TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

IN RE: TAMPA ELECTRIC'S

FUEL & PURCHASED POWER COST RECOVERY

AND CAPACITY COST RECOVERY PROJECTIONS

JANUARY 2008 THROUGH DECEMBER 2008

TESTIMONY AND EXHIBIT

OF

DAVID R. KNAPP

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

A. My name is David R. Knapp. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as a Senior Engineer in the Operations Planning area of the Resource Planning Department.

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department, where I led a team that provides engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities. In December 2006, I transferred to the Operations Planning area of the Resource Planning department, where I provide engineering and technical support for the daily operations of Tampa Electric's generating facilities.

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit No. ____ (DRK-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2008 period.

GPIF Calculations

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

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

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

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. Two outages on Big Bend Unit 1, three outages on Big Bend Unit 2, three outages on Big Bend Unit 3, and one outage on Big Bend unit 4 were identified as outlying outages; therefore, their associated forced outage hours were removed from the study.

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 2008 period. A range of potential improvements and degradations were determined for each of these parameters.

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

A. The Planned Outage Factor or POF and the Equivalent Unplanned Outage Factor or EUOF were subtracted from 100 percent to determine the target Equivalent Availability Factor or EAF. The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2008 period, the projected

Equivalent Unplanned Outage Factor for Big Bend Unit 2 is 14.33 percent, and the Planned Outage Factor is 8.74 percent. Therefore, the target equivalent availability factor for Big Bend Unit 2 equals 76.92 percent or:

$$100\% - [(14.34 + 8.74\%)] = 76.92\%$$

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

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

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

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

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 2 example:

$$EAF_{MAX} = 100\% - [0.8\ (14.33\%) + 0.95\ (8.74\%)] = 80.24\%$$

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

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

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

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

Again, continuing with the Big Bend Unit 2 example,

$$EAF_{MIN} = 100\% - [1.4\ (14.33\%) + 1.10\ (8.74\%)] = 70.31\%$$

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

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

A. The company's planned outages for January through December 2008 are shown on page 21 of Document No. 1. four GPIF units have a major outage (28 days or greater) in 2008; therefore, four Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 2 is scheduled for a planned outage from November 29, 2008 to December 30, 2008. There are 768 planned outage hours scheduled for the 2008 period, and a total of 8,784 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend Unit 4 is 8.74 percent or:

$$\frac{768}{8,784} \times 100 = 8.74\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a Planned Outage Factor of 3.8 percent. Big Bend Unit 2 has a Planned Outage Factor of 8.7 percent. Big Bend Unit 3 has a Planned Outage Factor of 26.5 percent. Big Bend Unit 4 has a Planned Outage Factor of 3.8 percent. Polk Unit 1 has a Planned Outage Factor of 7.9 percent.

Bayside Unit 1 has a Planned Outage Factor of 3.8 percent, and Bayside Unit 2 has a Planned Outage Factor of 15.3 percent.

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

A. Graphs for both factors, adjusted for planned outages, versus time were prepared. Monthly data and 12-month ending average data were recorded. For each unit the most current 12-month ending value, June 2007, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 23.09 percent for Big Bend Unit 4. The Equivalent Unplanned Outage Factor for Big Bend Unit 4 is verified by the data shown on page 17, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(1,573 + 455)}{8,784} \times 100 = 23.09\%$$

Relative to Big Bend Unit 4, the EUOF of 23.09 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 24.04 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 3.83 percent. Therefore, the target equivalent availability for this unit is 72.13 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 14.33 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 8.74 percent. Therefore, the target equivalent availability for this unit is 76.92 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 26.49 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is

26.50 percent. Therefore, the target equivalent availability for this unit is 47.01 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 23.09 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 3.83 percent. Therefore, the target equivalent availability for this unit is 73.08 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 14.91 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 7.88 percent. Therefore, the target equivalent availability for this unit is 77.21 percent.

Bayside Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 11.72 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 3.83 percent. Therefore, the target equivalent availability for this unit is 84.45 percent.

Bayside Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 1.09 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 15.30 percent. Therefore, the target equivalent availability for this unit is 83.61 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 68.60 percent is shown on Page 5 of Document No. 1. This target is similar to the January through December 2006 GPIF period.

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

A. The adjustment makes the factors more accurate and comparable. 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 baseload units, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the

Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 4 on page 17 of Document No. 1. During the months of January through October and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the month of November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to a scheduled 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 and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

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

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 33 through 39 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 2008 period.

A. The heat rate target for Big Bend Unit 1 is 10,910 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±313 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,695

Btu/Net kWh with a range of ±297 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,662 Btu/Net kWh, with a range of ±695 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,840 Btu/Net kWh with a range of ±627 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,607 Btu/Net kWh with a range of ±822 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,320 Btu/Net kWh with a range of ±129 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,359 Btu/Net kWh with a range of ±117 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 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 $1,117,430.90 is shown on page 6, column 2.

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

After all of the individual savings are calculated, column 4 totals $47,708,700 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 11.14 percent 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 77.1 percent equivalent availability, fuel savings would equal $5,315,900, and 10 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, or $47,708,700. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2008 is $1,561,125,636. This produces the maximum allowed jurisdictional incentive of $6,165,268 shown on line 21.

Q. Are there any other constraints set forth by the

Commission regarding the magnitude of incentive dollars?

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

Q. Please summarize your testimony on the GPIF.

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

$$\begin{aligned} GPIP: = (\ & 0.1114\ EAP_{BB1} + 0.0402\ EAP_{BB2} \\ & + 0.1200\ EAP_{BB3} + 0.1340\ EAP_{BB4} \\ & + 0.0847\ EAP_{PK1} + 0.0318\ EAP_{BAY1} \\ & + 0.0025\ EAP_{BAY2} + 0.0353\ HRP_{BB1} \\ & + 0.0384\ HRP_{BB2} + 0.0559\ HRP_{BB3} \\ & + 0.0874\ HRP_{BB4} + 0.0669\ HRP_{PK1} \\ & + 0.0921\ HRP_{BAY1} + 0.0994\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2008 period?

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

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2008 - DECEMBER 2008

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2008 - DECEMBER 2008

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2008 - DECEMBER 2008

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	47,708.7	6,165.3
+9	42,937.8	5,548.7
+8	38,166.9	4,932.2
+7	33,396.1	4,315.7
+6	28,625.2	3,699.2
+5	23,854.3	3,082.6
+4	19,083.5	2,466.1
+3	14,312.6	1,849.6
+2	9,541.7	1,233.1
+1	4,770.9	616.5
0	0.0	0.0
-1	(7,341.3)	(616.5)
-2	(14,682.6)	(1,233.1)
-3	(22,023.9)	(1,849.6)
-4	(29,365.2)	(2,466.1)
-5	(36,706.5)	(3,082.6)
-6	(44,047.8)	(3,699.2)
-7	(51,389.1)	(4,315.7)
-8	(58,730.4)	(4,932.2)
-9	(66,071.7)	(5,548.7)
-10	(73,413.0)	(6,165.3)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2008 - DECEMBER 2008

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,535,090,000	
Line 2	Month of January	2008	$	1,500,630,000	
Line 3	Month of February	2008	$	1,515,323,669	
Line 4	Month of March	2008	$	1,530,161,213	
Line 5	Month of April	2008	$	1,550,072,829	
Line 6	Month of May	2008	$	1,565,250,625	
Line 7	Month of June	2008	$	1,580,577,037	
Line 8	Month of July	2008	$	1,545,637,696	
Line 9	Month of August	2008	$	1,560,772,066	
Line 10	Month of September	2008	$	1,576,054,625	
Line 11	Month of October	2008	$	1,596,009,239	
Line 12	Month of November	2008	$	1,611,636,829	
Line 13	Month of December	2008	$	1,627,417,440	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,561,125,636	
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)		$	6,358,366	
Line 18	Jurisdictional Sales			20,347,237	MWH
Line 19	Total Sales			20,984,516	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			96.96%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**6,165,268**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2008 - DECEMBER 2008

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	11.14%	72.1	77.1	62.1	5,315.9	(10,291.1)
BIG BEND 2	4.02%	76.9	80.2	70.3	1,915.6	(4,438.6)
BIG BEND 3	12.00%	47.0	53.6	33.8	5,725.1	(11,662.2)
BIG BEND 4	13.40%	73.1	77.9	63.5	6,393.3	(11,814.9)
POLK 1	8.47%	77.2	80.6	70.5	4,039.9	(9,074.1)
BAYSIDE 1	3.18%	84.5	87.0	79.4	1,517.4	(3,451.6)
BAYSIDE 2	0.25%	83.6	84.6	81.6	121.0	(4,438.6)
GPIF SYSTEM	**52.46%**					

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	3.53%	10,910	79.4	10,598	11,223	1,684.8	(1,684.8)
BIG BEND 2	3.84%	10,695	84.4	10,398	10,992	1,832.1	(1,832.1)
BIG BEND 3	5.59%	10,662	74.4	9,967	11,357	2,669.1	(2,669.1)
BIG BEND 4	8.74%	10,840	85.7	10,213	11,467	4,170.1	(4,170.1)
POLK 1	6.69%	10,607	87.2	9,784	11,429	3,190.7	(3,190.7)
BAYSIDE1	9.21%	7,320	83.9	7,190	7,449	4,392.0	(4,392.0)
BAYSIDE 2	9.94%	7,359	80.8	7,242	7,475	4,741.6	(4,741.6)
GPIF SYSTEM	**47.54%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 08 - DEC 08 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 06 - DEC 06 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 05 - DEC 05 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 04 - DEC 04 POF	EUOF	EUOR
BIG BEND 1	11.14%	21.2%	3.8	24.0	25.0	18.5	26.3	32.3	6.5	32.5	34.8	7.5	25.9	28.0
BIG BEND 2	4.02%	7.7%	8.7	14.3	15.7	0.0	17.2	17.2	16.0	19.2	22.9	7.4	23.5	25.4
BIG BEND 3	12.00%	22.9%	26.5	26.5	36.0	7.9	30.2	32.8	7.1	41.4	44.6	7.9	25.0	27.1
BIG BEND 4	13.40%	25.5%	3.8	23.1	24.0	8.3	17.0	18.5	7.8	21.5	23.3	0.0	20.7	20.7
POLK 1	8.47%	16.1%	7.9	14.9	16.2	12.0	9.2	10.5	0.0	31.5	31.5	3.2	6.3	6.5
BAYSIDE 1	3.18%	6.1%	3.8	11.7	12.2	2.5	10.3	10.5	3.1	4.4	4.6	1.5	12.2	12.4
BAYSIDE 2	0.25%	0.5%	15.3	1.1	1.3	10.0	1.4	1.6	2.9	4.2	4.3	1.7	6.0	6.1
GPIF SYSTEM	52.46%	100.0%	10.1	21.3	24.2	10.0	20.3	22.7	6.4	28.7	32.8	4.6	20.1	21.2
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				68.6			69.7			64.9			75.3	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
7.0	23.0	25.6	70.0

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 08 - DEC 08	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 06 - DEC 06	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 05 - DEC 05	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 04 - DEC 04
BIG BEND 1	3.53%	7.4%	10,910	10,981	10,956	10,749
BIG BEND 2	3.84%	8.1%	10,695	10,437	10,262	10,483
BIG BEND 3	5.59%	11.8%	10,662	10,807	10,485	10,768
BIG BEND 4	8.74%	18.4%	10,840	10,942	10,970	10,530
POLK 1	6.69%	14.1%	10,607	10,466	10,278	10,373
BAYSIDE 1	9.21%	19.4%	7,320	7,329	7,405	7,332
BAYSIDE 2	9.94%	20.9%	7,359	7,428	7,388	7,445
GPIF SYSTEM	47.54%	100.0%				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			9,370	9,387	9,318	9,284

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2008 - DECEMBER 2008
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	1,117,430.9	1,112,115.0	5,316	11.14%
EA_2 BIG BEND 2	1,117,430.9	1,115,515.3	1,916	4.02%
EA_3 BIG BEND 3	1,117,430.9	1,111,705.8	5,725	12.00%
EA_4 BIG BEND 4	1,117,430.9	1,111,037.6	6,393	13.40%
EA_7 POLK 1	1,117,430.9	1,113,391.0	4,040	8.47%
EA_8 BAYSIDE 1	1,117,430.9	1,115,913.5	1,517	3.18%
EA_9 BAYSIDE 2	1,117,430.9	1,117,309.9	121	0.25%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	1,117,430.9	1,115,746.1	1,685	3.53%
AHR_2 BIG BEND 2	1,117,430.9	1,115,598.8	1,832	3.84%
AHR_3 BIG BEND 3	1,117,430.9	1,114,761.8	2,669	5.59%
AHR_4 BIG BEND 4	1,117,430.9	1,113,260.8	4,170	8.74%
AHR_7 POLK 1	1,117,430.9	1,114,240.2	3,191	6.69%
AHR_8 BAYSIDE 1	1,117,430.9	1,113,038.9	4,392	9.21%
AHR_9 BAYSIDE 2	1,117,430.9	1,112,689.3	4,742	9.94%
TOTAL SAVINGS			47,708.7	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 2008 - DECEMBER 2008

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,315.9	77.1	+10	1,684.8	10,598
+9	4,784.3	76.6	+9	1,516.3	10,621
+8	4,252.7	76.1	+8	1,347.9	10,645
+7	3,721.1	75.6	+7	1,179.4	10,669
+6	3,189.5	75.1	+6	1,010.9	10,693
+5	2,657.9	74.6	+5	842.4	10,717
+4	2,126.4	74.1	+4	673.9	10,740
+3	1,594.8	73.6	+3	505.4	10,764
+2	1,063.2	73.1	+2	337.0	10,788
+1	531.6	72.6	+1	168.5	10,812
					10,835
0	0.0	72.1	0	0.0	10,910
					10,985
-1	(1,029.1)	71.1	-1	(168.5)	11,009
-2	(2,058.2)	70.1	-2	(337.0)	11,033
-3	(3,087.3)	69.1	-3	(505.4)	11,057
-4	(4,116.4)	68.1	-4	(673.9)	11,080
-5	(5,145.6)	67.1	-5	(842.4)	11,104
-6	(6,174.7)	66.1	-6	(1,010.9)	11,128
-7	(7,203.8)	65.1	-7	(1,179.4)	11,152
-8	(8,232.9)	64.1	-8	(1,347.9)	11,175
-9	(9,262.0)	63.1	-9	(1,516.3)	11,199
-10	(10,291.1)	62.1	-10	(1,684.8)	11,223
	Weighting Factor =	11.14%		Weighting Factor =	3.53%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

