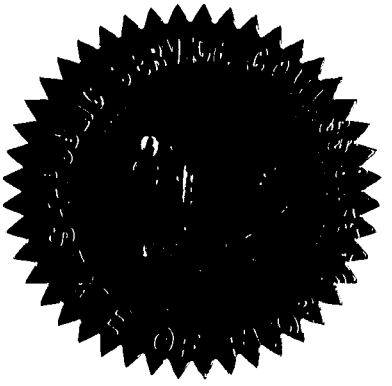
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 070001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE INCENTIVE
FACTOR.
_____/



VOLUME 2

Pages 190 through 444

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE
A CONVENIENCE COPY ONLY AND ARE NOT
THE OFFICIAL TRANSCRIPT OF THE HEARING,
THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Tuesday, November 6, 2007
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR, CRR JANE FAUROT, RPR Official FPSC Reporters (850) 413-6734/(850) 413-6732
PARTICIPATING:	(As heretofore noted.)

DOCUMENT NUMBER-DATE
10336 NOV 16 07
FPSC-COMMISSION CLERK

I N D E X

WITNESSES

NAME:	PAGE NO.
KOREL M. DUBIN	
Prefiled Direct Testimony Inserted	195
PAMELA SONNELITTER	
Prefiled Direct Testimony of Pamela Sonnelitter as adopted by Frank Irizarry Inserted	227
FRANK IRIZARRY	
Prefiled Direct Testimony Inserted	235
H.R. BALL	
Direct Examination by Mr. Badders	247
Prefiled Testimony Inserted	249
Cross Examination by Mr. McWhirter	283
Cross Examination by Mr. Young	284
R.J. MARTIN	
Prefiled Testimony Inserted	287
L.S. NOACK	
Prefiled Testimony Inserted	304
BENJAMIN SMITH	
Prefiled Testimony Inserted	316
JOANN T. WEHLE	
Direct Examination by Mr. Beasley	329
Prefiled Testimony Inserted	331
Cross Examination by Mr. McWhirter	356
Cross Examination by Ms. Bennett	360
Redirect Examination by Mr. Beasley	361
CARLOS ALDAZABAL	
Prefiled Testimony Inserted	364
DAVID KNAPP	
Prefiled Testimony Inserted	395

EXHIBITS

NUMBER:		ID.	ADMTD.
16	KMD-1	194	194
17	KMD-2	194	194
18	KMD-3	194	194
19	KMD-4	194	194
20	KMD-5	194	194
22	PS-1	226	226
23	PS-2	226	226
49	Progress Hedging Percentages Financial and Fiscal 2007	243	243
50	Gulf, Hedging	245	245
51	TECO, Hedging	286	286
27, 28, 47			286
29, 30, 31			286
32, 33			303
48	FPL Hedging		314
43, 44			362
34 through 40			362
41, 42			362

PROCEEDINGS

(Transcript follows in sequence from Volume 1.)

MR. BUTLER: Thank you. The next witness would be Witness --

CHAIRMAN EDGAR: And just to note, I'm sorry to interrupt, but Exhibit 15 was to be withdrawn.

MR. BUTLER: That's right. That's why I didn't --

CHAIRMAN EDGAR: That's why you didn't ask me about it. Yes.

MR. BUTLER: The next witness would be Witness K. M. Dubin. And we have withdrawn the portions of her direct testimony, excuse me, Page 5, Line 20, through Page 8, Line 4. Now this specifically applies to her September 4, 2007, testimony. Ms. Dubin also had testimony filed in March 2007 and in August of 2007 relating to the final true-up for 2006 and the estimated/actual true-up for. 2007, neither of those is affected by the withdrawal that I just described.

And then she had Exhibits 16 through 21. And I would move the admission of, I'm sorry, the insertion into the record as though read of all Ms. Dubin's testimonies, her final true-up, her estimated/actual true-up, and her projection testimony, with the withdrawal from the September 4th, 2007, testimony as just described.

CHAIRMAN EDGAR: Okay. So we will go ahead and admit into the record as though read the full prefiled testimony of

Witness Dubin from March of '07, August of '07 and the testimony from September of '07, with the removal of the portions that you have addressed for us, and we will admit into the record Exhibits 16, 17, 18, 19 and 20.

(Exhibits 16, 17, 18, 19 and 20 marked for identification and admitted into the record.)

MR. BUTLER: Thank you. That's right. I'm sorry. We had already admitted 21, hadn't we?

CHAIRMAN EDGAR: Yes, sir.

