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COMMISSION CLERK

September 1, 2010

HAND DELIVERED

Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 100001-EI

Dear Ms. Cole:

Enclosed for filing in the above docket on behalf of Tampa Electric Company are the original and fifteen (15) copies of each of the following:

1. Petition of Tampa Electric Company.
2. Prepared Direct Testimony and Exhibit (CA-3) of Carlos Aldazabal.
3. Prepared Direct Testimony and Exhibit (BSB-2) of Brian S. Buckley.
4. Prepared Direct Testimony of Benjamin F. Smith II.
5. Prepared Direct Testimony of Joann T. Wehle.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SSC
ADM
OPC
CLK CT.RPR

JDB/pp
Enclosures

cc: All Parties of Record (w/encls.)

DOCUMENT NUMBER-DATE
07381 SEP-1 ≌
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 100001-EI FILED: September 1, 2010

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "company"), hereby petitions the Commission for approval of the company's proposals concerning fuel and purchased power factors, capacity cost factors, generating performance incentive factors, and the projected wholesale sales incentive benchmark set forth herein, and in support thereof, says:

Fuel and Purchased Power Factors

1. Tampa Electric projects a fuel and purchased power net true-up amount for the period January 1, 2010 through December 31, 2010 will be an over-recovery of $67,087,873 (See Exhibit No. ____ (CA-3), Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2011 through December 31, 2011, when adjusted for the proposed GPIF reward and true-up over-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2011 through December 31, 2011, produce a fuel and purchased power factor for the new period of 4.225 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. ____ (CA-3), Document No. 2, Schedule E1-E).

3. The company's projected benchmark level for calendar year 2011 for gains on non-separated wholesale energy sales eligible for the shareholder incentive as set forth by Order

No. PSC-00-1744-PAA-EI, in Docket No. 991779 is $2,325,363, as provided in the direct testimony of Tampa Electric witness Carlos Aldazabal.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2010 through December 31, 2010 will be an under-recovery of $53,091, as shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 5.

5. As described in the direct testimony of Carlos Aldazabal, the company's proposed capacity factor for January through December 2011 reflects the rate modifications approved in Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009. The company's projected expenditures for the period January 1, 2011 through December 31, 2011, when adjusted for the true-up under-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of 0.291 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $1.07 per billed kW as set forth in Exhibit No. ____ (CA-3), Document No. 1, page 4 of 5.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF reward of $1,830,855 for performance experienced during the period January 1, 2009 through December 31, 2009.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2011 through December 31, 2011 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Brian S. Buckley filed herewith.

WHEREFORE, Tampa Electric Company requests that its proposals relative to fuel and purchased power cost recovery, capacity cost recovery and GPIF be approved as they relate to prior period true-up calculations and projected cost recovery charges, and that the Commission approve the company's projected wholesale sales incentive benchmark.

DATED this 1st day of September 2010.

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley & McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 1st day of September, 2010 to the following:

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ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY AND EXHIBIT

OF

CARLOS ALDAZABAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 15 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager, Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all cost recovery clauses.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2004, and I testified before this Florida Public Service Commission ("FPSC" or "Commission") in Docket Nos. 060001-EI and 080001-EI regarding the appropriateness and prudence of Tampa Electric's recoverable fuel and purchased power costs as well as capacity costs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2011 through December 2011. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2011.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. ____ (CA-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2011 through December 2011 as well as Schedule H1 for January through December, 2008 through 2011. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4. The capacity factors reflect the company's approved rate design modifications approved as part of Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009.

Q. Please describe the changes to the 2011 capacity cost recovery factors related to Tampa Electric's approved rate design approved in Order No. PSC-09-0283-FOF-EI.

A. As a result of Tampa Electric's base rate case, the Commission approved the consolidation of the company's General Service - Demand ("GSD") and General Service - Large Demand ("GSLD") rate customers into one new GSD rate class. Additionally, the allocation of production demand costs was modified to the 12 CP and 25 percent AD to better reflect cost causation. The Commission also approved the recovery of capacity costs through a factor applied to billed kW demand for demand-measured customers because that recovery method would be consistent with the recovery of production plant that otherwise would have been built.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2011 through December 2011.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor Cents per kW
RS Secondary	0.336	
GS and TS Secondary	0.294	
GSD, SBF Standard		
Secondary		1.07
Primary		1.06
Transmission		1.05
IS, IST, SBI		

Primary		0.87
Transmission		0.86
GSD Optional		
Secondary	0.255	
Primary	0.253	
LS1 Secondary	0.078	

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.291 cents per kWh compare to the factor for January 2010 through December 2010?

A. The proposed capacity cost recovery factor is 0.181 cents per kWh (or $1.81 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.472 cents per kWh for the January 2010 through December 2010 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2011?

A. The appropriate amount for the 2011 period is 4.225 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2011 through December 2011.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,830,855, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2010 through December 2010 period. The net true-up amount for this period is an over-recovery of $67,087,873.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2011 through

December 2011. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ____ (CA-3), Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2011 through December 2011.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	4.225
Tier I (Up to 1,000 kWh)	3.875
Tier II (Over 1,000 kWh)	4.875
Distribution Primary	4.183
Transmission	4.141
Lighting Service	4.134
Distribution Secondary	4.817 (on-peak)
	3.994 (off-peak)
Distribution Primary	4.769 (on-peak)
	3.954 (off-peak)
Transmission	4.721 (on-peak)
	3.914 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.225 cents per kWh compare to the levelized fuel adjustment factor for the January 2010 through December 2010 period?

A. The proposed fuel charge factor is 0.292 cents per kWh (or $2.92 per 1,000 kWh) lower than the average fuel charge factor of 4.517 cents per kWh for the January 2010 through December 2010 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2011 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events. These are 1) the continued decline in natural gas prices and related hedge results; and 2) the expiration of two existing firm purchase power cogeneration agreements with Hillsborough County and the City of Tampa.

Q. Please describe the first event that affects the company's projection filing.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Stations, Tampa Electric has increased its reliance on natural gas as a fuel source. In the fall of 2008 the prolonged economic downturn resulted in a dramatic decline in fuel commodity prices, particularly natural gas, which has resulted in a significant decrease in fuel and purchased power costs. In order to minimize fuel price volatility and comply with the company's Commission approved Risk Management Plan, financial hedges were entered into for natural gas in 2010 and 2011 which have partially mitigated some of that benefit. Witness J. T. Wehle's direct testimony describes the decrease in natural gas costs and associated hedge results in more detail.

Q. Please describe the second event.

A. Entering 2010 Tampa Electric had firm purchase power agreements with Hillsborough County for 23 MW and the City of Tampa for 19 MW, respectively. On March 1, 2010, the Hillsborough County agreement expired as both the County and Tampa Electric were unable to reach agreement on terms that would be acceptable to both parties. Similarly, Tampa Electric and the City of Tampa agreed to mutually terminate a December 2008 renegotiated extension of their agreement beyond August 1, 2011 when the parties were unable to successfully renegotiate some of the terms of that extension. The expiration of both agreements results in a significant reduction in capacity costs as well as a reduction in as-available energy payments.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2011?

A. The company's projected 2011 benchmark is $2,325,363, which is the three-year average of $1,676,141, $3,533,488 and $1,766,461 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2008, 2009 and 2010 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2011 from non-separated wholesale sales to exceed its 2011 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2011. Therefore, all sales margins will flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $5.22 beginning January 2011. These charges are shown in Exhibit No. ____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2011 - DECEMBER 2011

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2011 THROUGH DECEMBER 2011
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)
RS,RSVP	54.79%	8,863,147	1,847	1.08070	1.05580	9,357,688	1,996	46.99%	56.74%
GS, TS	65.43%	1,064,630	186	1.08070	1.05578	1,124,019	201	5.64%	5.71%
GSD Optional	4.00%	390,057	56	1.07588	1.05197	410,326	61	2.06%	1.73%
GSD, SBF	75.00%	7,310,448	1,056	1.07588	1.05197	7,690,338	1,137	38.62%	32.32%
IS,SBI	103.01%	1,066,368	118	1.03248	1.01870	1,086,314	122	5.46%	3.47%
LS1	2445.31%	231,963	1	1.08070	1.05580	244,906	1	1.23%	0.03%
TOTAL		18,926,613	3,264			19,913,591	3,518	100.00%	100.00%

(1) AVG 12 CP load factor based on 2010 projected calendar data.
(2) Projected MWH sales for the period January 2011 thru December 2011.
(3) Based on 12 months average CP at meter.
(4) Based on 2010 projected demand losses.
(5) Based on 2010 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2011 THROUGH DECEMBER 2011
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	3,998,430	3,998,430	3,998,430	3,998,420	3,381,330	3,381,320	3,381,330	3,381,330	3,381,330	3,381,330	3,381,320	3,381,330	43,044,330
2	CAPACITY PAYMENTS TO COGENERATORS	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	986,010	986,010	986,010	986,010	14,411,800
3	(UNIT POWER CAPACITY REVENUES)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,627)	(66,621)	(799,518)
4	TOTAL CAPACITY DOLLARS	$5,240,273	$5,240,273	$5,240,273	$5,240,263	$4,623,173	$4,623,163	$4,623,173	$4,623,173	$4,300,713	$4,300,713	$4,300,703	$4,300,719	$56,656,612
5	SEPARATION FACTOR	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
6	JURISDICTIONAL CAPACITY DOLLARS	$5,069,869	$5,069,869	$5,069,869	$5,069,860	$4,472,836	$4,472,827	$4,472,836	$4,472,836	$4,160,862	$4,160,862	$4,160,852	$4,160,868	$54,814,246
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2010 - DEC. 2010													53,091
8	TOTAL													$54,867,337
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$54,906,841

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2011 THROUGH DECEMBER 2011
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	46.99%	56.74%	6,450,182	23,365,607	29,815,789	8,863,147	8,863,147				0.00336
GS, TS	5.64%	5.71%	774,186	2,351,385	3,125,571	1,064,630	1,064,630				0.00294
GSD, SBF											
Secondary						6,025,287	6,025,287			1.07	
Primary						1,275,989	1,263,229			1.06	
Transmission						9,172	8,989			1.05	
GSD, SBF - Standard	38.62%	32.32%	5,301,255	13,309,418	18,610,673	7,310,448	7,297,505	57.63%	17,347,485		
GSD - Optional	2.06%	1.73%	282,770	712,416	995,186						
Secondary						380,665	380,665				0.00255
Primary						9,392	9,298				0.00253
IS, SBI											
Primary						302,459	299,434			0.87	
Transmission						763,909	748,631			0.86	
Total IS, SBI	5.46%	3.47%	749,478	1,428,951	2,178,429	1,066,368	1,048,065	58.29%	2,462,951		
LS1	1.23%	0.03%	168,839	12,354	181,193	231,963	231,963				0.00078
TOTAL	100.00%	100.00%	13,726,710	41,180,131	54,906,841	18,926,613	18,895,273				0.00291

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * .25 * Col (1).
(4) Total capacity costs * .75 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2011 through December 2011.
(7) Projected kWh sales at secondary for the period January 2011 through December 2011.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2011 through December 2011.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

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REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
MCKAY BAY REFUSE	8/26/1982	7/31/2011	QF
ORANGE COGEN LP	4/17/1989	12/31/2015	QF
HARDEE POWER PARTNERS	1/1/1993	12/31/2012	LT
SEMINOLE ELECTRIC	6/1/1992	12/31/2012	LT
CALPINE	5/1/2006	4/30/2011	LT
RELIANT	1/1/2009	5/31/2012	LT
PASCO COGEN	1/1/2009	12/31/2018	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT TERM

CONTRACT YEAR 2011	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
MCKAY BAY REFUSE	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	0.0	0.0	0.0	0.0
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
HARDEE POWER PARTNERS	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0
CALPINE	170.0	170.0	170.0	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RELIANT	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
PASCO COGEN	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
SEMINOLE ELECTRIC	4.6	4.6	5.0	6.0	4.2	4.6	5.0	5.8	4.7	4.6	3.9	3.9

CAPACITY YEAR 2011	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
MCKAY BAY REFUSE	322,460	322,460	322,460	322,460	322,460	322,460	322,460	322,460	0	0	0	0	2,579,680
ORANGE COGEN LP	986,010	986,010	986,010	986,010	986,010	986,010	986,010	986,010	986,010	986,010	986,010	986,010	11,832,120
TOTAL COGENERATION	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	1,308,470	986,010	986,010	986,010	986,010	14,411,800
HARDEE POWER PARTNERS	[redacted]												
CALPINE - D													
RELIANT ENERGY SERVICES - D													
PASCO COGEN - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	3,998,430	3,998,430	3,998,430	3,998,420	3,381,330	3,381,320	3,381,330	3,381,330	3,381,330	3,381,330	3,381,320	3,381,330	43,044,330
TOTAL CAPACITY	**$5,306,900**	**$5,306,900**	**$5,306,900**	**$5,306,890**	**$4,689,800**	**$4,689,790**	**$4,689,800**	**$4,689,800**	**$4,367,340**	**$4,367,340**	**$4,367,330**	**$4,367,340**	**$57,456,130**

Docket No. 100001-EI
FAC 2011 Projection Filing
Exhibit No. ____ (CA-3)
Document No. 2

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY
JANUARY 2011 - DECEMBER 2011

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

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PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2011 - DEC. 2011)
3	Schedule E1-A Calculation of Total True-Up	(")
4	Schedule E1-C GPIF & True-Up Adj. Factors	(")
5	Schedule E1-D Fuel Adjustment Factor for TOD	(")
6	Schedule E1-E Fuel Recovery Factor-with Line Losses	(")
7	Schedule E2 Cost Recovery Clause Calculation (By Month)	(")
8-9	Schedule E3 Generating System Comparative Data	(")
10-21	Schedule E4 System Net Generation & Fuel Cost	(")
22-23	Schedule E5 Inventory Analysis	(")
24-25	Schedule E6 Power Sold	(")
26-27	Schedule E7 Purchased Power	(")
28	Schedule E8 Energy Payment to Qualifying Facilities	(")
29	Schedule E9 Economy Energy Purchases	(")
30	Schedule E10 Residential Bill Comparison	(")
31	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2008-2011)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	809,526,621	18,989,720	4.26297
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustments to Fuel Cost (Wauchula Wheeling)	(72,000)	18,989,720 [1]	(0.00038)
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)**	**809,454,621**	**18,989,720**	**4.26259**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	25,521,760	395,670	6.45026
7.	Energy Cost of Economy Purchases (E9)	13,530,260	291,570	4.64048
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	30,022,870	571,920	5.24949
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**69,074,890**	**1,259,160**	**5.48579**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,248,880	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	620,420	13,720	4.52201
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	7,707,893	162,000	4.75796
14.	Gains on Sales	771,637	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**9,099,950**	**175,720**	**5.17866**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		2,865	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**869,429,561**	**20,070,295**	**4.33192**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,559,491 [1]	36,000	0.00817
22.	T & D Losses	40,939,165 [1]	945,058	0.21446
23.	System MWH Sales	869,429,561	19,089,236	4.55455
24.	Wholesale MWH Sales	(7,316,440)	(162,623)	4.49901
25.	Jurisdictional MWH Sales	862,113,121	18,926,613	4.55503
26.	Jurisdictional Loss Multiplier			1.00098
27.	Jurisdictional MWH Sales Adjusted for Line Loss	862,959,690	18,926,613	4.55950
28.	True-up [2]	(67,087,873)	18,926,613	(0.35446)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF and Incl. WCT)	795,871,817	18,926,613	4.20504
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	796,444,844	18,926,613	4.20807
32.	GPIF Adjusted for Taxes [2]	1,830,855	18,926,613	0.00967
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	798,275,699	18,926,613	4.21774
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**4.218**

[a] Data not available at this time.
[1] Included For Informational Purposes Only
[2] Calculation Based on Jurisdictional KWH Sales

TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2010 - December 2010 (6 months actual, 6 months estimated)	$52,979,582
2.	FINAL TRUE-UP (January 2009 - December 2009) (Per True-Up filed March 12, 2010)	14,108,291
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2011 through December 2011 (Schedule E1, line 28)	$67,087,873
4.	JURISDICTIONAL MWH SALES (Projected January 2011 through December 2011)	18,926,613
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.3545)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2011 through December 2011)	$1,830,855	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2010 through December 2010)	$67,087,873	
2.	TOTAL SALES (January 2011 through December 2011)	18,926,613	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0097**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.3545)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	28.05	$38.82
OFF PEAK	71.95	$32.19
	100.00	1.2060

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$862,113,121		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,926,613		
2a	Effective MWH Sales (Jurisd)		18,895,273		
3	Cost Per KWH Sold	(line 1 / line 2)	4.5550		
4	Jurisdictional Loss Factor		1.00098		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($67,087,873)		
7	TOTAL	(line 1 x line 4)+line 6	$795,871,817		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	4.2150		
10	GPIF Factor	(Sch E1-C line 3a)	0.0097		
11	Recovery Factor Including GPIF	(line 9 + line 10)	4.2247	4.8165	3.9939
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		4.225	4.817	3.994

13	Hours: ON PEAK	25.19% %
14	OFF PEAK	74.81% %
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,565,692	16,565,692
Distribution Primary	1,587,840	1,571,962
Transmission	773,081	757,619
Total	18,926,613	18,895,273

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SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		3.875	4.875
Distribution Secondary	4.225		
Distribution Primary	4.183		
Transmission	4.141		
Lighting Service [(1)]	4.134		
TIME-OF-USE			
Distribution Secondary - On-Peak	4.817		
Distribution Secondary - Off-Peak	3.994		
Distribution Primary - On-Peak	4.769		
Distribution Primary - Off-Peak	3.954		
Transmission - On-Peak	4.721		
Transmission - Off-Peak	3.914		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(g)	(h)	(i)	(j)	(k)	(l)	(m) TOTAL PERIOD
		Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	
1.	Fuel Cost of System Net Generation	57,908,232	53,397,612	57,165,461	57,245,790	69,622,965	76,737,390	81,836,606	84,309,941	77,845,877	71,742,781	60,315,232	61,398,733	809,526,621
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	680,310	454,020	580,730	407,670	566,250	777,210	1,101,130	1,129,890	983,560	984,180	601,590	833,410	9,099,950
4.	Fuel Cost of Purchased Power	90,990	148,400	562,900	1,938,700	4,313,020	3,767,290	3,025,400	3,134,420	3,197,390	1,738,550	1,299,210	2,305,490	25,521,760
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	2,508,910	2,181,240	2,466,530	2,592,030	3,139,560	2,810,410	2,852,930	2,438,450	2,338,620	2,237,610	2,185,010	2,271,570	30,022,870
7.	Energy Cost of Economy Purchases	542,330	213,290	557,610	1,320,530	2,927,600	821,450	556,390	634,430	2,134,630	1,542,740	256,810	2,022,450	13,530,260
8a.	Adj. to Fuel Cost (Wauchula Wheeling)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(72,000)
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**60,364,152**	**55,480,522**	**60,165,771**	**62,683,380**	**79,430,895**	**83,353,330**	**87,164,196**	**89,381,351**	**84,526,957**	**76,271,501**	**63,448,672**	**67,158,833**	**869,429,561**
10.	Jurisdictional MWH Sold	1,483,475	1,354,779	1,322,134	1,376,953	1,517,691	1,762,146	1,841,191	1,842,518	1,877,687	1,679,981	1,441,389	1,426,669	18,926,613
11.	Jurisdictional % of Total Sales	0.9933091	0.9780148	0.9917797	0.9906489	0.9908908	0.9927556	0.9928640	0.9922011	0.9938509	0.9951954	0.9910567	0.9923774	
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	59,960,262	54,260,771	59,671,191	62,097,222	78,707,343	82,749,485	86,542,193	88,684,275	84,007,192	75,905,047	62,881,232	66,646,908	862,113,121
13.	Jurisdictional Loss Multiplier	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	1.00098	
14.	**JURISD. TOTAL FUEL & NET PWR. TRANS.** Adjusted for Line Losses (Line 12 * Line 13)	**60,019,141**	**54,314,053**	**59,729,786**	**62,158,200**	**78,784,631**	**82,830,742**	**86,627,175**	**88,771,360**	**84,089,684**	**75,979,583**	**62,942,979**	**66,712,353**	**862,959,687**
15.	Cost Per kWh Sold (Cents/kWh)	4.0458	4.0091	4.5177	4.5142	5.1911	4.7006	4.7050	4.8179	4.4784	4.5226	4.3668	4.6761	4.5595
16.	True-up (Cents/kWh) [2]	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545	-0.3545
17.	Total (Cents/kWh) (Line 15+16)	3.6913	3.6546	4.1632	4.1597	4.8366	4.3461	4.3505	4.4634	4.1239	4.1681	4.0123	4.3216	4.2050
18.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
19.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.6940	3.6572	4.1662	4.1627	4.8401	4.3492	4.3536	4.4666	4.1269	4.1711	4.0152	4.3247	4.2080
20.	GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097
21.	**TOTAL RECOVERY FACTOR (LINE 19+20)**	**3.7037**	**3.6669**	**4.1759**	**4.1724**	**4.8498**	**4.3589**	**4.3633**	**4.4763**	**4.1366**	**4.1808**	**4.0249**	**4.3344**	**4.2177**
22.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.704**	**3.667**	**4.176**	**4.172**	**4.850**	**4.359**	**4.363**	**4.476**	**4.137**	**4.181**	**4.025**	**4.334**	**4.218**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

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TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH JUNE 2011

SCHEDULE E3

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	719,708	281,010	717,065	787,819	970,490	960,945
3. COAL	36,159,451	26,386,406	32,115,581	35,026,597	37,974,298	37,610,989
4. NATURAL GAS	21,029,073	26,730,196	24,332,815	21,431,374	30,678,177	38,165,456
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**57,908,232**	**53,397,612**	**57,165,461**	**57,245,790**	**69,622,965**	**76,737,390**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	4,060	1,580	4,000	4,340	5,310	5,220
10. COAL	1,066,300	758,990	912,240	995,940	1,077,060	1,058,270
11. NATURAL GAS	393,750	546,720	487,000	382,390	524,600	716,060
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,464,110**	**1,307,290**	**1,403,240**	**1,382,670**	**1,606,970**	**1,779,550**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	10,970	8,220	13,500	12,380	13,270	14,000
17. COAL (TON)	471,700	339,580	401,630	439,870	475,830	467,410
18. NATURAL GAS (MCF)	2,873,390	3,908,270	3,494,140	2,867,860	4,060,030	5,444,730
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	42,960	16,720	42,140	45,970	56,340	55,330
23. COAL	11,160,970	7,956,080	9,537,640	10,417,820	11,256,620	11,052,820
24. NATURAL GAS	2,953,840	4,017,740	3,591,930	2,948,190	4,173,710	5,597,190
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**14,157,770**	**11,990,540**	**13,171,710**	**13,411,980**	**15,486,670**	**16,705,340**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.28	0.12	0.29	0.31	0.33	0.29
30. COAL	72.83	58.06	65.00	72.03	67.02	59.47
31. NATURAL GAS	26.89	41.82	34.71	27.66	32.65	40.24
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	65.61	34.19	53.12	63.64	73.13	68.64
37. COAL ($/TON)	76.66	77.70	79.96	79.63	79.81	80.47
38. NATURAL GAS ($/MCF)	7.32	6.84	6.96	7.47	7.56	7.01
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	16.75	16.81	17.02	17.14	17.23	17.37
43. COAL	3.24	3.32	3.37	3.36	3.37	3.40
44. NATURAL GAS	7.12	6.65	6.77	7.27	7.35	6.82
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.09**	**4.45**	**4.34**	**4.27**	**4.50**	**4.59**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,581	10,582	10,535	10,592	10,610	10,600
50. COAL	10,467	10,482	10,455	10,460	10,451	10,444
51. NATURAL GAS	7,502	7,349	7,376	7,710	7,956	7,817
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,670**	**9,172**	**9,387**	**9,700**	**9,637**	**9,387**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	17.73	17.79	17.93	18.15	18.28	18.41
57. COAL	3.39	3.48	3.52	3.52	3.53	3.55
58. NATURAL GAS	5.34	4.89	5.00	5.60	5.85	5.33
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.96**	**4.08**	**4.07**	**4.14**	**4.33**	**4.31**