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	1,915.6	80.2	+10	1,832.1	10,398
+9	1,724.0	79.9	+9	1,648.9	10,420
+8	1,532.5	79.6	+8	1,465.7	10,442
+7	1,340.9	79.2	+7	1,282.5	10,464
+6	1,149.4	78.9	+6	1,099.3	10,487
+5	957.8	78.6	+5	916.1	10,509
+4	766.2	78.2	+4	732.9	10,531
+3	574.7	77.9	+3	549.6	10,553
+2	383.1	77.6	+2	366.4	10,575
+1	191.6	77.3	+1	183.2	10,598
					10,620
0	0.0	76.9	0	0.0	10,695
					10,770
-1	(443.9)	76.3	-1	(183.2)	10,792
-2	(887.7)	75.6	-2	(366.4)	10,814
-3	(1,331.6)	74.9	-3	(549.6)	10,836
-4	(1,775.4)	74.3	-4	(732.9)	10,859
-5	(2,219.3)	73.6	-5	(916.1)	10,881
-6	(2,663.2)	73.0	-6	(1,099.3)	10,903
-7	(3,107.0)	72.3	-7	(1,282.5)	10,925
-8	(3,550.9)	71.6	-8	(1,465.7)	10,947
-9	(3,994.7)	71.0	-9	(1,648.9)	10,970
-10	(4,438.6)	70.3	-10	(1,832.1)	10,992
	Weighting Factor =	4.02%		Weighting Factor =	3.84%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

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	5,725.1	53.6	+10	2,669.1	9,967
+9	5,152.6	53.0	+9	2,402.2	10,029
+8	4,580.1	52.3	+8	2,135.3	10,091
+7	4,007.6	51.6	+7	1,868.4	10,153
+6	3,435.1	51.0	+6	1,601.5	10,215
+5	2,862.5	50.3	+5	1,334.6	10,277
+4	2,290.0	49.7	+4	1,067.7	10,339
+3	1,717.5	49.0	+3	800.7	10,401
+2	1,145.0	48.3	+2	533.8	10,463
+1	572.5	47.7	+1	266.9	10,525
					10,587
0	0.0	47.0	0	0.0	10,662
					10,737
-1	(1,166.2)	45.7	-1	(266.9)	10,799
-2	(2,332.4)	44.4	-2	(533.8)	10,861
-3	(3,498.7)	43.0	-3	(800.7)	10,923
-4	(4,664.9)	41.7	-4	(1,067.7)	10,985
-5	(5,831.1)	40.4	-5	(1,334.6)	11,047
-6	(6,997.3)	39.1	-6	(1,601.5)	11,109
-7	(8,163.5)	37.7	-7	(1,868.4)	11,171
-8	(9,329.8)	36.4	-8	(2,135.3)	11,233
-9	(10,496.0)	35.1	-9	(2,402.2)	11,295
-10	(11,662.2)	33.8	-10	(2,669.1)	11,357
	Weighting Factor =	12.00%		Weighting Factor =	5.59%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	6,393.3	77.9	+10	4,170.1	10,213
+9	5,754.0	77.4	+9	3,753.1	10,268
+8	5,114.6	76.9	+8	3,336.1	10,324
+7	4,475.3	76.5	+7	2,919.0	10,379
+6	3,836.0	76.0	+6	2,502.0	10,434
+5	3,196.6	75.5	+5	2,085.0	10,489
+4	2,557.3	75.0	+4	1,668.0	10,544
+3	1,918.0	74.5	+3	1,251.0	10,600
+2	1,278.7	74.0	+2	834.0	10,655
+1	639.3	73.6	+1	417.0	10,710
					10,765
0	0.0	73.1	0	0.0	10,840
					10,915
-1	(1,181.5)	72.1	-1	(417.0)	10,970
-2	(2,363.0)	71.2	-2	(834.0)	11,025
-3	(3,544.5)	70.2	-3	(1,251.0)	11,081
-4	(4,726.0)	69.2	-4	(1,668.0)	11,136
-5	(5,907.5)	68.3	-5	(2,085.0)	11,191
-6	(7,088.9)	67.3	-6	(2,502.0)	11,246
-7	(8,270.4)	66.3	-7	(2,919.0)	11,301
-8	(9,451.9)	65.4	-8	(3,336.1)	11,357
-9	(10,633.4)	64.4	-9	(3,753.1)	11,412
-10	(11,814.9)	63.5	-10	(4,170.1)	11,467
	Weighting Factor =	13.40%		Weighting Factor =	8.74%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,039.9	80.6	+10	3,190.7	9,784
+9	3,635.9	80.3	+9	2,871.6	9,859
+8	3,231.9	79.9	+8	2,552.5	9,934
+7	2,827.9	79.6	+7	2,233.5	10,009
+6	2,423.9	79.2	+6	1,914.4	10,083
+5	2,019.9	78.9	+5	1,595.3	10,158
+4	1,616.0	78.6	+4	1,276.3	10,233
+3	1,212.0	78.2	+3	957.2	10,307
+2	808.0	77.9	+2	638.1	10,382
+1	404.0	77.5	+1	319.1	10,457
					10,532
0	0.0	77.2	0	0.0	10,607
					10,682
-1	(907.4)	76.5	-1	(319.1)	10,756
-2	(1,814.8)	75.9	-2	(638.1)	10,831
-3	(2,722.2)	75.2	-3	(957.2)	10,906
-4	(3,629.6)	74.5	-4	(1,276.3)	10,981
-5	(4,537.1)	73.8	-5	(1,595.3)	11,055
-6	(5,444.5)	73.2	-6	(1,914.4)	11,130
-7	(6,351.9)	72.5	-7	(2,233.5)	11,205
-8	(7,259.3)	71.8	-8	(2,552.5)	11,280
-9	(8,166.7)	71.1	-9	(2,871.6)	11,354
-10	(9,074.1)	70.5	-10	(3,190.7)	11,429
	Weighting Factor =	8.47%		Weighting Factor =	6.69%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,517.4	87.0	+10	4,392.0	7,190
+9	1,365.7	86.7	+9	3,952.8	7,196
+8	1,213.9	86.5	+8	3,513.6	7,201
+7	1,062.2	86.2	+7	3,074.4	7,207
+6	910.4	86.0	+6	2,635.2	7,212
+5	758.7	85.7	+5	2,196.0	7,217
+4	607.0	85.5	+4	1,756.8	7,223
+3	455.2	85.2	+3	1,317.6	7,228
+2	303.5	85.0	+2	878.4	7,234
+1	151.7	84.7	+1	439.2	7,239
					7,245
0	0.0	84.5	0	0.0	7,320
					7,395
-1	(345.2)	83.9	-1	(439.2)	7,400
-2	(690.3)	83.4	-2	(878.4)	7,405
-3	(1,035.5)	82.9	-3	(1,317.6)	7,411
-4	(1,380.6)	82.4	-4	(1,756.8)	7,416
-5	(1,725.8)	81.9	-5	(2,196.0)	7,422
-6	(2,071.0)	81.4	-6	(2,635.2)	7,427
-7	(2,416.1)	80.9	-7	(3,074.4)	7,433
-8	(2,761.3)	80.4	-8	(3,513.6)	7,438
-9	(3,106.4)	79.9	-9	(3,952.8)	7,443
-10	(3,451.6)	79.4	-10	(4,392.0)	7,449
	Weighting Factor =	3.18%		Weighting Factor =	9.21%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BAYSIDE 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	121.0	84.6	+10	4,741.6	7,242
+9	108.9	84.5	+9	4,267.5	7,246
+8	96.8	84.4	+8	3,793.3	7,251
+7	84.7	84.3	+7	3,319.1	7,255
+6	72.6	84.2	+6	2,845.0	7,259
+5	60.5	84.1	+5	2,370.8	7,263
+4	48.4	84.0	+4	1,896.7	7,267
+3	36.3	83.9	+3	1,422.5	7,271
+2	24.2	83.8	+2	948.3	7,275
+1	12.1	83.7	+1	474.2	7,280
					7,284
0	0.0	83.6	0	0.0	7,359
					7,434
-1	(443.9)	83.4	-1	(474.2)	7,438
-2	(887.7)	83.2	-2	(948.3)	7,442
-3	(1,331.6)	83.0	-3	(1,422.5)	7,446
-4	(1,775.4)	82.8	-4	(1,896.7)	7,450
-5	(2,219.3)	82.6	-5	(2,370.8)	7,455
-6	(2,663.2)	82.4	-6	(2,845.0)	7,459
-7	(3,107.0)	82.2	-7	(3,319.1)	7,463
-8	(3,550.9)	82.0	-8	(3,793.3)	7,467
-9	(3,994.7)	81.8	-9	(4,267.5)	7,471
-10	(4,438.6)	81.6	-10	(4,741.6)	7,475
	Weighting Factor =	0.25%		Weighting Factor =	9.94%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	47.5	67.7	75.0	75.0	72.13
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.7	9.7	0.0	0.0	3.83
3. EUOF	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	15.8	22.6	25.0	25.0	24.04
4. EUOR	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	624	583	624	603	624	603	624	624	383	562	603	624	7,080
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	120	113	120	117	120	117	120	120	337	182	117	120	1704
9. POH	0	0	0	0	0	0	0	0	264	72	0	0	336
10. FOH & EFOH	158	148	158	153	158	153	158	158	97	143	153	158	1,795
11. MOH & EMOH	28	26	28	27	28	27	28	28	17	25	27	28	316
12. OPER BTU (GBTU)	2,053	1,922	2,043	1,980	2,046	1,980	2,046	2,046	1,257	1,845	1,989	2,047	23,251
13. NET GEN (MWH)	187,735	175,727	186,581	181,816	187,895	181,849	187,883	187,901	115,436	169,411	181,879	187,020	2,131,133
14. ANOHR (Btu/kwh)	10,937	10,936	10,947	10,889	10,889	10,889	10,889	10,889	10,889	10,889	10,935	10,943	10,910
15. NOF (%)	78.2	78.3	77.7	80.4	80.4	80.4	80.4	80.4	80.4	80.3	78.3	77.9	79.4
16. NPC (MW)	385	385	385	375	375	375	375	375	375	375	385	385	379

17. ANOHR EQUATION ANOHR = NOF(-22.19) + 12,672.08

34

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	84.3	84.3	84.3	84.3	84.3	84.3	84.3	84.3	84.3	84.3	78.7	2.7	76.92
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7	96.8	8.74
3. EUOF	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	14.7	0.5	14.33
4. EUOR	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	696	651	696	673	696	673	696	696	673	696	629	22	7,495
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	48	45	48	47	48	47	48	48	47	48	91	722	1,289
9. POH	0	0	0	0	0	0	0	0	0	0	48	720	768
10. FOH & EFOH	114	107	114	110	114	110	114	114	110	114	103	4	1,227
11. MOH & EMOH	3	3	3	3	3	3	3	3	3	3	3	0	32
12. OPER BTU (GBTU)	2,465	2,296	2,445	2,358	2,436	2,358	2,434	2,432	2,358	2,436	2,228	78	26,327
13. NET GEN (MWH)	230,248	214,345	228,197	220,678	228,042	220,705	227,769	227,584	220,669	228,012	208,183	7,277	2,461,709
14. ANOHR (Btu/kwh)	10,704	10,710	10,715	10,684	10,684	10,683	10,685	10,686	10,684	10,684	10,703	10,725	10,695
15. NOF (%)	83.8	83.4	83.0	85.1	85.1	85.1	85.0	85.0	85.1	85.1	83.9	82.4	84.4
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	395	395	389
17. ANOHR EQUATION	ANOHR = NOF(		-15.00	) +	11,960.68								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	0.0	0.0	0.0	51.2	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	47.01
2. POF	100.0	100.0	100.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.50
3. EUOF	0.0	0.0	0.0	28.8	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	26.49
4. EUOR	0.0	0.0	0.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	0	0	0	463	597	578	597	597	578	597	578	597	5,182
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	744	696	744	257	147	142	147	147	142	147	142	147	3,602
9. POH	744	696	744	144	0	0	0	0	0	0	0	0	2,328
10. FOH & EFOH	0	0	0	163	211	204	211	211	204	211	204	211	1,832
11. MOH & EMOH	0	0	0	44	57	55	57	57	55	57	55	57	495
12. OPER BTU (GBTU)	0	0	0	1,450	1,873	1,812	1,853	1,842	1,808	1,870	1,822	1,854	16,208
13. NET GEN (MWH)	0	0	0	136,708	176,669	170,999	174,015	172,534	170,368	176,308	170,345	172,246	1,520,192
14. ANOHR (Btu/kwh)	13,900	13,900	13,900	10,605	10,599	10,599	10,649	10,677	10,611	10,606	10,694	10,762	10,662
15. NOF (%)	0.0	0.0	0.0	75.7	75.9	75.9	74.7	74.1	75.6	75.7	73.7	72.1	74.4
16. NPC (MW)	400	400	400	390	390	390	390	390	390	390	400	400	394

17. ANOHR EQUATION ANOHR = NOF(-43.50) + 13,899.80

36

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	40.5	76.0	73.08
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.83
3. EUOF	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	12.8	24.0	23.09
4. EUOR	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	622	582	622	602	622	602	622	622	602	622	321	622	7,064
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	122	114	122	118	122	118	122	122	118	122	399	122	1,720
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. FOH & EFOH	139	130	139	134	139	134	139	139	134	139	72	139	1,573
11. MOH & EMOH	40	37	40	39	40	39	40	40	39	40	21	40	455
12. OPER BTU (GBTU)	2,557	2,380	2,497	2,440	2,525	2,443	2,501	2,484	2,439	2,522	1,323	2,506	28,623
13. NET GEN (MWH)	235,944	219,298	228,747	225,745	233,810	226,201	230,883	228,772	225,711	233,328	122,211	229,828	2,640,478
14. ANOHR (Btu/kwh)	10,837	10,854	10,915	10,807	10,801	10,802	10,834	10,857	10,808	10,807	10,828	10,903	10,840
15. NOF (%)	85.8	85.3	83.2	86.8	87.0	87.0	85.9	85.1	86.8	86.8	86.1	83.6	85.7
16. NPC (MW)	442	442	442	432	432	432	432	432	432	432	442	442	436

