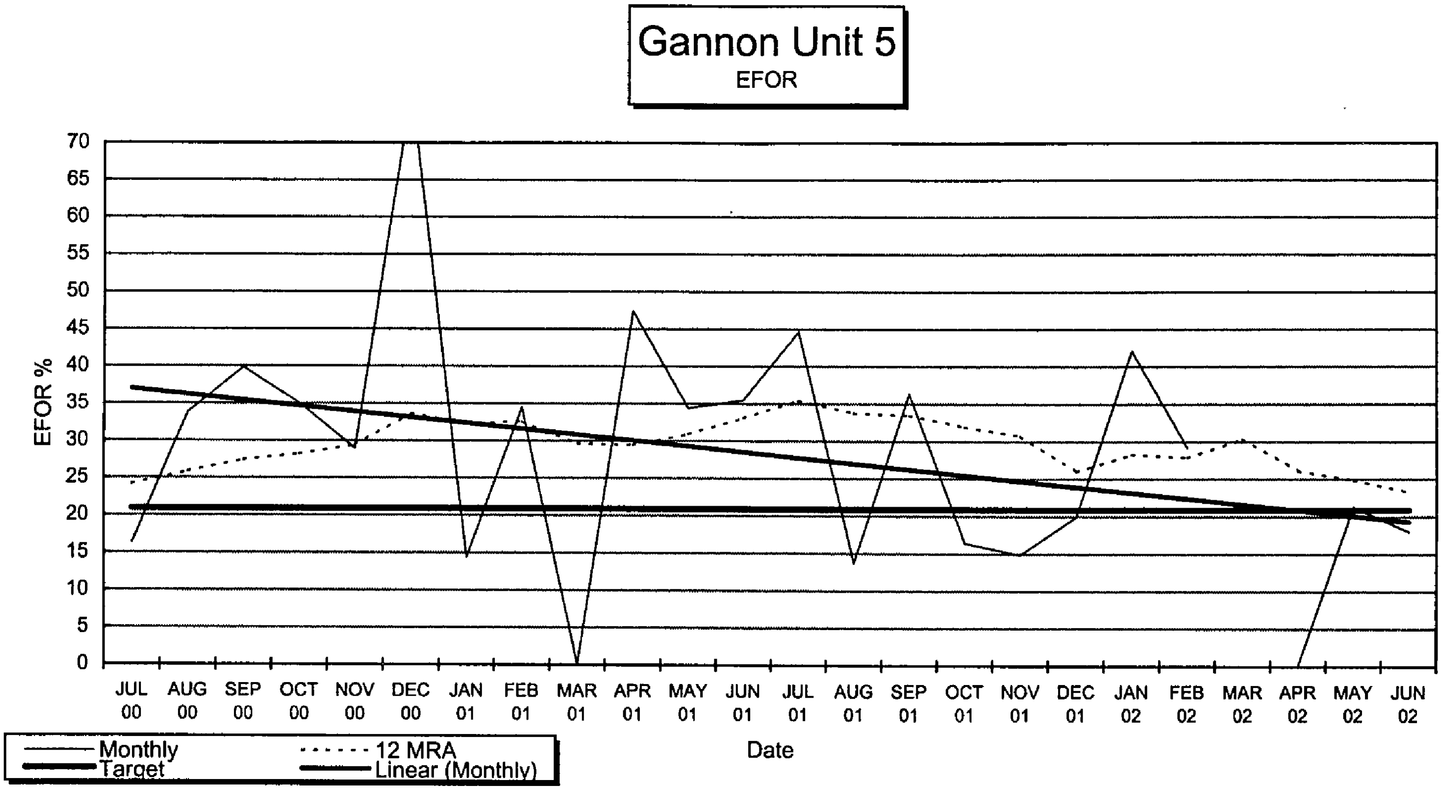


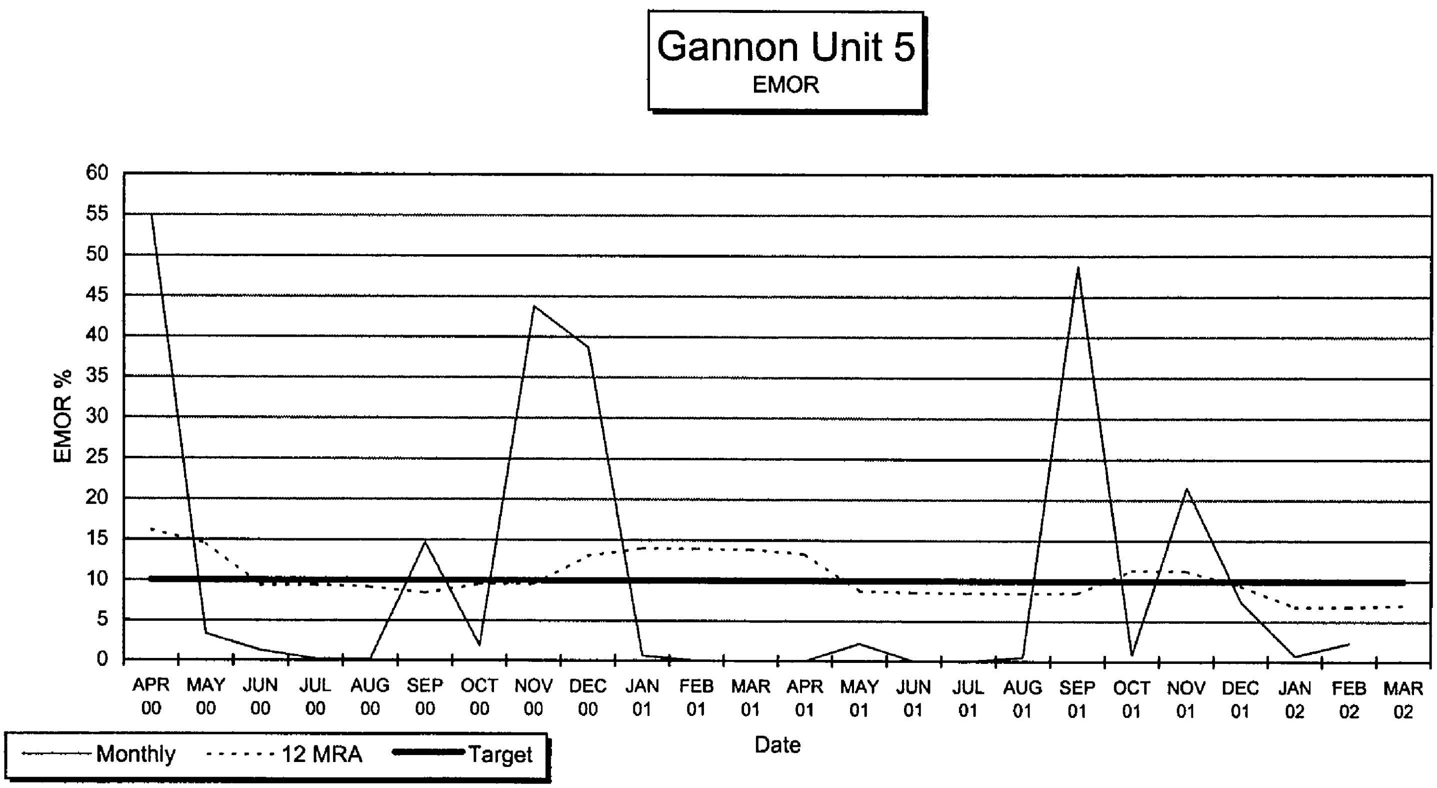
12 MRA = 12 Month Rolling Average