SCHEDULE E3

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2011 THROUGH DECEMBER 2011

		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	951,813	942,418	917,741	737,872	803,043	811,467	9,601,392
3.	COAL	38,887,681	38,975,363	30,816,760	27,517,245	28,678,916	34,490,643	404,639,930
4.	NATURAL GAS	41,997,112	44,392,160	46,111,376	43,487,664	30,833,273	26,096,623	395,285,299
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**81,836,606**	**84,309,941**	**77,845,877**	**71,742,781**	**60,315,232**	**61,398,733**	**809,526,621**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	5,150	5,070	4,920	3,940	4,230	4,220	52,040
10.	COAL	1,093,810	1,095,140	855,240	764,800	792,090	961,870	11,431,750
11.	NATURAL GAS	809,220	858,060	909,680	860,890	573,680	443,880	7,505,930
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**1,908,180**	**1,958,270**	**1,769,840**	**1,629,630**	**1,370,000**	**1,409,970**	**18,989,720**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	12,960	12,810	12,510	9,820	13,950	13,080	147,470
17.	COAL (TON)	483,050	483,600	379,570	340,700	349,630	423,240	5,055,810
18.	NATURAL GAS (MCF)	6,058,700	6,436,730	6,797,020	6,349,770	4,237,300	3,276,400	55,804,340
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	54,480	53,600	51,880	41,440	44,750	44,890	550,500
23.	COAL	11,423,090	11,436,020	8,947,600	8,011,530	8,289,700	10,048,830	119,538,720
24.	NATURAL GAS	6,228,300	6,616,940	6,987,370	6,527,640	4,355,980	3,368,100	57,366,930
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,705,870**	**18,106,560**	**15,986,850**	**14,580,610**	**12,690,430**	**13,461,820**	**177,456,150**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.27	0.26	0.28	0.24	0.31	0.30	0.27
30.	COAL	57.32	55.92	48.32	46.93	57.82	68.22	60.20
31.	NATURAL GAS	42.41	43.82	51.40	52.83	41.87	31.48	39.53
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	73.44	73.57	73.36	75.14	57.57	62.04	65.11
37.	COAL ($/TON)	80.50	80.59	81.19	80.77	82.03	81.49	80.03
38.	NATURAL GAS ($/MCF)	6.93	6.90	6.78	6.85	7.28	7.97	7.08
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	17.47	17.58	17.69	17.81	17.95	18.08	17.44
43.	COAL	3.40	3.41	3.44	3.43	3.46	3.43	3.39
44.	NATURAL GAS	6.74	6.71	6.60	6.66	7.08	7.75	6.89
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**4.62**	**4.66**	**4.87**	**4.92**	**4.75**	**4.56**	**4.56**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,579	10,572	10,545	10,518	10,579	10,637	10,578
50.	COAL	10,443	10,443	10,462	10,475	10,466	10,447	10,457
51.	NATURAL GAS	7,697	7,712	7,681	7,582	7,593	7,588	7,643
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,279**	**9,246**	**9,033**	**8,947**	**9,263**	**9,548**	**9,345**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56.	LIGHT OIL	18.48	18.59	18.65	18.73	18.98	19.23	18.45
57.	COAL	3.56	3.56	3.60	3.60	3.62	3.59	3.54
58.	NATURAL GAS	5.19	5.17	5.07	5.05	5.37	5.88	5.27
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**4.29**	**4.31**	**4.40**	**4.40**	**4.40**	**4.35**	**4.26**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	237,580	80.8	85.0	89.4	10,330	COAL	103,510	23,710,946	2,454,320.0	7,629,748	3.21	73.71
2. B.B.#2	395	238,220	81.1	83.4	90.8	10,349	COAL	103,030	23,927,497	2,465,250.0	7,594,367	3.19	73.71
3. B.B.#3	365	207,060	76.2	85.4	84.4	10,585	COAL	95,470	22,957,264	2,191,730.0	7,037,118	3.40	73.71
4. B.B.#4	427	252,150	79.4	88.4	86.7	10,552	COAL	116,250	22,887,656	2,660,690.0	8,615,623	3.42	74.11
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	-	342,406	-	96.18
5. B.B. COAL	**1,582**	**935,010**	**79.4**	**85.6**	**87.9**	**10,451**		-	-	**9,771,990.0**	**31,219,262**	**3.34**	-
6. POLK #1 GASIFIER	220	131,290	80.2	-	-	10,579	COAL	53,440	25,991,392	1,388,980.0	4,940,189	3.76	92.44
7. POLK #1 CT OIL	235	4,060	2.3	-	-	10,581	LGT OIL	7,410	5,797,571	42,960.0	719,708	17.73	97.13
8. POLK #1 TOTAL	**220**	**135,350**	**82.7**	**85.9**	**96.1**	**10,580**		-	-	**1,431,940.0**	**5,659,897**	**4.18**	-
9. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
12. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
16. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	792	310,110	52.6	96.7	71.5	7,472	GAS	2,253,970	1,028,004	2,317,090.0	16,495,811	5.32	7.32
19. BAYSIDE #2	1,047	80,310	10.3	97.3	80.1	7,429	GAS	580,360	1,027,983	596,600.0	4,247,399	5.29	7.32
20. BAYSIDE #3	61	630	1.4	98.6	86.1	11,810	GAS	7,240	1,027,624	7,440.0	52,986	8.41	7.32
21. BAYSIDE #4	61	100	0.2	98.6	82.0	12,500	GAS	1,220	1,024,590	1,250.0	8,929	8.93	7.32
22. BAYSIDE #5	61	1,710	3.8	98.6	71.9	11,947	GAS	19,870	1,028,183	20,430.0	145,420	8.50	7.32
23. BAYSIDE #6	61	890	2.0	98.6	63.4	12,393	GAS	10,730	1,027,959	11,030.0	78,528	8.82	7.32
24. BAYSIDE TOTAL	**2,083**	**393,750**	**25.4**	**97.2**	**73.1**	**7,502**	**GAS**	**2,873,390**	**1,027,998**	**2,953,840.0**	**21,029,073**	**5.34**	**7.32**
25. B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
28. SYSTEM	**4,692**	**1,464,110**	**41.9**	**76.0**	**84.0**	**9,670**	-	-	-	**14,157,770.0**	**57,908,232**	**3.96**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	137,900	52.0	54.7	89.3	10,336	COAL	60,110	23,712,194	1,425,340.0	4,494,830	3.26	74.78
2. B.B.#2	395	141,490	53.3	56.6	88.0	10,364	COAL	61,290	23,925,763	1,466,410.0	4,583,067	3.24	74.78
3. B.B.#3	365	192,120	78.3	67.1	86.7	10,572	COAL	88,480	22,956,374	2,031,180.0	6,616,246	3.44	74.78
4. B.B.#4	427	236,300	82.4	88.4	90.0	10,548	COAL	108,900	22,888,522	2,492,560.0	8,189,994	3.47	75.21
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	5,340	-	-	517,913	-	96.99
5. B.B. COAL	**1,582**	**707,810**	**66.6**	**67.1**	**88.5**	**10,477**		-	-	**7,415,490.0**	**24,402,050**	**3.45**	-
6. POLK #1 GASIFIER	220	51,180	34.6	-	-	10,563	COAL	20,800	25,989,904	540,590.0	1,984,356	3.88	95.40
7. POLK #1 CT OIL	235	1,580	1.0	-	-	10,582	LGT OIL	2,880	5,805,556	16,720.0	281,010	17.79	97.57
8. POLK #1 TOTAL	**220**	**52,760**	**35.7**	**36.8**	**96.7**	**10,563**		-	-	**557,310.0**	**2,265,366**	**4.29**	-
9. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	(0)	0.00	0.00
11. POLK #2 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**(0)**	**0.00**	-
12. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
16. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	792	364,290	68.4	96.7	81.1	7,322	GAS	2,594,510	1,028,009	2,667,180.0	17,744,874	4.87	6.84
19. BAYSIDE #2	1,047	178,020	25.3	97.3	87.1	7,291	GAS	1,262,510	1,028,008	1,297,870.0	8,634,803	4.85	6.84
20. BAYSIDE #3	61	630	1.5	98.6	86.1	11,873	GAS	7,280	1,027,473	7,480.0	49,791	7.90	6.84
21. BAYSIDE #4	61	260	0.6	98.6	85.2	11,923	GAS	3,000	1,033,333	3,100.0	20,518	7.89	6.84
22. BAYSIDE #5	61	2,540	6.2	98.6	63.1	11,799	GAS	29,160	1,027,778	29,970.0	199,437	7.85	6.84
23. BAYSIDE #6	61	980	2.4	98.6	57.4	12,388	GAS	11,810	1,027,942	12,140.0	80,773	8.24	6.84
24. BAYSIDE TOTAL	**2,083**	**546,720**	**39.1**	**97.2**	**82.8**	**7,349**	**GAS**	**3,908,270**	**1,028,010**	**4,017,740.0**	**26,730,196**	**4.89**	**6.84**
25. B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
28. SYSTEM	**4,692**	**1,307,290**	**41.5**	**67.5**	**86.3**	**9,172**	-	-	-	**11,990,540.0**	**53,397,612**	**4.08**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2011

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	395	205,850	70.0	74.1	88.9	10,340	COAL	89,760	23,713,124	2,128,490.0	6,803,254	3.30	75.79
2.	B.B.#2	395	229,700	78.2	80.7	90.4	10,352	COAL	99,380	23,925,740	2,377,740.0	7,532,391	3.28	75.79
3.	B.B.#3	365	172,030	63.3	74.4	87.0	10,571	COAL	79,220	22,955,188	1,818,510.0	6,004,387	3.49	75.79
4.	B.B.#4	427	175,270	55.2	59.9	88.8	10,557	COAL	80,830	22,890,511	1,850,240.0	6,223,222	3.55	76.99
	B.B. IGNITION	-	-	-	-	-	-	LGT OIL	6,230	-	-	609,690	-	97.86
5.	**B.B. COAL**	**1,582**	**782,850**	**66.5**	**72.0**	**88.9**	**10,443**		**-**	**-**	**8,174,980.0**	**27,172,944**	**3.47**	**-**
6.	POLK #1 GASIFIER	220	129,390	79.1	-	-	10,531	COAL	52,440	25,985,126	1,362,660.0	4,942,637	3.82	94.25
7.	POLK #1 CT OIL	235	4,000	2.3	-	-	10,535	LGT OIL	7,270	5,796,424	42,140.0	717,065	17.93	98.63
8.	**POLK #1 TOTAL**	**220**	**133,390**	**81.5**	**83.1**	**98.0**	**10,532**		**-**	**-**	**1,404,800.0**	**5,659,702**	**4.24**	**-**
9.	POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10.	POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11.	**POLK #2 TOTAL**	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12.	POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13.	POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14.	**POLK #3 TOTAL**	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15.	**POLK #4 CT GAS**	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
16.	**POLK #5 CT GAS**	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17.	**CITY OF TAMPA GAS**	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18.	BAYSIDE #1	792	367,900	62.4	96.7	79.9	7,349	GAS	2,630,180	1,028,002	2,703,830.0	18,316,290	4.98	6.96
19.	BAYSIDE #2	1,047	116,790	15.0	75.3	87.5	7,363	GAS	836,530	1,027,973	859,930.0	5,825,505	4.99	6.96
20.	BAYSIDE #3	61	400	0.9	76.3	72.9	12,125	GAS	4,730	1,025,370	4,850.0	32,939	8.23	6.96
21.	BAYSIDE #4	61	330	0.7	76.3	90.2	11,727	GAS	3,780	1,023,810	3,870.0	26,324	7.98	6.96
22.	BAYSIDE #5	61	1,040	2.3	76.3	63.1	12,346	GAS	12,490	1,028,022	12,840.0	86,979	8.36	6.96
23.	BAYSIDE #6	61	540	1.2	82.7	63.2	12,241	GAS	6,430	1,027,994	6,610.0	44,778	8.29	6.96
24.	**BAYSIDE TOTAL**	**2,083**	**487,000**	**31.4**	**83.7**	**81.5**	**7,376**	**GAS**	**3,494,140**	**1,027,987**	**3,591,930.0**	**24,332,815**	**5.00**	**6.96**
25.	B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26.	B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27.	**B.B.C.T.#4 TOTAL**	**61**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
28.	**SYSTEM**	**4,692**	**1,403,240**	**40.2**	**65.3**	**86.9**	**9,387**	**-**	**-**	**-**	**13,171,710.0**	**57,165,461**	**4.07**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	230,270	83.1	85.0	91.9	10,310	COAL	100,120	23,712,944	2,374,140.0	7,664,468	3.33	76.55
2. B.B.#2	385	227,330	82.0	83.4	91.8	10,350	COAL	98,340	23,925,564	2,352,840.0	7,528,204	3.31	76.55
3. B.B.#3	365	167,190	63.6	85.4	81.2	10,594	COAL	77,160	22,955,936	1,771,280.0	5,906,815	3.53	76.55
4. B.B.#4	417	244,110	81.3	88.4	88.8	10,550	COAL	112,520	22,887,842	2,575,340.0	8,660,529	3.55	76.97
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,450	-	-	438,364	-	98.51
5. B.B. COAL	**1,552**	**868,900**	**77.8**	**85.6**	**88.8**	**10,443**		**-**	**-**	**9,073,600.0**	**30,198,380**	**3.48**	**-**
6. POLK #1 GASIFIER	220	127,040	80.2	-	-	10,581	COAL	51,730	25,985,308	1,344,220.0	4,828,217	3.80	93.33
7. POLK #1 CT OIL	215	3,930	2.5	-	-	10,578	LGT OIL	7,170	5,797,768	41,570.0	712,952	18.14	99.44
8. POLK #1 TOTAL	**220**	**130,970**	**82.7**	**85.9**	**96.2**	**10,581**		**-**	**-**	**1,385,790.0**	**5,541,169**	**4.23**	**-**
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. POLK #4 CT GAS	**151**	**300**	**0.3**	**99.4**	**99.3**	**13,000**	**GAS**	**3,790**	**1,029,024**	**3,900.0**	**28,322**	**9.44**	**7.47**
16. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. BAYSIDE #2	929	367,870	55.0	97.3	83.7	7,563	GAS	2,706,330	1,028,008	2,782,130.0	20,224,269	5.50	7.47
20. BAYSIDE #3	56	2,300	5.7	98.6	100.2	11,322	GAS	25,330	1,028,030	26,040.0	189,290	8.23	7.47
21. BAYSIDE #4	56	780	1.9	98.6	99.5	11,500	GAS	8,720	1,028,670	8,970.0	65,164	8.35	7.47
22. BAYSIDE #5	56	4,670	11.6	98.6	98.1	11,246	GAS	51,090	1,027,990	52,520.0	381,793	8.18	7.47
23. BAYSIDE #6	56	2,800	6.9	92.0	100.0	11,421	GAS	31,110	1,027,965	31,980.0	232,483	8.30	7.47
24. BAYSIDE TOTAL	**1,854**	**378,420**	**28.3**	**60.4**	**84.1**	**7,668**	**GAS**	**2,822,580**	**1,028,010**	**2,901,640.0**	**21,092,999**	**5.57**	**7.47**
25. B.B.C.T.#4 OIL	56	410	1.0	-	-	10,732	LGT OIL	760	5,789,474	4,400.0	74,867	18.26	98.51
26. B.B.C.T.#4 GAS	56	3,670	9.1	-	-	11,621	GAS	41,490	1,027,959	42,650.0	310,053	8.45	7.47
27. B.B.C.T.#4 TOTAL	**56**	**4,080**	**10.1**	**76.2**	**98.5**	**11,532**		**-**	**-**	**47,050.0**	**384,920**	**9.43**	**-**
28. SYSTEM	**4,308**	**1,382,670**	**44.6**	**65.7**	**88.3**	**9,700**	**-**	**-**	**-**	**13,411,980.0**	**57,245,790**	**4.14**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	239,990	83.8	85.0	92.6	10,309	COAL	104,340	23,710,466	2,473,950.0	8,045,488	3.35	77.11
2. B.B.#2	385	236,030	82.4	83.4	92.3	10,347	COAL	102,070	23,927,109	2,442,240.0	7,870,452	3.33	77.11
3. B.B.#3	365	209,420	77.1	85.4	85.4	10,571	COAL	96,430	22,956,445	2,213,690.0	7,435,561	3.55	77.11
4. B.B.#4	417	258,630	83.4	88.4	91.1	10,533	COAL	119,020	22,888,506	2,724,190.0	9,224,244	3.57	77.50
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	-	352,878	-	99.12
5. B.B. COAL	**1,552**	**944,070**	**81.8**	**85.6**	**90.4**	**10,438**		**-**	**-**	**9,854,070.0**	**32,928,623**	**3.49**	**-**
6. POLK #1 GASIFIER	220	132,990	81.3	-	-	10,546	COAL	53,970	25,987,586	1,402,550.0	5,045,675	3.79	93.49
7. POLK #1 CT OIL	215	4,110	2.6	-	-	10,555	LGT OIL	7,480	5,799,465	43,380.0	749,320	18.23	100.18
8. POLK #1 TOTAL	**220**	**137,100**	**83.8**	**85.9**	**97.4**	**10,547**		**-**	**-**	**1,445,930.0**	**5,794,995**	**4.23**	**-**
9. POLK #2 CT GAS	151	670	0.6	-	-	12,239	GAS	7,980	1,027,569	8,200.0	60,298	9.00	7.56
10. POLK #2 CT OIL	159	40	0.0	-	-	10,250	LGT OIL	70	5,857,143	410.0	7,012	17.53	100.18
11. POLK #2 TOTAL	**159**	**710**	**0.6**	**98.8**	**89.3**	**12,127**		**-**	**-**	**8,610.0**	**67,310**	**9.48**	**-**
12. POLK #3 CT GAS	151	520	0.5	-	-	11,577	GAS	5,850	1,029,060	6,020.0	44,203	8.50	7.56
13. POLK #3 CT OIL	159	30	0.0	-	-	10,333	LGT OIL	50	6,200,000	310.0	5,009	16.70	100.18
14. POLK #3 TOTAL	**159**	**550**	**0.5**	**98.9**	**86.5**	**11,509**		**-**	**-**	**6,330.0**	**49,212**	**8.95**	**-**
15. POLK #4 CT GAS	**151**	**14,290**	**12.7**	**99.4**	**95.6**	**11,912**	**GAS**	**165,590**	**1,027,961**	**170,220.0**	**1,251,222**	**8.76**	**7.56**
16. POLK #5 CT GAS	**151**	**6,250**	**5.6**	**99.4**	**96.3**	**11,843**	**GAS**	**72,010**	**1,027,913**	**74,020.0**	**544,118**	**8.71**	**7.56**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. BAYSIDE #2	929	463,510	67.1	97.3	88.7	7,493	GAS	3,378,520	1,028,000	3,473,120.0	25,528,589	5.51	7.56
20. BAYSIDE #3	56	6,090	14.6	98.6	98.0	11,059	GAS	65,520	1,027,930	67,350.0	495,079	8.13	7.56
21. BAYSIDE #4	56	3,840	9.2	98.6	99.4	11,130	GAS	41,570	1,028,145	42,740.0	314,109	8.18	7.56
22. BAYSIDE #5	56	10,960	26.3	98.6	98.3	11,026	GAS	117,550	1,028,073	120,850.0	888,225	8.10	7.56
23. BAYSIDE #6	56	8,270	19.8	98.6	98.5	11,074	GAS	89,080	1,028,065	91,580.0	673,101	8.14	7.56
24. BAYSIDE TOTAL	**1,854**	**492,670**	**35.7**	**60.6**	**89.2**	**7,704**	**GAS**	**3,692,240**	**1,028,005**	**3,795,640.0**	**27,899,103**	**5.66**	**7.56**
25. B.B.C.T.#4 OIL	56	1,130	2.7	-	-	10,832	LGT OIL	2,110	5,800,948	12,240.0	209,149	18.51	99.12
26. B.B.C.T.#4 GAS	56	10,200	24.5	-	-	11,726	GAS	116,360	1,027,931	119,610.0	879,233	8.62	7.56
27. B.B.C.T.#4 TOTAL	**56**	**11,330**	**27.2**	**99.4**	**97.7**	**11,637**		**-**	**-**	**131,850.0**	**1,088,382**	**9.61**	**-**
28. SYSTEM	**4,308**	**1,606,970**	**50.1**	**76.9**	**91.3**	**9,637**	**-**	**-**	**-**	**15,486,670.0**	**69,622,965**	**4.33**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	230,950	83.3	85.0	92.1	10,317	COAL	100,490	23,710,419	2,382,660.0	7,791,994	3.37	77.54
2. B.B.#2	385	228,020	82.3	83.4	92.1	10,347	COAL	98,610	23,925,870	2,359,330.0	7,646,219	3.35	77.54
3. B.B.#3	365	212,790	81.0	85.4	89.6	10,545	COAL	97,750	22,954,680	2,243,820.0	7,579,534	3.56	77.54
4. B.B.#4	417	256,510	85.4	88.4	93.3	10,524	COAL	117,940	22,889,096	2,699,540.0	9,191,873	3.58	77.94
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,450	-	-	443,870	-	99.75
5. B.B. COAL	**1,552**	**928,270**	**83.1**	**85.6**	**91.9**	**10,434**		**-**	**-**	**9,685,350.0**	**32,653,490**	**3.52**	**-**
6. POLK #1 GASIFIER	220	130,000	82.1	-	-	10,519	COAL	52,620	25,987,647	1,367,470.0	4,957,499	3.81	94.21
7. POLK #1 CT OIL	215	4,020	2.6	-	-	10,520	LGT OIL	7,300	5,793,151	42,290.0	736,238	18.31	100.85
8. POLK #1 TOTAL	**220**	**134,020**	**84.6**	**85.9**	**98.4**	**10,519**		**-**	**-**	**1,409,760.0**	**5,693,737**	**4.25**	**-**
9. POLK #2 CT GAS	151	2,150	2.0	-	-	11,967	GAS	25,030	1,027,966	25,730.0	175,451	8.16	7.01
10. POLK #2 CT OIL	159	110	0.1	-	-	11,545	LGT OIL	220	5,772,727	1,270.0	22,179	20.16	100.81
11. POLK #2 TOTAL	**159**	**2,260**	**2.0**	**98.8**	**94.8**	**11,947**		**-**	**-**	**27,000.0**	**197,630**	**8.74**	**-**
12. POLK #3 CT GAS	151	430	0.4	-	-	12,419	GAS	5,200	1,026,923	5,340.0	36,450	8.48	7.01
13. POLK #3 CT OIL	159	20	0.0	-	-	12,500	LGT OIL	40	6,250,000	250.0	4,033	20.17	100.83
14. POLK #3 TOTAL	**159**	**450**	**0.4**	**98.9**	**94.3**	**12,422**		**-**	**-**	**5,590.0**	**40,483**	**9.00**	**-**
15. POLK #4 CT GAS	**151**	**14,350**	**13.2**	**99.4**	**99.0**	**11,666**	**GAS**	**162,850**	**1,028,001**	**167,410.0**	**1,141,516**	**7.95**	**7.01**
16. POLK #5 CT GAS	**151**	**8,130**	**7.5**	**99.4**	**96.1**	**12,043**	**GAS**	**95,240**	**1,028,034**	**97,910.0**	**667,596**	**8.21**	**7.01**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	149,810	29.7	67.7	95.0	7,508	GAS	1,094,160	1,027,994	1,124,790.0	7,669,639	5.12	7.01
19. BAYSIDE #2	929	504,460	75.4	97.3	88.7	7,467	GAS	3,664,280	1,028,006	3,766,900.0	25,685,188	5.09	7.01
20. BAYSIDE #3	56	6,160	15.3	98.6	100.0	10,948	GAS	65,610	1,027,892	67,440.0	459,901	7.47	7.01
21. BAYSIDE #4	56	4,640	11.5	98.6	99.8	10,955	GAS	49,450	1,027,907	50,830.0	346,625	7.47	7.01
22. BAYSIDE #5	56	9,020	22.4	98.6	100.0	10,980	GAS	96,340	1,028,026	99,040.0	675,306	7.49	7.01
23. BAYSIDE #6	56	7,290	18.1	98.6	99.4	10,982	GAS	77,880	1,027,992	80,060.0	545,909	7.49	7.01
24. BAYSIDE TOTAL	**1,854**	**681,380**	**51.0**	**86.2**	**90.4**	**7,616**	**GAS**	**5,047,720**	**1,028,001**	**5,189,060.0**	**35,382,568**	**5.19**	**7.01**
25. B.B.C.T.#4 OIL	56	1,070	2.7	-	-	10,766	LGT OIL	1,990	5,788,945	11,520.0	198,495	18.55	99.75
26. B.B.C.T.#4 GAS	56	9,620	23.9	-	-	11,615	GAS	108,690	1,028,061	111,740.0	761,875	7.92	7.01
27. B.B.C.T.#4 TOTAL	**56**	**10,690**	**26.5**	**99.4**	**98.4**	**11,530**		**-**	**-**	**123,260.0**	**960,370**	**8.98**	**-**
28. SYSTEM	**4,308**	**1,779,550**	**57.4**	**87.9**	**92.4**	**9,387**	**-**	**-**	**-**	**16,705,340.0**	**76,737,390**	**4.31**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	241,190	84.2	85.0	93.1	10,309	COAL	104,860	23,711,425	2,486,380.0	8,167,332	3.39	77.89
2. B.B.#2	385	234,300	81.8	83.4	91.7	10,353	COAL	101,390	23,925,042	2,425,760.0	7,897,061	3.37	77.89
3. B.B.#3	365	218,420	80.4	85.4	89.0	10,548	COAL	100,360	22,956,158	2,303,880.0	7,816,837	3.58	77.89
4. B.B.#4	417	265,550	85.6	88.4	93.5	10,521	COAL	122,060	22,888,743	2,793,800.0	9,603,812	3.62	78.68
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	-	356,889	-	100.25
5. B.B. COAL	**1,552**	**959,460**	**83.1**	**85.6**	**91.9**	**10,433**		-	-	**10,009,820.0**	**33,841,931**	**3.53**	-
6. POLK #1 GASIFIER	220	134,350	82.1	-	-	10,519	COAL	54,380	25,988,783	1,413,270.0	5,045,750	3.76	92.79
7. POLK #1 CT OIL	215	4,160	2.6	-	-	10,507	LGT OIL	7,540	5,797,082	43,710.0	765,010	18.39	101.46
8. POLK #1 TOTAL	**220**	**138,510**	**84.6**	**85.9**	**98.4**	**10,519**		-	-	**1,456,980.0**	**5,810,760**	**4.20**	-
9. POLK #2 CT GAS	151	1,580	1.4	-	-	11,570	GAS	17,790	1,027,544	18,280.0	123,315	7.80	6.93
10. POLK #2 CT OIL	159	80	0.1	-	-	11,625	LGT OIL	160	5,812,500	930.0	16,234	20.29	101.46
11. POLK #2 TOTAL	**159**	**1,660**	**1.4**	**98.8**	**94.9**	**11,572**		-	-	**19,210.0**	**139,549**	**8.41**	-
12. POLK #3 CT GAS	151	1,120	1.0	-	-	12,232	GAS	13,330	1,027,757	13,700.0	92,400	8.25	6.93
13. POLK #3 CT OIL	159	60	0.1	-	-	11,167	LGT OIL	120	5,583,333	670.0	12,175	20.29	101.46
14. POLK #3 TOTAL	**159**	**1,180**	**1.0**	**98.9**	**92.8**	**12,178**		-	-	**14,370.0**	**104,575**	**8.86**	-
15. POLK #4 CT GAS	**151**	**8,370**	**7.5**	**99.4**	**99.0**	**11,925**	**GAS**	**97,100**	**1,027,909**	**99,810.0**	**673,068**	**8.04**	**6.93**
16. POLK #5 CT GAS	**151**	**5,860**	**5.2**	**99.4**	**97.0**	**11,850**	**GAS**	**67,550**	**1,027,979**	**69,440.0**	**468,237**	**7.99**	**6.93**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	241,800	46.4	96.7	95.0	7,492	GAS	1,762,270	1,027,992	1,811,600.0	12,215,533	5.05	6.93
19. BAYSIDE #2	929	522,570	75.6	97.3	88.7	7,467	GAS	3,795,730	1,028,003	3,902,020.0	26,310,874	5.03	6.93
20. BAYSIDE #3	56	4,140	9.9	98.6	99.9	11,010	GAS	44,340	1,027,966	45,580.0	307,352	7.42	6.93
21. BAYSIDE #4	56	3,400	8.2	98.6	97.9	10,991	GAS	36,360	1,027,778	37,370.0	252,037	7.41	6.93
22. BAYSIDE #5	56	7,300	17.5	98.6	96.6	11,048	GAS	78,450	1,028,043	80,650.0	543,792	7.45	6.93
23. BAYSIDE #6	56	5,430	13.0	98.6	100.0	11,013	GAS	58,170	1,028,021	59,800.0	403,217	7.43	6.93
24. BAYSIDE TOTAL	**1,854**	**784,640**	**56.9**	**97.2**	**90.8**	**7,567**	**GAS**	**5,775,320**	**1,027,998**	**5,937,020.0**	**40,032,805**	**5.10**	**6.93**
25. B.B.C.T.#4 OIL	56	850	2.0	-	-	10,788	LGT OIL	1,580	5,803,797	9,170.0	158,394	18.63	100.25
26. B.B.C.T.#4 GAS	56	7,650	18.4	-	-	11,771	GAS	87,610	1,027,851	90,050.0	607,287	7.94	6.93
27. B.B.C.T.#4 TOTAL	**56**	**8,500**	**20.4**	**99.4**	**97.9**	**11,673**		-	-	**99,220.0**	**765,681**	**9.01**	-
28. SYSTEM	**4,308**	**1,908,180**	**59.5**	**92.6**	**92.3**	**9,279**	-	-	-	**17,705,870.0**	**81,836,606**	**4.29**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