MR. BUTLER: Thank you for the correction.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 070001-EI

MARCH 1, 2007

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

A. My name is Korel M. Dubin, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL or the Company) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in the predecessors to this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2006 through December 2006. The Net True-Up for the FCR is an under-recovery, including interest, of $53,744,558. The Net True-Up for the CCR is an under-recovery, including interest, of $4,030,283. I am requesting Commission approval to include this FCR true-up under-recovery of $53,744,558 in the calculation of the FCR factor for the period January 2008 through December 2008. I am also requesting Commission approval to include this CCR true-up

under-recovery of $4,030,283 in the calculation of the CCR factor for the period January 2008 through December 2008.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules, and Appendix II contains the CCR related schedules. In addition, FCR Schedules A-1 through A-12 for the January 2006 through December 2006 period have been filed monthly with the Commission and served on all parties. Those schedules are incorporated herein by reference.

Q. What is the source of the data that you will present through testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE (FCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix I, page 3, entitled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2006 through December 2006, an under-recovery of $53,744,558.

The Summary of the Net True-up amount shown on Appendix I, page 3 shows the actual End-of-Period True-Up over-recovery for the period January 2006 through December 2006 of $162,686,084 on line 1. The Estimated/Actual True-Up over-recovery for the same period of $216,430,642 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2006 through December 2006 shown on line 3, an under-recovery of $53,744,558.

The calculation of the true-up amount for the period follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the actual true-up by month?

A. Yes. Appendix I, pages 4 and 5, entitled "Calculation of Actual True-up Amount," shows the calculation of the FCR actual true-up by month for January through December 2006.

Q. Have you provided a schedule showing the variances between actual and estimated/actual fuel costs and revenues for 2006?

A. Yes. Appendix I, page 6 compares the actual fuel costs and revenues to the estimated/actuals for January through December 2006.

Q. Please describe the variance in fuel costs.

A. Appendix I, page 6, line C11 compares the Actual End of Period Net True-up under-recovery of $144,751,516 to the Estimated/Actual End of Period Net

True-up under-recovery of $91,006,958 resulting in a variance of $53,744,558. This variance is due primarily to a $14,172,965 (0.3%) increase in Jurisdictional Total Fuel Costs and Net Power Transactions (page 6, line C6), a $39,175,169 (0.7%) decrease in Jurisdictional Fuel Revenues (page 6, line C3), and an increase of $396,424(1.3%) in interest (page 6, line C8).

The $14.5 million increase in Adjusted Total Fuel Costs and Net Power Transactions is due primarily to an $18.2 million (17.9%) variance in the Fuel Cost of Power Sold, a $3.0 million (13.3%) variance in Gains from Off-System Sales, and a $12.6 million (4.3%) increase in Fuel Cost of Purchased Power, and a $3.3 (5.1%) variance in Sales to Florida Keys Electric Cooperative and the City of Key West. These amounts are offset by a $5.5 million (0.1%) decrease in the Fuel Cost of System Net Generation, a $3.0 million (1.9%) decrease in Energy Payments to Qualifying Facilities, and a $13.2 million (11.8%) decrease in the Energy Cost of Economy Purchases.

The $18.2 million (17.9%) variance in Fuel Cost of Power Sold is primarily due to lower than projected off-system sales (130,965 MWh) and lower than expected fuel costs. The $12.6 million (4.3%) increase in Fuel Cost of Purchased Power is primarily due to greater than expected utilization of purchased power.

As shown on the December 2006 A3 Schedule, the $5.5 million (0.1%)

decrease in the Fuel Cost of System Net Generation is primarily due to $47.2 million (6.3%) greater than projected heavy oil cost and $9.6 million (8.0%) greater than projected coal cost offset by $64 million (1.6%) lower than projected natural gas cost. Heavy oil averaged $8.15 per MMBtu, $0.21 per MMBtu (2.5%) lower than projected, and 8,074,828 more MMBtu's (9.1%) of heavy oil were used during the period than projected. Coal averaged $2.03 per MMBtu, $0.10 per MMBtu (5.3%) higher than projected, and 1,609,164 more MMBtu's (2.6%) of coal were used during the period than projected. The natural gas price averaged $8.80 per MMBtu, $0.03 per MMBtu (0.4%) higher than projected, but 9,057,778 fewer MMBtu's (2.0%) of natural gas were used during the period than projected.

The $3 million (1.9%) decrease in Energy Payments to Qualifying Facilities is due primarily to a decrease in the energy purchases from ICL due to an outage in October 2006. The $13.2 million (11.8%) decrease in the Energy Cost of Economy Purchases is mainly attributable to lower than projected economy purchases (112,267 MWh) and lower than expected market prices.

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on Appendix I, page 6, line C3, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $39.2 million (0.7%) lower than the estimated/actual projection. This decrease was due primarily to lower than projected jurisdictional sales, which were 548,767,914 kWh (0.5%)

lower than the estimated/actual projection.