17. ANOHR EQUATION ANOHR = NOF(-29.85) + 13,398.36

37

ORIGINAL SHEET NO. 8.401.07E
PAGE 17 OF 42

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	83.8	28.9	59.5	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	81.6	77.21
2. POF	0.0	65.5	29.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	7.88
3. EUOF	16.2	5.6	11.5	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	15.8	14.91
4. EUOR	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	667	212	476	645	667	645	667	667	645	667	645	516	7,119
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	77	484	268	75	77	75	77	77	75	77	75	228	1,665
9. POH	0	456	216	0	0	0	0	0	0	0	0	20	692
10. FOH & EFOH	73	24	52	71	73	71	73	73	71	73	71	71	793
11. MOH & EMOH	47	15	34	46	47	46	47	47	46	47	46	46	517
12. OPER BTU (GBTU)	1,604	507	1,139	1,532	1,586	1,534	1,580	1,577	1,532	1,586	1,550	1,235	16,963
13. NET GEN (MWH)	151,179	47,745	107,308	144,501	149,622	144,761	149,002	148,739	144,576	149,380	146,105	116,342	1,599,260
14. ANOHR (Btu/kwh)	10,608	10,614	10,613	10,599	10,598	10,597	10,602	10,604	10,598	10,620	10,608	10,613	10,607
15. NOF (%)	87.2	86.6	86.7	87.9	88.0	88.0	87.6	87.4	87.9	86.1	87.1	86.7	87.2
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	258
17. ANOHR EQUATION	ANOHR = NOF(	-12.42	) +		11,690.03								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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
BAYSIDE 1	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	87.8	87.8	68.0	87.8	87.8	87.8	87.8	87.8	87.8	87.8	67.3	87.8	84.45
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	3.83
3. EUOF	12.2	12.2	9.4	12.2	12.2	12.2	12.2	12.2	12.2	12.2	9.3	12.2	11.72
4. EUOR	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.19
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	503	575	470	567	510	481	521	581	541	501	468	633	6,349
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	241	121	274	153	234	239	223	163	179	243	252	111	2,435
9. POH	0	0	168	0	0	0	0	0	0	0	168	0	336
10. FOH & EFOH	48	45	37	46	48	46	48	48	46	48	35	48	543
11. MOH & EMOH	43	40	33	42	43	42	43	43	42	43	32	43	487
12. OPER BTU (GBTU)	2,011	2,431	2,210	2,691	2,262	2,152	2,322	2,574	2,396	2,230	2,101	3,168	28,553
13. NET GEN (MWH)	272,716	330,382	301,450	369,266	309,400	294,471	317,694	352,000	327,692	305,103	287,546	433,246	3,900,966
14. ANOHR (Btu/kwh)	7,374	7,360	7,330	7,288	7,311	7,308	7,309	7,311	7,311	7,309	7,307	7,311	7,320
15. NOF (%)	68.3	72.5	81.0	92.8	86.4	87.3	86.9	86.3	86.2	86.8	87.6	86.3	83.9
16. NPC (MW)	793	793	793	702	702	702	702	702	702	702	702	793	732

17. ANOHR EQUATION ANOHR = NOF(-3.51) + 7,614.23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

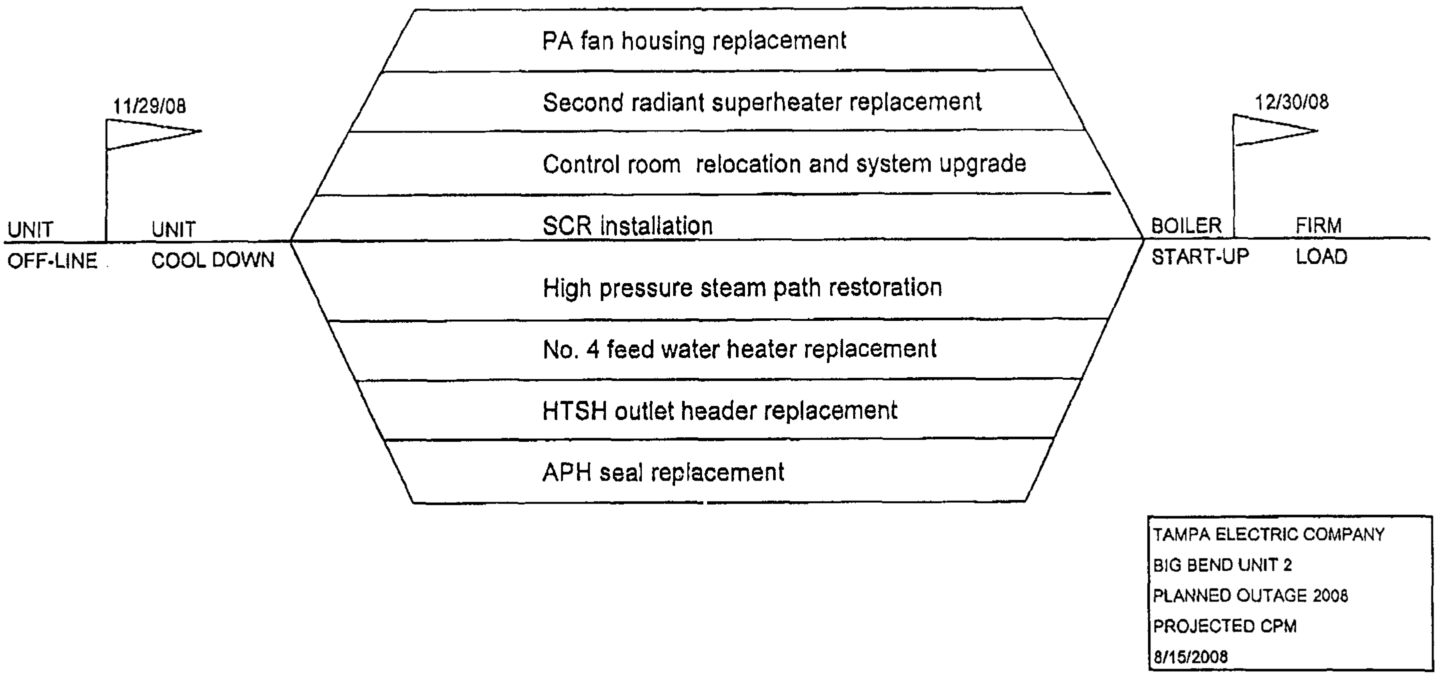
JANUARY 2008 - DECEMBER 2008

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
BAYSIDE 2	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	98.7	98.7	44.6	0.0	92.3	98.7	98.7	98.7	98.7	98.7	98.7	76.4	83.61
2. POF	0.0	0.0	54.8	100.0	6.5	0.0	0.0	0.0	0.0	0.0	0.0	22.6	15.30
3. EUOF	1.3	1.3	0.6	0.0	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.0	1.09
4. EUOR	1.3	1.3	1.3	0.0	0.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.29
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	290	509	291	0	606	633	728	721	679	598	508	471	6,033
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	454	187	453	720	138	87	16	23	41	146	212	273	2,751
9. POH	0	0	408	720	48	0	0	0	0	0	0	168	1,344
10. FOH & EFOH	3	3	1	0	3	3	3	3	3	3	3	3	32
11. MOH & EMOH	6	6	3	0	6	6	6	6	6	6	6	5	63
12. OPER BTU (GBTU)	1,474	2,502	1,817	0	3,573	3,748	4,372	4,338	4,044	3,379	2,638	2,836	34,763
13. NET GEN (MWH)	197,837	335,280	246,906	0	487,717	511,784	597,612	593,118	552,504	459,847	356,965	384,522	4,724,092
14. ANOHR (Btu/kwh)	7,449	7,463	7,358	7,828	7,325	7,323	7,315	7,314	7,320	7,347	7,389	7,375	7,359
15. NOF (%)	65.2	62.8	80.9	0.0	86.5	86.9	88.3	88.5	87.5	82.7	75.6	77.9	80.8
16. NPC (MW)	1048	1048	1048	930	930	930	930	930	930	930	930	1048	969
17. ANOHR EQUATION	ANOHR = NOF(		-5.81	) +	7,828.21								

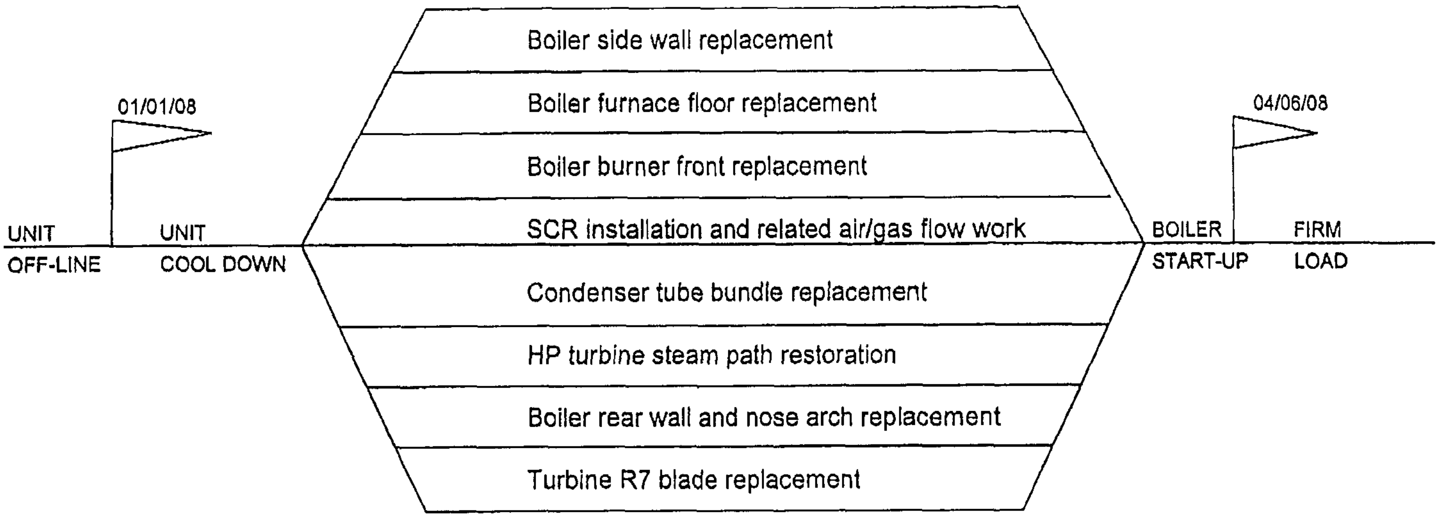
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2008 - DECEMBER 2008

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Sep 20	-	Oct 03	Fuel System Clean-up
+	BIG BEND 2	Nov 29	-	Dec 30	SCR Outage
+	BIG BEND 3	Jan 01		Apr 06	SCR Outage
	BIG BEND 4	Nov 01	-	Nov 14	Fuel System Clean-up
+	POLK 1	Feb 11	-	Mar 09	Gasifier / CT Outage
		Dec 01	-	Dec 07	Gasifier Outage
	BAYSIDE 1	Mar 03	-	Mar 09	Fuel System Clean-up
		Nov 24	-	Nov 30	Fuel System Clean-up
+	BAYSIDE 2	Mar 15	-	May 02	Combustion Path Inspection & Steam Turbine
		Dec 08	-	Dec 14	Fuel System Clean-up

**TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008**

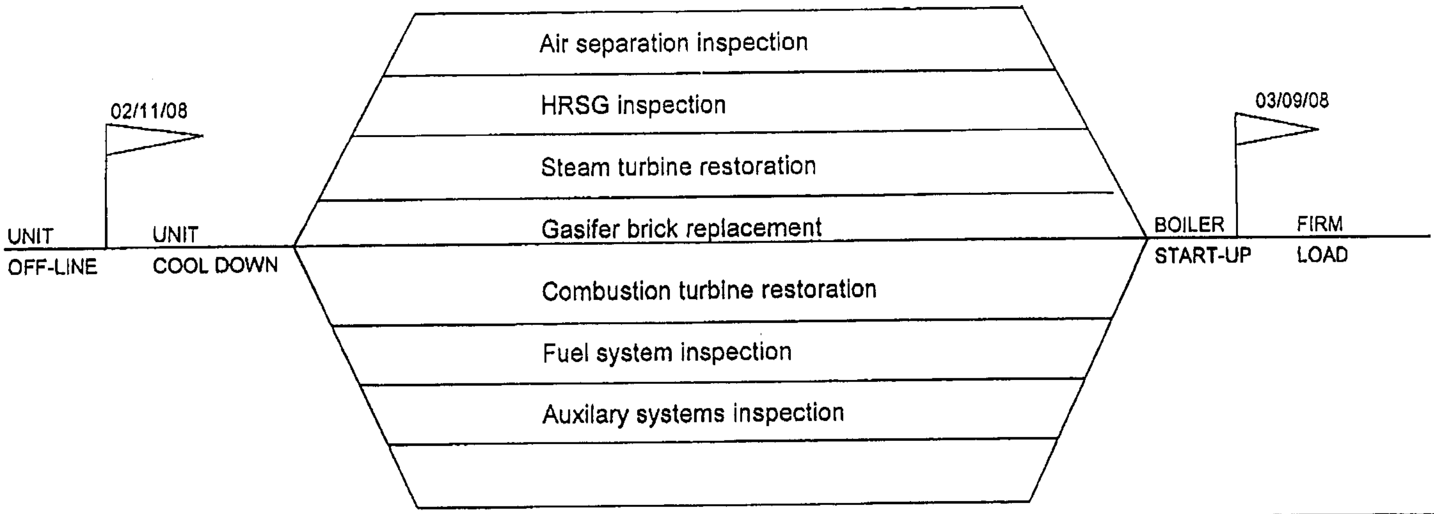


**TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008**



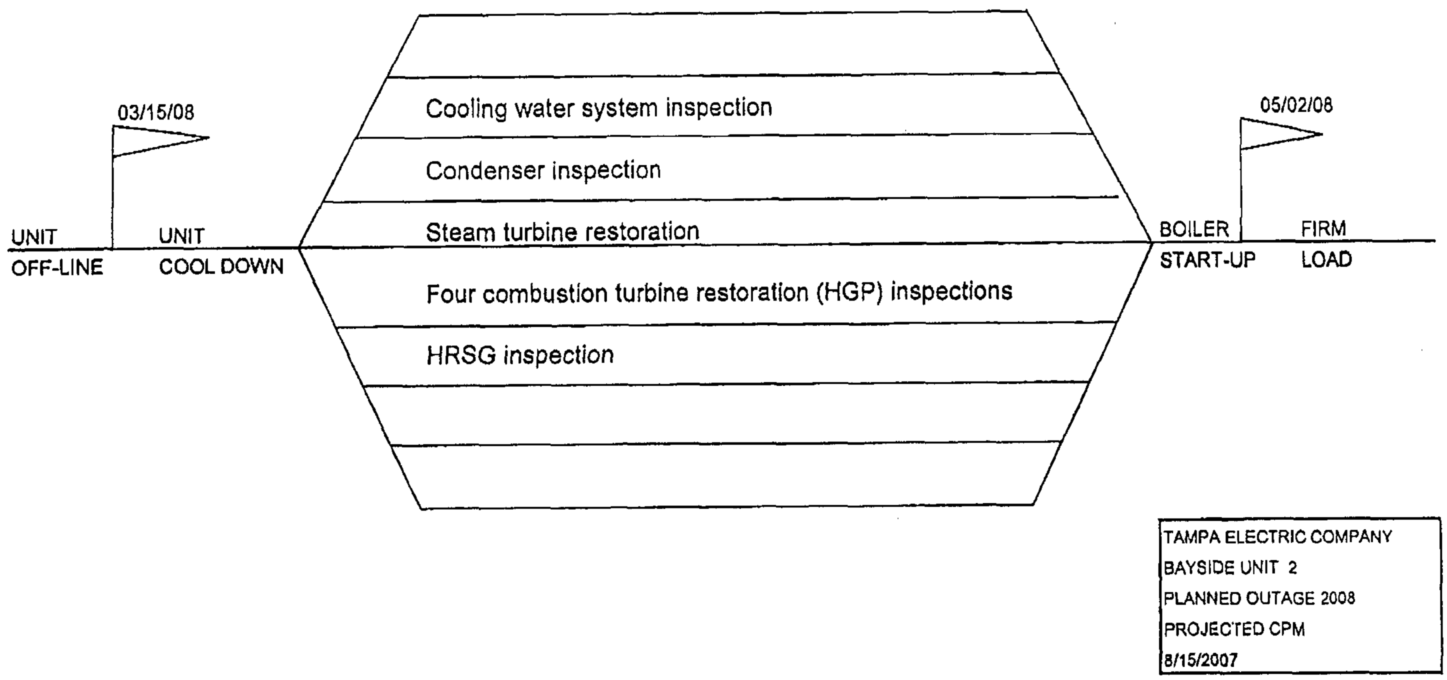
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 3
PLANNED OUTAGE 2008
PROJECTED CPM
8/15/2008