35

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	240,530	84.0	85.0	92.8	10,310	COAL	104,590	23,709,724	2,479,800.0	8,165,572	3.39	78.07
2. B.B.#2	385	236,620	82.6	83.4	92.6	10,346	COAL	102,320	23,925,625	2,448,070.0	7,988,348	3.38	78.07
3. B.B.#3	365	218,830	80.6	85.4	89.2	10,547	COAL	100,540	22,956,336	2,308,030.0	7,849,379	3.59	78.07
4. B.B.#4	417	264,810	85.4	88.4	93.3	10,524	COAL	121,760	22,887,319	2,786,760.0	9,552,877	3.61	78.46
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	-	358,739	-	100.77
5. B.B. COAL	**1,552**	**960,790**	**83.2**	**85.6**	**92.0**	**10,432**		-	-	**10,022,660.0**	**33,914,915**	**3.53**	-
6. POLK #1 GASIFIER	220	134,350	82.1	-	-	10,520	COAL	54,390	25,985,659	1,413,360.0	5,060,448	3.77	93.04
7. POLK #1 CT OIL	215	4,160	2.6	-	-	10,507	LGT OIL	7,540	5,797,082	43,710.0	769,889	18.51	102.11
8. POLK #1 TOTAL	**220**	**138,510**	**84.6**	**85.9**	**98.4**	**10,520**		-	-	**1,457,070.0**	**5,830,337**	**4.21**	-
9. POLK #2 CT GAS	151	1,470	1.3	-	-	12,435	GAS	17,780	1,028,121	18,280.0	122,623	8.34	6.90
10. POLK #2 CT OIL	159	80	0.1	-	-	11,375	LGT OIL	160	5,687,500	910.0	16,337	20.42	102.11
11. POLK #2 TOTAL	**159**	**1,550**	**1.3**	**98.8**	**81.2**	**12,381**		-	-	**19,190.0**	**138,960**	**8.97**	-
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**151**	**11,960**	**10.6**	**99.4**	**99.0**	**11,776**	**GAS**	**137,020**	**1,027,879**	**140,840.0**	**944,985**	**7.90**	**6.90**
16. POLK #5 CT GAS	**151**	**6,970**	**6.2**	**99.4**	**98.2**	**11,956**	**GAS**	**81,070**	**1,027,877**	**83,330.0**	**559,115**	**8.02**	**6.90**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	256,860	49.2	96.7	94.6	7,490	GAS	1,871,560	1,028,003	1,923,970.0	12,907,577	5.03	6.90
19. BAYSIDE #2	929	548,840	79.4	97.3	88.5	7,461	GAS	3,983,100	1,028,003	4,094,640.0	27,470,224	5.01	6.90
20. BAYSIDE #3	56	5,220	12.5	98.6	98.1	10,983	GAS	55,780	1,027,788	57,330.0	384,698	7.37	6.90
21. BAYSIDE #4	56	3,450	8.3	98.6	99.4	10,986	GAS	36,870	1,027,936	37,900.0	254,281	7.37	6.90
22. BAYSIDE #5	56	8,840	21.2	98.6	99.9	10,945	GAS	94,110	1,028,052	96,750.0	649,048	7.34	6.90
23. BAYSIDE #6	56	6,950	16.7	98.6	99.3	10,947	GAS	74,010	1,027,969	76,080.0	510,424	7.34	6.90
24. BAYSIDE TOTAL	**1,854**	**830,160**	**60.2**	**97.2**	**90.6**	**7,573**	**GAS**	**6,115,430**	**1,028,001**	**6,286,670.0**	**42,176,252**	**5.08**	**6.90**
25. B.B.C.T.#4 OIL	56	830	2.0	-	-	10,819	LGT OIL	1,550	5,793,548	8,980.0	156,192	18.82	100.77
26. B.B.C.T.#4 GAS	56	7,500	18.0	-	-	11,709	GAS	85,430	1,027,976	87,820.0	589,185	7.86	6.90
27. B.B.C.T.#4 TOTAL	**56**	**8,330**	**20.0**	**99.4**	**98.5**	**11,621**		-	-	**96,800.0**	**745,377**	**8.95**	-
28. SYSTEM	**4,308**	**1,958,270**	**61.1**	**89.0**	**92.3**	**9,246**	-	-	-	**18,106,560.0**	**84,309,941**	**4.31**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

36

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2011

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. B.B.#1	385	233,130	84.1	85.0	93.0	10,309	COAL	101,360	23,711,227	2,403,370.0	7,902,952	3.39	77.97
2. B.B.#2	385	12,380	4.5	5.6	74.8	10,466	COAL	5,420	23,905,904	129,570.0	422,593	3.41	77.97
3. B.B.#3	365	219,350	83.5	85.4	92.3	10,529	COAL	100,600	22,957,256	2,309,500.0	7,843,696	3.58	77.97
4. B.B.#4	417	259,440	86.4	88.4	94.4	10,523	COAL	119,280	22,888,078	2,730,090.0	9,346,965	3.60	78.36
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	-	360,740	-	101.33
5. B.B. COAL	**1,552**	**724,300**	**64.8**	**66.3**	**92.9**	**10,455**		-	-	**7,572,530.0**	**25,876,946**	**3.57**	-
6. POLK #1 GASIFIER	220	130,940	82.7	-	-	10,502	COAL	52,910	25,988,849	1,375,070.0	4,939,814	3.77	93.36
7. POLK #1 CT OIL	215	4,050	2.6	-	-	10,501	LGT OIL	7,340	5,794,278	42,530.0	754,597	18.63	102.81
8. POLK #1 TOTAL	**220**	**134,990**	**85.2**	**85.9**	**99.1**	**10,502**		-	-	**1,417,600.0**	**5,694,411**	**4.22**	-
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	(0)	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**(0)**	**0.00**	-
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**151**	**11,260**	**10.4**	**99.4**	**90.9**	**12,210**	**GAS**	**133,740**	**1,027,965**	**137,480.0**	**907,300**	**8.06**	**6.78**
16. POLK #5 CT GAS	**151**	**5,760**	**5.3**	**99.4**	**93.0**	**12,345**	**GAS**	**69,160**	**1,028,195**	**71,110.0**	**469,185**	**8.15**	**6.78**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	287,280	56.9	96.7	92.9	7,474	GAS	2,088,510	1,028,006	2,147,000.0	14,168,573	4.93	6.78
19. BAYSIDE #2	929	571,930	85.5	97.3	88.9	7,439	GAS	4,138,830	1,028,005	4,254,740.0	28,078,062	4.91	6.78
20. BAYSIDE #3	56	5,360	13.3	98.6	97.7	11,235	GAS	58,580	1,027,996	60,220.0	397,410	7.41	6.78
21. BAYSIDE #4	56	3,550	8.8	98.6	97.5	11,299	GAS	39,020	1,027,934	40,110.0	264,714	7.46	6.78
22. BAYSIDE #5	56	9,370	23.2	98.6	97.8	11,077	GAS	100,960	1,028,031	103,790.0	684,918	7.31	6.78
23. BAYSIDE #6	56	7,350	18.2	98.6	99.4	11,121	GAS	79,520	1,027,918	81,740.0	539,468	7.34	6.78
24. BAYSIDE TOTAL	**1,854**	**884,840**	**66.3**	**97.2**	**90.4**	**7,558**	**GAS**	**6,505,420**	**1,028,004**	**6,687,600.0**	**44,133,145**	**4.99**	**6.78**
25. B.B.C.T.#4 OIL	56	870	2.2	-	-	10,747	LGT OIL	1,610	5,807,453	9,350.0	163,144	18.75	101.33
26. B.B.C.T.#4 GAS	56	7,820	19.4	-	-	11,660	GAS	88,700	1,027,959	91,180.0	601,746	7.69	6.78
27. B.B.C.T.#4 TOTAL	**56**	**8,690**	**21.6**	**99.4**	**98.8**	**11,568**		-	-	**100,530.0**	**764,890**	**8.80**	-
28. SYSTEM	**4,308**	**1,769,840**	**57.1**	**78.4**	**92.5**	**9,033**	-	-	-	**15,986,850.0**	**77,845,877**	**4.40**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	182,460	63.7	65.8	91.0	10,323	COAL	79,440	23,709,215	1,883,460.0	6,184,728	3.39	77.85
2. B.B.#2	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. B.B.#3	365	201,540	74.2	77.2	91.0	10,537	COAL	92,500	22,957,405	2,123,560.0	7,201,502	3.57	77.85
4. B.B.#4	417	267,790	86.3	88.4	94.3	10,518	COAL	123,050	22,889,069	2,816,500.0	9,626,750	3.59	78.23
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,670	-	-	271,667	-	101.75
5. B.B. COAL	**1,552**	**651,790**	**56.4**	**58.2**	**92.3**	**10,469**		-	-	**6,823,520.0**	**23,284,647**	**3.57**	-
6. POLK #1 GASIFIER	220	113,010	69.0	-	-	10,512	COAL	45,710	25,990,155	1,188,010.0	4,232,598	3.75	92.60
7. POLK #1 CT OIL	215	3,500	2.2	-	-	10,497	LGT OIL	6,340	5,794,953	36,740.0	655,456	18.73	103.38
8. POLK #1 TOTAL	**220**	**116,510**	**71.2**	**72.0**	**98.6**	**10,512**		-	-	**1,224,750.0**	**4,888,054**	**4.20**	-
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**151**	**3,200**	**2.8**	**99.4**	**84.8**	**12,722**	**GAS**	**39,600**	**1,028,030**	**40,710.0**	**271,208**	**8.48**	**6.85**
16. POLK #5 CT GAS	**151**	**240**	**0.2**	**99.4**	**79.5**	**14,167**	**GAS**	**3,310**	**1,027,190**	**3,400.0**	**22,669**	**9.45**	**6.85**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	264,240	50.7	96.7	91.1	7,510	GAS	1,930,380	1,028,005	1,984,440.0	13,220,592	5.00	6.85
19. BAYSIDE #2	929	575,000	83.2	97.3	87.3	7,461	GAS	4,173,450	1,028,010	4,290,350.0	28,582,703	4.97	6.85
20. BAYSIDE #3	56	2,550	6.1	98.6	99.0	11,510	GAS	28,540	1,028,381	29,350.0	195,462	7.67	6.85
21. BAYSIDE #4	56	940	2.3	98.6	93.3	12,053	GAS	11,030	1,027,199	11,330.0	75,541	8.04	6.85
22. BAYSIDE #5	56	6,450	15.5	98.6	96.8	11,271	GAS	70,710	1,028,143	72,700.0	484,272	7.51	6.85
23. BAYSIDE #6	56	4,350	10.4	98.6	98.3	11,391	GAS	48,200	1,028,008	49,550.0	330,107	7.59	6.85
24. BAYSIDE TOTAL	**1,854**	**853,530**	**61.9**	**97.2**	**88.6**	**7,542**	**GAS**	**6,262,310**	**1,028,010**	**6,437,720.0**	**42,888,677**	**5.02**	**6.85**
25. B.B.C.T.#4 OIL	56	440	1.1	-	-	10,682	LGT OIL	810	5,802,469	4,700.0	82,416	18.73	101.75
26. B.B.C.T.#4 GAS	56	3,920	9.4	-	-	11,686	GAS	44,550	1,028,283	45,810.0	305,110	7.78	6.85
27. B.B.C.T.#4 TOTAL	**56**	**4,360**	**10.5**	**99.4**	**96.1**	**11,585**		-	-	**50,510.0**	**387,526**	**8.89**	-
28. SYSTEM	**4,308**	**1,629,630**	**50.8**	**74.7**	**90.9**	**8,947**	-	-	-	**14,580,610.0**	**71,742,781**	**4.40**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2011

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. B.B.#1	385	231,260	83.4	85.0	92.3	10,312	COAL	100,580	23,709,286	2,384,680.0	7,837,548	3.39	77.92
2. B.B.#2	385	86,740	31.3	33.3	87.7	10,369	COAL	37,590	23,927,906	899,450.0	2,929,145	3.38	77.92
3. B.B.#3	365	121,290	46.2	54.1	80.7	10,596	COAL	55,980	22,957,128	1,285,140.0	4,362,159	3.60	77.92
4. B.B.#4	417	224,390	74.7	79.5	90.7	10,539	COAL	103,320	22,889,566	2,364,950.0	8,097,864	3.61	78.38
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	6,230	-	-	638,989	-	102.57
5. B.B. COAL	**1,552**	**663,680**	**59.4**	**63.5**	**88.8**	**10,448**		-	-	**6,934,220.0**	**23,865,705**	**3.60**	-
6. POLK #1 GASIFIER	220	128,410	81.1	-	-	10,556	COAL	52,160	25,986,963	1,355,480.0	4,813,211	3.75	92.28
7. POLK #1 CT OIL	215	3,970	2.6	-	-	10,559	LGT OIL	7,230	5,798,064	41,920.0	752,785	18.96	104.12
8. POLK #1 TOTAL	**220**	**132,380**	**83.6**	**85.9**	**97.2**	**10,556**		-	-	**1,397,400.0**	**5,565,996**	**4.20**	-
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**151**	**1,870**	**1.7**	**99.4**	**88.5**	**12,155**	**GAS**	**22,120**	**1,027,577**	**22,730.0**	**160,959**	**8.61**	**7.28**
16. POLK #5 CT GAS	**151**	**790**	**0.7**	**99.4**	**87.2**	**11,734**	**GAS**	**9,010**	**1,028,857**	**9,270.0**	**65,562**	**8.30**	**7.28**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	110,740	21.9	74.1	92.2	7,502	GAS	808,090	1,028,004	830,720.0	5,880,174	5.31	7.28
19. BAYSIDE #2	929	450,890	67.4	97.3	85.4	7,511	GAS	3,294,400	1,028,008	3,386,670.0	23,972,137	5.32	7.28
20. BAYSIDE #3	56	1,020	2.5	98.6	95.9	11,549	GAS	11,460	1,027,923	11,780.0	83,390	8.18	7.28
21. BAYSIDE #4	56	520	1.3	98.6	92.9	11,365	GAS	5,750	1,027,826	5,910.0	41,841	8.05	7.28
22. BAYSIDE #5	56	3,260	8.1	98.6	98.7	11,239	GAS	35,640	1,028,058	36,640.0	259,339	7.96	7.28
23. BAYSIDE #6	56	2,220	5.5	98.6	94.4	11,396	GAS	24,610	1,028,037	25,300.0	179,078	8.07	7.28
24. BAYSIDE TOTAL	**1,854**	**568,650**	**42.6**	**88.7**	**86.8**	**7,557**	**GAS**	**4,179,950**	**1,028,008**	**4,297,020.0**	**30,415,959**	**5.35**	**7.28**
25. B.B.C.T.#4 OIL	56	260	0.6	-	-	10,885	LGT OIL	490	5,775,510	2,830.0	50,258	19.33	102.57
26. B.B.C.T.#4 GAS	56	2,370	5.9	-	-	11,376	GAS	26,220	1,028,223	26,960.0	190,793	8.05	7.28
27. B.B.C.T.#4 TOTAL	**56**	**2,630**	**6.5**	**99.4**	**99.9**	**11,327**		-	-	**29,790.0**	**241,051**	**9.17**	-
28. SYSTEM	**4,308**	**1,370,000**	**44.2**	**73.7**	**88.9**	**9,263**	-	-	-	**12,690,430.0**	**60,315,232**	**4.40**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2011

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	235,830	80.2	85.0	88.7	10,340	COAL	102,830	23,712,924	2,438,400.0	8,038,721	3.41	78.17
2. B.B.#2	395	237,290	80.7	83.4	90.5	10,340	COAL	102,550	23,925,012	2,453,510.0	8,016,832	3.38	78.17
3. B.B.#3	365	204,640	75.4	85.4	83.4	10,545	COAL	94,010	22,954,898	2,157,990.0	7,349,219	3.59	78.17
4. B.B.#4	427	154,370	48.6	57.0	82.2	10,503	COAL	70,840	22,886,505	1,621,280.0	5,634,717	3.65	79.54
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	5,340	-	-	551,522	-	103.28
5. B.B. COAL	**1,582**	**832,130**	**70.7**	**77.1**	**86.6**	**10,420**		-	-	**8,671,180.0**	**29,591,011**	**3.56**	-
6. POLK #1 GASIFIER	220	129,740	79.3	-	-	10,619	COAL	53,010	25,988,493	1,377,650.0	4,899,632	3.78	92.43
7. POLK #1 CT OIL	235	4,010	2.3	-	-	10,626	LGT OIL	7,350	5,797,279	42,610.0	771,187	19.23	104.92
8. POLK #1 TOTAL	**220**	**133,750**	**81.7**	**85.9**	**95.0**	**10,619**		-	-	**1,420,260.0**	**5,670,819**	**4.24**	-
9. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	(0)	0.00	0.00
11. POLK #2 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**(0)**	**0.00**	-
12. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**187**	**0**	**0.0**	**0.0**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**183**	**3,810**	**2.8**	**89.8**	**99.1**	**11,478**	**GAS**	**42,550**	**1,027,732**	**43,730.0**	**338,912**	**8.90**	**7.97**
16. POLK #5 CT GAS	**183**	**1,770**	**1.3**	**89.8**	**96.7**	**11,571**	**GAS**	**19,920**	**1,028,112**	**20,480.0**	**158,663**	**8.96**	**7.97**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	792	364,350	61.8	96.7	77.4	7,392	GAS	2,619,770	1,027,999	2,693,120.0	20,866,546	5.73	7.97
19. BAYSIDE #2	1,047	58,440	7.5	75.3	77.8	7,425	GAS	422,070	1,028,005	433,890.0	3,361,800	5.75	7.97
20. BAYSIDE #3	61	3,040	6.7	98.6	90.6	11,270	GAS	33,340	1,027,594	34,260.0	265,554	8.74	7.97
21. BAYSIDE #4	61	1,620	3.6	98.6	85.7	11,148	GAS	17,570	1,027,888	18,060.0	139,946	8.64	7.97
22. BAYSIDE #5	61	5,330	11.7	98.6	80.2	11,443	GAS	59,330	1,027,979	60,990.0	472,565	8.87	7.97
23. BAYSIDE #6	61	3,590	7.9	98.6	85.3	11,429	GAS	39,920	1,027,806	41,030.0	317,964	8.86	7.97
24. BAYSIDE TOTAL	**2,083**	**436,370**	**28.2**	**86.1**	**77.7**	**7,520**	**GAS**	**3,192,000**	**1,027,992**	**3,281,350.0**	**25,424,375**	**5.83**	**7.97**
25. B.B.C.T.#4 OIL	61	210	0.5	-	-	10,857	LGT OIL	390	5,846,154	2,280.0	40,280	19.18	103.28
26. B.B.C.T.#4 GAS	61	1,930	4.3	-	-	11,679	GAS	21,930	1,027,816	22,540.0	174,673	9.05	7.97
27. B.B.C.T.#4 TOTAL	**61**	**2,140**	**4.7**	**99.4**	**97.4**	**11,598**		-	-	**24,820.0**	**214,953**	**10.04**	-
28. SYSTEM	**4,692**	**1,409,970**	**40.4**	**76.6**	**84.5**	**9,548**	-	-	-	**13,461,820.0**	**61,398,733**	**4.35**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

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SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH JUNE 2011

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	10,970	8,220	13,500	12,380	13,270	14,000
16. UNIT COST ($/BBL)	103.85	104.75	105.10	104.88	104.70	104.72
17. AMOUNT ($)	1,139,197	861,074	1,418,816	1,298,429	1,389,311	1,466,145
18. BURNED:						
19. UNITS (BBL)	10,970	8,220	13,500	12,380	13,270	14,000
20. UNIT COST ($/BBL)	65.61	34.19	53.12	63.64	73.13	68.64
21. AMOUNT ($)	719,708	281,010	717,065	787,819	970,490	960,945
22. ENDING INVENTORY:						
23. UNITS (BBL)	97,797	97,797	97,797	97,797	97,797	97,797
24. UNIT COST ($/BBL)	96.63	97.26	98.21	98.95	99.62	100.25
25. AMOUNT ($)	9,450,069	9,512,220	9,604,575	9,676,820	9,742,763	9,804,387
26. DAYS SUPPLY: NORMAL	242	242	248	249	249	252
27. DAYS SUPPLY: EMERGENCY	14	14	14	14	14	14
COAL						
28. PURCHASES:						
29. UNITS (TONS)	404,167	356,667	381,667	447,667	401,667	429,167
30. UNIT COST ($/TON)	80.26	79.28	79.74	80.31	79.47	79.58
31. AMOUNT ($)	32,438,911	28,276,081	30,432,299	35,950,256	31,921,678	34,153,490
32. BURNED:						
33. UNITS (TONS)	471,700	339,580	401,630	439,870	475,830	467,410
34. UNIT COST ($/TON)	76.66	77.70	79.96	79.63	79.81	80.47
35. AMOUNT ($)	36,159,451	26,386,406	32,115,581	35,026,597	37,974,298	37,610,989
36. ENDING INVENTORY:						
37. UNITS (TONS)	792,347	809,434	789,471	797,269	723,105	684,863
38. UNIT COST ($/TON)	77.03	78.52	79.38	80.45	80.98	81.27
39. AMOUNT ($)	61,034,834	63,557,914	62,666,329	64,143,509	58,558,816	55,660,198
40. DAYS SUPPLY:	59	61	55	52	47	44
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	2,877,184	3,908,270	3,494,140	2,867,860	4,460,906	5,444,730
43. UNIT COST ($/MCF)	7.29	6.84	6.96	7.47	7.34	7.02
44. AMOUNT ($)	20,973,904	26,730,196	24,332,814	21,431,375	32,763,640	38,222,252
45. BURNED:						
46. UNITS (MCF)	2,873,390	3,908,270	3,494,140	2,867,860	4,060,030	5,444,730
47. UNIT COST ($/MCF)	7.32	6.84	6.96	7.47	7.56	7.01
48. AMOUNT ($)	21,029,073	26,730,196	24,332,815	21,431,374	30,678,177	38,165,456
49. ENDING INVENTORY:						
50. UNITS (MCF)	674,027	674,027	674,027	674,027	1,074,903	1,074,903
51. UNIT COST ($/MCF)	5.14	5.14	5.14	5.14	5.17	5.22
52. AMOUNT ($)	3,467,826	3,467,826	3,467,826	3,467,826	5,553,288	5,610,085
53. DAYS SUPPLY:	4	4	4	5	7	7
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2011 THROUGH DECEMBER 2011

		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	12,960	12,810	12,510	9,820	13,950	13,080	147,470
16.	UNIT COST ($/BBL)	105.29	106.00	106.93	107.90	108.83	109.70	106.09
17.	AMOUNT ($)	1,364,542	1,357,882	1,337,646	1,059,615	1,518,234	1,434,869	15,645,760
18.	BURNED:							
19.	UNITS (BBL)	12,960	12,810	12,510	9,820	13,950	13,080	147,470
20.	UNIT COST ($/BBL)	73.44	73.57	73.36	75.14	57.57	62.04	65.11
21.	AMOUNT ($)	951,813	942,418	917,741	737,872	803,043	811,467	9,601,392
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	97,797	97,797	97,797	97,797	97,797	97,797	97,797
24.	UNIT COST ($/BBL)	100.82	101.40	102.01	102.52	103.30	104.04	104.04
25.	AMOUNT ($)	9,860,227	9,916,952	9,976,411	10,026,486	10,102,689	10,174,863	10,174,863
26.	DAYS SUPPLY: NORMAL	255	254	252	253	249	254	-
27.	DAYS SUPPLY: EMERGENCY	14	14	14	14	14	14	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	467,667	433,500	381,667	422,667	376,667	411,667	4,914,837
30.	UNIT COST ($/TON)	79.94	79.43	79.76	79.68	79.61	80.33	79.79
31.	AMOUNT ($)	37,384,952	34,431,848	30,440,182	33,677,654	29,985,789	33,071,135	392,164,275
32.	BURNED:							
33.	UNITS (TONS)	483,050	483,600	379,570	340,700	349,630	423,240	5,055,810
34.	UNIT COST ($/TON)	80.50	80.59	81.19	80.77	82.03	81.49	80.03
35.	AMOUNT ($)	38,887,681	38,975,363	30,816,760	27,517,245	28,678,916	34,490,643	404,639,930
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	669,479	619,379	621,477	703,443	730,481	718,908	718,908
38.	UNIT COST ($/TON)	81.67	81.71	81.59	81.42	81.23	81.56	81.56
39.	AMOUNT ($)	54,679,390	50,609,708	50,709,055	57,273,123	59,334,310	58,631,705	58,631,705
40.	DAYS SUPPLY:	46	47	53	58	58	53	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	6,058,700	6,436,730	6,797,020	5,945,101	4,237,300	3,276,400	55,804,341
43.	UNIT COST ($/MCF)	6.94	6.90	6.79	6.96	7.32	8.02	7.09
44.	AMOUNT ($)	42,068,937	44,441,222	46,142,759	41,377,837	30,998,908	26,281,826	395,765,670
45.	BURNED:							
46.	UNITS (MCF)	6,058,700	6,436,730	6,797,020	6,349,770	4,237,300	3,276,400	55,804,340
47.	UNIT COST ($/MCF)	6.93	6.90	6.78	6.85	7.28	7.97	7.08
48.	AMOUNT ($)	41,997,112	44,392,160	46,111,376	43,487,664	30,833,273	26,096,623	395,285,299
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,074,903	1,074,903	1,074,903	670,233	670,233	670,233	670,233
51.	UNIT COST ($/MCF)	5.29	5.33	5.36	5.45	5.70	5.97	0.00
52.	AMOUNT ($)	5,681,910	5,730,972	5,762,354	3,652,527	3,818,162	4,003,366	4,003,366
53.	DAYS SUPPLY:	7	7	7	4	4	4	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH JUNE 2011