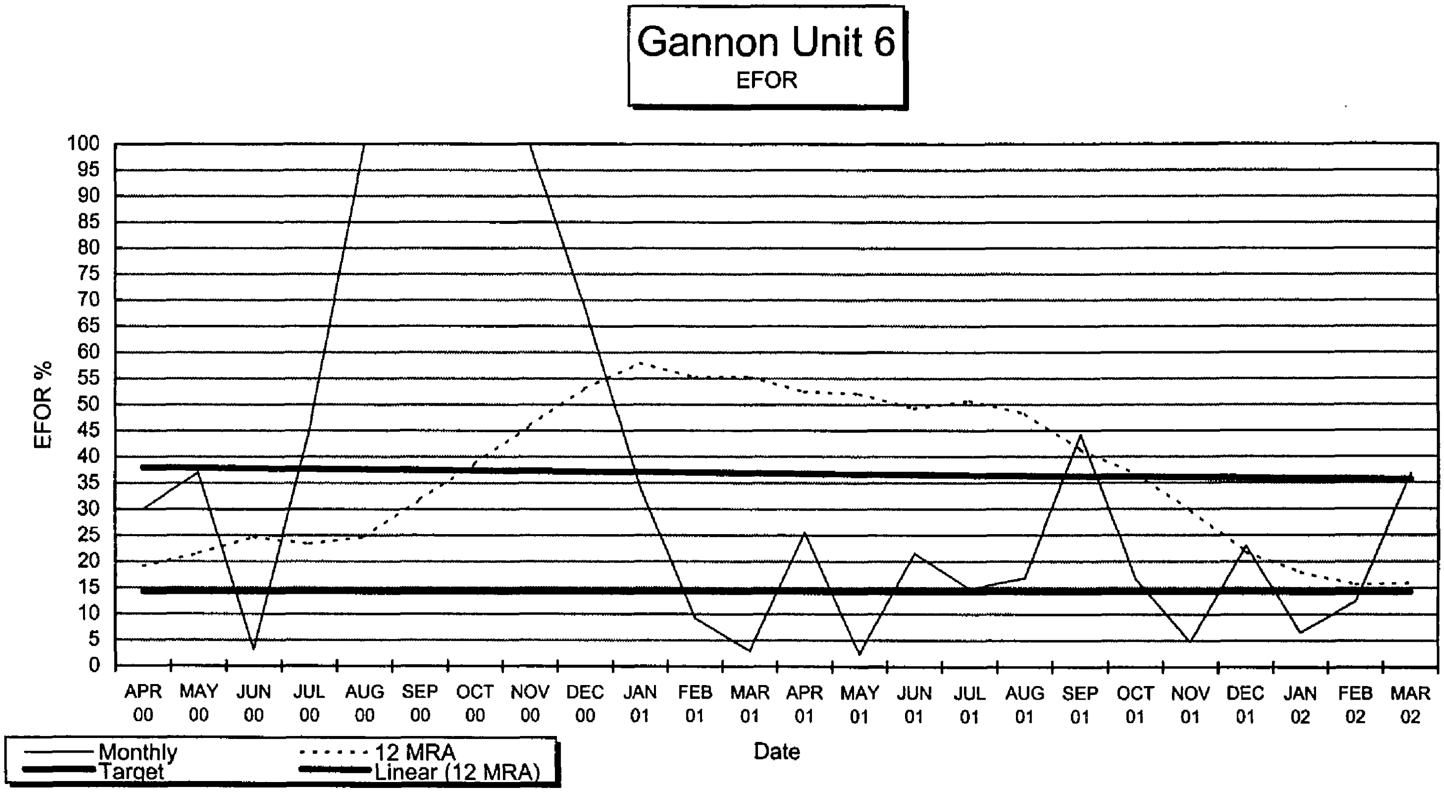


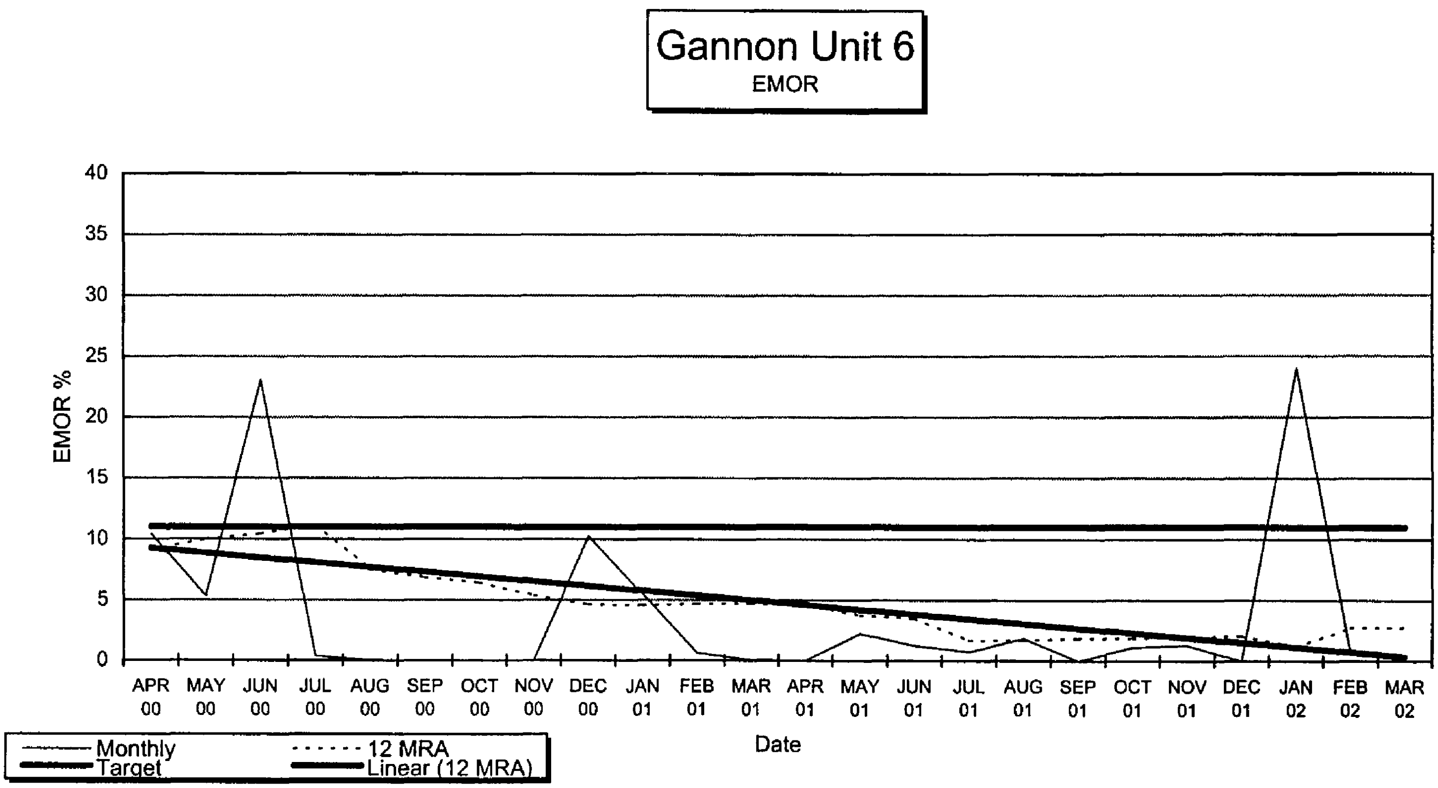
12 MRA = 12 Month Rolling Average