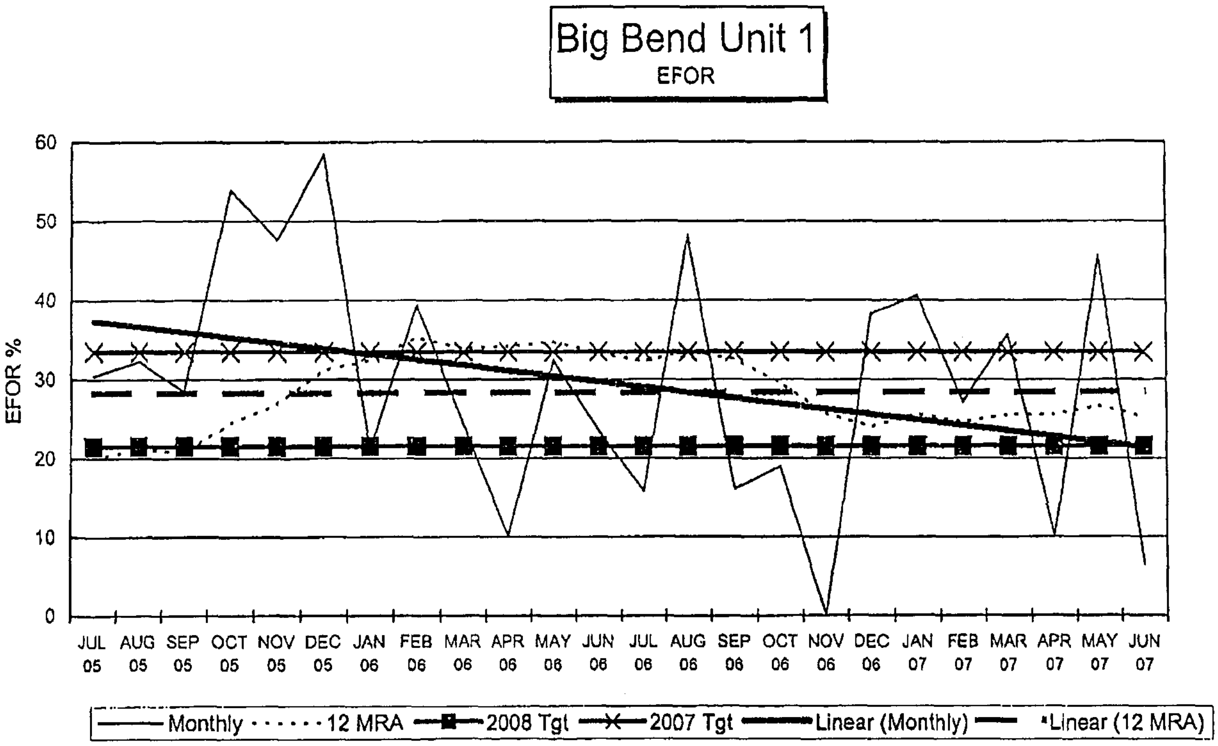
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008

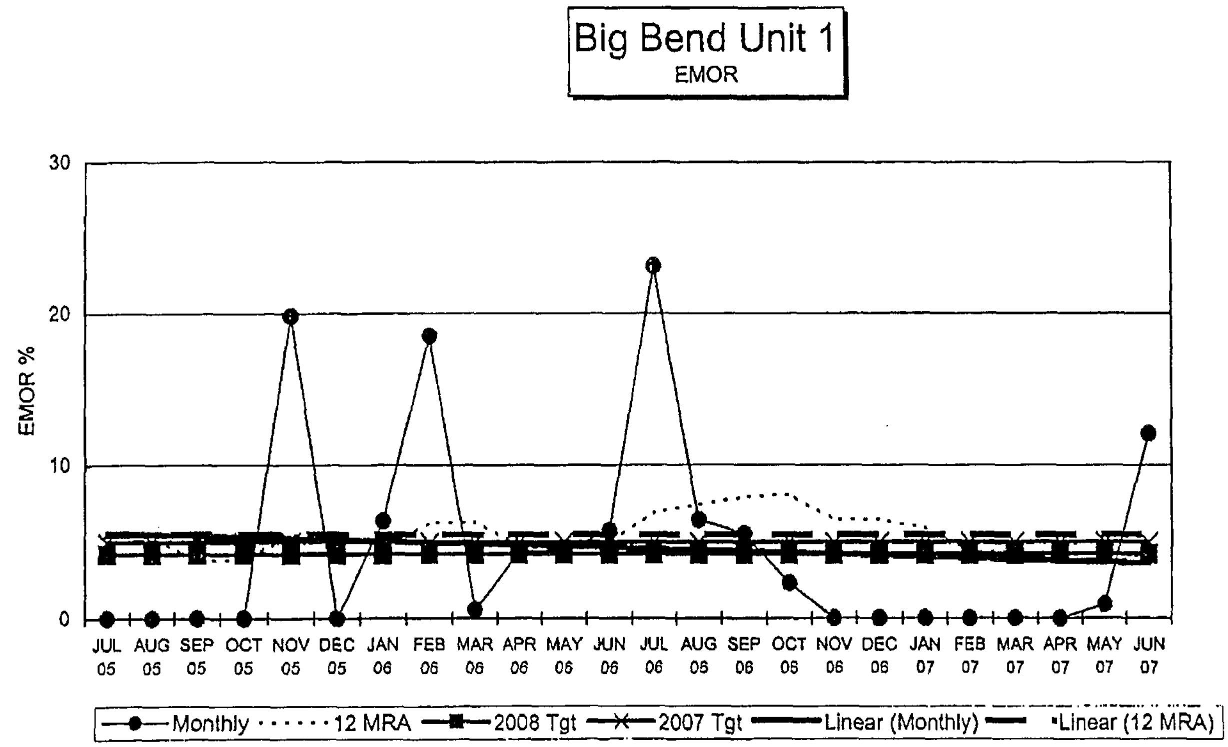


TAMPA ELECTRIC COMPANY
POLK UNIT 1
PLANNED OUTAGE 2008
PROJECTED CPM
8/15/2007

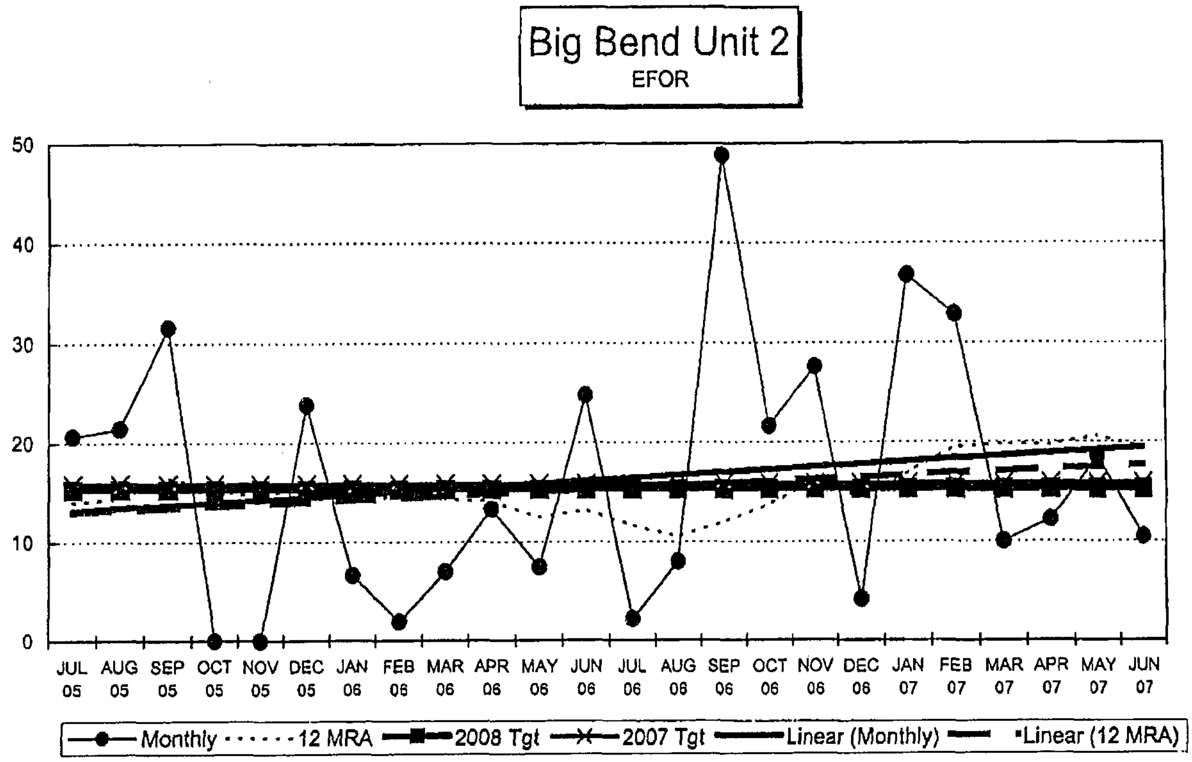
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008