SCHEDULE E6

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-11	SEMINOLE	JURISD.	SCH. -D	1,130.0	0.0	1,130.0	4.237	4.237	47,880.00	47,880.00	0.00
	VARIOUS	JURISD.	MKT. BASE	13,030.0	0.0	13,030.0	4.412	5.243	574,879.00	683,110.00	57,551.00
	TOTAL			**14,160.0**	**0.0**	**14,160.0**	**4.398**	**5.162**	**622,759.00**	**730,990.00**	**57,551.00**
Feb-11	SEMINOLE	JURISD.	SCH. -D	840.0	0.0	840.0	4.532	4.532	38,070.00	38,070.00	0.00
	VARIOUS	JURISD.	MKT. BASE	7,950.0	0.0	7,950.0	4.756	5.621	378,099.00	446,880.00	37,851.00
	TOTAL			**8,790.0**	**0.0**	**8,790.0**	**4.735**	**5.517**	**416,169.00**	**484,950.00**	**37,851.00**
Mar-11	SEMINOLE	JURISD.	SCH. -D	1,240.0	0.0	1,240.0	4.241	4.241	52,590.00	52,590.00	0.00
	VARIOUS	JURISD.	MKT. BASE	10,720.0	0.0	10,720.0	4.478	5.316	480,079.00	569,850.00	48,061.00
	TOTAL			**11,960.0**	**0.0**	**11,960.0**	**4.454**	**5.204**	**532,669.00**	**622,440.00**	**48,061.00**
Apr-11	SEMINOLE	JURISD.	SCH. -D	1,330.0	0.0	1,330.0	4.199	4.199	55,850.00	55,850.00	0.00
	VARIOUS	JURISD.	MKT. BASE	6,600.0	0.0	6,600.0	4.846	5.720	319,804.00	377,490.00	32,016.00
	TOTAL			**7,930.0**	**0.0**	**7,930.0**	**4.737**	**5.465**	**375,654.00**	**433,340.00**	**32,016.00**
May-11	SEMINOLE	JURISD.	SCH. -D	1,240.0	0.0	1,240.0	4.575	4.575	56,730.00	56,730.00	0.00
	VARIOUS	JURISD.	MKT. BASE	9,950.0	0.0	9,950.0	4.655	5.510	463,154.00	548,240.00	46,366.00
	TOTAL			**11,190.0**	**0.0**	**11,190.0**	**4.646**	**5.406**	**519,884.00**	**604,970.00**	**46,366.00**
Jun-11	SEMINOLE	JURISD.	SCH. -D	1,330.0	0.0	1,330.0	4.602	4.602	61,200.00	61,200.00	0.00
	VARIOUS	JURISD.	MKT. BASE	13,150.0	0.0	13,150.0	4.949	5.834	650,853.00	767,140.00	65,157.00
	TOTAL			**14,480.0**	**0.0**	**14,480.0**	**4.917**	**5.721**	**712,053.00**	**828,340.00**	**65,157.00**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2011 THROUGH DECEMBER 2011

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jul-11	SEMINOLE	JURISD.	SCH. -D	1,340.0	0.0	1,340.0	4.655	4.655	62,380.00	62,380.00	0.00
	VARIOUS	JURISD.	MKT. BASE	19,600.0	0.0	19,600.0	4.817	5.689	944,224.00	1,114,990.00	94,526.00
	TOTAL			**20,940.0**	**0.0**	**20,940.0**	**4.807**	**5.623**	**1,006,604.00**	**1,177,370.00**	**94,526.00**
Aug-11	SEMINOLE	JURISD.	SCH. -D	1,320.0	0.0	1,320.0	4.678	4.678	61,750.00	61,750.00	0.00
	VARIOUS	JURISD.	MKT. BASE	20,670.0	0.0	20,670.0	4.697	5.557	970,939.00	1,148,540.00	97,201.00
	TOTAL			**21,990.0**	**0.0**	**21,990.0**	**4.696**	**5.504**	**1,032,689.00**	**1,210,290.00**	**97,201.00**
Sep-11	SEMINOLE	JURISD.	SCH. -D	1,350.0	0.0	1,350.0	4.613	4.613	62,280.00	62,280.00	0.00
	VARIOUS	JURISD.	MKT. BASE	17,360.0	0.0	17,360.0	4.824	5.696	837,444.00	988,800.00	83,836.00
	TOTAL			**18,710.0**	**0.0**	**18,710.0**	**4.809**	**5.618**	**899,724.00**	**1,051,080.00**	**83,836.00**
Oct-11	SEMINOLE	JURISD.	SCH. -D	970.0	0.0	970.0	4.568	4.568	44,310.00	44,310.00	0.00
	VARIOUS	JURISD.	MKT. BASE	18,470.0	0.0	18,470.0	4.626	5.478	854,342.00	1,011,730.00	85,528.00
	TOTAL			**19,440.0**	**0.0**	**19,440.0**	**4.623**	**5.432**	**898,652.00**	**1,056,040.00**	**85,528.00**
Nov-11	SEMINOLE	JURISD.	SCH. -D	810.0	0.0	810.0	4.512	4.512	36,550.00	36,550.00	0.00
	VARIOUS	JURISD.	MKT. BASE	10,800.0	0.0	10,800.0	4.756	5.621	513,621.00	607,050.00	51,419.00
	TOTAL			**11,610.0**	**0.0**	**11,610.0**	**4.739**	**5.543**	**550,171.00**	**643,600.00**	**51,419.00**
Dec-11	SEMINOLE	JURISD.	SCH. -D	820.0	0.0	820.0	4.979	4.979	40,830.00	40,830.00	0.00
	VARIOUS	JURISD.	MKT. BASE	13,700.0	0.0	13,700.0	5.259	6.174	720,455.00	845,870.00	72,125.00
	TOTAL			**14,520.0**	**0.0**	**14,520.0**	**5.243**	**6.107**	**761,285.00**	**886,700.00**	**72,125.00**
TOTAL	SEMINOLE	JURISD.	SCH. -D	13,720.0	0.0	13,720.0	4.522	4.522	620,420.00	620,420.00	0.00
Jan-11	VARIOUS	JURISD.	MKT. BASE	162,000.0	0.0	162,000.0	4.758	5.623	7,707,893.00	9,109,690.00	771,637.00
THRU											
Dec-11	**TOTAL**			**175,720.0**	**0.0**	**175,720.0**	**4.740**	**5.537**	**8,328,313.00**	**9,730,110.00**	**771,637.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH JUNE 2011

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-11									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	1,360.0	0.0	0.0	1,360.0	6.690	6.690	90,990.00
	TOTAL		**1,360.0**	**0.0**	**0.0**	**1,360.0**	**6.690**	**6.690**	**90,990.00**
Feb-11									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	2,420.0	0.0	0.0	2,420.0	6.132	6.132	148,400.00
	TOTAL		**2,420.0**	**0.0**	**0.0**	**2,420.0**	**6.132**	**6.132**	**148,400.00**
Mar-11									
	HPP	IPP	4,230.0	0.0	0.0	4,230.0	6.259	6.259	264,740.00
	CALPINE	SCH. D	220.0	0.0	0.0	220.0	9.118	9.118	20,060.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	4,410.0	0.0	0.0	4,410.0	6.306	6.306	278,100.00
	TOTAL		**8,860.0**	**0.0**	**0.0**	**8,860.0**	**6.353**	**6.353**	**562,900.00**
Apr-11									
	HPP	IPP	12,500.0	0.0	0.0	12,500.0	6.367	6.367	795,890.00
	CALPINE	SCH. D	2,330.0	0.0	0.0	2,330.0	8.383	8.383	195,330.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	14,160.0	0.0	0.0	14,160.0	6.691	6.691	947,480.00
	TOTAL		**28,990.0**	**0.0**	**0.0**	**28,990.0**	**6.687**	**6.687**	**1,938,700.00**
May-11									
	HPP	IPP	43,480.0	0.0	0.0	43,480.0	6.146	6.146	2,672,470.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	1,640.0	0.0	0.0	1,640.0	8.662	8.662	142,050.00
	PASCO COGEN	SCH. D	22,460.0	0.0	0.0	22,460.0	6.672	6.672	1,498,500.00
	TOTAL		**67,580.0**	**0.0**	**0.0**	**67,580.0**	**6.382**	**6.382**	**4,313,020.00**
Jun-11									
	HPP	IPP	35,160.0	0.0	0.0	35,160.0	6.265	6.265	2,202,650.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	3,730.0	0.0	0.0	3,730.0	8.523	8.523	317,920.00
	PASCO COGEN	SCH. D	20,060.0	0.0	0.0	20,060.0	6.215	6.215	1,246,720.00
	TOTAL		**58,950.0**	**0.0**	**0.0**	**58,950.0**	**6.391**	**6.391**	**3,767,290.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2011 THROUGH DECEMBER 2011

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jul-11									
	HPP	IPP	27,670.0	0.0	0.0	27,670.0	6.375	6.375	1,763,860.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	2,220.0	0.0	0.0	2,220.0	8.350	8.350	185,370.00
	PASCO COGEN	SCH. D	17,390.0	0.0	0.0	17,390.0	6.188	6.188	1,076,170.00
	TOTAL		**47,280.0**	**0.0**	**0.0**	**47,280.0**	**6.399**	**6.399**	**3,025,400.00**
Aug-11									
	HPP	IPP	32,140.0	0.0	0.0	32,140.0	6.396	6.396	2,055,810.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	400.0	0.0	0.0	400.0	13.838	13.838	55,350.00
	PASCO COGEN	SCH. D	16,670.0	0.0	0.0	16,670.0	6.138	6.138	1,023,260.00
	TOTAL		**49,210.0**	**0.0**	**0.0**	**49,210.0**	**6.369**	**6.369**	**3,134,420.00**
Sep-11									
	HPP	IPP	29,510.0	0.0	0.0	29,510.0	6.473	6.473	1,910,250.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	960.0	0.0	0.0	960.0	13.697	13.697	131,490.00
	PASCO COGEN	SCH. D	19,090.0	0.0	0.0	19,090.0	6.054	6.054	1,155,650.00
	TOTAL		**49,560.0**	**0.0**	**0.0**	**49,560.0**	**6.452**	**6.452**	**3,197,390.00**
Oct-11									
	HPP	IPP	15,350.0	0.0	0.0	15,350.0	6.507	6.507	998,790.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	12,090.0	0.0	0.0	12,090.0	6.119	6.119	739,760.00
	TOTAL		**27,440.0**	**0.0**	**0.0**	**27,440.0**	**6.336**	**6.336**	**1,738,550.00**
Nov-11									
	HPP	IPP	8,400.0	0.0	0.0	8,400.0	6.783	6.783	569,730.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	11,120.0	0.0	0.0	11,120.0	6.560	6.560	729,480.00
	TOTAL		**19,520.0**	**0.0**	**0.0**	**19,520.0**	**6.656**	**6.656**	**1,299,210.00**
Dec-11									
	HPP	IPP	21,550.0	0.0	0.0	21,550.0	6.411	6.411	1,381,520.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	RELIANT	SCH. D	410.0	0.0	0.0	410.0	11.627	11.627	47,670.00
	PASCO COGEN	SCH. D	12,540.0	0.0	0.0	12,540.0	6.988	6.988	876,300.00
	TOTAL		**34,500.0**	**0.0**	**0.0**	**34,500.0**	**6.683**	**6.683**	**2,305,490.00**
TOTAL	HPP	IPP	229,990.0	0.0	0.0	229,990.0	6.355	6.355	14,615,710.00
Jan-11	CALPINE	SCH. D	2,550.0	0.0	0.0	2,550.0	8.447	8.447	215,390.00
THRU	RELIANT	SCH. D	9,360.0	0.0	0.0	9,360.0	9.400	9.400	879,850.00
Dec-11	PASCO COGEN	SCH. D	153,770.0	0.0	0.0	153,770.0	6.380	6.380	9,810,810.00
	TOTAL		**395,670.0**	**0.0**	**0.0**	**395,670.0**	**6.450**	**6.450**	**25,521,760.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E8

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUST-MENT
Jan-11	VARIOUS	CO-GEN.							
		FIRM	19,590.0	0.0	0.0	19,590.0	3.368	3.368	659,870.00
		AS AVAIL.	34,340.0	0.0	0.0	34,340.0	5.385	5.385	1,849,040.00
	TOTAL		53,930.0	0.0	0.0	53,930.0	4.652	4.652	2,508,910.00
Feb-11	VARIOUS	CO-GEN.							
		FIRM	17,690.0	0.0	0.0	17,690.0	3.470	3.470	613,900.00
		AS AVAIL.	30,790.0	0.0	0.0	30,790.0	5.090	5.090	1,567,340.00
	TOTAL		48,480.0	0.0	0.0	48,480.0	4.499	4.499	2,181,240.00
Mar-11	VARIOUS	CO-GEN.							
		FIRM	19,600.0	0.0	0.0	19,600.0	3.532	3.532	692,190.00
		AS AVAIL.	34,410.0	0.0	0.0	34,410.0	5.156	5.156	1,774,340.00
	TOTAL		54,010.0	0.0	0.0	54,010.0	4.567	4.567	2,466,530.00
Apr-11	VARIOUS	CO-GEN.							
		FIRM	19,640.0	0.0	0.0	19,640.0	3.495	3.495	686,500.00
		AS AVAIL.	32,840.0	0.0	0.0	32,840.0	5.802	5.802	1,905,530.00
	TOTAL		52,480.0	0.0	0.0	52,480.0	4.939	4.939	2,592,030.00
May-11	VARIOUS	CO-GEN.							
		FIRM	20,230.0	0.0	0.0	20,230.0	3.515	3.515	711,130.00
		AS AVAIL.	33,940.0	0.0	0.0	33,940.0	7.155	7.155	2,428,430.00
	TOTAL		54,170.0	0.0	0.0	54,170.0	5.796	5.796	3,139,560.00
Jun-11	VARIOUS	CO-GEN.							
		FIRM	19,720.0	0.0	0.0	19,720.0	3.533	3.533	696,730.00
		AS AVAIL.	33,390.0	0.0	0.0	33,390.0	6.330	6.330	2,113,680.00
	TOTAL		53,110.0	0.0	0.0	53,110.0	5.292	5.292	2,810,410.00
Jul-11	VARIOUS	CO-GEN.							
		FIRM	20,270.0	0.0	0.0	20,270.0	3.552	3.552	719,970.00
		AS AVAIL.	33,950.0	0.0	0.0	33,950.0	6.283	6.283	2,132,960.00
	TOTAL		54,220.0	0.0	0.0	54,220.0	5.262	5.262	2,852,930.00
Aug-11	VARIOUS	CO-GEN.							
		FIRM	8,370.0	0.0	0.0	8,370.0	3.557	3.557	297,720.00
		AS AVAIL.	34,000.0	0.0	0.0	34,000.0	6.296	6.296	2,140,730.00
	TOTAL		42,370.0	0.0	0.0	42,370.0	5.755	5.755	2,438,450.00
Sep-11	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.581	3.581	222,380.00
		AS AVAIL.	33,280.0	0.0	0.0	33,280.0	6.359	6.359	2,116,240.00
	TOTAL		39,490.0	0.0	0.0	39,490.0	5.922	5.922	2,338,620.00
Oct-11	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.545	3.545	227,610.00
		AS AVAIL.	34,140.0	0.0	0.0	34,140.0	5.888	5.888	2,010,000.00
	TOTAL		40,560.0	0.0	0.0	40,560.0	5.517	5.517	2,237,610.00
Nov-11	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.612	3.612	224,310.00
		AS AVAIL.	32,840.0	0.0	0.0	32,840.0	5.970	5.970	1,960,700.00
	TOTAL		39,050.0	0.0	0.0	39,050.0	5.595	5.595	2,185,010.00
Dec-11	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.639	3.639	207,400.00
		AS AVAIL.	34,350.0	0.0	0.0	34,350.0	6.009	6.009	2,064,170.00
	TOTAL		40,050.0	0.0	0.0	40,050.0	5.672	5.672	2,271,570.00
TOTAL	VARIOUS	CO-GEN.							
Jan-11		FIRM	169,650.0	0.0	0.0	169,650.0	3.513	3.513	5,959,710.00
THRU		AS AVAIL.	402,270.0	0.0	0.0	402,270.0	5.982	5.982	24,063,160.00
Dec-11	TOTAL		571,920.0	0.0	0.0	571,920.0	5.249	5.249	30,022,870.00

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2011 THROUGH DECEMBER 2011

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
Jan-11	VARIOUS	ECONOMY	11,980.0	0.0	11,980.0	4.527	542,330.00	4.527	542,330.00	0.00
Feb-11	VARIOUS	ECONOMY	5,120.0	0.0	5,120.0	4.166	213,290.00	4.166	213,290.00	0.00
Mar-11	VARIOUS	ECONOMY	13,070.0	0.0	13,070.0	4.266	557,610.00	4.266	557,610.00	0.00
Apr-11	VARIOUS	ECONOMY	32,120.0	0.0	32,120.0	4.111	1,320,530.00	4.111	1,320,530.00	0.00
May-11	VARIOUS	ECONOMY	60,000.0	0.0	60,000.0	4.879	2,927,600.00	4.879	2,927,600.00	0.00
Jun-11	VARIOUS	ECONOMY	16,170.0	0.0	16,170.0	5.080	821,450.00	5.080	821,450.00	0.00
Jul-11	VARIOUS	ECONOMY	10,880.0	0.0	10,880.0	5.114	556,390.00	5.114	556,390.00	0.00
Aug-11	VARIOUS	ECONOMY	13,270.0	0.0	13,270.0	4.781	634,430.00	4.781	634,430.00	0.00
Sep-11	VARIOUS	ECONOMY	45,100.0	0.0	45,100.0	4.733	2,134,630.00	4.733	2,134,630.00	0.00
Oct-11	VARIOUS	ECONOMY	33,200.0	0.0	33,200.0	4.647	1,542,740.00	4.647	1,542,740.00	0.00
Nov-11	VARIOUS	ECONOMY	5,390.0	0.0	5,390.0	4.765	256,810.00	4.765	256,810.00	0.00
Dec-11	VARIOUS	ECONOMY	45,270.0	0.0	45,270.0	4.468	2,022,450.00	4.468	2,022,450.00	0.00
TOTAL	VARIOUS	ECONOMY	291,570.0	0.0	291,570.0	4.640	13,530,260.00	4.640	13,530,260.00	0.00

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Jan 10 - Dec 10	Projected Jan 11 - Dec 11	Difference $	Difference %
Base Rate Revenue	55.45	55.45	0.00	0%
Fuel Recovery Revenue	41.67	38.75	(2.92)	-7%
Conservation Revenue	2.54	3.22	0.68	27%
Capacity Revenue	5.39	3.36	(2.03)	-38%
Environmental Revenue	4.86	4.04	(0.82)	-17%
Florida Gross Receipts Tax Revenue	2.82	2.69	(0.13)	-5%
TOTAL REVENUE	**$112.73**	**$107.51**	**($5.22)**	**-5%**

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2008	ACTUAL 2009	ACT/EST 2010	EST 2011	DIFFERENCE (%) 2009-2008	2010-2009	2011-2010
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	3,030,195	3,015,616	0	0	-0.5%	-100.0%	0.0%
2 LIGHT OIL [1]	7,265,628	6,186,693	8,210,479	9,601,392	-14.8%	32.7%	16.9%
3 COAL	316,207,516	305,837,556	350,032,342	404,639,930	-3.3%	14.5%	15.6%
4 NATURAL GAS	593,652,315	519,527,349	430,646,133	395,285,299	-12.5%	-17.1%	-8.2%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	920,155,654	834,567,214	788,888,954	809,526,621	-9.3%	-5.5%	2.6%
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	18,437	23,796	0	0	29.1%	-100.0%	0.0%
9 LIGHT OIL [1]	33,159	33,256	49,534	52,040	0.3%	48.9%	5.1%
10 COAL	10,193,095	9,619,445	10,837,080	11,431,750	-5.6%	12.7%	5.5%
11 NATURAL GAS	7,535,297	8,660,347	8,471,552	7,505,930	14.9%	-2.2%	-11.4%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	17,779,988	18,336,844	19,358,166	18,989,720	3.1%	5.6%	-1.9%
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	31,690	39,682	0	0	25.2%	-100.0%	0.0%
16 LIGHT OIL (BBL) [1]	60,655	62,998	114,725	147,470	3.9%	82.1%	28.5%
17 COAL (TON)	4,621,065	4,238,624	4,711,333	5,055,810	-8.3%	11.2%	7.3%
18 NATURAL GAS (MCF)	54,408,485	63,535,787	62,615,706	55,804,340	16.8%	-1.4%	-10.9%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	198,802	248,834	0	0	25.2%	-100.0%	0.0%
22 LIGHT OIL [1]	327,063	351,269	490,525	550,500	7.4%	39.6%	12.2%
23 COAL	109,791,173	101,367,908	112,329,879	119,538,720	-7.7%	10.8%	6.4%
24 NATURAL GAS	56,000,801	65,028,004	64,046,452	57,366,930	16.1%	-1.5%	-10.4%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	166,317,839	166,996,015	176,866,856	177,456,150	0.4%	5.9%	0.3%
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.10	0.13	0.00	0.00	30.0%	-100.0%	0.0%
29 LIGHT OIL [1]	0.19	0.18	0.26	0.27	-5.3%	44.4%	3.8%
30 COAL	57.33	52.46	55.98	60.20	-8.5%	6.7%	7.5%
31 NATURAL GAS	42.38	47.23	43.76	39.53	11.4%	-7.3%	-9.7%
32 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	100.00	100.00	100.00	100.00	0.0%	0.0%	0.0%
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	95.62	75.99	0.00	0.00	-20.5%	-100.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	119.79	98.20	71.57	65.11	-18.0%	-27.1%	-9.0%
37 COAL ($/TON)	68.43	72.15	74.30	80.03	5.4%	3.0%	7.7%
38 NATURAL GAS ($/MCF)	10.91	8.18	6.88	7.08	-25.0%	-15.9%	2.9%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	15.24	12.12	0.00	0.00	-20.5%	-100.0%	0.0%
42 LIGHT OIL [1]	22.21	17.61	16.74	17.44	-20.7%	-4.9%	4.2%
43 COAL	2.88	3.02	3.12	3.39	4.9%	3.3%	8.7%
44 NATURAL GAS	10.60	7.99	6.72	6.89	-24.6%	-15.9%	2.5%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	5.53	5.00	4.46	4.56	-9.6%	-10.8%	2.2%
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	10,783	10,457	0	0	-3.0%	-100.0%	0.0%
49 LIGHT OIL [1]	9,863	10,563	9,903	10,578	7.1%	-6.2%	6.8%
50 COAL	10,771	10,538	10,365	10,457	-2.2%	-1.6%	0.9%
51 NATURAL GAS	7,432	7,509	7,560	7,643	1.0%	0.7%	1.1%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	9,354	9,107	9,137	9,345	-2.6%	0.3%	2.3%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	16.44	12.67	0.00	0.00	-22.9%	-100.0%	0.0%
56 LIGHT OIL [1]	21.91	18.60	16.58	18.45	-15.1%	-10.9%	11.3%
57 COAL	3.10	3.18	3.23	3.54	2.6%	1.6%	9.6%
58 NATURAL GAS	7.88	6.00	5.08	5.27	-23.9%	-15.3%	3.7%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	5.18	4.55	4.08	4.26	-12.2%	-10.3%	4.4%

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2011 - DECEMBER 2011

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2011 through December 2011

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	5,751,510	4.225	243,001,300	3.875	222,871,015
TIER II (Over 1,000) kWh	3,096,967	4.225	130,846,854	4.875	150,977,139
Total	8,848,477		373,848,153		373,848,154

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI

IN RE: TAMPA ELECTRIC'S

FUEL & PURCHASED POWER COST RECOVERY

AND CAPACITY COST RECOVERY PROJECTIONS

JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations Planning.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including operations, instrumentation and controls, performance planning and asset management. In October 2008, I was promoted to Manager, Operations Planning, where I am currently responsible for unit commitment and reporting of generation statistics.

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. ____ (BSB-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 2011 period.

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

A. Four of the company's coal-fired units, 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. One outage from Big Bend Unit 1, one outage from Big Bend Unit 2, one outage from Big Bend Unit 3 and one outage from Polk Unit 1 were identified as outlying outages; therefore, the 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 2011 period. A range of potential improvements and degradations were determined for each of these metrics.

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 percent 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 2011 period, the projected EUOF for Big Bend Unit 3 is 11.3 percent, and the POF is 6.6 percent. Therefore, the target EAF for Big Bend Unit 3 equals 82.1 percent or:

$$100\% - (11.3\% + 6.6\%) = 82.1\%$$

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:

$$EAF_{MAX} = 1 - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

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 EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Big Bend Unit 3 example:

$$EAF_{MAX} = 1 - [0.8 \ (11.3\%) + 0.95 \ (6.6\%)] = 84.7\%$$

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:

$$EAF_{MIN} = 1 - [1.40 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Big Bend Unit 3 example,

$$EAF_{MIN} = 1 - [1.40 \ (11.3\%) + 1.10 \ (6.6\%)] = 76.9\%$$

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 2011 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2011; therefore, two 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 February 20, 2011 to March 1, 2011 and September 3, 2011 to November 18, 2011. There are 2,089 planned outage hours scheduled for the 2011 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 2 is 23.8 percent or:

$$\frac{2{,}089}{8{,}760} \times 100\% = 23.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 5.8 percent. Big Bend Unit 2 has a POF of 23.8 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 6.0 percent. Bayside Unit 1 has a POF of 21.1 percent, and Bayside Unit 2 has a POF of 3.8 percent.

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

A. For each unit the most current 12-month ending value, June 2011, 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 a EUOF of 11.3 percent for Big Bend Unit 3. The EUOF for Big Bend Unit 3 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(702 + 292)}{8,760} \times 100\% = 11.3\%$$

Relative to Big Bend Unit 3, the EUOF of 11.3 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 EUOF for this unit is 26.3 percent. The unit will have a planned outage in 2011, and the POF is 5.8 percent. Therefore, the target equivalent availability for this unit is 67.9 percent.

Big Bend Unit 2

The projected EUOF for this unit is 13.8 percent. The unit will have a planned outage in 2011, and the POF is 23.8 percent. Therefore, the target equivalent availability for this unit is 62.4 percent.

Big Bend Unit 3

The projected EUOF for this unit is 11.3 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 82.1 percent.

Big Bend Unit 4

The projected EUOF for this unit is 15.5 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 77.9 percent.

Polk Unit 1

The projected EUOF for this unit is 5.3 percent. The unit will have a planned outage in 2011, and the POF is 6.0 percent. Therefore, the target equivalent availability for this unit is 88.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 0.7 percent. The unit will have a planned outage in 2011, and the POF is 21.1 percent. Therefore, the target equivalent availability for this unit is 78.2 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.8 percent. The unit will have a planned outage in 2011, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 94.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.2 percent is shown on Page 5 of Document No. 1. This target is greater than the 2007, 2008 and 2009 January through December actual performances.

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. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 3 on page 16 of Document No. 1. Except for the months of March, April, October and November, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March, April, October and November, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. 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 metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

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 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 2011 period.

A. The heat rate target for Big Bend Unit 1 is 10,676 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±431 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,350 Btu/Net kWh with a range of ±410 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,582 Btu/Net kWh, with a range of ±404 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,538 Btu/Net kWh with a range of ±384 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,820 Btu/Net kWh with a range of ±703 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,212 Btu/Net kWh with a range of ±93 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,311 Btu/Net kWh with a range of ±89 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 $872,944,300 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 $29,671,000 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 3, the weighting factor for equivalent availability is 6.2 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 3, page 9, if the unit operates at 84.7 percent equivalent availability, fuel savings would equal $1,833,900, 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 $29,671,000. 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 2011 is $1,902,870,049. This produces the maximum allowed jurisdictional incentive of $7,711,175 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.