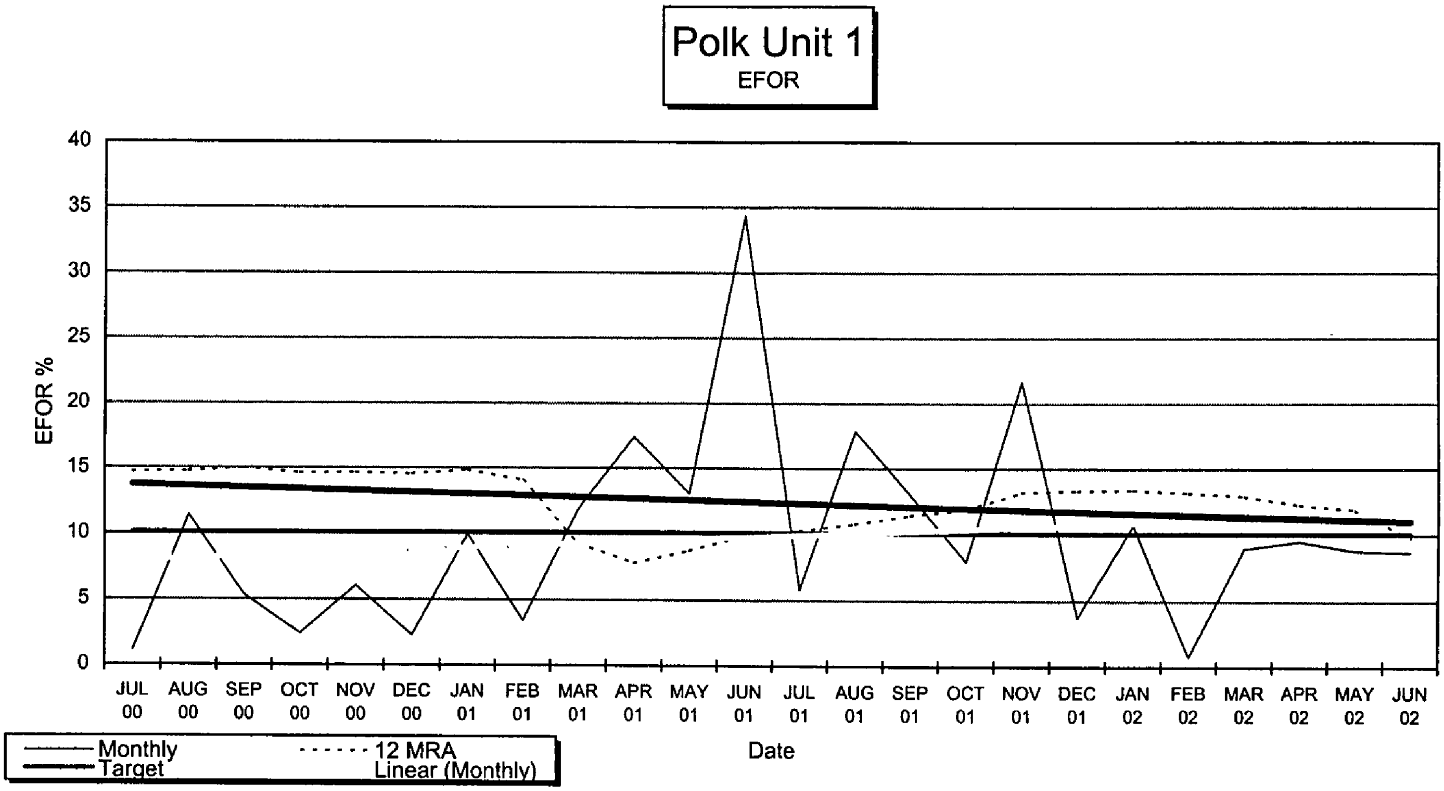


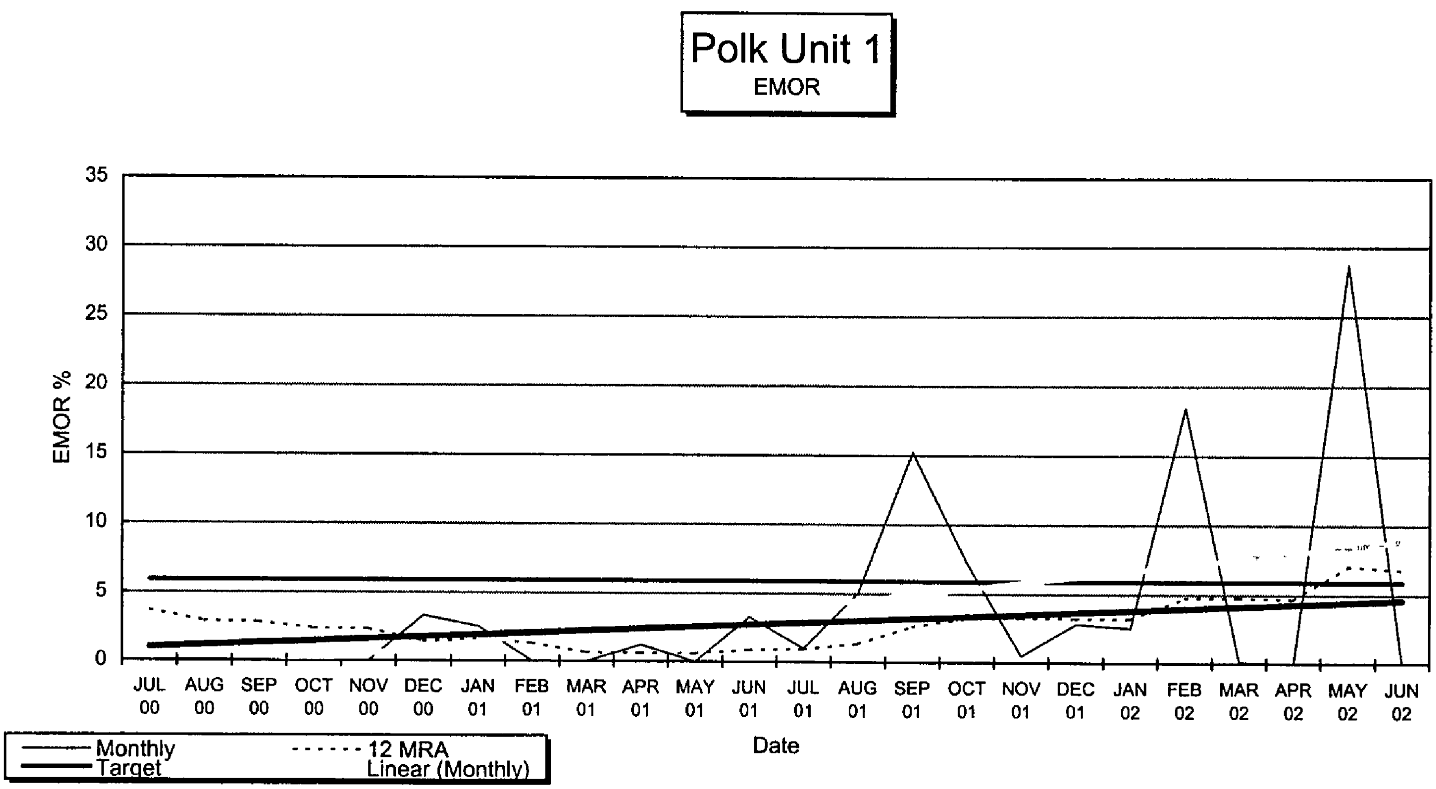
12 MRA = 12 Month Rolling Avreage