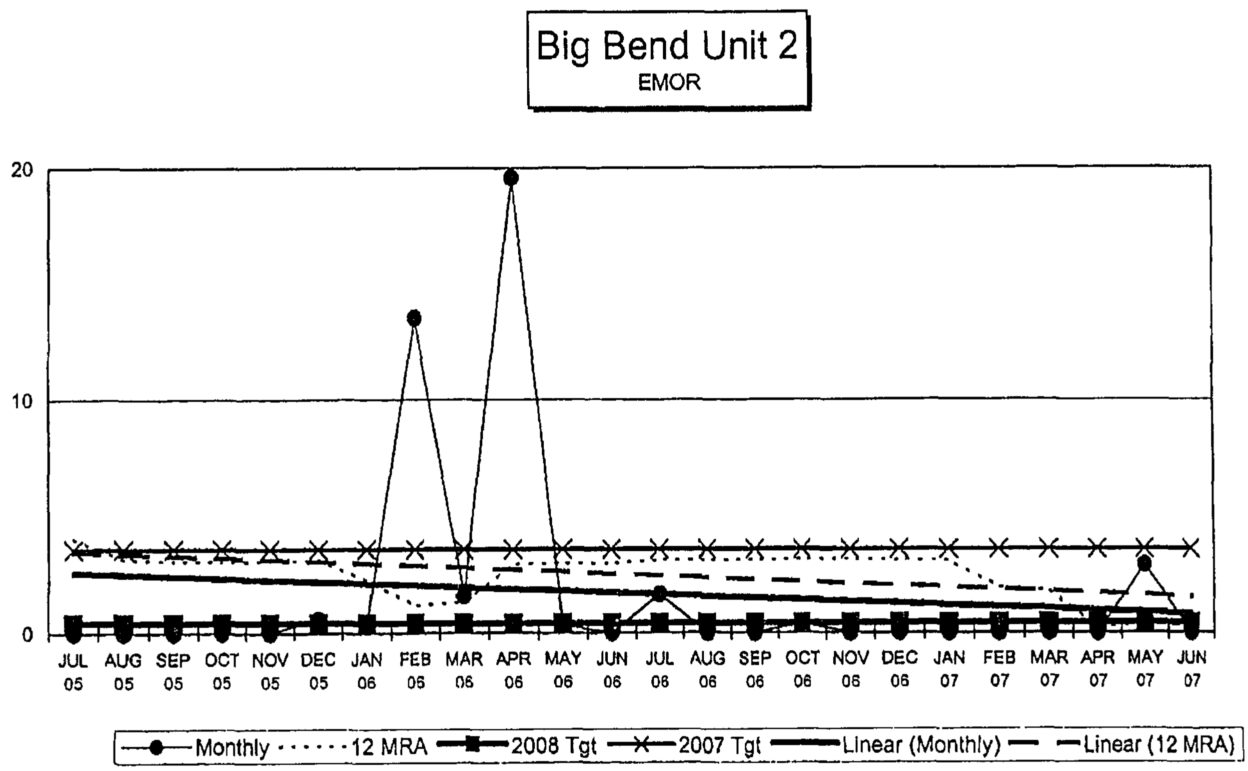




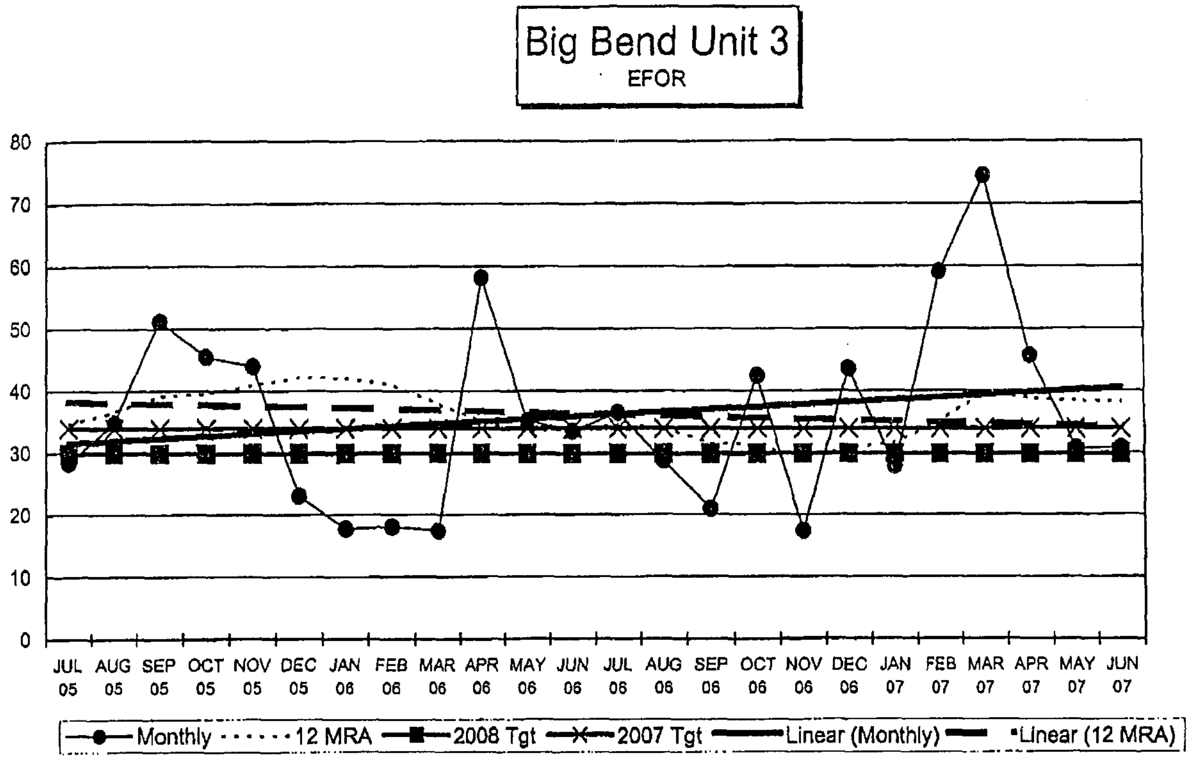


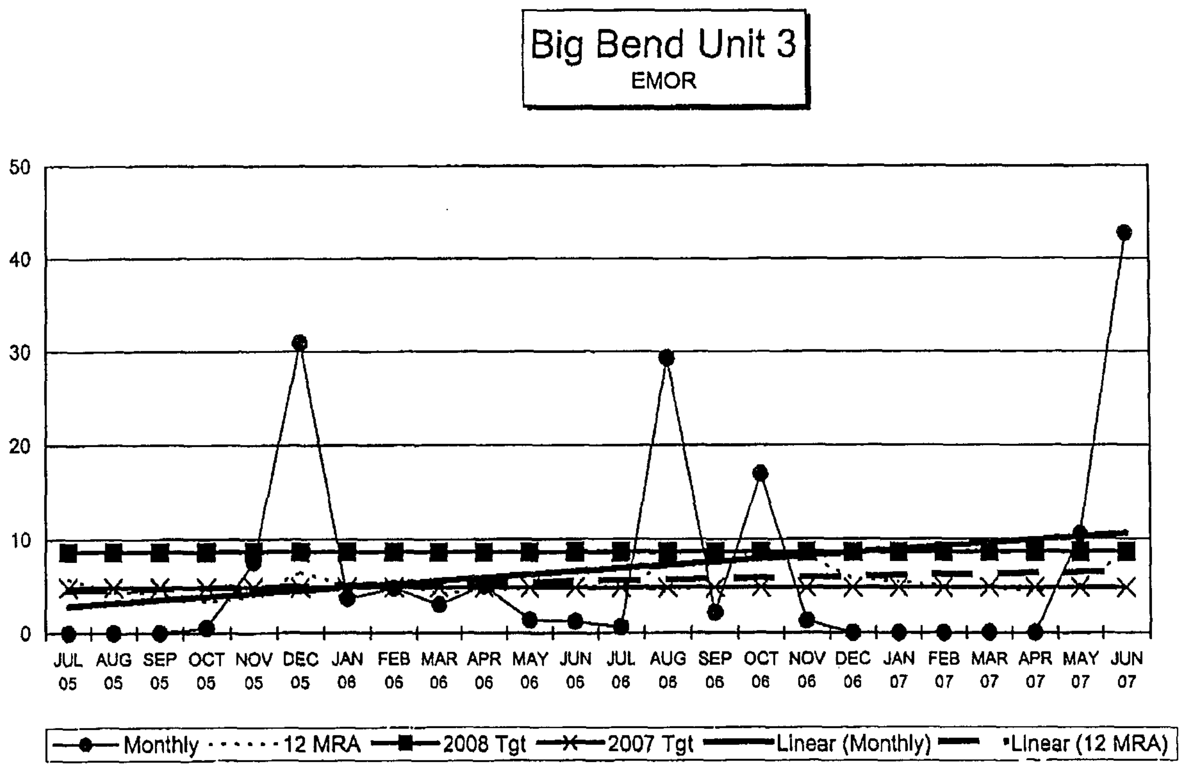
12 MRA = 12 Month Rolling Average



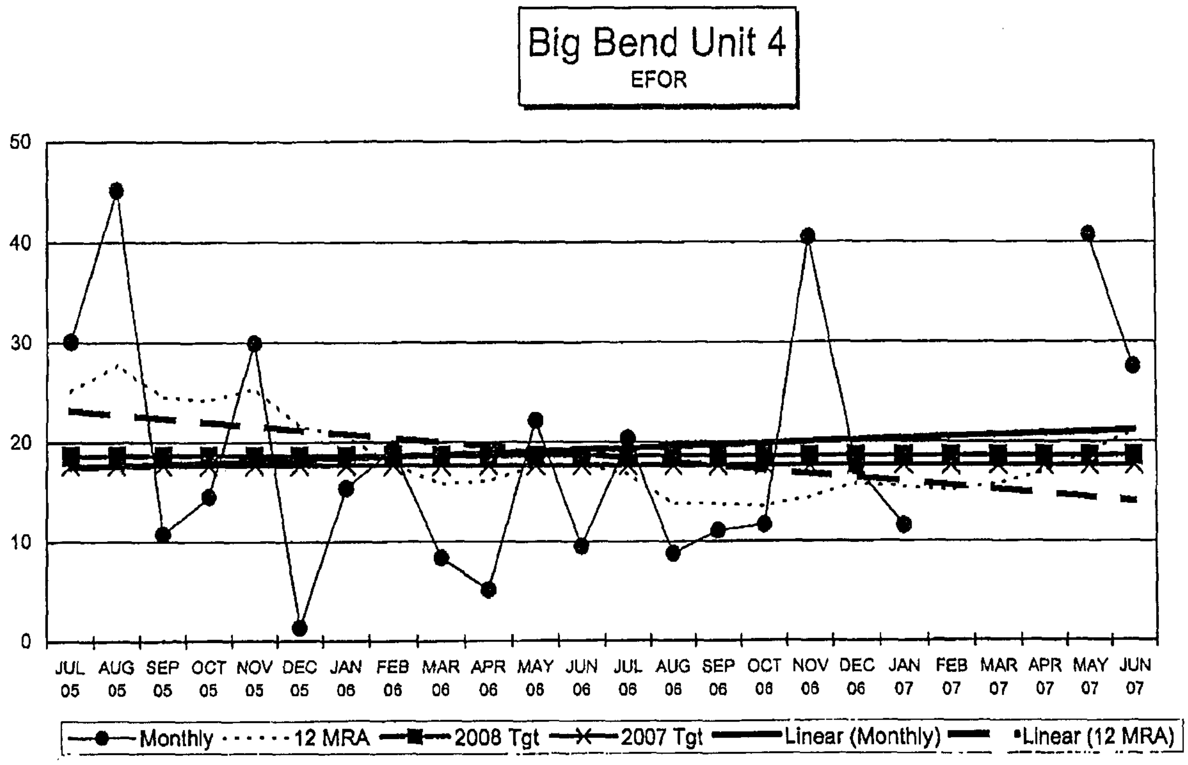


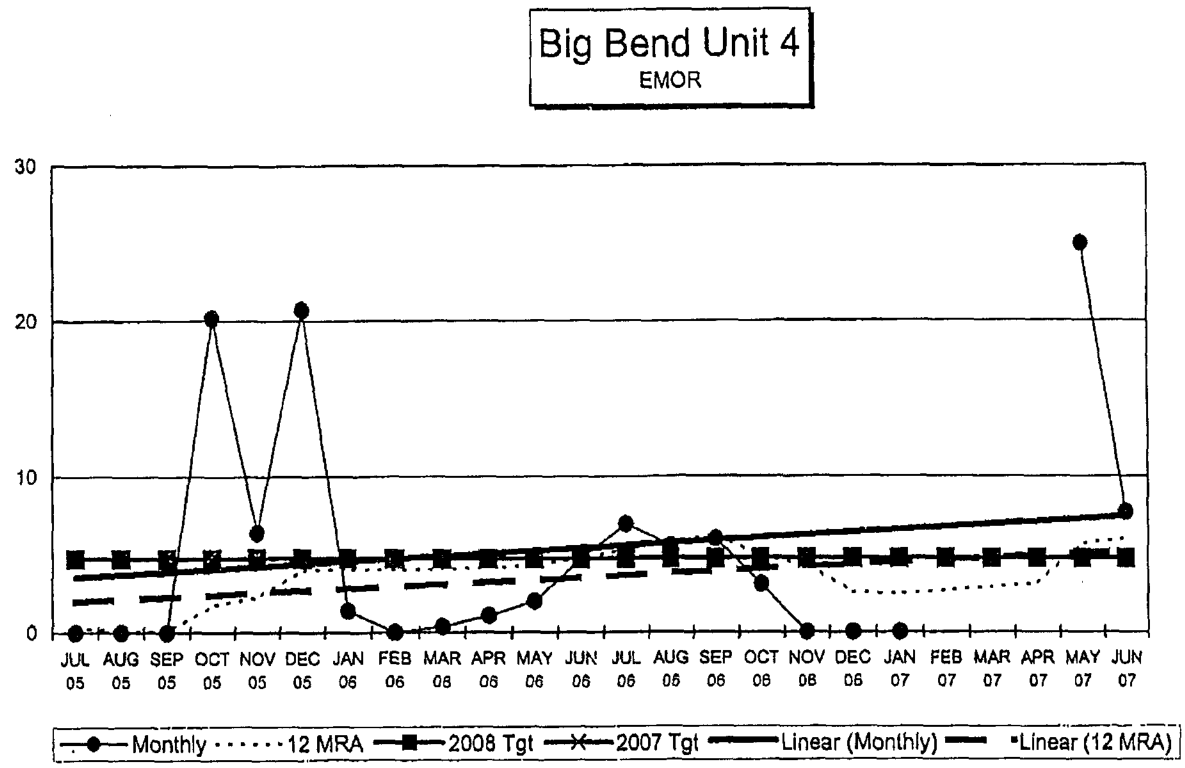
12 MRA= 12 Month Rolling Average





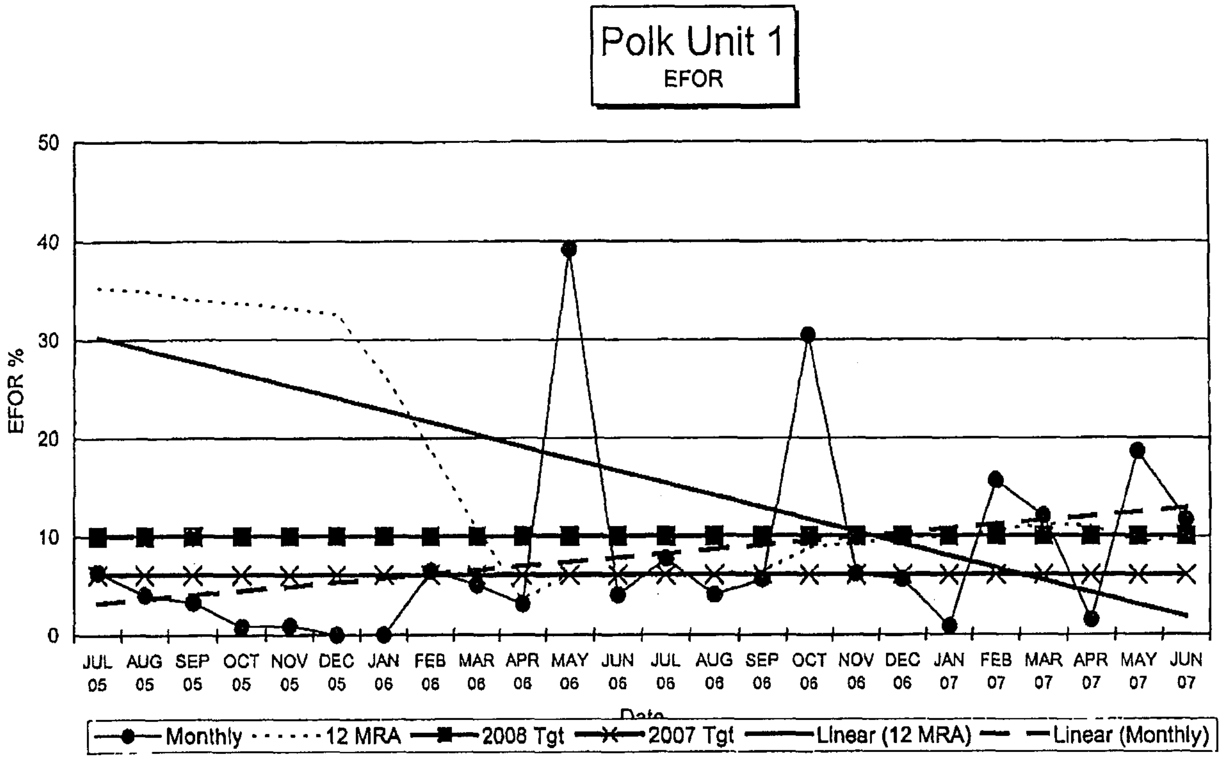
12 MRA = 12 Month Rolling Average

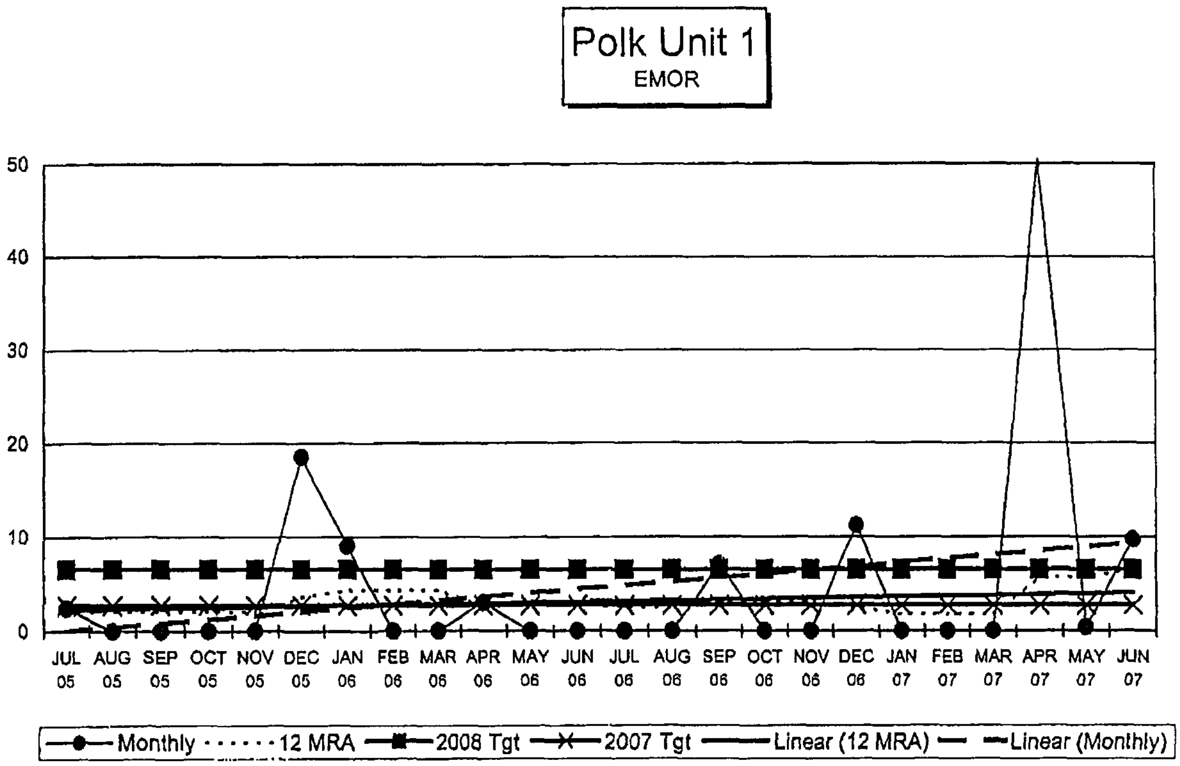




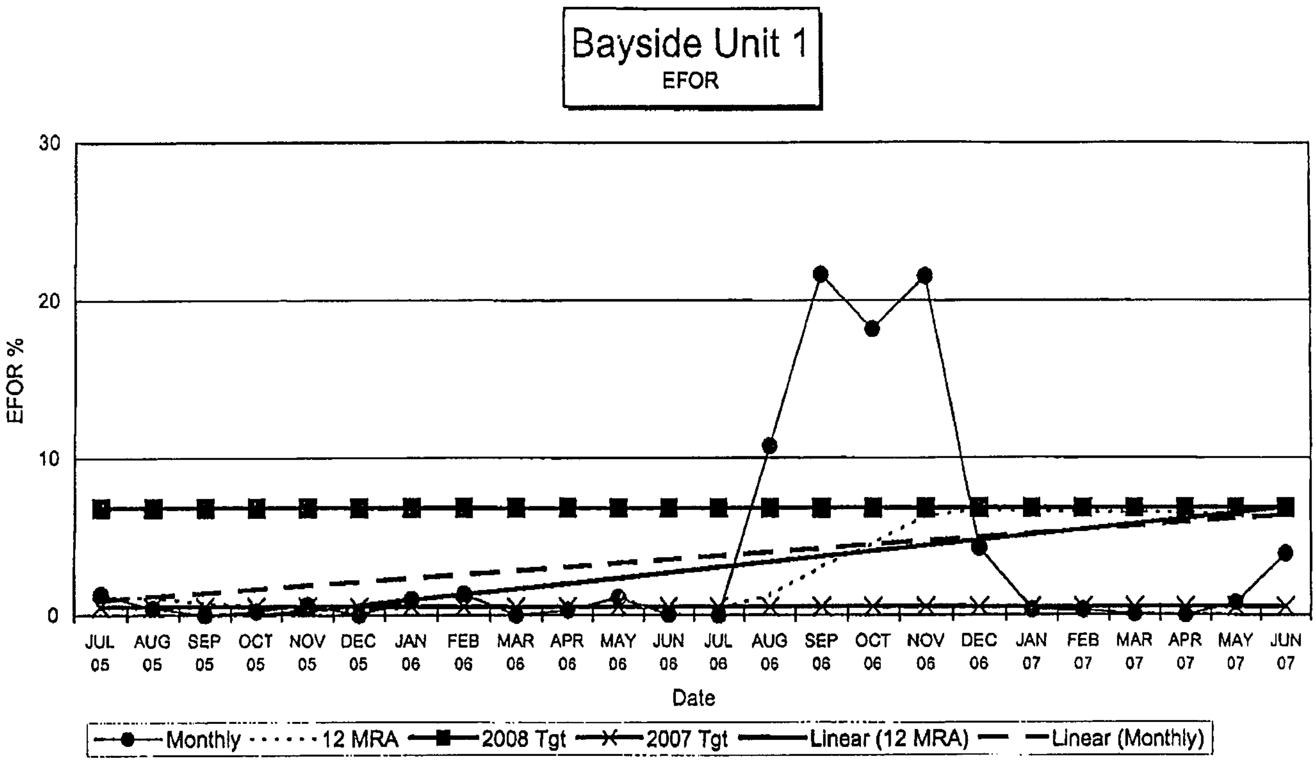
Note: Big Bend Unit 4 was offline for SCR installation from 2/1/2007 to 5/19/2007; therefore, data is not available for the months of February, March and April.