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):

$$\begin{aligned} GPIP: = (\ & 0.0458\ EAP_{BB1} + 0.0595\ EAP_{BB2} \\ & + 0.0618\ EAP_{BB3} + 0.0788\ EAP_{BB4} \\ & + 0.0067\ EAP_{PK1} + 0.0134\ EAP_{BAY1} \\ & + 0.0032\ EAP_{BAY2} + 0.1138\ HRP_{BB1} \\ & + 0.0963\ HRP_{BB2} + 0.1160\ HRP_{BB3} \\ & + 0.1248\ HRP_{BB4} + 0.1559\ HRP_{PK1} \\ & + 0.0492\ HRP_{BAY1} + 0.0748\ HRP_{BAY2}) \end{aligned}$$

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 2011 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

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2011 - DECEMBER 2011

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2011 - DECEMBER 2011
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2011 - DECEMBER 2011

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,671.0	7,711.2
+9	26,703.9	6,940.1
+8	23,736.8	6,168.9
+7	20,769.7	5,397.8
+6	17,802.6	4,626.7
+5	14,835.5	3,855.6
+4	11,868.4	3,084.5
+3	8,901.3	2,313.4
+2	5,934.2	1,542.2
+1	2,967.1	771.1
0	0.0	0.0
-1	(3,412.1)	(771.1)
-2	(6,824.2)	(1,542.2)
-3	(10,236.3)	(2,313.4)
-4	(13,648.5)	(3,084.5)
-5	(17,060.6)	(3,855.6)
-6	(20,472.7)	(4,626.7)
-7	(23,884.8)	(5,397.8)
-8	(27,296.9)	(6,168.9)
-9	(30,709.0)	(6,940.1)
-10	(34,121.2)	(7,711.2)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2011 - DECEMBER 2011

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,876,746,000	
Line 2	Month of January	2011	$	1,827,320,000	
Line 3	Month of February	2011	$	1,844,451,125	
Line 4	Month of March	2011	$	1,861,742,854	
Line 5	Month of April	2011	$	1,894,199,839	
Line 6	Month of May	2011	$	1,911,957,963	
Line 7	Month of June	2011	$	1,929,882,569	
Line 8	Month of July	2011	$	1,879,835,503	
Line 9	Month of August	2011	$	1,897,458,961	
Line 10	Month of September	2011	$	1,915,247,639	
Line 11	Month of October	2011	$	1,947,838,015	
Line 12	Month of November	2011	$	1,966,098,997	
Line 13	Month of December	2011	$	1,984,531,175	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,902,870,049	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.17%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	7,777,432	
Line 18	Jurisdictional Sales			18,926,613	MWH
Line 19	Total Sales			19,089,236	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			99.15%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**7,711,175**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2011 - DECEMBER 2011

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	4.58%	67.9	73.5	56.8	1,359.3	(5,657.4)
BIG BEND 2	5.95%	62.4	66.3	54.5	1,765.3	(1,487.8)
BIG BEND 3	6.18%	82.1	84.7	76.9	1,833.9	(1,379.9)
BIG BEND 4	7.88%	77.9	81.3	71.0	2,339.2	(2,354.1)
POLK 1	0.67%	88.6	90.0	85.9	198.3	(455.9)
BAYSIDE 1	1.34%	78.2	79.4	75.9	397.4	(821.4)
BAYSIDE 2	0.32%	94.4	95.0	93.3	93.8	(280.8)
GPIF SYSTEM	**26.92%**					

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	11.38%	10,676	91.3	10,245	11,107	3,376.5	(3,376.5)
BIG BEND 2	9.63%	10,350	91.2	9,940	10,759	2,858.3	(2,858.3)
BIG BEND 3	11.60%	10,582	86.9	10,179	10,986	3,442.7	(3,442.7)
BIG BEND 4	12.48%	10,538	90.8	10,153	10,922	3,703.5	(3,703.5)
POLK 1	15.59%	9,820	97.5	9,117	10,522	4,624.5	(4,624.5)
BAYSIDE 1	4.92%	7,212	86.6	7,120	7,305	1,459.8	(1,459.8)
BAYSIDE 2	7.48%	7,311	84.7	7,222	7,400	2,218.6	(2,218.6)
GPIF SYSTEM	**73.08%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 11 - DEC 11			ACTUAL PERFORMANCE JAN 09 - DEC 09			ACTUAL PERFORMANCE JAN 08 - DEC 08			ACTUAL PERFORMANCE JAN 07 - DEC 07		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	4.58%	17.0%	5.8	26.3	27.9	14.0	30.3	35.3	4.9	19.4	20.4	0.0	23.7	23.7
BIG BEND 2	5.95%	22.1%	23.8	13.8	18.1	26.5	36.7	49.9	10.2	18.8	20.8	2.5	18.0	18.4
BIG BEND 3	6.18%	23.0%	6.6	11.3	12.1	5.0	16.2	17.0	32.4	23.1	34.2	11.8	41.7	47.3
BIG BEND 4	7.88%	29.3%	6.6	15.5	16.6	1.9	18.6	19.0	5.8	21.4	22.7	27.0	19.8	27.0
POLK 1	0.67%	2.5%	6.0	5.3	5.7	14.1	9.4	12.7	3.0	13.8	16.9	4.1	0.0	0.0
BAYSIDE 1	1.34%	5.0%	21.1	0.7	0.9	5.6	1.3	1.4	2.4	2.8	3.1	11.5	3.3	3.9
BAYSIDE 2	0.32%	1.2%	3.8	1.8	1.8	6.8	1.3	1.4	14.5	1.9	2.4	2.0	1.7	1.7
GPIF SYSTEM	**26.92%**	**100.0%**	**10.9**	**14.9**	**16.6**	**10.7**	**22.7**	**26.9**	**12.6**	**19.5**	**23.2**	**11.9**	**23.6**	**27.1**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**74.2**			**66.6**			**67.9**			**64.6**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
11.7	**21.9**	**25.7**	**66.3**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 11 - DEC 11	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 09 - DEC 09	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 08 - DEC 08	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 07 - DEC 07
BIG BEND 1	11.38%	15.6%	10,676	10,598	10,889	10,740
BIG BEND 2	9.63%	13.2%	10,350	10,178	10,579	10,355
BIG BEND 3	11.60%	15.9%	10,582	10,540	10,708	10,514
BIG BEND 4	12.48%	17.1%	10,538	10,500	10,669	10,830
POLK 1	15.59%	21.3%	9,820	9,795	9,527	9,744
BAYSIDE 1	4.92%	6.7%	7,212	7,274	7,250	7,310
BAYSIDE 2	7.48%	10.2%	7,311	7,353	7,373	7,378
GPIF SYSTEM	**73.08%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,834**	**9,790**	**9,887**	**9,881**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2011 - DECEMBER 2011
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	872,944.3	871,585.0	1,359.3	4.58%
EA_2 BIG BEND 2	872,944.3	871,179.0	1,765.3	5.95%
EA_3 BIG BEND 3	872,944.3	871,110.4	1,833.9	6.18%
EA_4 BIG BEND 4	872,944.3	870,605.1	2,339.2	7.88%
EA_7 POLK 1	872,944.3	872,746.0	198.3	0.67%
EA_8 BAYSIDE 1	872,944.3	872,546.9	397.4	1.34%
EA_9 BAYSIDE 2	872,944.3	872,850.5	93.8	0.32%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	872,944.3	869,567.7	3,376.5	11.38%
AHR_2 BIG BEND 2	872,944.3	870,086.0	2,858.3	9.63%
AHR_3 BIG BEND 3	872,944.3	869,501.5	3,442.7	11.60%
AHR_4 BIG BEND 4	872,944.3	869,240.8	3,703.5	12.48%
AHR_7 POLK 1	872,944.3	868,319.7	4,624.5	15.59%
AHR_8 BAYSIDE 1	872,944.3	871,484.5	1,459.8	4.92%
AHR_9 BAYSIDE 2	872,944.3	870,725.7	2,218.6	7.48%
TOTAL SAVINGS			**29,671.0**	**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 2011 - DECEMBER 2011

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	1,359.3	73.5	+10	3,376.5	10,245
+9	1,223.4	72.9	+9	3,038.9	10,281
+8	1,087.4	72.4	+8	2,701.2	10,316
+7	951.5	71.8	+7	2,363.6	10,352
+6	815.6	71.3	+6	2,025.9	10,388
+5	679.6	70.7	+5	1,688.3	10,423
+4	543.7	70.2	+4	1,350.6	10,459
+3	407.8	69.6	+3	1,013.0	10,494
+2	271.9	69.0	+2	675.3	10,530
+1	135.9	68.5	+1	337.7	10,566
					10,601
0	0.0	67.9	0	0.0	10,676
					10,751
-1	(565.7)	66.8	-1	(337.7)	10,787
-2	(1,131.5)	65.7	-2	(675.3)	10,822
-3	(1,697.2)	64.6	-3	(1,013.0)	10,858
-4	(2,262.9)	63.5	-4	(1,350.6)	10,894
-5	(2,828.7)	62.4	-5	(1,688.3)	10,929
-6	(3,394.4)	61.3	-6	(2,025.9)	10,965
-7	(3,960.2)	60.2	-7	(2,363.6)	11,000
-8	(4,525.9)	59.1	-8	(2,701.2)	11,036
-9	(5,091.6)	57.9	-9	(3,038.9)	11,072
-10	(5,657.4)	56.8	-10	(3,376.5)	11,107
	Weighting Factor =	4.58%		Weighting Factor =	11.38%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	1,765.3	66.3	+10	2,858.3	9,940
+9	1,588.8	65.9	+9	2,572.4	9,974
+8	1,412.2	65.5	+8	2,286.6	10,007
+7	1,235.7	65.1	+7	2,000.8	10,040
+6	1,059.2	64.7	+6	1,715.0	10,074
+5	882.7	64.4	+5	1,429.1	10,107
+4	706.1	64.0	+4	1,143.3	10,141
+3	529.6	63.6	+3	857.5	10,174
+2	353.1	63.2	+2	571.7	10,208
+1	176.5	62.8	+1	285.8	10,241
					10,275
0	0.0	62.4	0	0.0	10,350
					10,425
-1	(148.8)	61.6	-1	(285.8)	10,458
-2	(297.6)	60.8	-2	(571.7)	10,492
-3	(446.3)	60.0	-3	(857.5)	10,525
-4	(595.1)	59.2	-4	(1,143.3)	10,559
-5	(743.9)	58.4	-5	(1,429.1)	10,592
-6	(892.7)	57.6	-6	(1,715.0)	10,626
-7	(1,041.5)	56.8	-7	(2,000.8)	10,659
-8	(1,190.2)	56.1	-8	(2,286.6)	10,693
-9	(1,339.0)	55.3	-9	(2,572.4)	10,726
-10	(1,487.8)	54.5	-10	(2,858.3)	10,759
	Weighting Factor =	5.95%		Weighting Factor =	9.63%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	1,833.9	84.7	+10	3,442.7	10,179
+9	1,650.5	84.4	+9	3,098.5	10,211
+8	1,467.1	84.1	+8	2,754.2	10,244
+7	1,283.7	83.9	+7	2,409.9	10,277
+6	1,100.3	83.6	+6	2,065.6	10,310
+5	916.9	83.4	+5	1,721.4	10,343
+4	733.6	83.1	+4	1,377.1	10,376
+3	550.2	82.8	+3	1,032.8	10,409
+2	366.8	82.6	+2	688.5	10,442
+1	183.4	82.3	+1	344.3	10,474
					10,507
0	0.0	82.1	0	0.0	10,582
					10,657
-1	(138.0)	81.6	-1	(344.3)	10,690
-2	(276.0)	81.0	-2	(688.5)	10,723
-3	(414.0)	80.5	-3	(1,032.8)	10,756
-4	(551.9)	80.0	-4	(1,377.1)	10,789
-5	(689.9)	79.5	-5	(1,721.4)	10,822
-6	(827.9)	79.0	-6	(2,065.6)	10,855
-7	(965.9)	78.4	-7	(2,409.9)	10,887
-8	(1,103.9)	77.9	-8	(2,754.2)	10,920
-9	(1,241.9)	77.4	-9	(3,098.5)	10,953
-10	(1,379.9)	76.9	-10	(3,442.7)	10,986
	Weighting Factor =	6.18%		Weighting Factor =	11.60%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	2,339.2	81.3	+10	3,703.5	10,153
+9	2,105.3	81.0	+9	3,333.2	10,184
+8	1,871.4	80.6	+8	2,962.8	10,215
+7	1,637.4	80.3	+7	2,592.5	10,246
+6	1,403.5	79.9	+6	2,222.1	10,277
+5	1,169.6	79.6	+5	1,851.8	10,308
+4	935.7	79.3	+4	1,481.4	10,339
+3	701.8	78.9	+3	1,111.1	10,370
+2	467.8	78.6	+2	740.7	10,401
+1	233.9	78.2	+1	370.4	10,432
					10,463
0	0.0	77.9	0	0.0	10,538
					10,613
-1	(235.4)	77.2	-1	(370.4)	10,643
-2	(470.8)	76.5	-2	(740.7)	10,674
-3	(706.2)	75.8	-3	(1,111.1)	10,705
-4	(941.6)	75.1	-4	(1,481.4)	10,736
-5	(1,177.0)	74.4	-5	(1,851.8)	10,767
-6	(1,412.4)	73.8	-6	(2,222.1)	10,798
-7	(1,647.8)	73.1	-7	(2,592.5)	10,829
-8	(1,883.2)	72.4	-8	(2,962.8)	10,860
-9	(2,118.7)	71.7	-9	(3,333.2)	10,891
-10	(2,354.1)	71.0	-10	(3,703.5)	10,922
	Weighting Factor =	7.88%		Weighting Factor =	12.48%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	198.3	90.0	+10	4,624.5	9,117
+9	178.4	89.9	+9	4,162.1	9,179
+8	158.6	89.7	+8	3,699.6	9,242
+7	138.8	89.6	+7	3,237.2	9,305
+6	119.0	89.5	+6	2,774.7	9,368
+5	99.1	89.3	+5	2,312.3	9,431
+4	79.3	89.2	+4	1,849.8	9,493
+3	59.5	89.1	+3	1,387.4	9,556
+2	39.7	88.9	+2	924.9	9,619
+1	19.8	88.8	+1	462.5	9,682
					9,745
0	0.0	88.6	0	0.0	9,820
					9,895
-1	(45.6)	88.4	-1	(462.5)	9,957
-2	(91.2)	88.1	-2	(924.9)	10,020
-3	(136.8)	87.8	-3	(1,387.4)	10,083
-4	(182.4)	87.6	-4	(1,849.8)	10,146
-5	(227.9)	87.3	-5	(2,312.3)	10,208
-6	(273.5)	87.0	-6	(2,774.7)	10,271
-7	(319.1)	86.7	-7	(3,237.2)	10,334
-8	(364.7)	86.5	-8	(3,699.6)	10,397
-9	(410.3)	86.2	-9	(4,162.1)	10,460
-10	(455.9)	85.9	-10	(4,624.5)	10,522
	Weighting Factor =	0.67%		Weighting Factor =	15.59%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	397.4	79.4	+10	1,459.8	7,120
+9	357.6	79.3	+9	1,313.8	7,121
+8	317.9	79.2	+8	1,167.8	7,123
+7	278.2	79.1	+7	1,021.8	7,125
+6	238.4	78.9	+6	875.9	7,127
+5	198.7	78.8	+5	729.9	7,128
+4	159.0	78.7	+4	583.9	7,130
+3	119.2	78.6	+3	437.9	7,132
+2	79.5	78.5	+2	292.0	7,134
+1	39.7	78.4	+1	146.0	7,136
					7,137
0	0.0	78.2	0	0.0	7,212
					7,287
-1	(82.1)	78.0	-1	(146.0)	7,289
-2	(164.3)	77.8	-2	(292.0)	7,291
-3	(246.4)	77.5	-3	(437.9)	7,293
-4	(328.6)	77.3	-4	(583.9)	7,295
-5	(410.7)	77.0	-5	(729.9)	7,296
-6	(492.9)	76.8	-6	(875.9)	7,298
-7	(575.0)	76.6	-7	(1,021.8)	7,300
-8	(657.1)	76.3	-8	(1,167.8)	7,302
-9	(739.3)	76.1	-9	(1,313.8)	7,304
-10	(821.4)	75.9	-10	(1,459.8)	7,305
	Weighting Factor =	1.34%		Weighting Factor =	4.92%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	93.8	95.0	+10	2,218.6	7,222
+9	84.4	94.9	+9	1,996.7	7,223
+8	75.1	94.8	+8	1,774.8	7,224
+7	65.7	94.8	+7	1,553.0	7,226
+6	56.3	94.7	+6	1,331.1	7,227
+5	46.9	94.7	+5	1,109.3	7,229
+4	37.5	94.6	+4	887.4	7,230
+3	28.1	94.6	+3	665.6	7,231
+2	18.8	94.5	+2	443.7	7,233
+1	9.4	94.5	+1	221.9	7,234
					7,236
0	0.0	94.4	0	0.0	7,311
					7,386
-1	(28.1)	94.3	-1	(221.9)	7,387
-2	(56.2)	94.2	-2	(443.7)	7,388
-3	(84.2)	94.1	-3	(665.6)	7,390
-4	(112.3)	94.0	-4	(887.4)	7,391
-5	(140.4)	93.9	-5	(1,109.3)	7,393
-6	(168.5)	93.8	-6	(1,331.1)	7,394
-7	(196.6)	93.7	-7	(1,553.0)	7,395
-8	(224.7)	93.5	-8	(1,774.8)	7,397
-9	(252.7)	93.4	-9	(1,996.7)	7,398
-10	(280.8)	93.3	-10	(2,218.6)	7,400
	Weighting Factor =	0.32%		Weighting Factor =	7.48%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	72.1	46.3	62.8	72.1	72.1	72.1	72.1	72.1	72.1	55.8	72.1	72.1	67.9
2. POF	0.0	35.7	12.9	0.0	0.0	0.0	0.0	0.0	0.0	22.6	0.0	0.0	5.8
3. EUOF	27.9	17.9	24.3	27.9	27.9	27.9	27.9	27.9	27.9	21.6	27.9	27.9	26.3
4. EUOR	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	673	391	586	651	673	651	673	673	651	521	651	673	7,467
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	71	281	157	69	71	69	71	71	69	223	70	71	1,293
9. POH	0	240	96	0	0	0	0	0	0	168	0	0	504
10. EFOH	135	78	117	130	135	130	135	135	130	104	131	135	1,496
11. EMOH	73	42	63	71	73	71	73	73	71	56	71	73	809
12. OPER BTU (GBTU)	2,539	1,474	2,200	2,458	2,561	2,465	2,573	2,566	2,487	1,948	2,468	2,521	28,259
13. NET GEN (MWH)	237,580	137,900	205,850	230,270	239,990	230,950	241,190	240,530	233,130	182,460	231,260	235,830	2,646,940
14. ANOHR (Btu/kwh)	10,686	10,686	10,688	10,673	10,669	10,672	10,667	10,668	10,668	10,678	10,671	10,689	10,676
15. NOF (%)	89.4	89.3	88.9	91.9	92.6	92.1	93.1	92.8	93.0	91.0	92.3	88.7	91.3
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		-5.001	) +	11,133								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	81.9	55.6	79.3	81.9	81.9	81.9	81.9	81.9	5.5	0.0	32.7	81.9	62.4
2. POF	0.0	32.1	3.2	0.0	0.0	0.0	0.0	0.0	93.3	100.0	60.1	0.0	23.8
3. EUOF	18.1	12.3	17.5	18.1	18.1	18.1	18.1	18.1	1.2	0.0	7.2	18.1	13.8
4. EUOR	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	0.0	18.1	18.1	18.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
34 6. SH	664	407	643	643	664	643	664	664	43	0	257	664	5,956
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	80	265	100	77	80	77	80	80	677	744	464	80	2,804
9. POH	0	216	24	0	0	0	0	0	672	744	433	0	2,089
10. EFOH	117	72	113	114	117	114	117	117	8	0	45	117	1,052
11. EMOH	17	11	17	17	17	17	17	17	1	0	7	17	155
12. OPER BTU (GBTU)	2,466	1,470	2,379	2,351	2,440	2,357	2,424	2,445	131	0	901	2,458	21,819
13. NET GEN (MWH)	238,220	141,490	229,700	227,330	236,030	228,020	234,300	236,620	12,380	0	86,740	237,290	2,108,120
14. ANOHR (Btu/kwh)	10,354	10,387	10,358	10,342	10,336	10,338	10,344	10,333	10,545	0	10,391	10,358	10,350
15. NOF (%)	90.8	88.0	90.4	91.8	92.3	92.1	91.7	92.6	74.8	0.0	87.7	90.5	91.2
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	-11.920	) +		11,436								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	87.9	87.9	70.8	76.1	87.9	87.9	87.9	87.9	87.9	79.4	55.6	87.9	82.1
2. POF	0.0	0.0	19.4	13.3	0.0	0.0	0.0	0.0	0.0	9.7	36.8	0.0	6.6
3. EUOF	12.1	12.1	9.8	10.5	12.1	12.1	12.1	12.1	12.1	11.0	7.7	12.1	11.3
4. EUOR	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	672	607	542	564	672	651	672	672	651	607	412	672	7,394
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	72	65	201	156	72	69	72	72	69	137	309	72	1,366
9. POH	0	0	144	96	0	0	0	0	0	72	265	0	577
10. EFOH	64	58	51	54	64	62	64	64	62	58	39	64	702
11. EMOH	27	24	21	22	27	26	27	27	26	24	16	27	292
12. OPER BTU (GBTU)	2,198	2,034	1,820	1,783	2,221	2,244	2,305	2,309	2,305	2,121	1,294	2,175	24,812
13. NET GEN (MWH)	207,060	192,120	172,030	167,190	209,420	212,790	218,420	218,830	219,350	201,540	121,290	204,640	2,344,680
14. ANOHR (Btu/kwh)	10,617	10,585	10,581	10,662	10,603	10,545	10,552	10,550	10,506	10,525	10,669	10,631	10,582
15. NOF (%)	84.4	86.7	87.0	81.2	85.4	89.6	89.0	89.2	92.3	91.0	80.7	83.4	86.9
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365
17. ANOHR EQUATION	ANOHR = NOF(	-13.984	) +		11,797								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	83.4	83.4	56.4	83.4	83.4	83.4	83.4	83.4	83.4	83.4	75.0	53.8	77.9
2. POF	0.0	0.0	32.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	35.5	6.6
3. EUOF	16.6	16.6	11.3	16.6	16.6	16.6	16.6	16.6	16.6	16.6	15.0	10.7	15.5
4. EUOR	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	681	615	462	659	681	659	681	681	659	681	593	440	7,492
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	63	57	281	61	63	61	63	63	61	63	128	304	1,268
9. POH	0	0	240	0	0	0	0	0	0	0	72	264	576
10. EFOH	112	101	76	109	112	109	112	112	109	112	98	72	1,233
11. EMOH	12	11	8	11	12	11	12	12	11	12	10	8	128
12. OPER BTU (GBTU)	2,693	2,497	1,859	2,589	2,723	2,680	2,773	2,768	2,701	2,789	2,365	1,674	30,130
13. NET GEN (MWH)	252,150	236,300	175,270	244,110	258,630	256,510	265,550	264,810	259,440	267,790	224,390	154,370	2,859,320
14. ANOHR (Btu/kwh)	10,682	10,566	10,607	10,607	10,528	10,448	10,442	10,451	10,410	10,414	10,540	10,842	10,538
15. NOF (%)	86.7	90.0	88.8	88.8	91.1	93.3	93.5	93.3	94.4	94.3	90.7	82.2	90.8
16. NPC (MW)	427	427	427	417	417	417	417	417	417	417	417	427	420
17. ANOHR EQUATION	ANOHR = NOF(		-35.305	) +	13,743								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	94.3	37.1	94.3	94.3	94.3	94.3	94.3	94.3	94.3	79.1	94.3	94.3	88.6
2. POF	0.0	60.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.0	0.0	6.0
3. EUOF	5.7	2.2	5.7	5.7	5.7	5.7	5.7	5.7	5.7	4.8	5.7	5.7	5.3
4. EUOR	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	640	248	619	619	640	619	640	640	619	537	619	640	7,080
7. RSH	0	0	0	0	0	0	0	0	0	0	92	0	92
8. UH	104	424	124	101	104	101	104	104	101	207	10	104	1,588
9. POH	0	408	0	0	0	0	0	0	0	120	0	0	528
10. EFOH	40	14	40	39	40	39	40	40	39	34	39	40	446
11. EMOH	2	1	2	2	2	2	2	2	2	2	2	2	20
12. OPER BTU (GBTU)	1,345	522	1,304	1,301	1,347	1,305	1,349	1,349	1,306	1,132	1,303	1,343	14,908
13. NET GEN (MWH)	135,350	52,760	133,390	130,970	137,100	134,020	138,510	138,500	134,980	116,500	132,380	133,750	1,518,210
14. ANOHR (Btu/kwh)	9,940	9,888	9,777	9,936	9,828	9,735	9,739	9,739	9,672	9,717	9,843	10,041	9,820
15. NOF (%)	96.1	96.7	98.0	96.2	97.4	98.4	98.4	98.4	99.1	98.6	97.2	95.0	97.5
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(	-89.476	) +		18,541								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	99.1	99.1	99.1	0.0	0.0	69.4	99.1	99.1	99.1	99.1	76.0	99.1	78.2
2. POF	0.0	0.0	0.0	100.0	100.0	30.0	0.0	0.0	0.0	0.0	23.3	0.0	21.1
3. EUOF	0.9	0.9	0.9	0.0	0.0	0.6	0.9	0.9	0.9	0.9	0.7	0.9	0.7
4. EUOR	0.9	0.9	0.9	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	548	567	581	0	0	225	363	387	441	414	171	594	4,292
7. RSH	190	99	155	0	0	275	375	350	273	324	377	144	2,561
8. UH	6	6	6	720	744	220	6	6	6	6	173	6	1,907
9. POH	0	0	0	720	744	216	0	0	0	0	168	0	1,848
10. EFOH	1	1	1	0	0	1	1	1	1	1	1	1	12
11. EMOH	5	5	5	0	0	3	5	5	5	5	4	5	47
12. OPER BTU (GBTU)	2,259	2,637	2,665	0	0	1,074	1,734	1,843	2,063	1,900	796	2,644	19,599
13. NET GEN (MWH)	310,110	364,290	367,900	0	0	149,810	241,800	256,860	287,280	264,240	110,740	364,350	2,717,380
14. ANOHR (Btu/kwh)	7,285	7,239	7,245	0	0	7,172	7,172	7,174	7,182	7,191	7,185	7,257	7,212
15. NOF (%)	71.5	81.1	79.9	0.0	0.0	95.0	95.0	94.6	92.9	91.1	92.2	77.4	86.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-4.817	) +	7,630								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