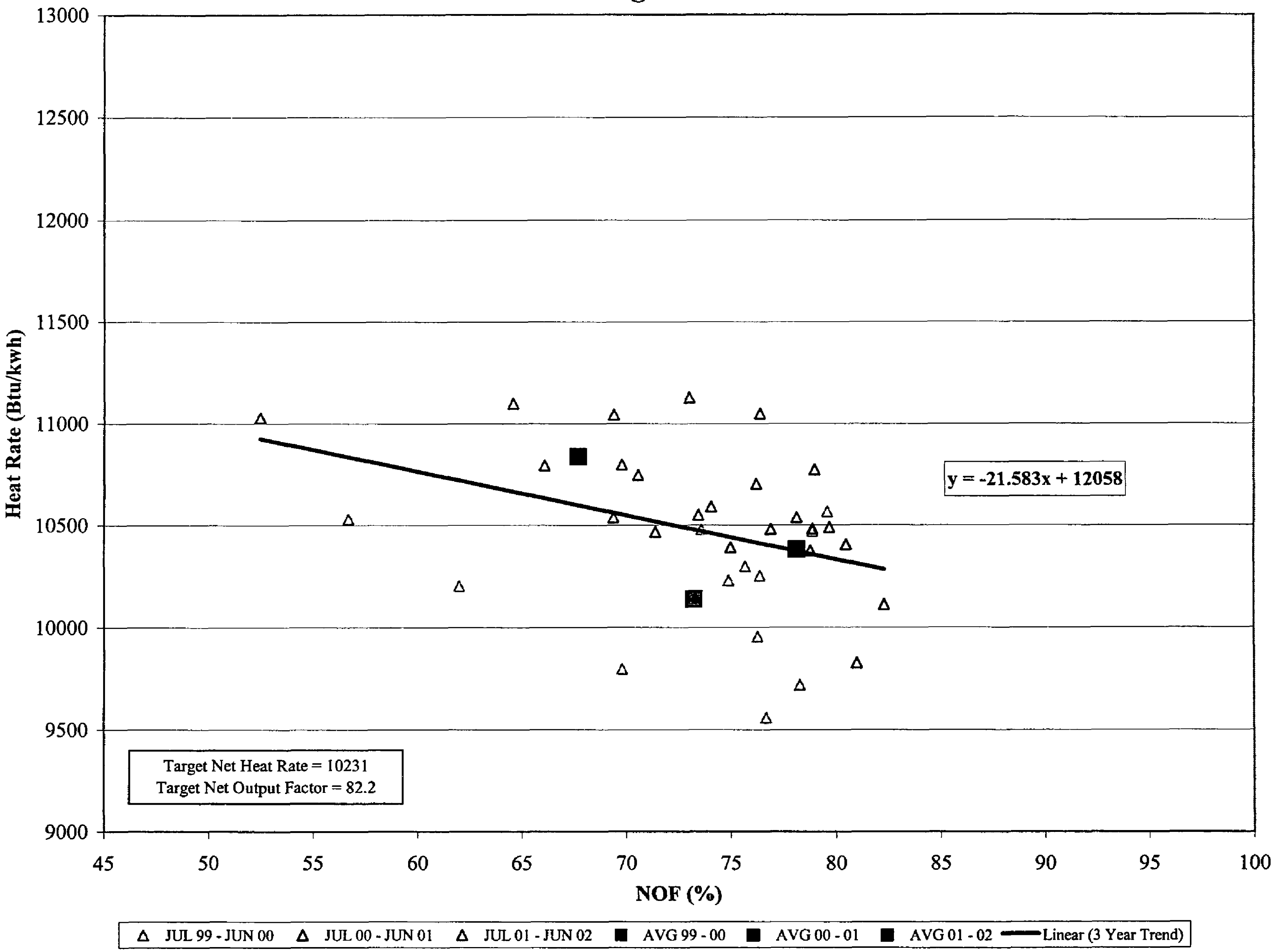
12 MRA = 12 Month Rolling Avreage



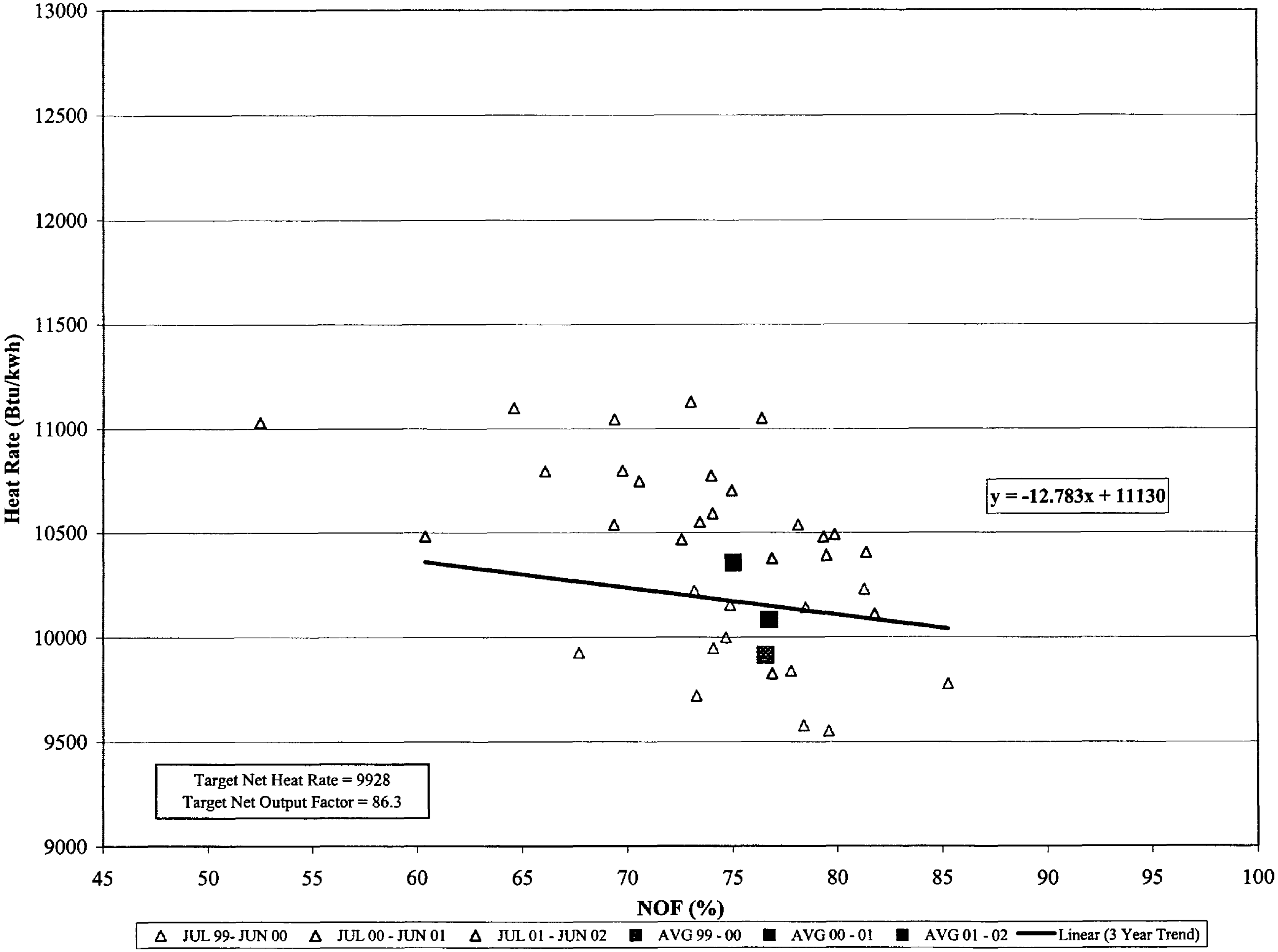