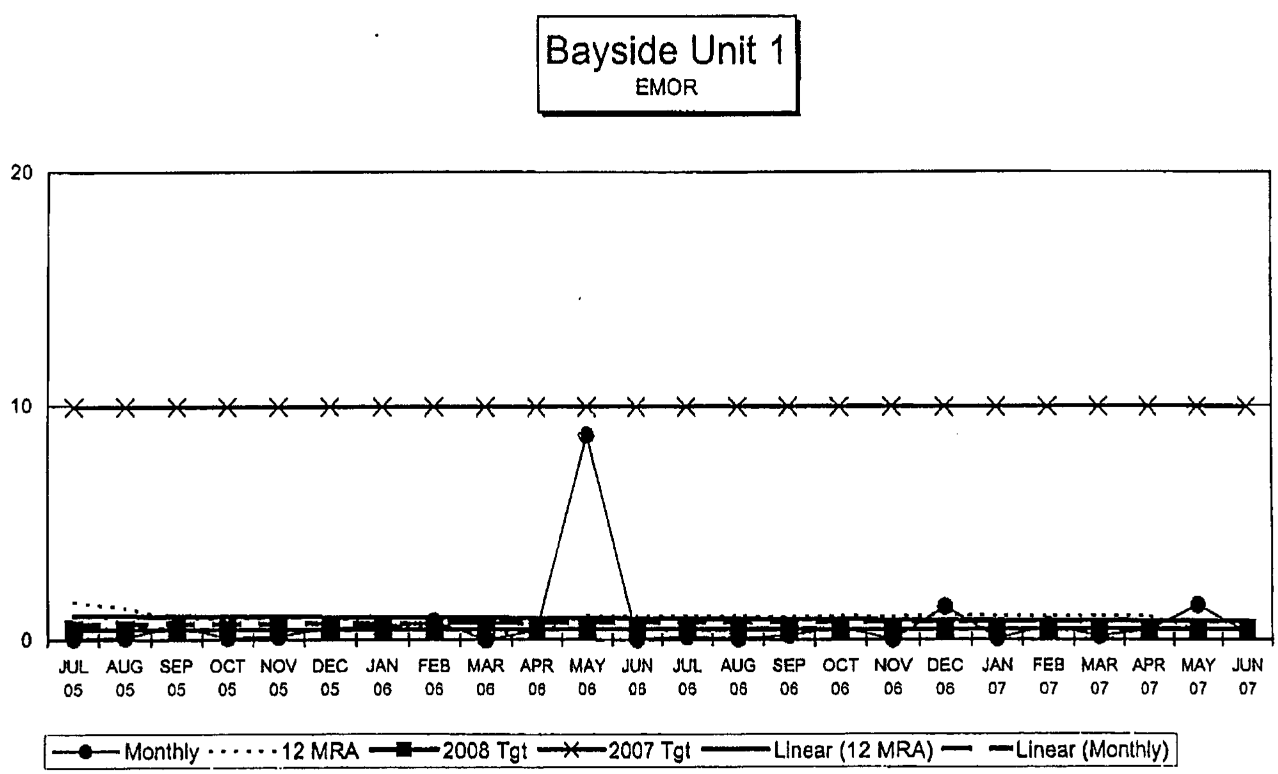
12 MRA = 12 Month Rolling Average





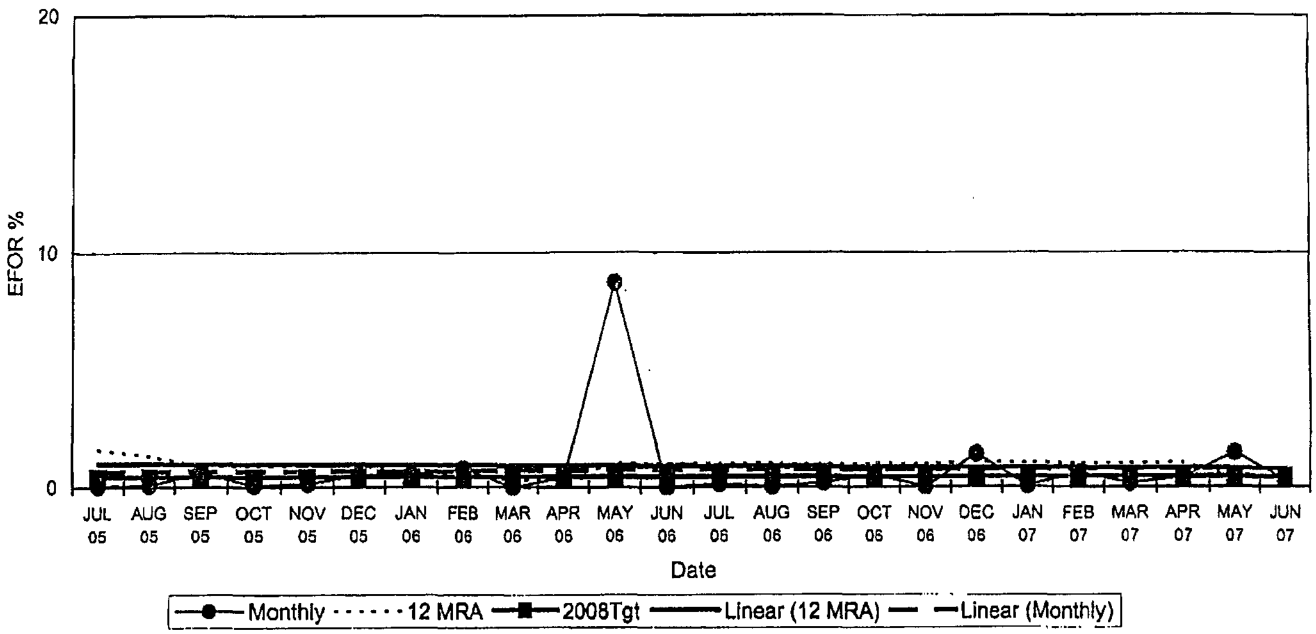
12 MRA = 12 Month Rolling Average



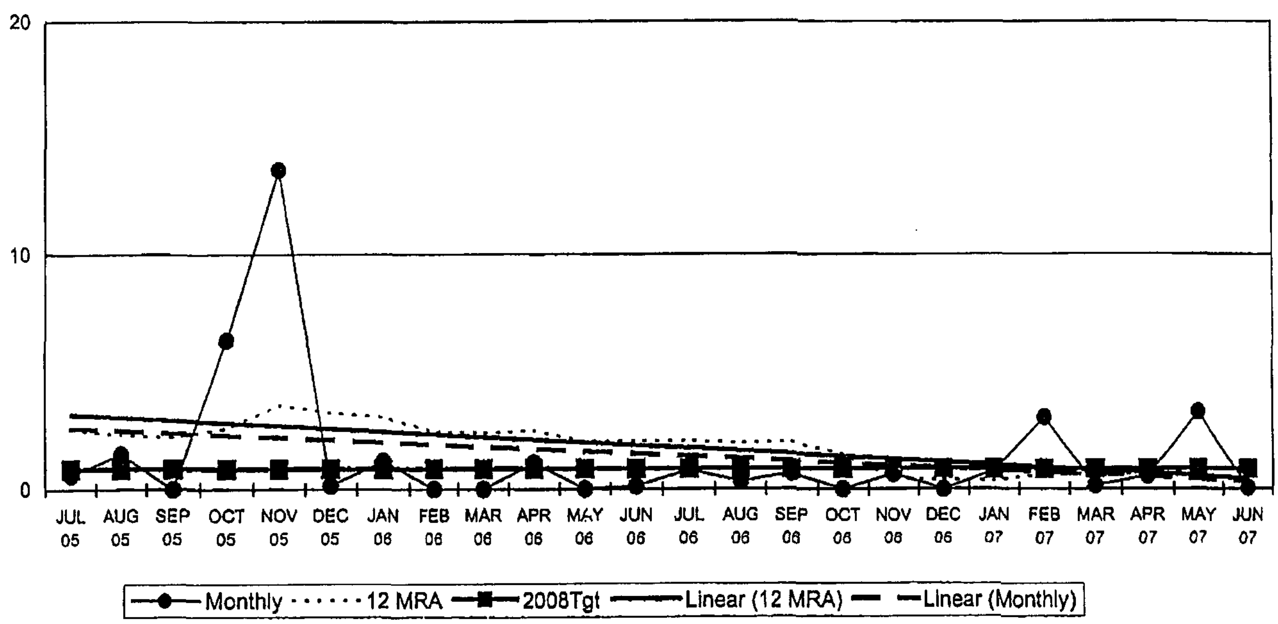


12 MRA = 12 Month Rolling Average

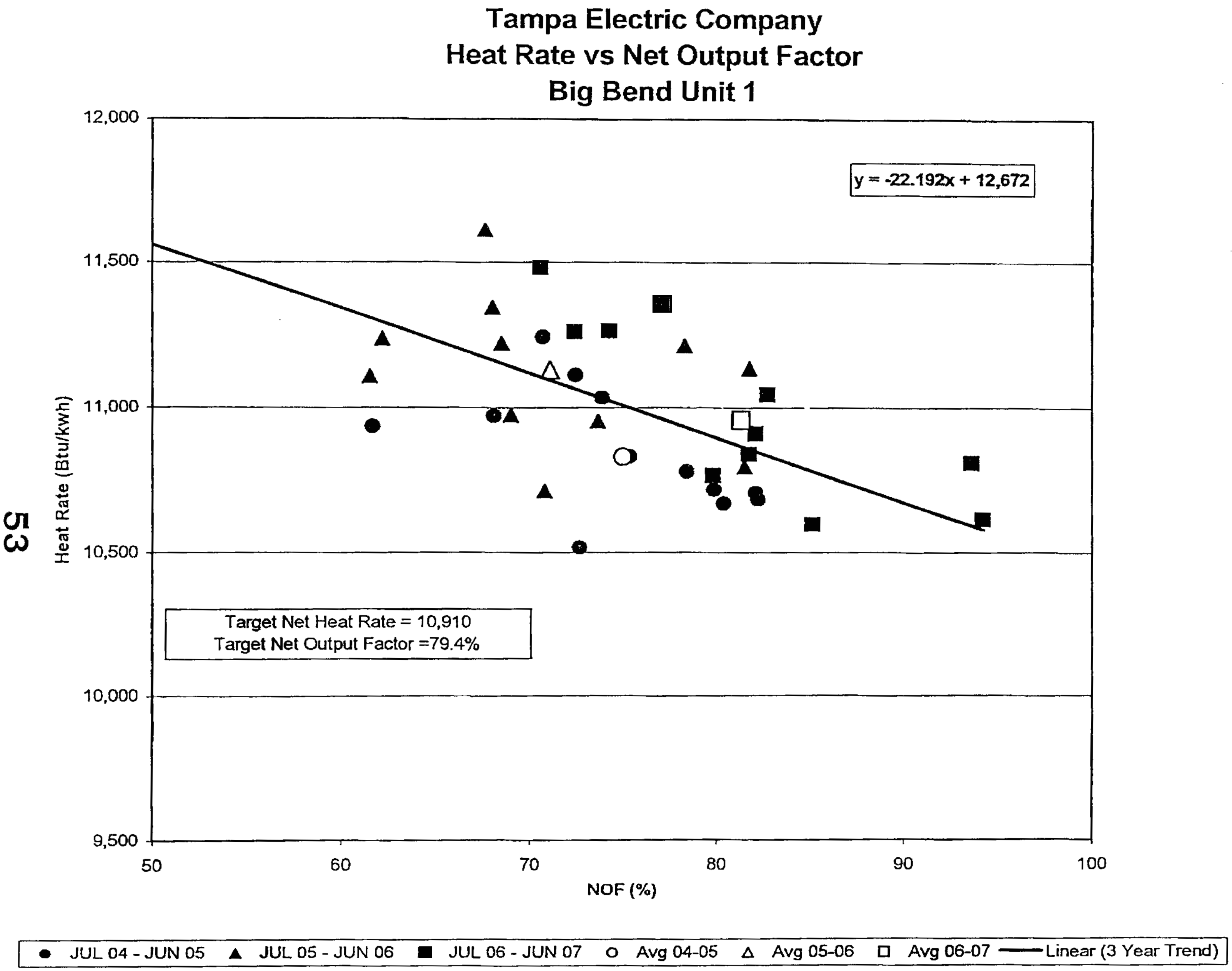
Bayside Unit 2
EFOR



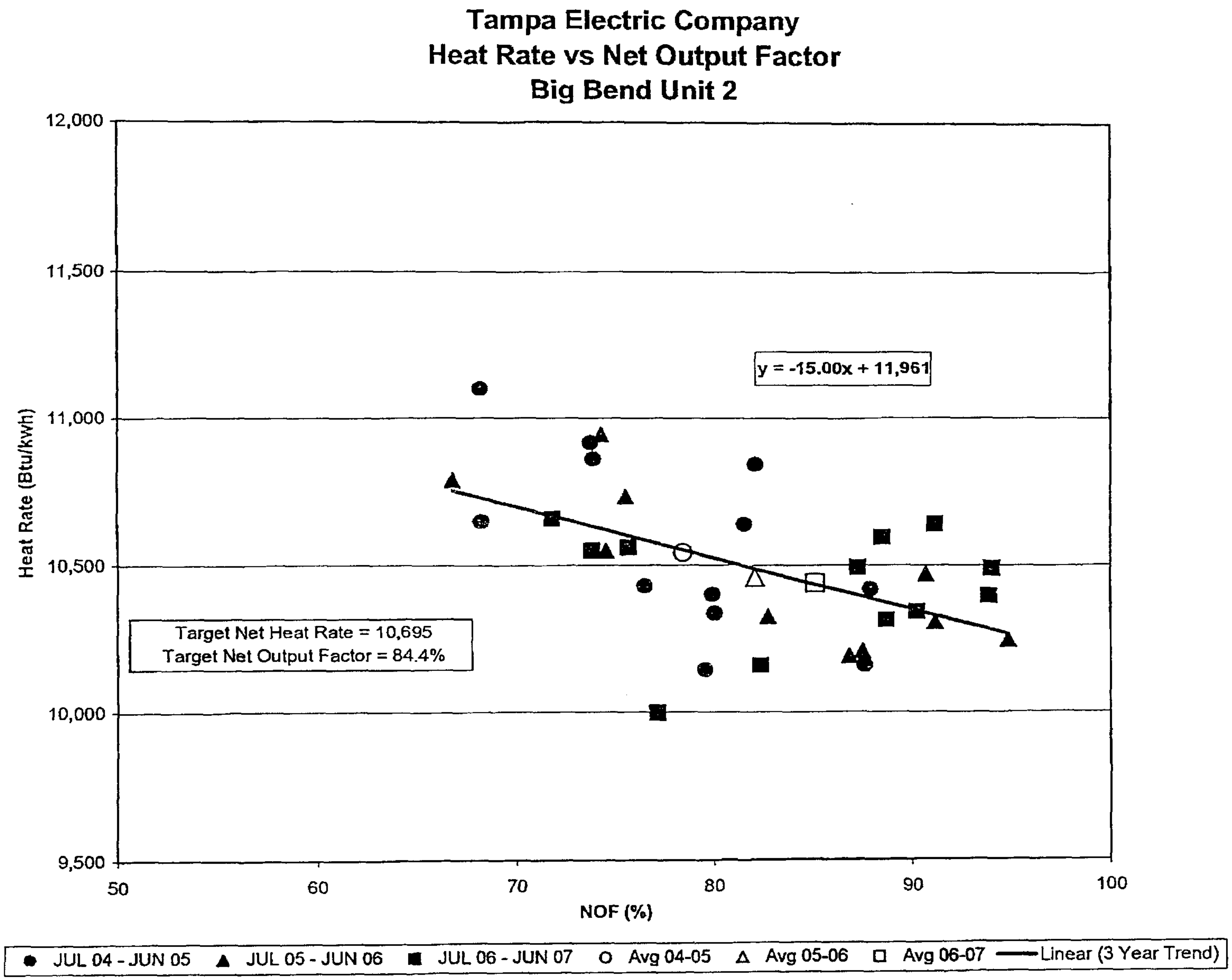
Bayside Unit 2
EMOR



12 MRA = 12 Month Rolling Average

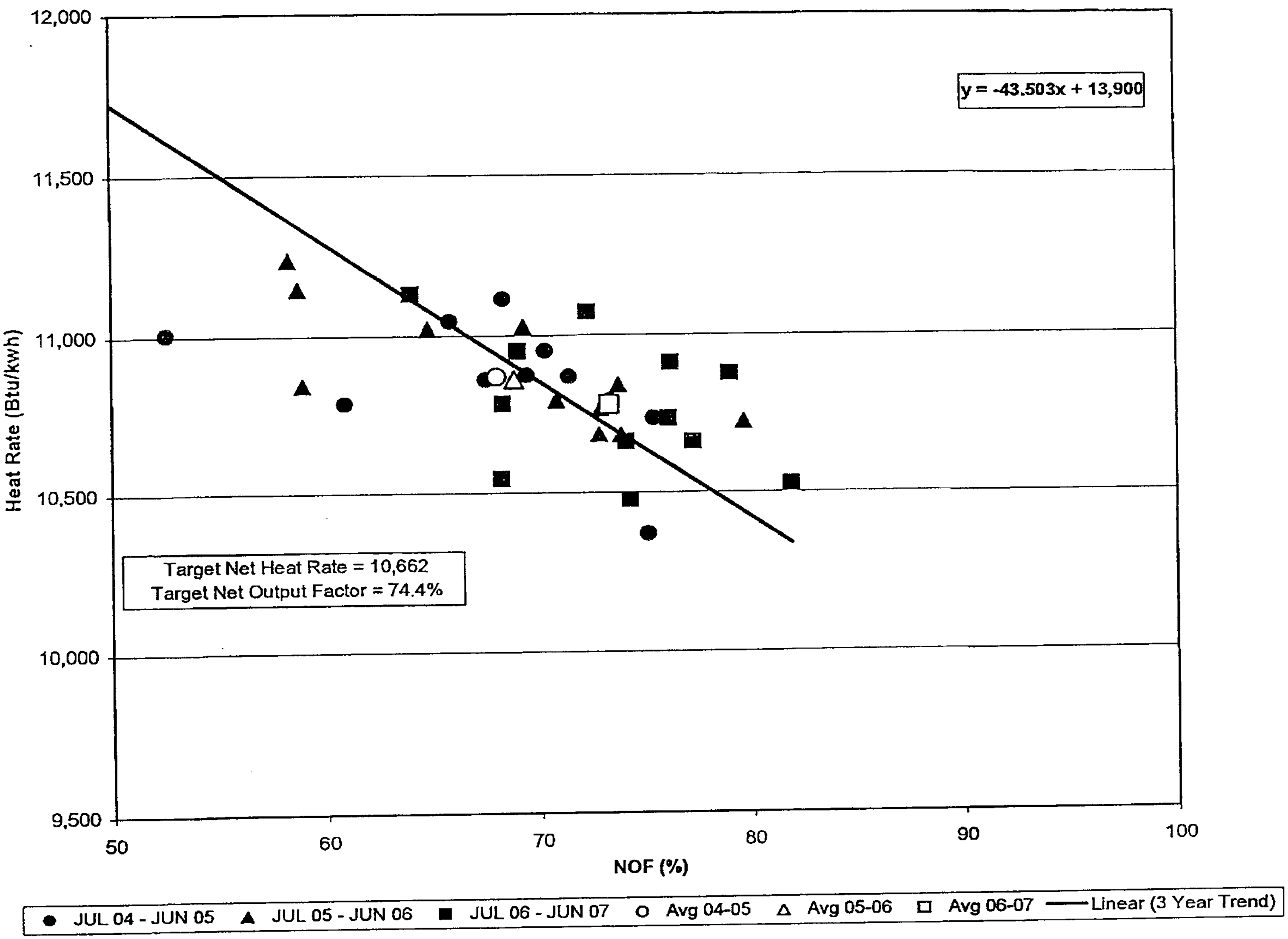

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1
y = -22.192x + 12,672
Target Net Heat Rate = 10,910
Target Net Output Factor =79.4%