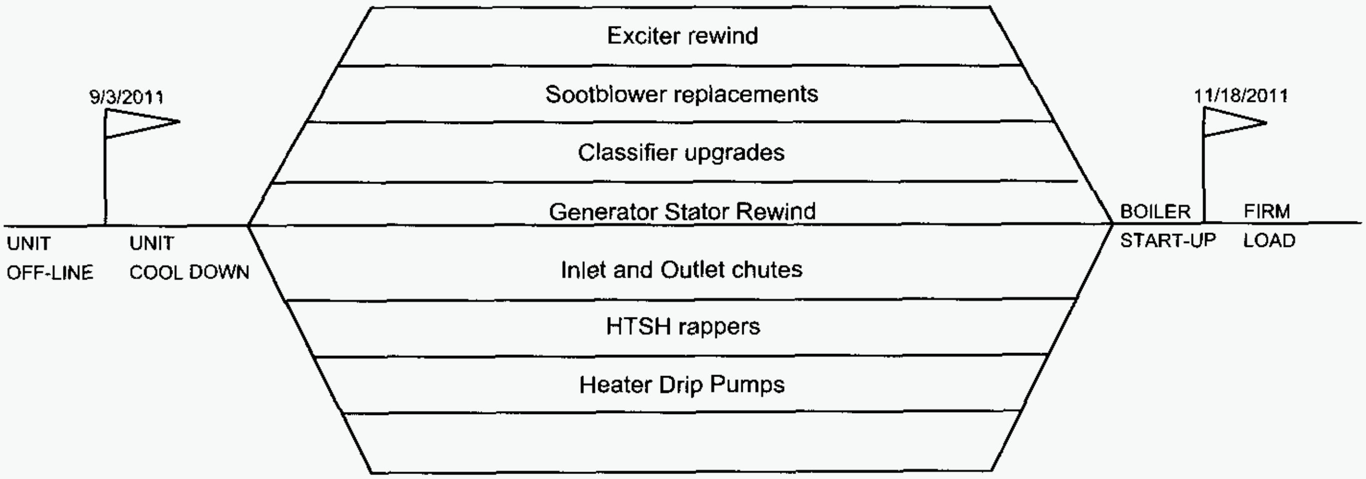
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	98.2	98.2	76.0	98.2	98.2	98.2	98.2	98.2	98.2	98.2	98.2	76.0	94.4
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	3.8
3. EUOF	1.8	1.8	1.4	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.4	1.8
4. EUOR	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	96	195	128	473	563	612	634	668	693	709	568	72	5,410
7. RSH	635	465	437	234	168	95	96	63	14	21	140	494	2,861
8. UH	14	12	178	13	14	13	14	14	13	14	13	178	489
9. POH	0	0	168	0	0	0	0	0	0	0	0	168	336
10. EFOH	2	2	2	2	2	2	2	2	2	2	2	2	25
11. EMOH	11	10	9	11	11	11	11	11	11	11	11	9	128
12. OPER BTU (GBTU)	590	1,299	852	2,692	3,376	3,674	3,806	3,998	4,165	4,193	3,294	430	32,449
13. NET GEN (MWH)	80,310	178,020	116,790	367,870	463,510	504,460	522,570	548,840	571,930	575,000	450,890	58,440	4,438,630
14. ANOHR (Btu/kwh)	7,343	7,294	7,291	7,318	7,283	7,283	7,283	7,284	7,282	7,293	7,306	7,360	7,311
15. NOF (%)	80.1	87.1	87.5	83.7	88.7	88.7	88.7	88.5	88.9	87.3	85.4	77.8	84.7
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF(		-7.036	) +	7,907								

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2011 - DECEMBER 2011

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Feb 19	-	Mar 04	Fuel System Cleanup and Scrubber work
		Oct 15	-	Oct 21	Fuel System Cleanup
+	BIG BEND 2	Feb 20	-	Mar 01	Fuel System Cleanup and Scrubber work
		Sep 03	-	Nov 18	Major outage - Generator Stator Rewind, Classifier upgrades, Inlet and Outlet chutes, Sootblower replacements, Excitier rewind and Heater Drip Pumps
	BIG BEND 3	Mar 26	-	Apr 04	Fuel System Cleanup
		Oct 29	-	Nov 11	Fuel System Cleanup and Scrubber work
	BIG BEND 4	Mar 12	-	Mar 21	Fuel System Cleanup
		Nov 28	-	Dec 11	Fuel System Cleanup and Scrubber work
	POLK 1	Feb 13	-	Feb 26	Gasifier / CT Outage
		Oct 16	-	Oct 20	Gasifier Outage
+	BAYSIDE 1	Apr 01	-	Jun 09	Generator Stator and core iron replacement, Steam Path inspection, HP/IP/LP Steam Turbine Ring and Seal replacements, Steam Turbine Valve overhauls, Heat Exchanger replacements, Coarse Mesh Screen replacements, CT Major Overhauls and CT Inlet Filter replacements
		Nov 14	-	Nov 20	Fuel System Cleanup
	BAYSIDE 2	Mar 05	-	Mar 11	Fuel System Cleanup
		Dec 03	-	Dec 09	Fuel System Cleanup

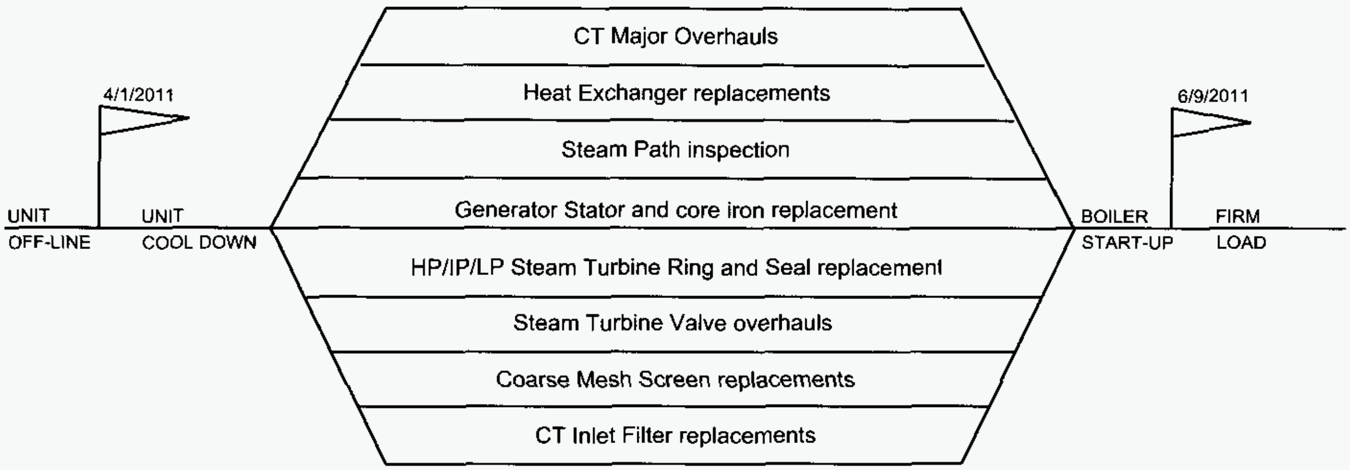
\+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2011 - DECEMBER 2011

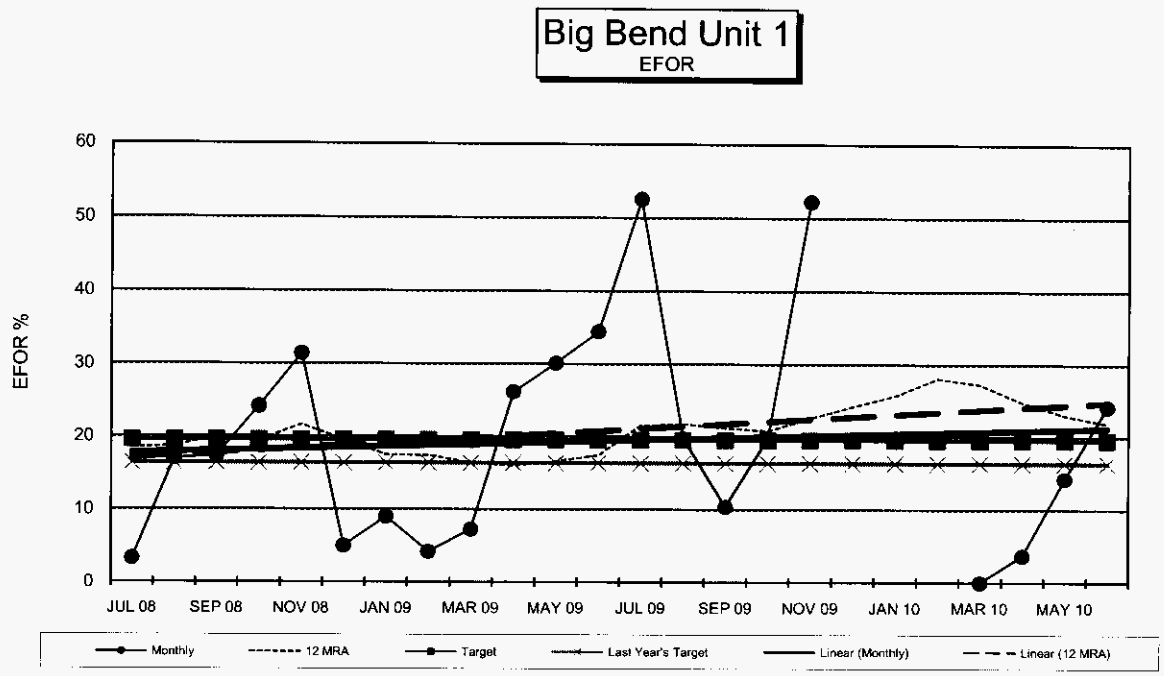


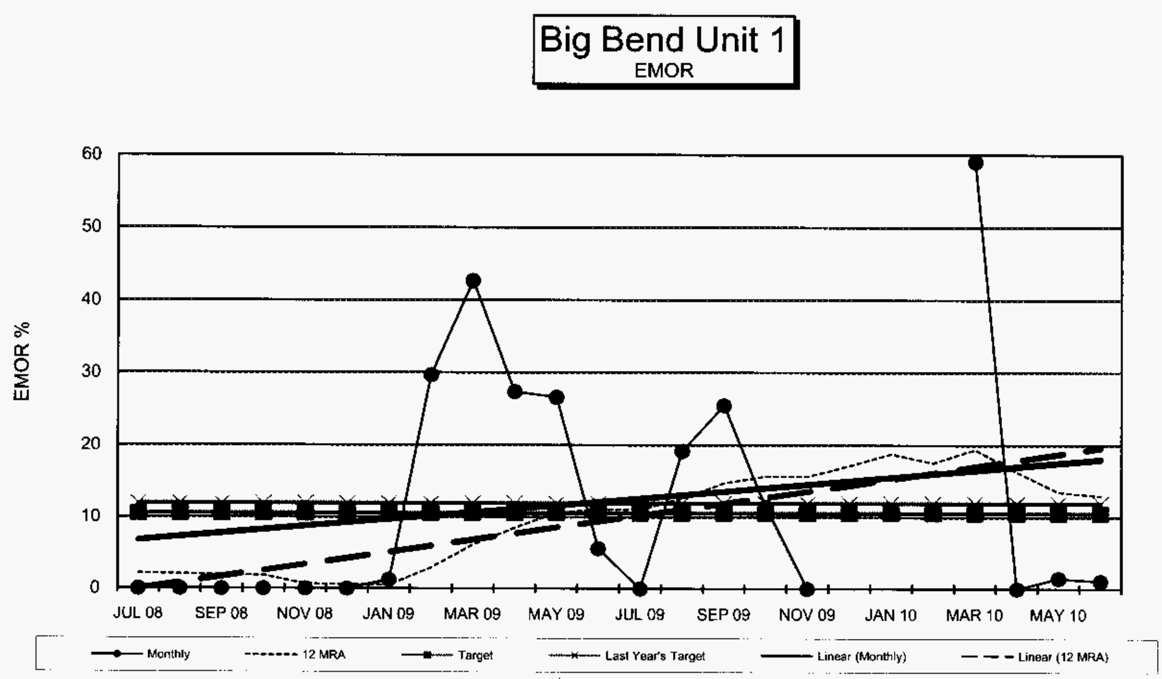
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 2
PLANNED OUTAGE 2011
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2011 - DECEMBER 2011

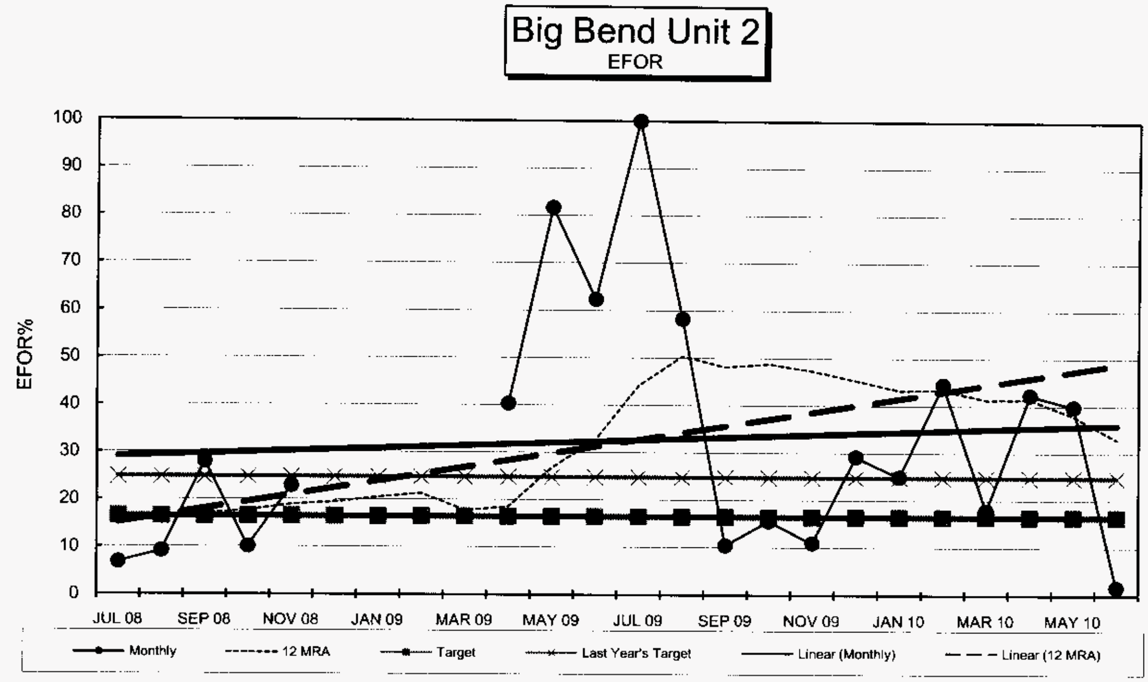


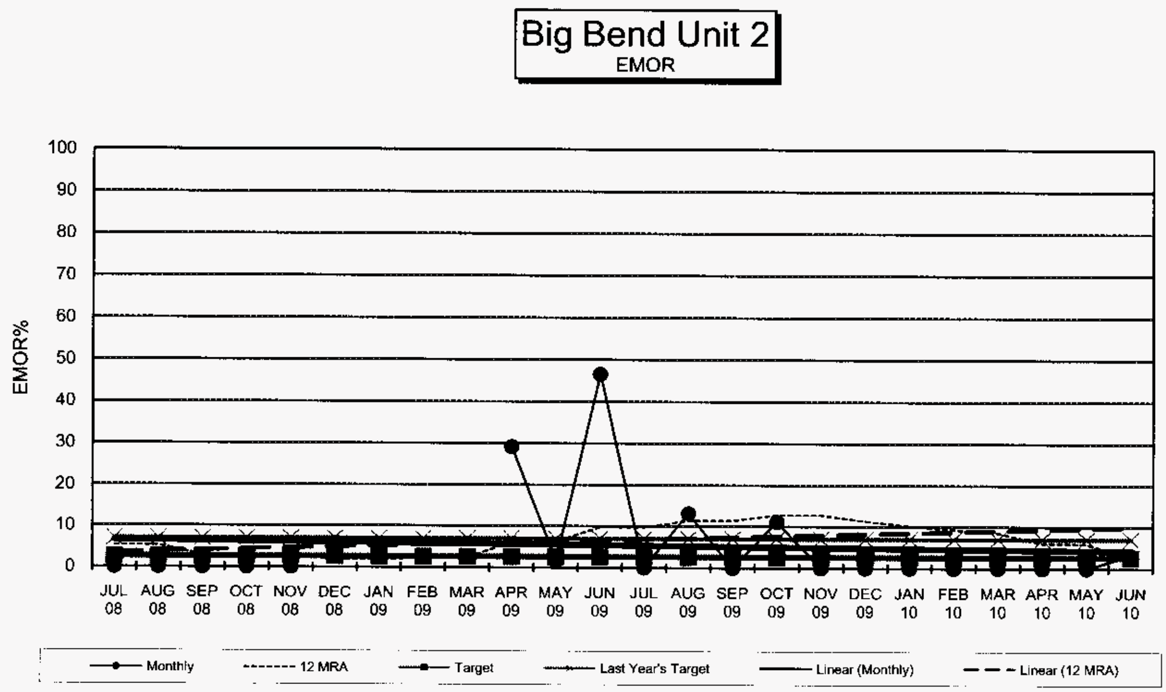
TAMPA ELECTRIC COMPANY
BAYSIDE UNIT 1
PLANNED OUTAGE 2011
PROJECTED CPM



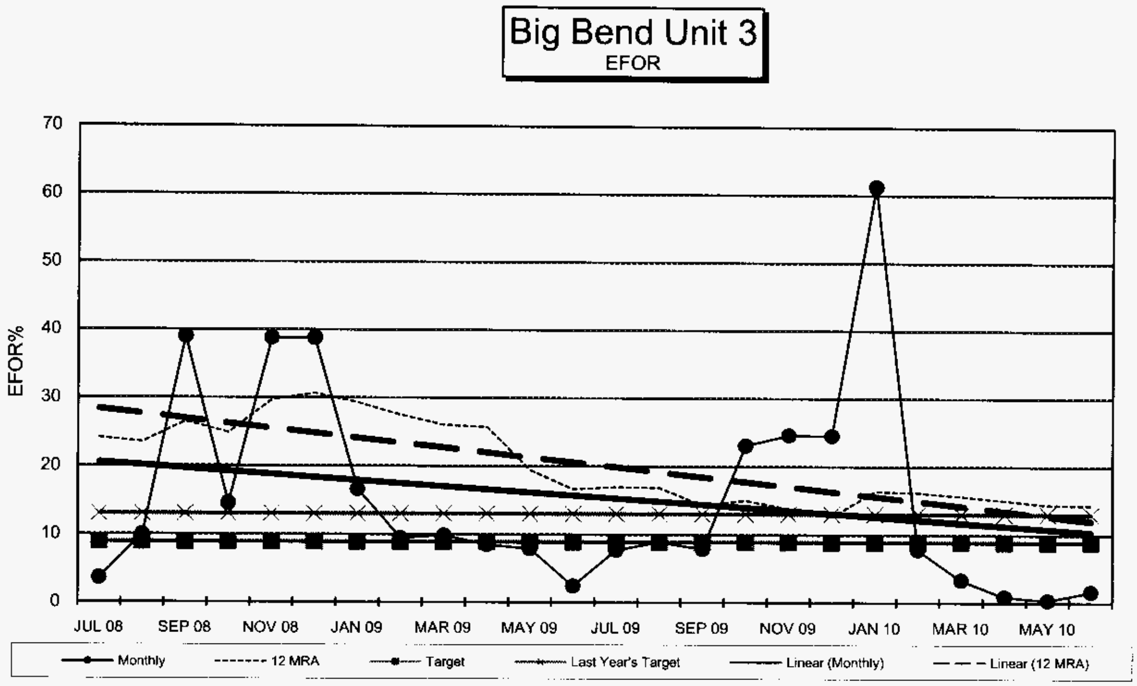


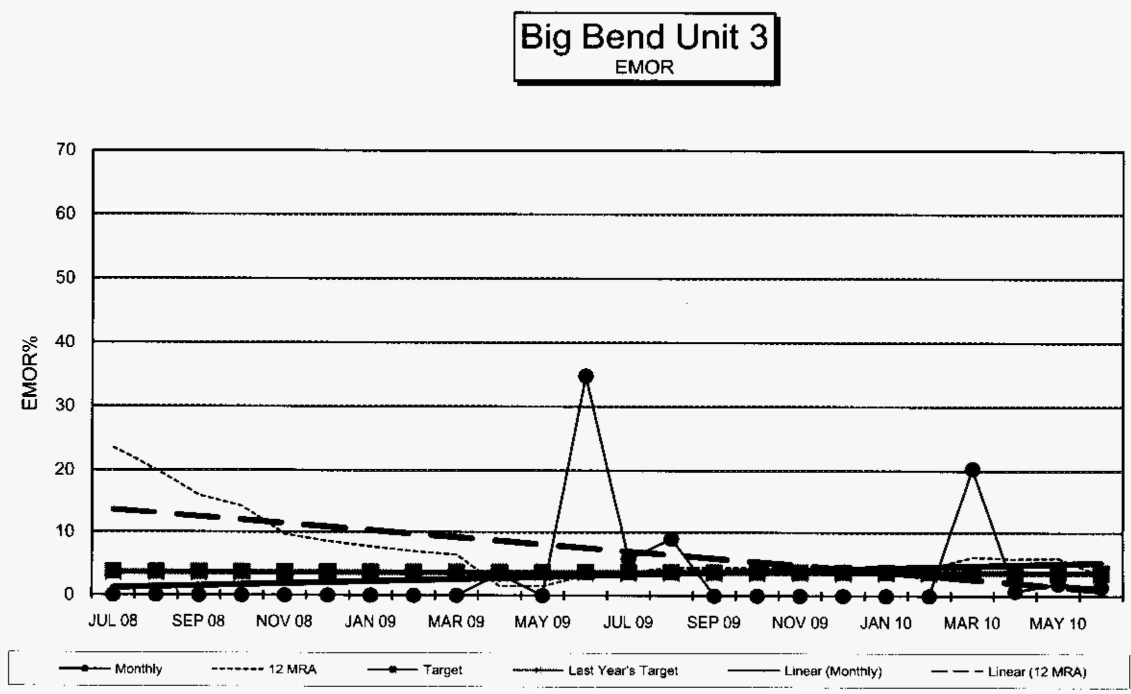
Note: Big Bend Unit 1 was offline for SCR installation from 11/23/2009 to 4/6/2010; therefore, data is not available for this time period.

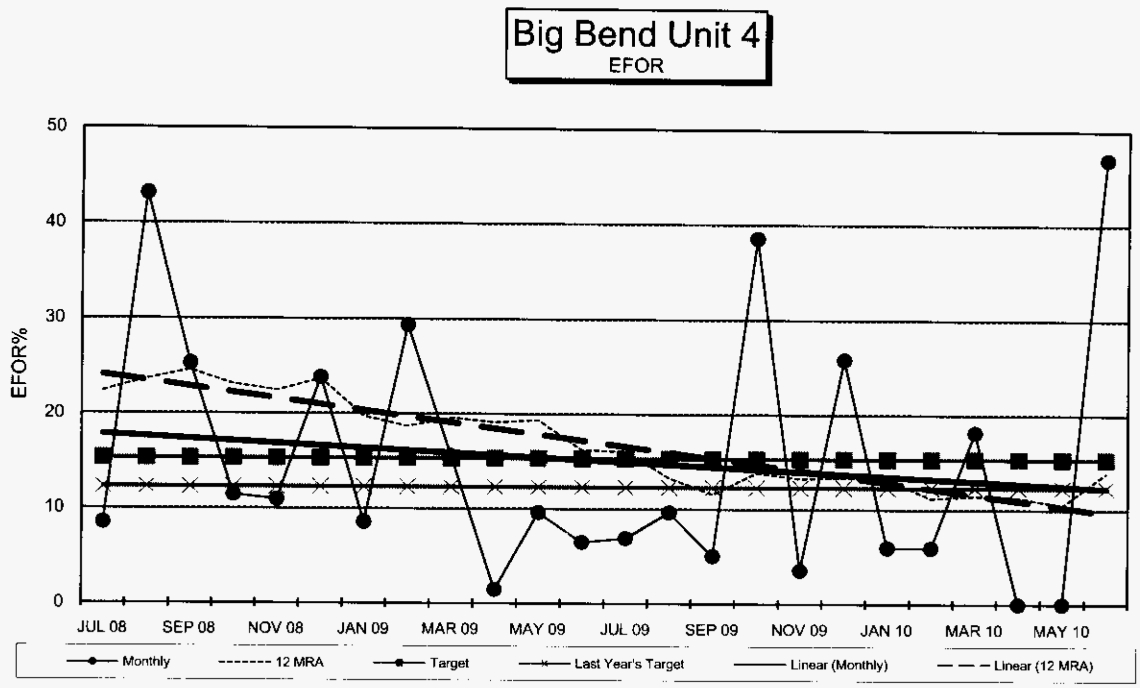


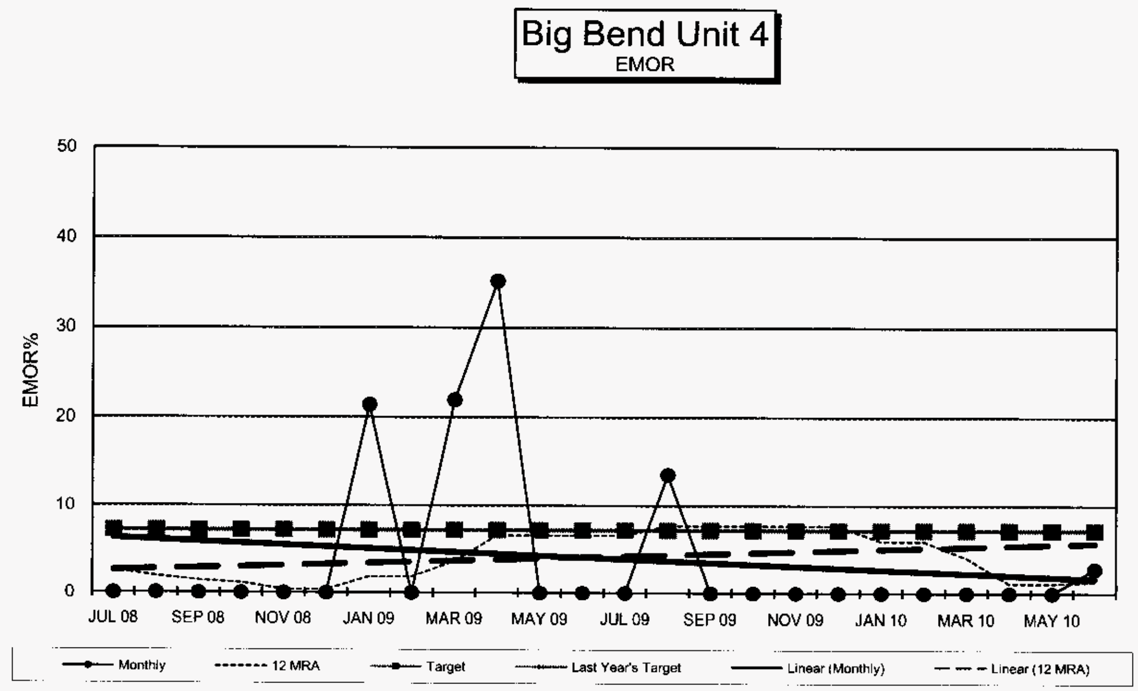


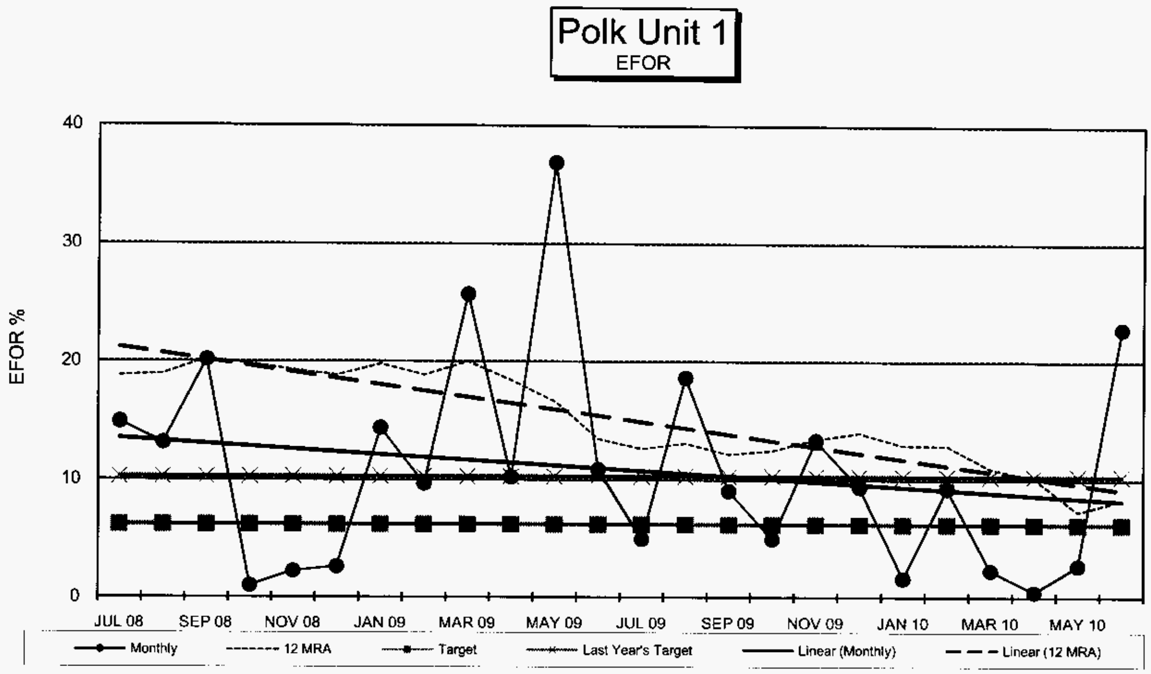
Note: Big Bend Unit 2 was offline for SCR installation from 11/24/2008 to 4/7/2009; therefore, data is not available for this time period.