12 MRA = 12 Month Rolling Avreage

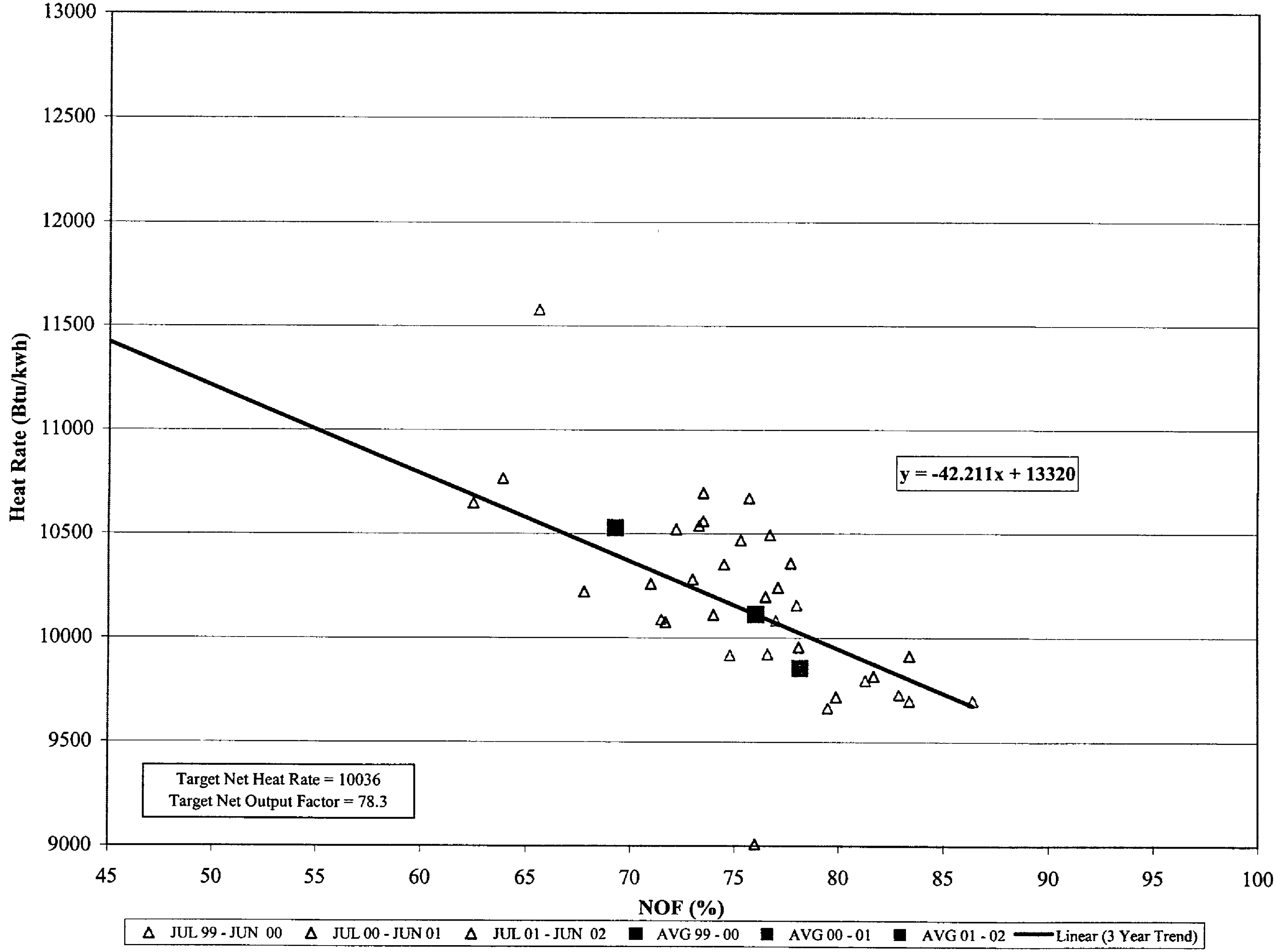
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