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
50
60
70
80
90
100
NOF (%)
JUL 04 - JUN 05
JUL 05 - JUN 06
JUL 06 - JUN 07
Avg 04-05
Avg 05-06
Avg 06-07
Linear (3 Year Trend)

54

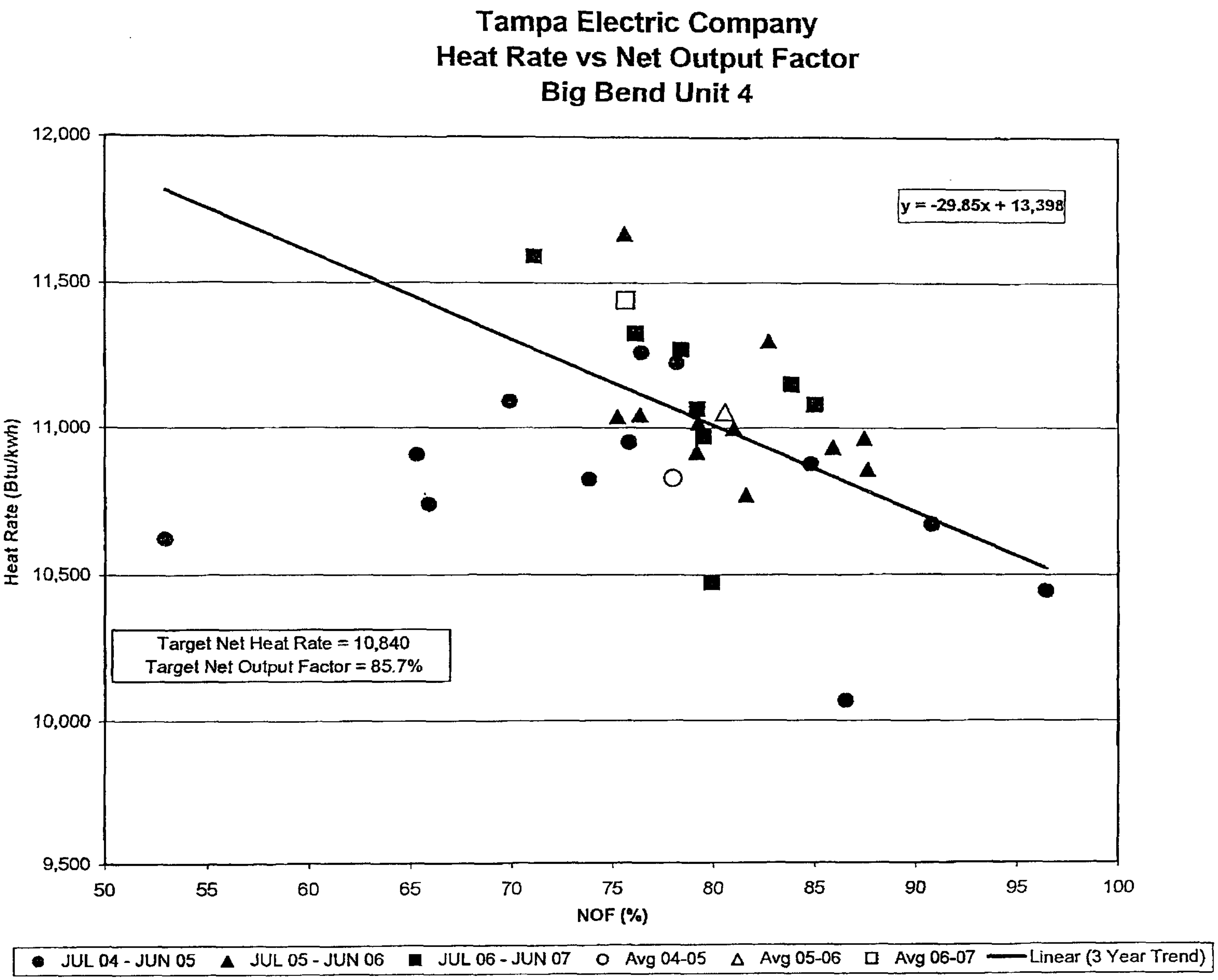


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
y = -15.00x + 11,961
Target Net Heat Rate = 10,695
Target Net Output Factor = 84.4%
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
50
60
70
80
90
100
NOF (%)
JUL 04 - JUN 05
JUL 05 - JUN 06
JUL 06 - JUN 07
Avg 04-05
Avg 05-06
Avg 06-07
Linear (3 Year Trend)