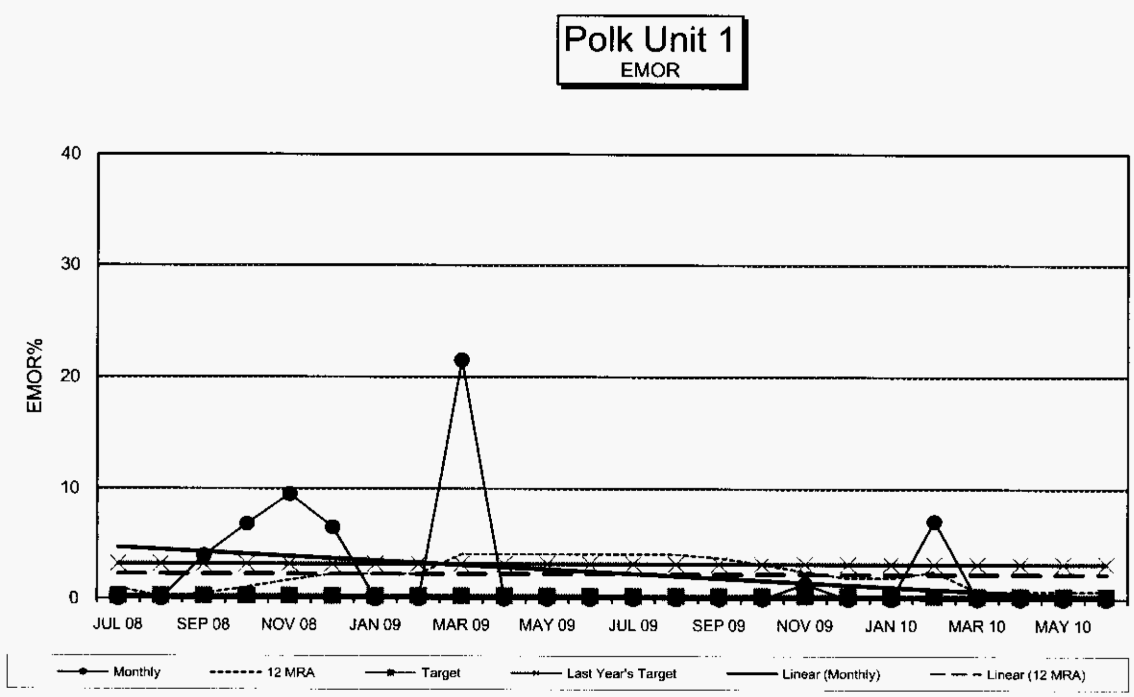

Big Bend Unit 3
EFOR
EFOR%
70
60
50
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

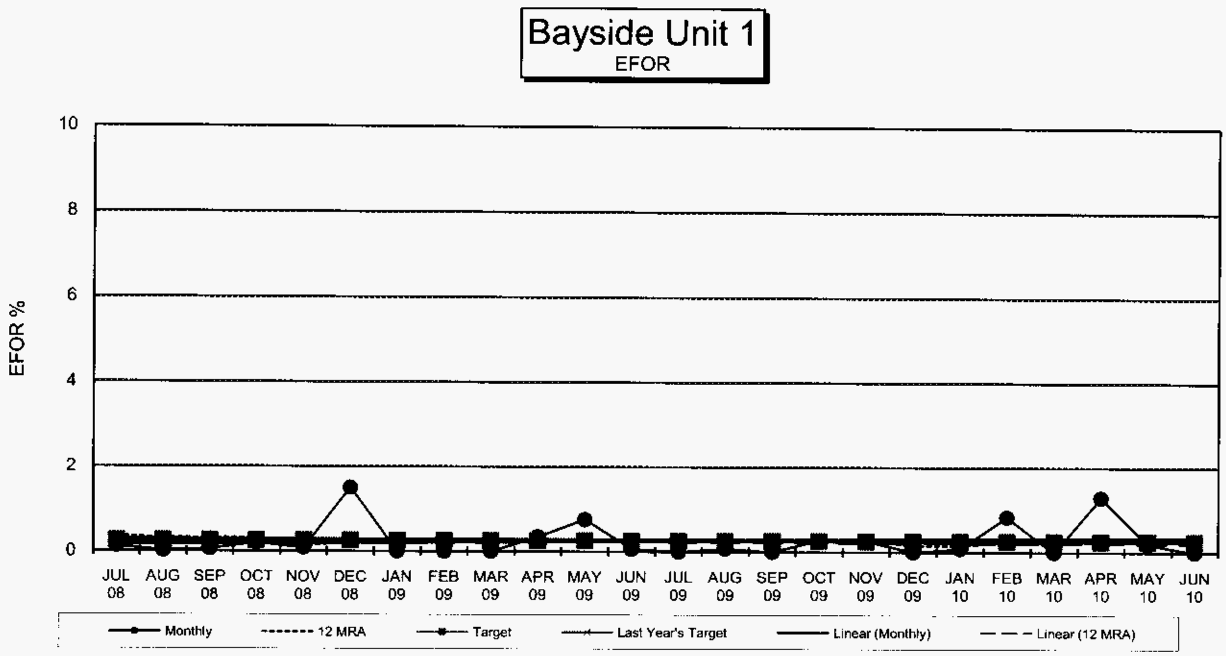

Big Bend Unit 3
EMOR
EMOR%
70
60
50
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

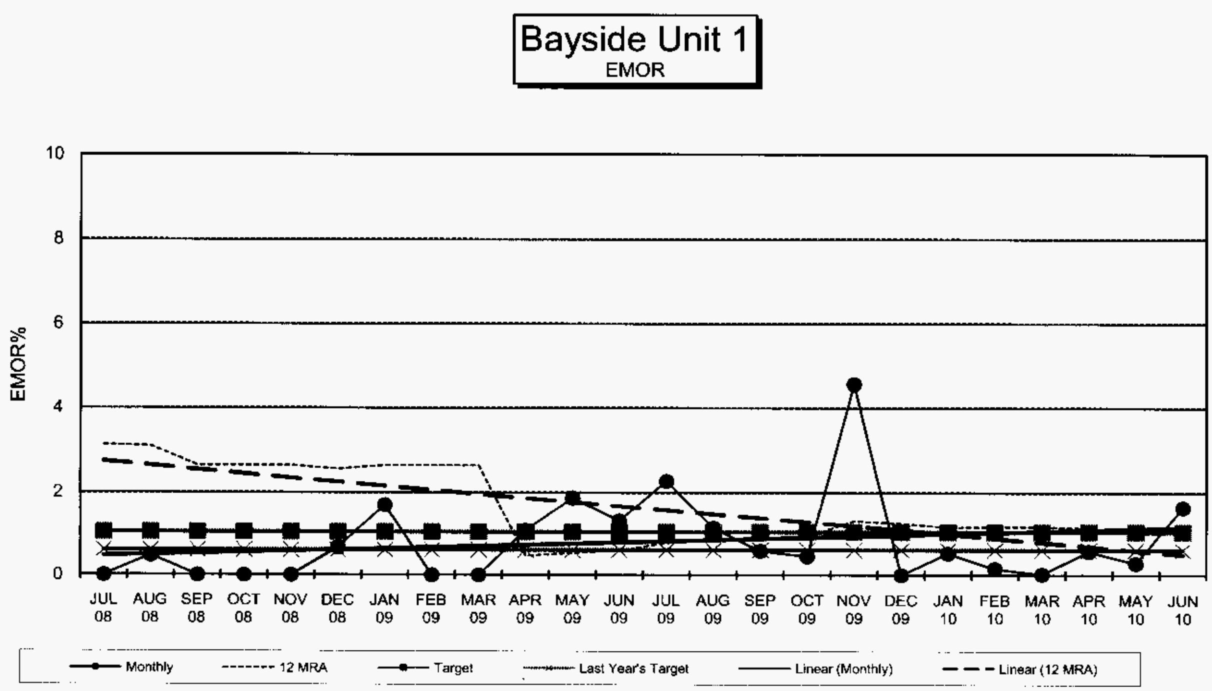

Big Bend Unit 4
EFOR
EFOR%
50
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

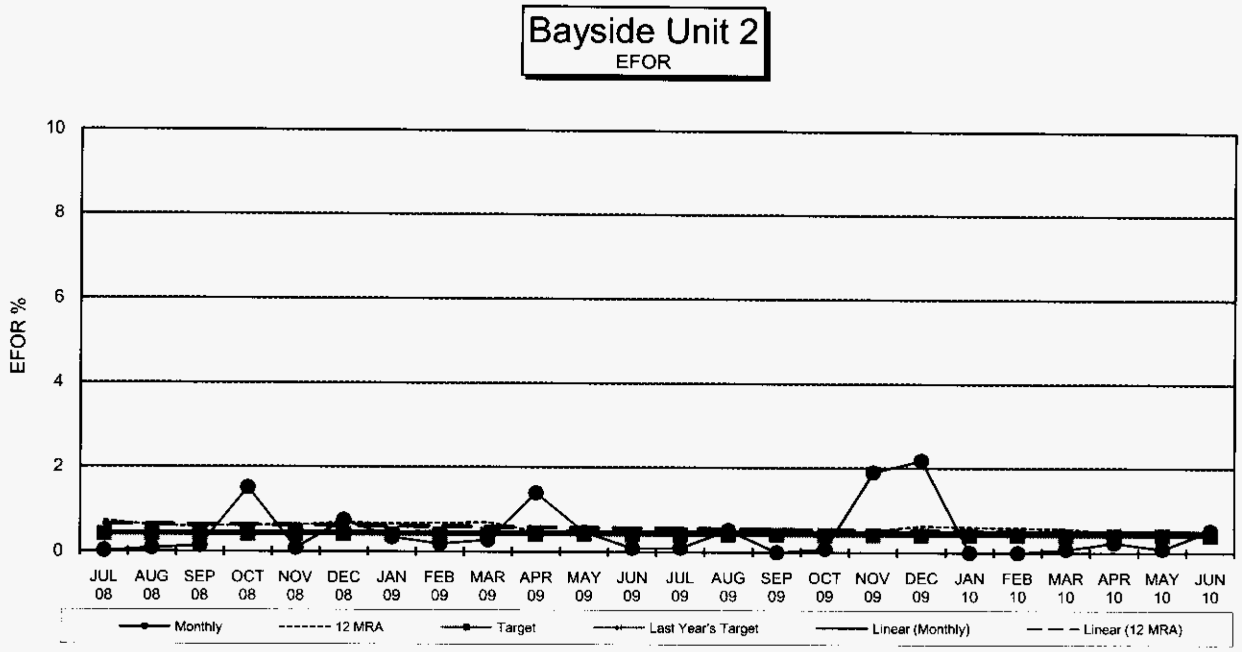

Big Bend Unit 4
EMOR
EMOR%
50
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

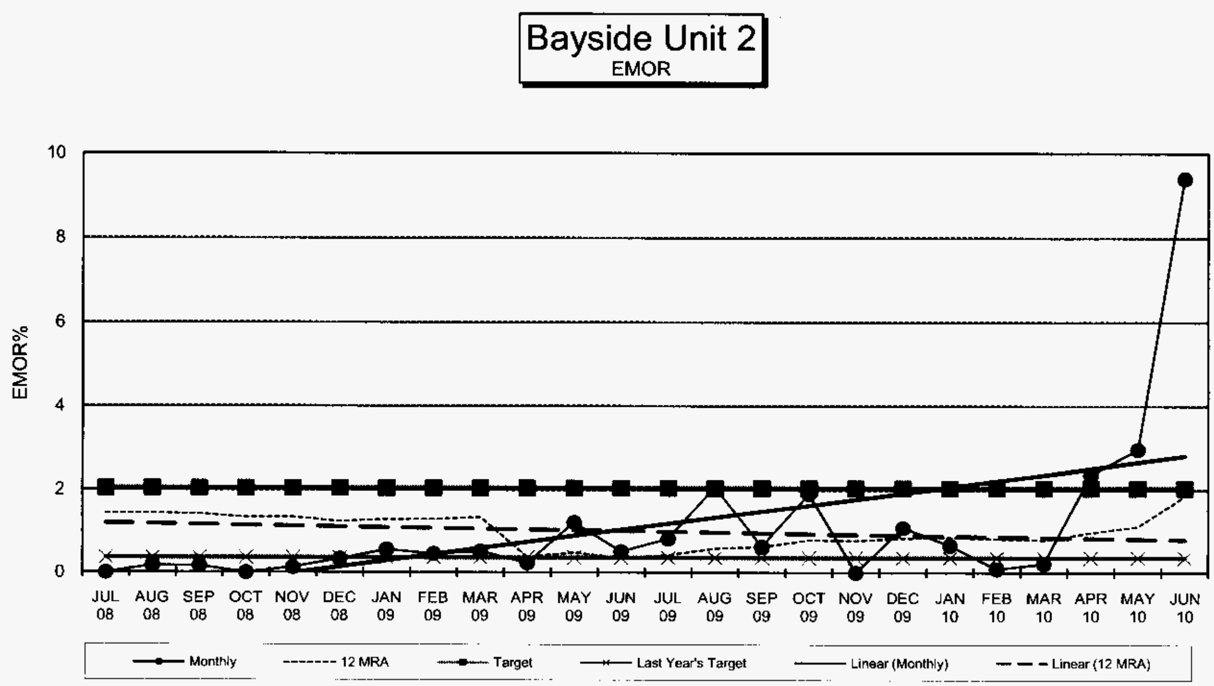

Polk Unit 1
EFOR
EFOR %
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

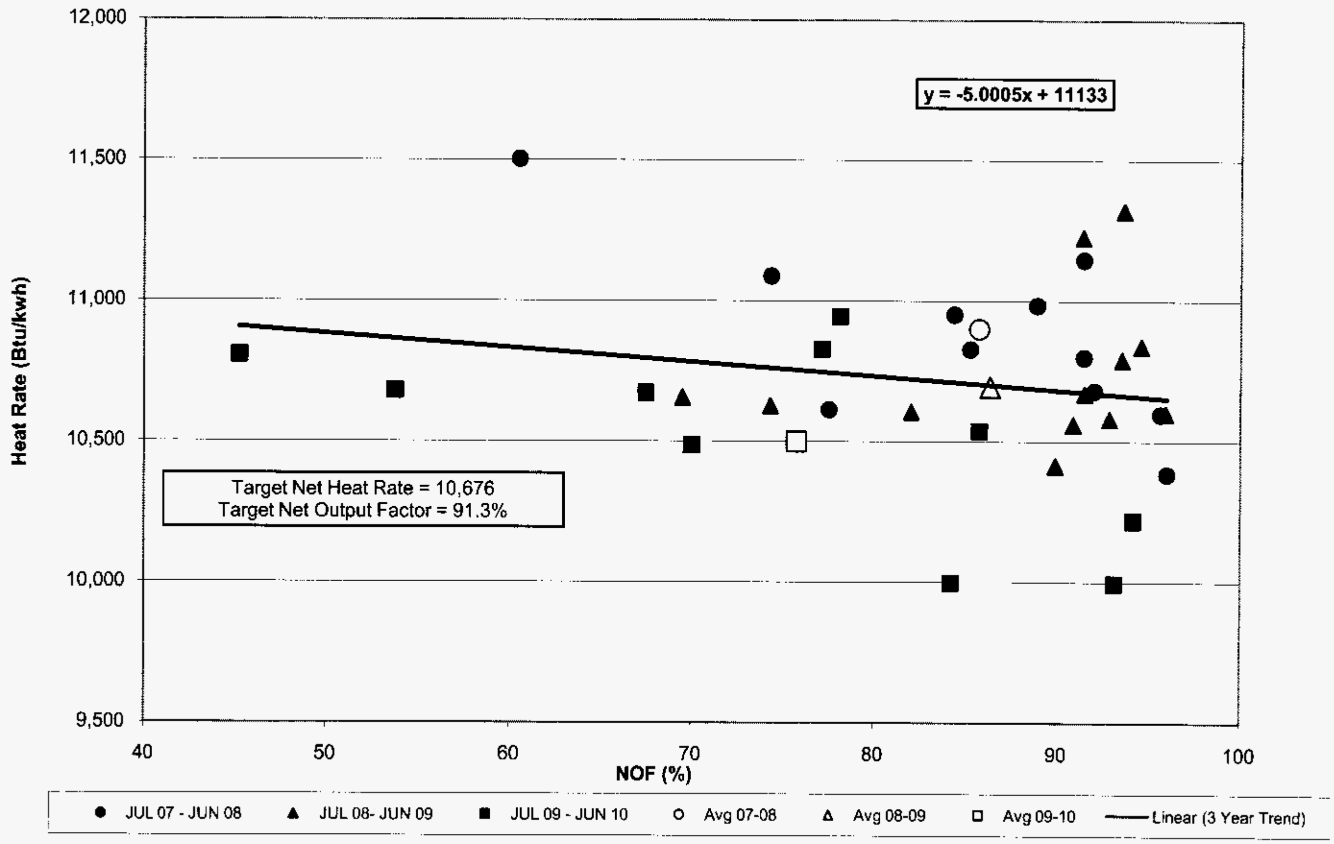

Bayside Unit 1
EFOR
10
8
6
4
2
0
EFOR %
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
10
8
6
4
2
0
EMOR%
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
EFOR %
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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



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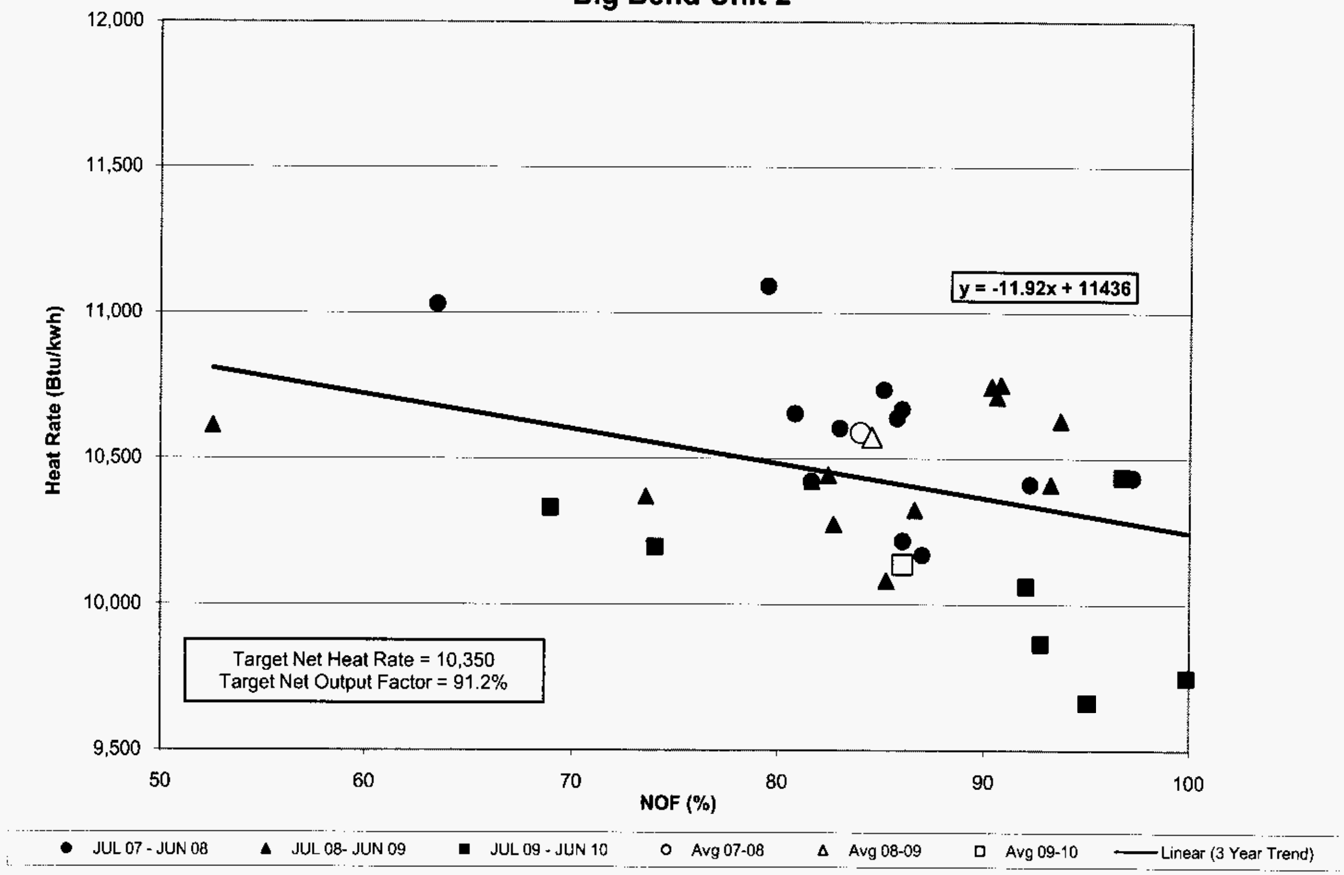
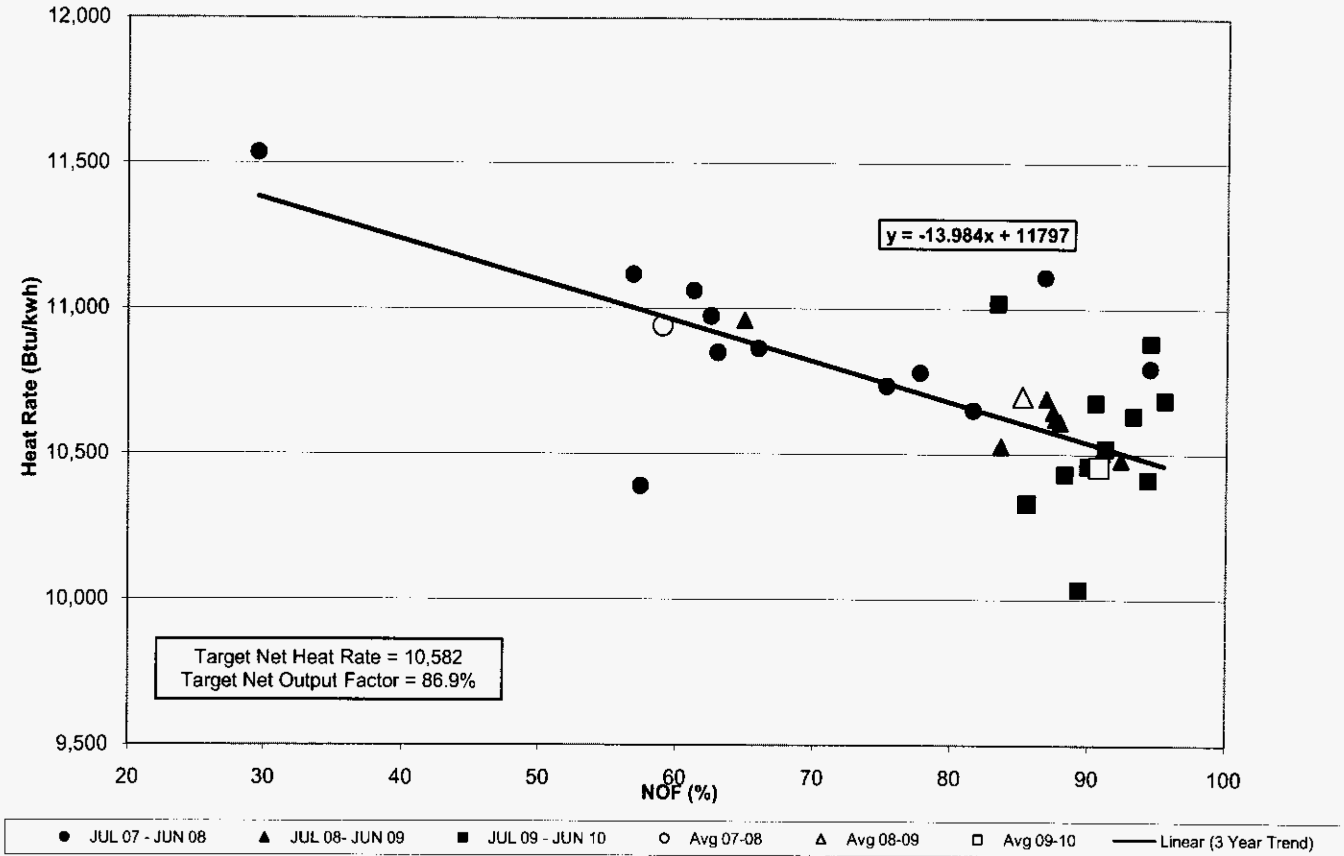
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