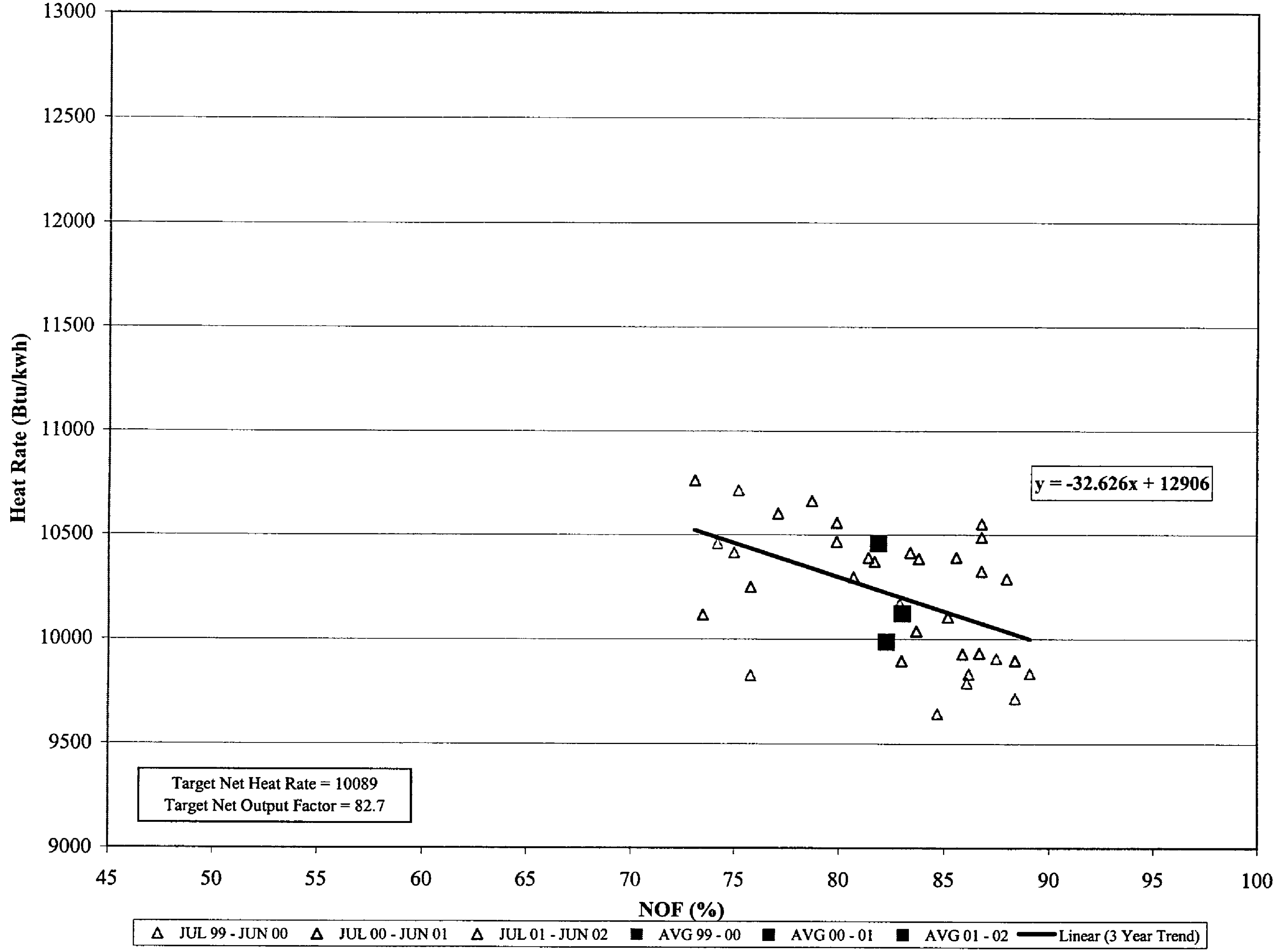
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2



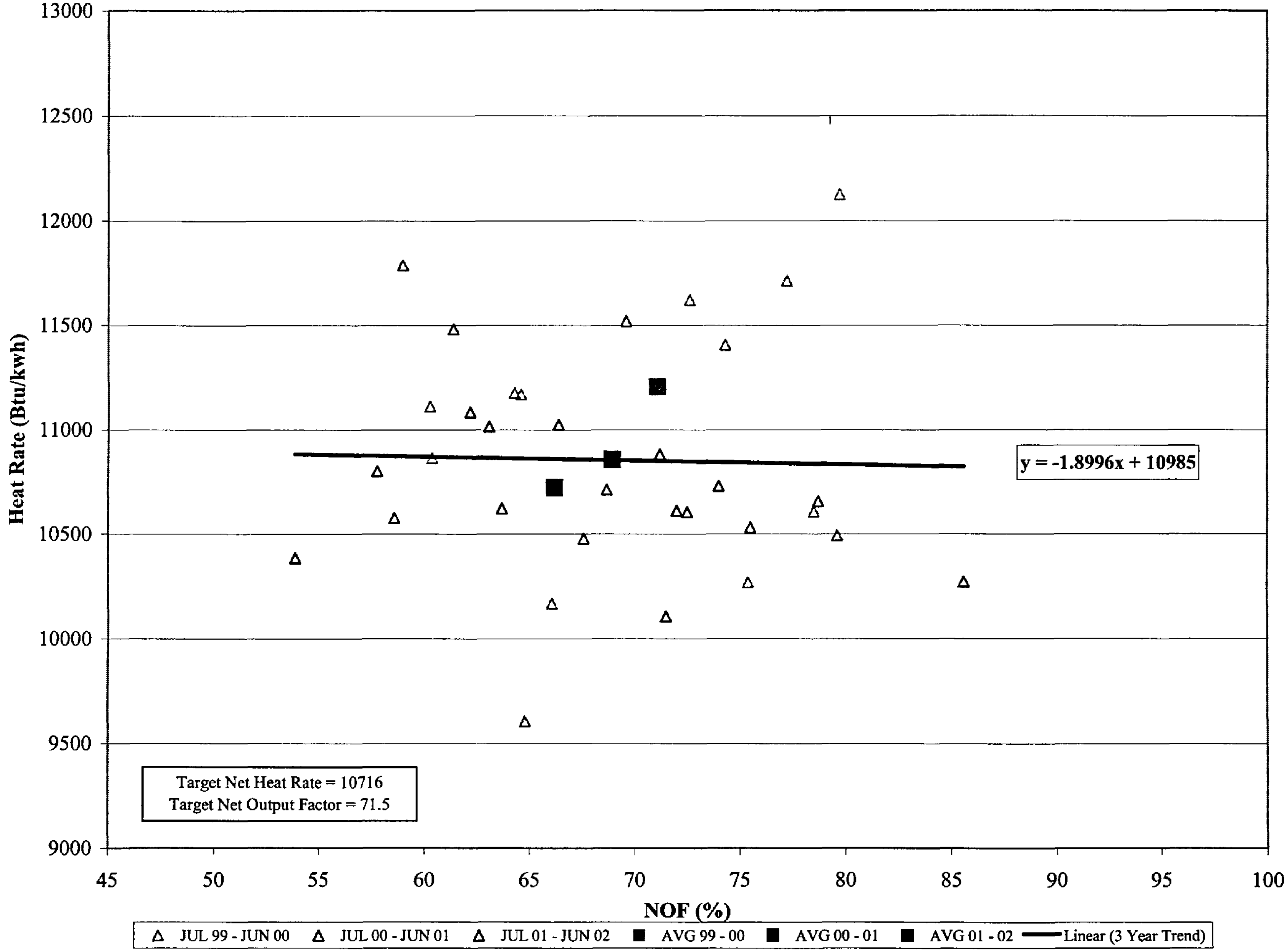
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3