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



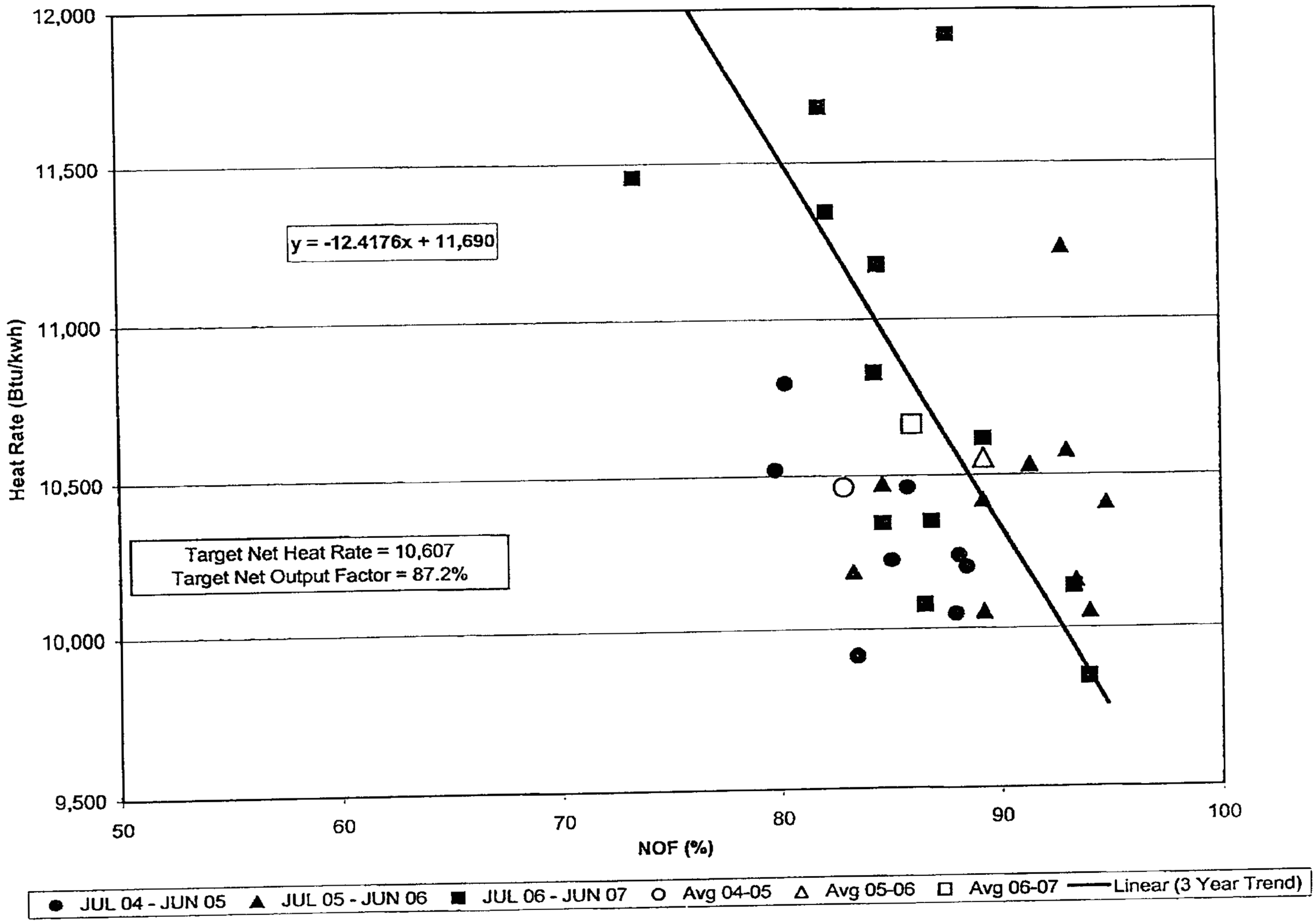
55



56

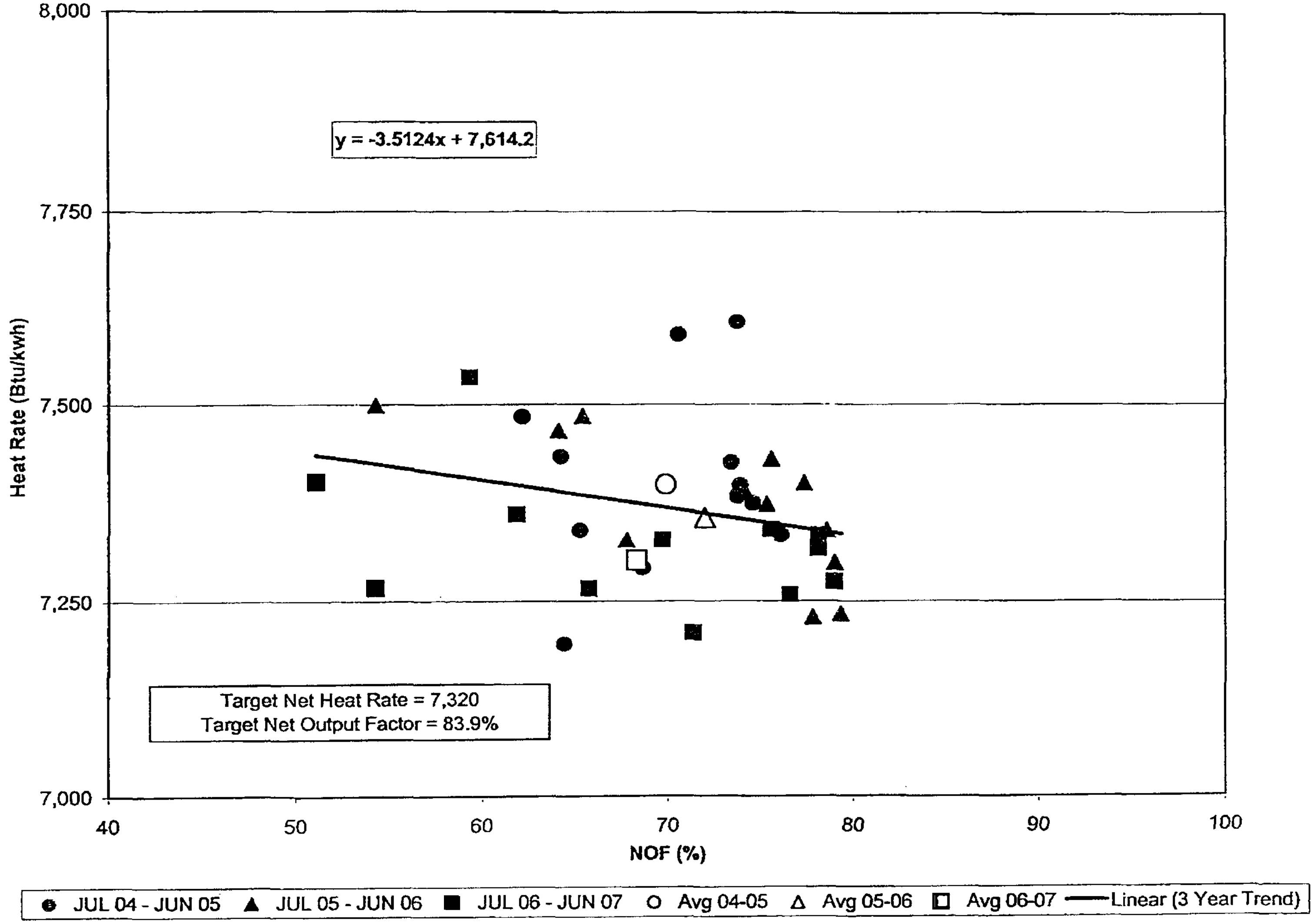
ORIGINAL SHEET NO. 8.401.07E
PAGE 36 OF 42

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

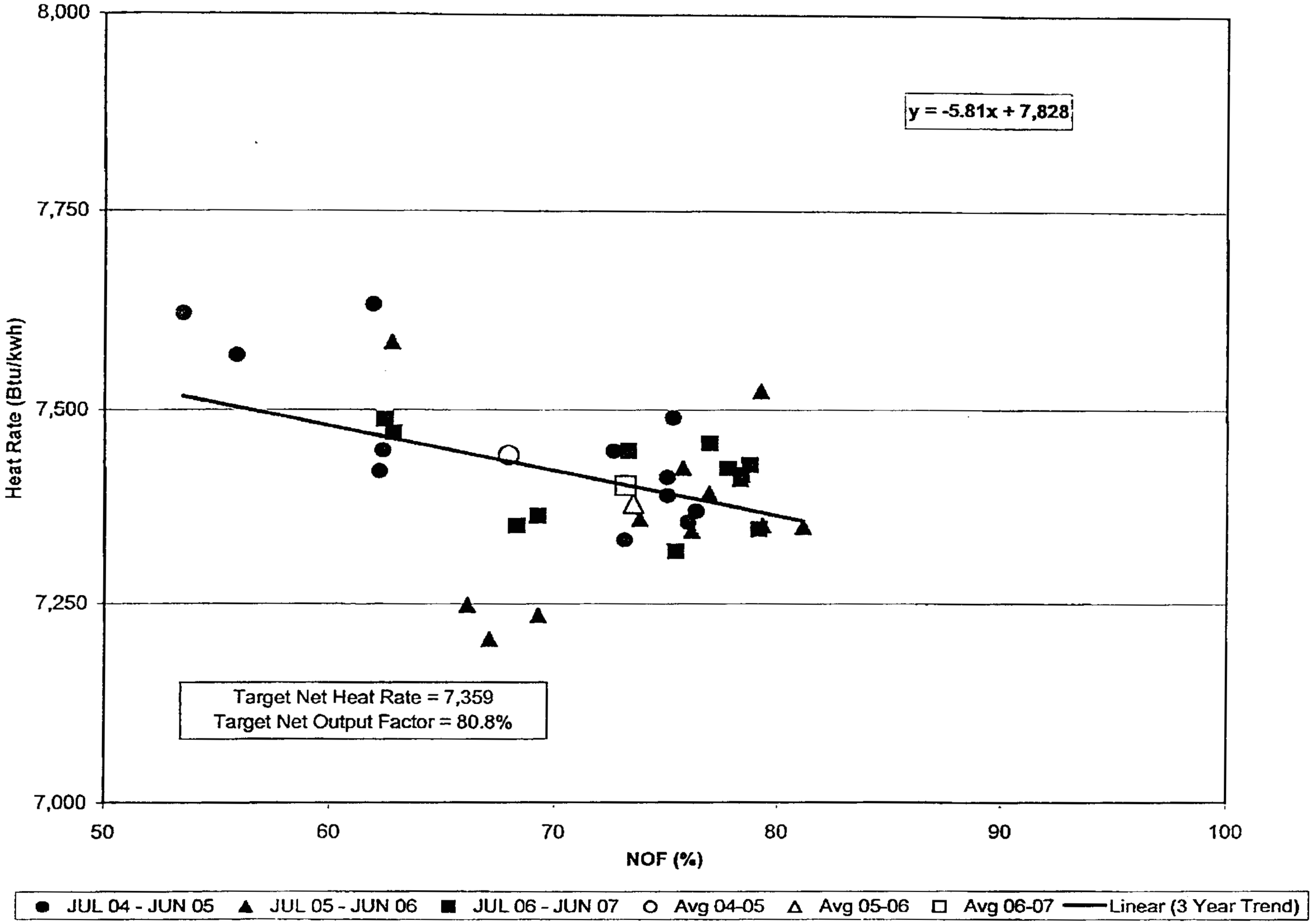


57

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



Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2008 - DECEMBER 2008

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		400.0	380.0
BIG BEND 2		410.0	390.0
BIG BEND 3		420.0	395.0
BIG BEND 4		470.0	437.0
POLK 1		325.0	257.5
BAYSIDE 1		801.0	747.5
BAYSIDE 2		1,058.0	989.0
	GPIF TOTAL	3,884.0	3,596.0
	SYSTEM TOTAL	**4,787.0**	**4,437.5**
	% OF SYSTEM TOTAL	**81.14%**	**81.04%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2008 - DECEMBER 2008

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		400.0	380.0
BIG BEND 2		410.0	390.0
BIG BEND 3		420.0	395.0
BIG BEND 4		470.0	437.0
	BIG BEND TOTAL	1,700.0	1,602.0
BIG BEND CT1		13.0	12.5
BIG BEND CT2		80.0	70.0
BIG BEND CT3		45.0	45.0
	CT TOTAL	138.0	127.5
PHILLIPS 1		18.5	17.5
PHILLIPS 2		18.5	17.5
	PHILLIPS TOTAL	37.0	35.0
POLK 1		325.0	257.5
POLK 2		184.0	172.0
POLK 3		184.0	172.0
POLK 4		180.0	167.5
POLK 5		180.0	167.5
	POLK TOTAL	1,053.0	936.5
BAYSIDE 1		801.0	747.5
BAYSIDE 2		1,058.0	989.0
	BAYSIDE TOTAL	1,859.0	1,736.5
	SYSTEM TOTAL	**4,787.0**	**4,437.5**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2008 - DECEMBER 2008

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,724,092	24.39%	24.39%
BAYSIDE	1	3,900,966	20.14%	44.53%
BIG BEND	4	2,640,478	13.63%	58.16%
BIG BEND	2	2,461,709	12.71%	70.87%
BIG BEND	1	2,131,133	11.00%	81.87%
POLK	1	1,599,260	8.26%	90.13%
BIG BEND	3	1,520,192	7.85%	97.98%
POLK	4	124,941	0.65%	98.62%
POLK	5	95,950	0.50%	99.12%
POLK	2	64,266	0.33%	99.45%
POLK	3	44,625	0.23%	99.68%
PHILLIPS	2	31,711	0.16%	99.84%
PHILLIPS	1	30,373	0.16%	100.00%
BIG BEND CT	2	169	0.00%	100.00%
BIG BEND CT	3	100	0.00%	100.00%
BIG BEND CT	1	14	0.00%	100.00%
TOTAL GENERATION		19,369,979	100.00%	

GENERATION BY COAL UNITS: 10,352,772 MWH

% GENERATION BY COAL UNITS 53.45%

GENERATION BY OIL UNITS: 62,367 MWH

% GENERATION BY OIL UNITS: 0.32%

GENERATION BY NATURAL GAS UNITS: 8,954,840 MWH

% GENERATION BY NATURAL GAS UNITS 46.23%

GENERATION BY GPIF UNITS: 18,977,830 MWH

% GENERATION BY GPIF UNITS: 97.98%

DOCKET NO. 070001-EI
GPIF 2008 PROJECTION FILING
EXHIBIT NO. DRK-2
DOCUMENT 2

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2008 - DECEMBER 2008

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2008 - DECEMBER 2008

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	72.1	3.8	24.0	10,910
Big Bend 2[2]	76.9	8.7	14.3	10,695
Big Bend 3[3]	47.0	26.5	26.5	10,662
Big Bend 4[4]	73.1	3.8	23.1	10,840
Polk 1[5]	77.2	7.9	14.9	10,607
Bayside 1[6]	84.5	3.8	11.7	7,320
Bayside 2[7]	83.6	15.3	1.1	7,359

1/ Original Sheet 8.401.07E, Page 14

2/ Original Sheet 8.401.07E, Page 15

3/ Original Sheet 8.401.07E, Page 16

4/ Original Sheet 8.401.07E, Page 17

5/ Original Sheet 8.401.07E, Page 18

6/ Original Sheet 8.401.07E, Page 19

7/ Original Sheet 8.401.07E, Page 20