ORIGINAL SHEET NO. 8.401.11E
PAGE 32 OF 40

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



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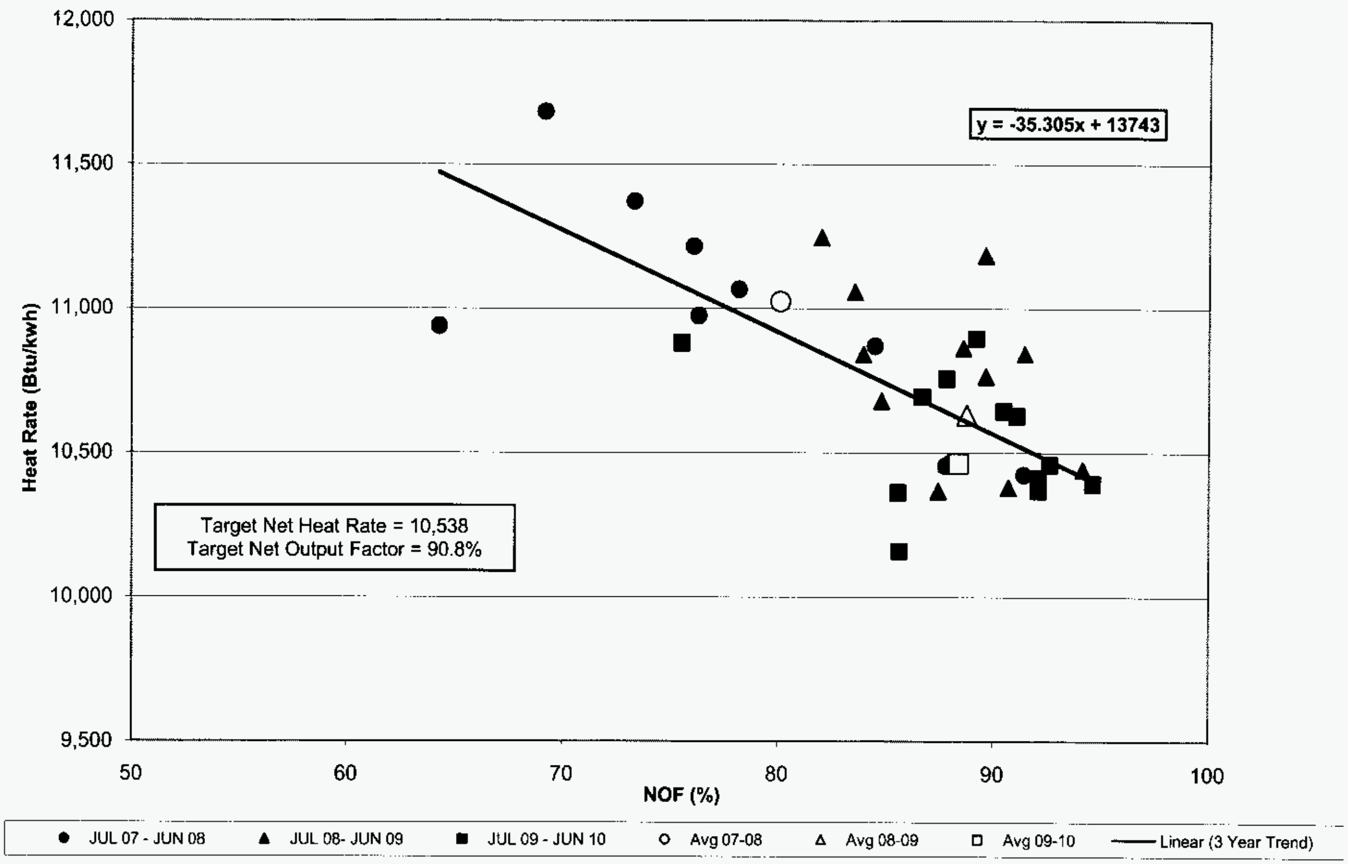
ORIGINAL SHEET NO. 8.401.11E
PAGE 33 OF 40

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



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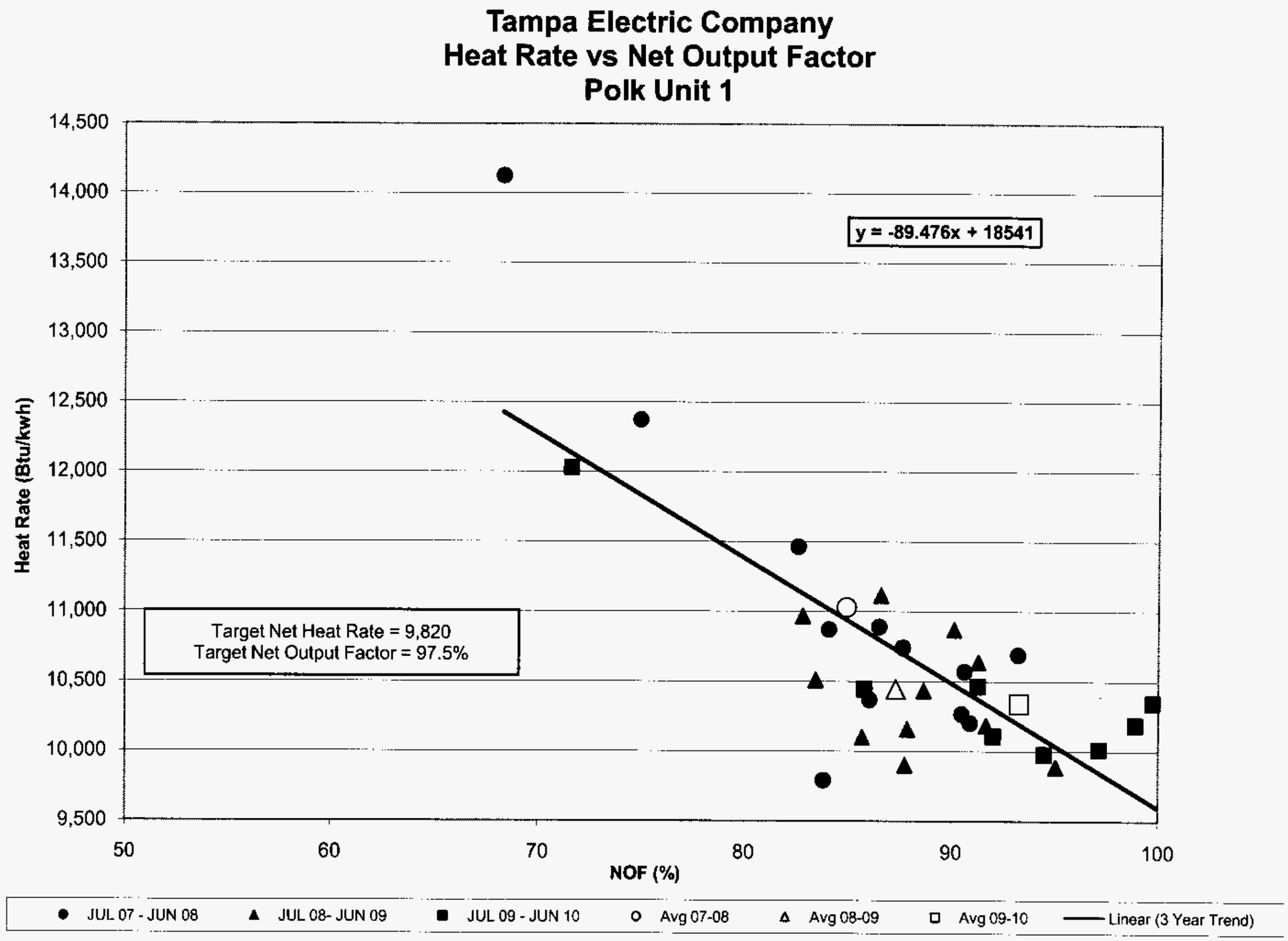

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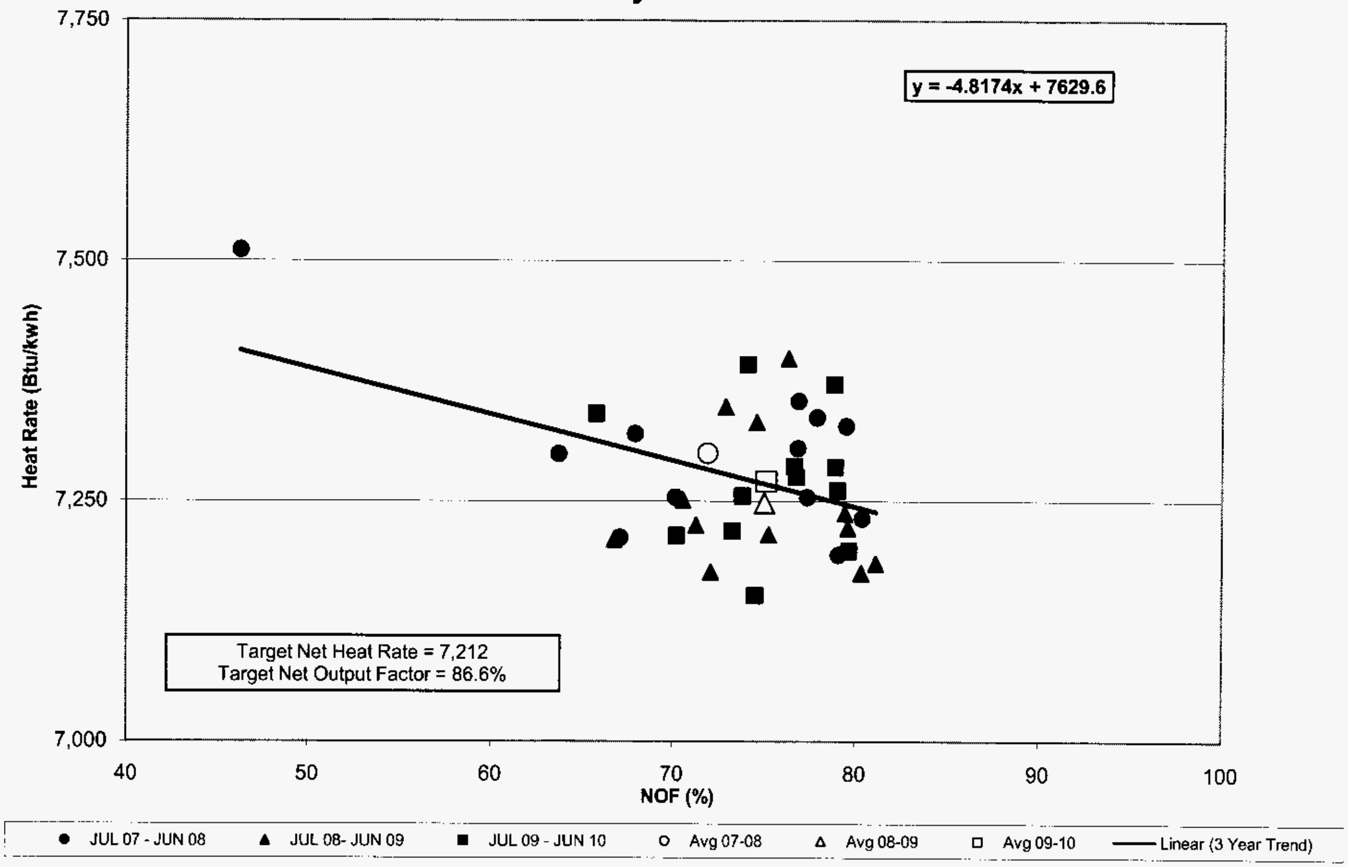
ORIGINAL SHEET NO. 8.401.11E
PAGE 35 OF 40

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



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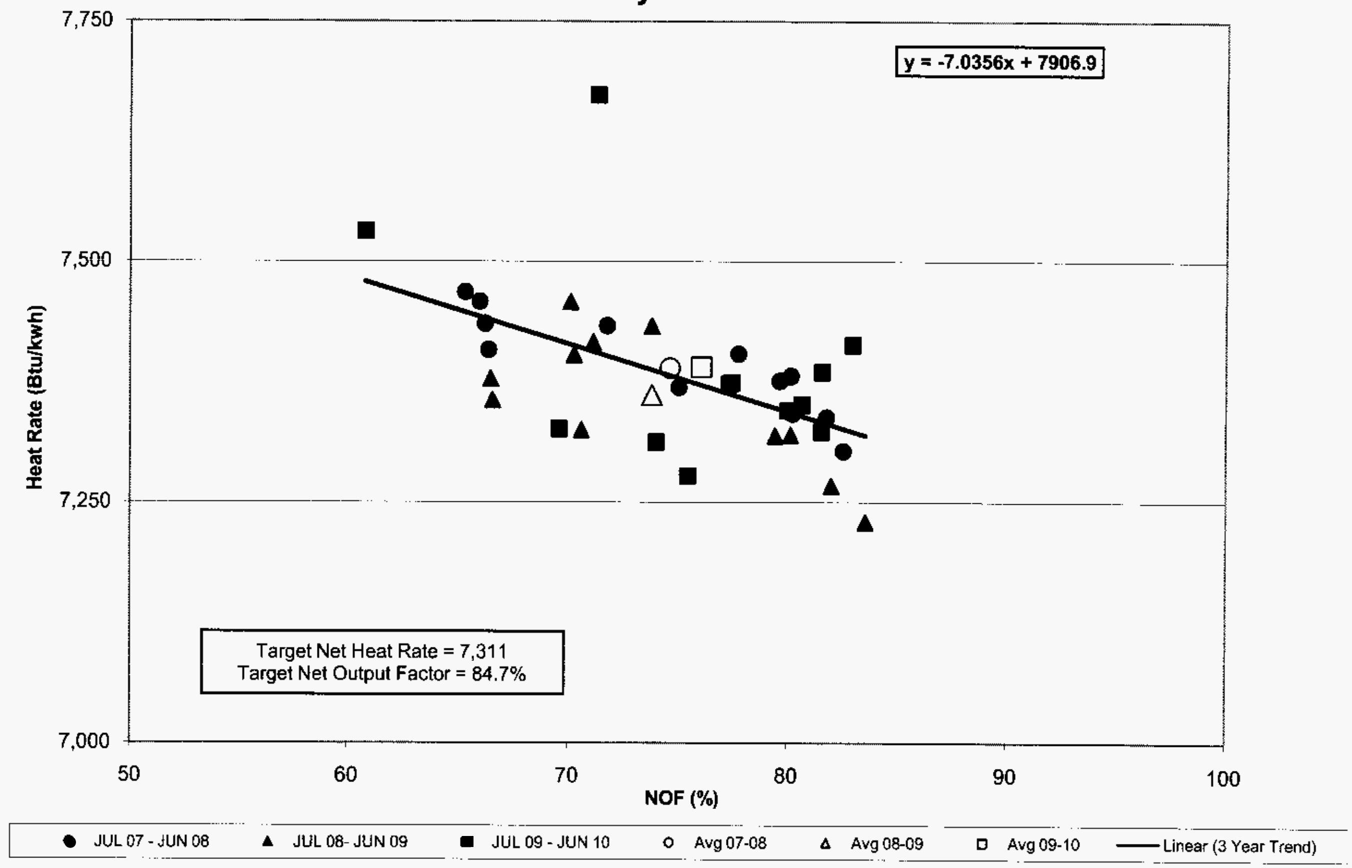
ORIGINAL SHEET NO. 8.401.11E
PAGE 36 OF 40

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



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TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2011 - DECEMBER 2011

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		453	420
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,680	3,482
	SYSTEM TOTAL	**4,624**	**4,417**
	% OF SYSTEM TOTAL	**79.6%**	**78.8%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2011 - DECEMBER 2011

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		453	420
	BIG BEND COAL TOTAL	1,670	1,562
BIG BEND CT4		59	58
	BIG BEND CT TOTAL	59	58
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,624**	**4,417**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2011 - DECEMBER 2011

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,438,630	23.37%	23.37%
BIG BEND	4	2,859,320	15.06%	38.43%
BAYSIDE	1	2,717,380	14.31%	52.74%
BIG BEND	1	2,646,940	13.94%	66.68%
BIG BEND	3	2,344,680	12.35%	79.03%
BIG BEND	2	2,108,120	11.10%	90.13%
POLK	1	1,518,210	7.99%	98.12%
BAYSIDE	5	70,490	0.37%	98.49%
POLK	4	69,380	0.37%	98.86%
BIG BEND CT	4	60,750	0.32%	99.18%
BAYSIDE	6	50,660	0.27%	99.45%
BAYSIDE	3	37,540	0.20%	99.64%
POLK	5	35,780	0.19%	99.83%
BAYSIDE	4	23,430	0.12%	99.96%
POLK	2	6,190	0.03%	99.99%
POLK	3	2,170	0.01%	100.00%
TOTAL GENERATION		18,989,670	100.00%	

GENERATION BY COAL UNITS: 11,477,270 MWH

% GENERATION BY COAL UNITS 60.44%

GENERATION BY NATURAL GAS UNITS: 7,512,400 MWH

% GENERATION BY NATURAL GAS UNITS: 39.56%

GENERATION BY OIL UNITS: - MWH

% GENERATION BY OIL UNITS: 0.00%

GENERATION BY GPIF UNITS: 18,633,280 MWH

% GENERATION BY GPIF UNITS: 98.12%

DOCKET NO. 100001-EI
GPIF 2011 PROJECTION FILING
EXHIBIT NO. ____ (BSB-2)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2011 - DECEMBER 2011

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2011 - DECEMBER 2011

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	67.9	5.8	26.3	10,676
Big Bend 2[2]	62.4	23.8	13.8	10,350
Big Bend 3[3]	82.1	6.6	11.3	10,582
Big Bend 4[4]	77.9	6.6	15.5	10,538
Polk 1[5]	88.6	6.0	5.3	9,820
Bayside 1[6]	78.2	21.1	0.7	7,212
Bayside 2[7]	94.4	3.8	1.8	7,311

1 Original Sheet 8.401.11E, Page 14

2 Original Sheet 8.401.11E, Page 15

3 Original Sheet 8.401.11E, Page 16

4 Original Sheet 8.401.11E, Page 17

5 Original Sheet 8.401.11E, Page 18

6 Original Sheet 8.401.11E, Page 19

7 Original Sheet 8.401.11E, Page 20

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY
OF
BENJAMIN F. SMITH II

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of

Energy Products and Structures in the Wholesale Marketing group. My responsibilities are to evaluate short-term and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale contract structure and help evaluate the processes used to value wholesale power opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchased power needs and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When there is a purchased power need, the company aggressively polls the marketplace for wholesale capacity or energy, searching for reliable supplies at the best possible price from creditworthy counterparties.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs. The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2010 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short-term and long-term purchases based on price and availability of supply. Approximately 8 percent of the expected energy needs for 2010 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, qualifying facilities, Calpine, RRI Energy Services (formally known as Reliant), and Pasco Cogen. The testimony in previous years describes each existing firm purchased power agreement, which were subsequently approved by the

Commission as being cost-effective for Tampa Electric customers. Hillsborough County chose not to extend the sale of its firm capacity and energy from its waste facility to Tampa Electric as of March 2010. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility.

Q. Has Tampa Electric entered into any other wholesale energy purchases for 2010 and beyond?

A. No. However, the company projects approximately 6 percent of the expected energy needs for 2011 will be met using economy purchases and existing purchased power agreements. This projection includes energy from both the Calpine and City of Tampa firm purchased power agreements through their respective 2011 contract end dates. The Calpine agreement for firm peaking capacity and energy expires May 2011, and the City of Tampa agreement for firm capacity and energy out of its waste facility expires August 2011. Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties and there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives but the company does employ a diversified power supply strategy which includes self-generation and short-term and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2010?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 170 MW Calpine purchase and the 158 MW purchase from Reliant in 2010 are reliable, cost-based call options for peaking power. These purchases serve as both a physical hedge and reliable source of economical power in 2010. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2010 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such a hurricane?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather related events. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual fuel capabilities; and focusing on fuel-diversified purchases. Notably, both the RRI Energy Services and Pasco Cogen purchases are dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2010 and 2011.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2010, and the company anticipates making additional non-separated sales during the balance of 2010 and in 2011. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2010, Tampa Electric anticipates its gains from non-separated wholesale sales to be $1,766,461, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $2,002,890. Similarly, in 2011, the company's projected gains from non-separated wholesale sales are $771,637, of which 100 percent would flow back to customers since they are less than the projected 2011 three-year rolling average threshold of $2,325,363.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and those efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY
OF
JOANN T. WEHLE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing & Fuels.

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

A. I received a Bachelor of Business Administration Degree in Accounting in 1985 from St. Mary's College in Notre Dame, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001.

I became Director, Wholesale Marketing and Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I also sponsor Tampa Electric's 2011 risk management plan submitted on August 2, 2010 in this docket.

Q. Have you previously testified before this Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets, including Docket No. 011605-EI, 031033-EI and 080317-EI as well as the annual fuel and purchased power cost recovery dockets from 2001 through 2009. My testimony in these dockets described the appropriateness and prudence of Tampa Electric's fuel procurement activities, fuel supply risk management, fuel price volatility hedging activities, and fuel transportation costs.

2011 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2011?

A. In 2011, Tampa Electric expects its fuel mix to be comparable to 2010. In 2011, natural gas-fired and coal-fired generation is expected to be 40 percent and 60 percent of total generation, respectively. Generation from No. 2 oil is less than one percent of the total expected generation.

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. This consists of a blend of pre-arranged base load, intermediate and swing supply complemented with daily spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric has improved the reliability of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") pipeline and Gulfstream Natural Gas System, LLC ("Gulfstream"). The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, the largest natural gas units on Tampa Electric's system.

Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the new aero derivative combustion turbine.

Q. Will there be any changes to Tampa Electric's pipeline capacity for the balance of 2010 or 2011?

A. Yes. Tampa Electric has contracted for FGT Phase VIII capacity. Tampa Electric has reserved an additional 45,000 MMBtu of winter only capacity beginning in November 2010 and an additional 50,000 MMBtu beginning in April of 2011. The Phase VIII capacity provides enhanced reliability delivery of gas supply and allows Tampa Electric to meet its peak system demands.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric has maintained natural gas storage capacity with Bay Gas Storage near Mobile, Alabama since 2005. Currently the company reserves 850,000 MMBtu of storage capacity, which enhances access to natural gas in the case of severe weather or other events that disrupt supply. Tampa Electric's storage capacity at Bay Gas Storage will increase to 1,200,000 MMBtu when the fourth cavern is completed in the fall 2011.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to lower priced gas supply.

Tampa Electric also participated in the Southeast Supply Header ("SESH") project. SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. What is Tampa Electric's coal procurement strategy?

A. Tampa Electric's two coal-fired plants are Big Bend Station and Polk Station. Big Bend Station is a fully scrubbed plant whose design fuel is high-sulfur Illinois Basin coal. Polk Station is an integrated gasification combined cycle plant currently burning a mix of petroleum coke and low sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as ash, fusion temperature, sulfur, heat content and chlorine. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, along with price, availability, deliverability and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bilateral contracts varying in term lengths of long, intermediate, and short for coal supply. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply sources while providing flexibility to take advantage of favorable spot market opportunities. The company's efforts to obtain the most favorable coal prices directly benefit its customers.

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2011 delivery?

A. Yes, Tampa Electric has contracted over half of its 2011 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Additionally, the majority of the company's 2011 expected natural gas requirements are already under contract. Tampa Electric anticipates the remaining purchases will be procured by the fourth quarter of 2010 or in the spot market.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Coal Transportation Costs

Q. Are there any changes to Tampa Electric's coal transportation portfolio in 2011?

A. Yes. In 2009, Tampa Electric completed a rail delivery and unloading facility at Big Bend Station and rail deliveries commenced in December of 2009. Tampa Electric expects to receive 1.8 and 2.1 million tons of coal for use at Big Bend and Polk Stations through this rail facility in 2010 and 2011, respectively.

As part of the CSX transportation agreement, Tampa Electric receives a per ton reimbursement for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order. Tampa Electric anticipates these amounts to be $13.5 million and $8.4 million for 2010 and 2011, respectively.

Q. What benefits exist from rail transportation of coal for Tampa Electric and its customers?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitive, overall delivered cost, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Did the Commission agree that there are customer benefits associated with bi-modal waterborne and rail deliveries?

A. Yes. In the 080001 Docket, the Commission determined that the company complied with all requirements of Order No. PSC-04-0999-FOF-EI in procuring its fuel transportation contracts, which required a fair and open competitive procurement process to ensure the lowest possible delivered costs through the use of a bimodal fuel delivery system.

Projected 2011 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including Wood Mackenzie, the Energy Information Administration, the New York Mercantile Exchange ("NYMEX") and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2011 projected fuel prices compare to the fuel prices projected for 2010?

A. Projected fuel prices are expected to increase slightly in 2011 compared to 2010 as the global economy is projected to improve and inventory surpluses diminish.

Q. What are the market drivers of the expected 2011 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2011 as compared to 2010. Once again, an improving economy and market adjustment to shale gas production is expected to raise the price slightly but not dramatically.

Q. What are the market drivers of the change in the price of coal?

A. Coal prices dropped dramatically in 2009 as the global economy deteriorated and inventories rose. Additionally, low natural gas prices caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. The reduced demand for coal caused inventories to increase throughout the nation. Recently, international demand for coal has increased and inventories are beginning to decline. These changes should lead to small increases in coal pricing.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent lower for both natural gas and No. 2 oil.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed August 2, 2010 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2010 and 2011 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2010 natural gas supply needs and a portion of its expected 2011 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges was provided in the Risk Management Plan submitted on August 2, 2010.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2010 and 2011 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Risk Management Plan filed August 2, 2010.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the quantity or volume of natural gas expected to be consumed in its power plants. The volume hedged is driven primarily by the projected total gas consumption in the plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2010 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 1, 2010, the company filed its 2009 hedging results as part of the final true-up process. Additionally, the Commission Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2010 in this docket on August 16, 2010.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers.

Q. Does this conclude your testimony?

A. Yes, it does.