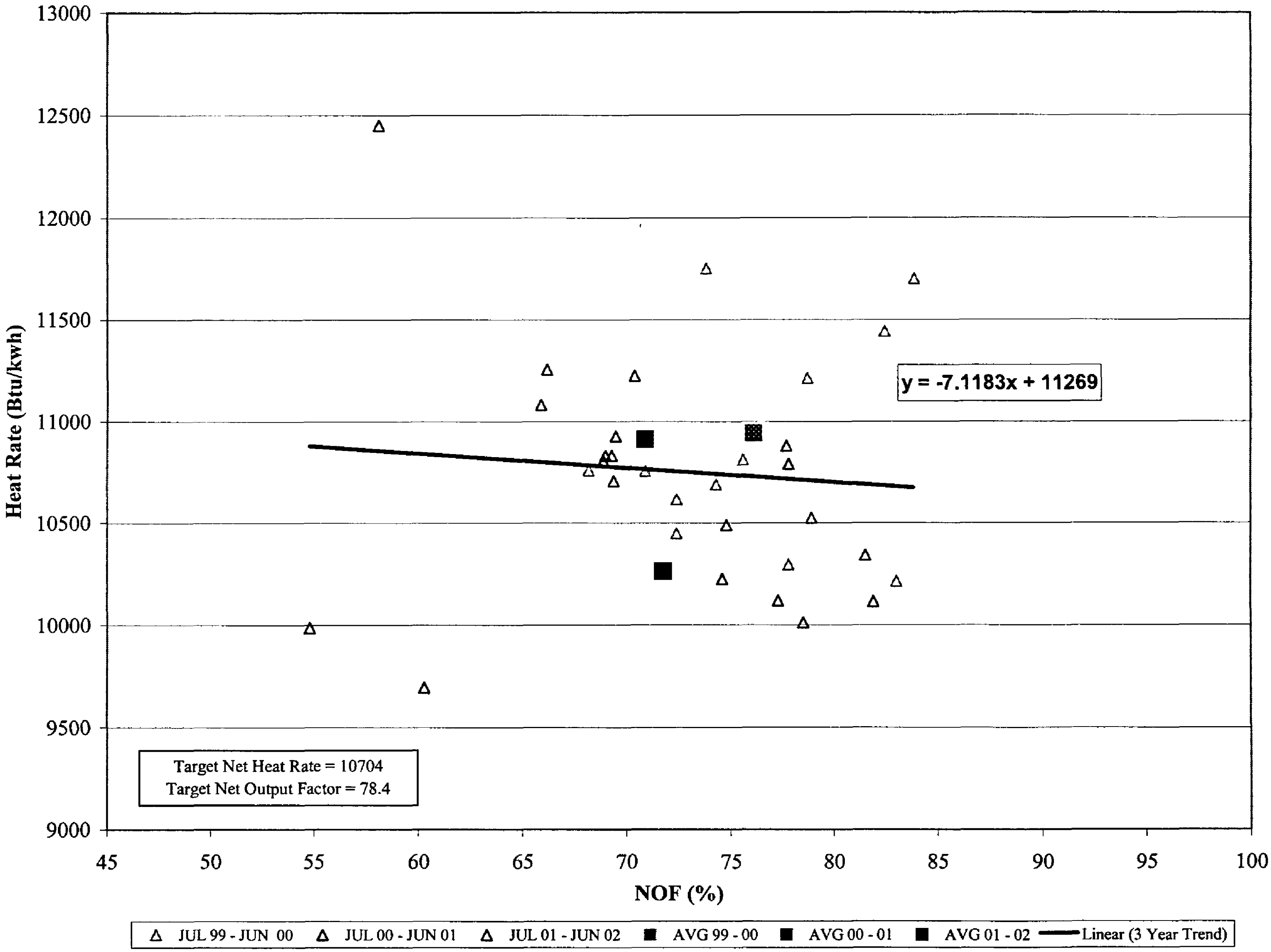
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4



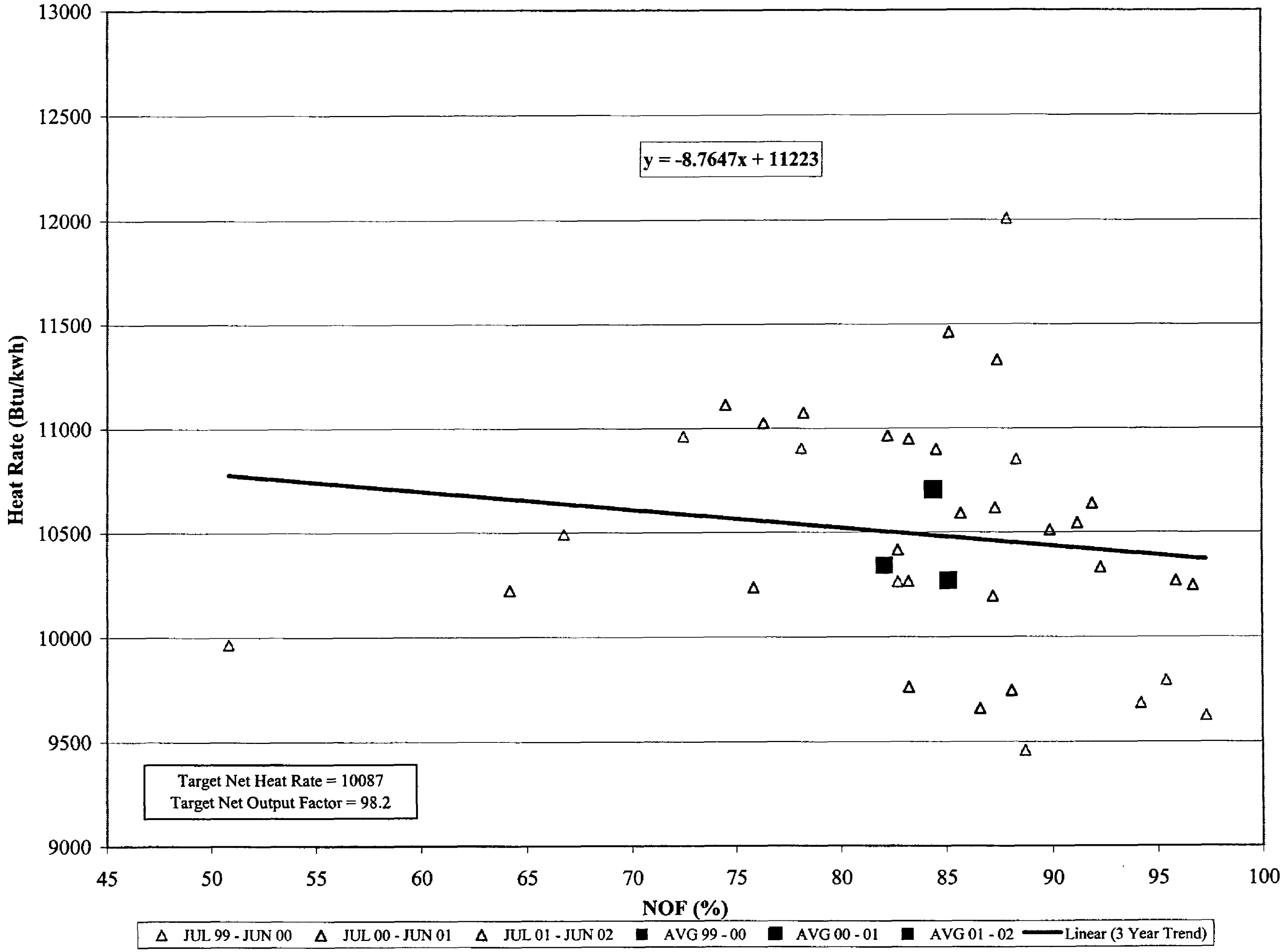
Tampa Electric Company
Heat Rate vs Net Output Factor
Gannon Unit #5



Tampa Electric Company
Heat Rate vs Net Output Factor
Gannon Unit #6



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



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2003 - DECEMBER 2003

PLANT / UNIT	ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1 w/o FGD	440	426
BIG BEND 2 w/o FGD	440	426
BIG BEND 3	450	433
BIG BEND 4	473	445
GANNON 5	230	217
GANNON 6	395	382
POLK 1	315	250
GPIF TOTAL	2743	2579
SYSTEM TOTAL	**3820**	**3619**
% OF SYSTEM TOTAL	**71.79%**	**71.25%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2003 - DECEMBER 2003

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
GANNON 1		120	114
GANNON 2		105	98
GANNON 3		160	150
GANNON 4		170	159
GANNON 5		230	217
GANNON 6		395	382
	GANNON TOTAL	1180	1120
BIG BEND 1 w/o FGD		440	426
BIG BEND 2 w/o FGD		440	426
BIG BEND 3		450	433
BIG BEND 4		473	445
	BIG BEND TOTAL	1803	1730
BIG BEND CT1		15	15
BIG BEND CT2		73	73
BIG BEND CT3		73	73
	CT TOTAL	160.5	160.5
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK 1		315	250
POLK 2		163	162.5
POLK 3		163	163
	POLK TOTAL	641	575
	SYSTEM TOTAL	**3820**	**3619**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2003 - DECEMBER 2003

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BIG BEND	4	2,741,549	15.72%	15.72%
BIG BEND	1	2,122,181	12.17%	27.89%
BIG BEND	2	2,381,812	13.66%	41.55%
BIG BEND	3	2,210,820	12.68%	54.22%
GANNON	6	1,274,936	7.31%	61.53%
POLK	1	1,459,663	8.37%	69.90%
GANNON	5	96,771	0.55%	70.46%
GANNON	4	549,471	3.15%	73.61%
GANNON	3	604,246	3.46%	77.08%
GANNON	1	504,523	2.89%	79.97%
POLK	2	223,323	1.28%	81.25%
GANNON	2	371,525	2.13%	83.38%
POLK	3	197,173	1.13%	84.51%
PHILLIPS	1	36,822	0.21%	84.72%
PHILLIPS	2	38,889	0.22%	84.94%
BIG BEND CT	2	1,786	0.01%	84.95%
BIG BEND CT	3	670	0.00%	84.96%
BIG BEND CT	1	307	0.00%	84.96%
BAYSIDE	1	2,417,198	13.86%	98.82%
BAYSIDE	2	205,747	1.18%	100.00%
TOTAL GENERATION		17,439,412	100.00%	

GENERATION BY COAL UNITS: 14,317,497 MWH

% GENERATION BY COAL UNITS: 82.10%

GENERATION BY OIL UNITS: 78,474 MWH

% GENERATION BY OIL UNITS: 0.45%

GENERATION BY NATURAL GAS UNITS: 420,496 MWH

% GENERATION BY NATURAL GAS UNITS: 2.41%

GENERATION BY GPIF UNITS: 12,287,732 MWH

% GENERATION BY GPIF UNITS: 70.46%

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 020001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2003 - DECEMBER 2003

Availability				Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1	69.9	5.75	24.35	10,533[1/]
Big Bend 2	63.0	3.84	33.16	10,111[2/]
Big Bend 3	67.3	3.84	28.9	10,132[3/]
Big Bend 4	77.7	9.59	12.68	10,028[4/]
Gannon 5	71.9	0.0	28.07	10,862[5/]
Gannon 6	75.9	0.0	24.05	10,775[6/]
Polk 1	74.6	12.05	13.39	10,382[7/]

[1/] Original Sheet 8.401.03E, Page 14

[2/] Original Sheet 8.401.03E, Page 15

[3/] Original Sheet 8.401.03E, Page 16

[4/] Original Sheet 8.401.03E, Page 17

[5/] Original Sheet 8.401.03E, Page 18

[6/] Original Sheet 8.401.03E, Page 19

[7/] Original Sheet 8.401.03E, Page 20