Q. Pursuant to Commission Order No. PSC-06-1057-FOF-EI, FPL's 2006 gains on non-separated wholesale energy sales are to be measured against a three-year average Shareholder Incentive Benchmark of $19,136,028. Did FPL exceed this benchmark?

A. Yes. As shown on the year-to-date December Schedule A6 that was filed on January 23, 2007, FPL's 2005 gains on off-system sales were $19,438,254. This $19,438,254 exceeds the $19,136,028 benchmark by $302,226. Consistent with Commission Order No. PSC-00-1744-PAA-EI in Docket No. 991779-EI, this $302,226 amount is to be shared between FPL's customers and shareholders, with 80%, or $241,781, going to customers and 20%, or $60,445, going to shareholders. Thus customers receive 80% of the amount above the benchmark ($241,781), plus 100% of the gains on off-system sales below the benchmark ($19,136,028), for a total of $19,377,809. FPL is requesting that the Commission approve $60,445 as its Shareholder Incentive for 2006. FPL has reflected this incentive in the FCR Actual True-Up calculation for 2006 by reducing the amount of total gains on off-system sales by $60,445, from $19,438,254 to $19,377,809 (see Appendix I, page 5, Line A2b, column 13).

Q. What is the appropriate final Shareholder Incentive Benchmark level for calendar year 2007 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI in Docket No. 991779-EI?

A. For the year 2007, the three year average Shareholder Incentive Benchmark consists of actual gains for 2004, 2005 and 2006 (see below) resulting in a three year average threshold of:

2004	$18,558,415
2005	$21,022,022
2006	$19,438,254
Average threshold	$19,672,897

Gains on sales in 2007 are to be measured against this three-year average Shareholder Incentive Benchmark.

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix II, page 3, entitled "Summary of Net True-Up" shows the calculation of the Net True-Up for the period January 2006 through December 2006, an under-recovery of $4,030,283, which I am requesting to be included in the calculation of the CCR factors for the January 2008 through December 2008 period.

The actual End-of-Period under-recovery for the period January 2006 through December 2006 of $22,245,729 (shown on line 1) less the estimated/actual End-of-Period under-recovery for the same period of $18,215,446 that was approved by the Commission in Order No. PSC-06-1057-FOF-EI (shown on

line 2), results in the Net True-Up under-recovery for the period January 2006 through December 2006 (shown on line 3) of $4,030,283.

Q. Have you provided a schedule showing the calculation of the actual true-up by month?

A. Yes. Appendix II, page 4, entitled "Calculation of Actual True-up Amount," shows the calculation of the CCR End-of-Period true-up for the period January 2006 through December 2006 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals?

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period January 2006 through December 2006.

Q. What was the variance in net capacity charges?

A. Appendix II, page 6, Line 13 provides the variance in Jurisdictional Capacity Charges of $1,960,386 or 0.3%. This $1,960,386 variance was primarily due to a $2,553,140 or 0.8% increase in Payments to Cogenerators (QF's) due to higher than estimated capacity payments to QF's partially offset by a

$1,817,537 or 6.8% decrease in Power Plant Security Costs. This decrease in Power Plant Security Costs is primarily due to certain expenditures being delayed until 2007.

Q. What was the variance in Capacity Cost Recovery revenues?

A. As shown on page 6, line 14, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $2,069,038 (0.4%) lower than the estimated/actual projection. This $2,069,038 decrease in revenues, plus the $1,960,386 increase in costs, plus interest of $858 (page 6, line 18), results in the final under-recovery of $4,030,283.

Q. Have you provided Schedule A12 showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 7 and 8. Page 7, shows the actual capacity payments for Qualifying Facilities, the Southern Company – UPS contract and the St John River Power Park (SJRPP) contract. Page 8 provides the Short Term Capacity payments for the period January 2006 through December 2006.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 070001-EI

August 6, 2007

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery (FCR) Clause and the Capacity Cost Recovery (CCR) Clause for the period January 2007 through December 2007.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. It consists of various schedules included in Appendices I and II. Appendix I contains the FCR related schedules and Appendix

II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2007 through December 2007. FCR Schedules A1 through A9 provides actual data for the period January 2007 through June 2007. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

Q. What is the source of the actuals data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actuals data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please describe what data FPL has used as a comparison when calculating the FCR and CCR true-ups that are presented in your testimony.

A. The FCR true-up calculation compares estimated/actual data consisting of actuals for January through June 2007, and revised estimates for July through December 2007, with the original estimates for January through December 2007. The CCR true-up calculation makes the same comparison.

Q. Please explain the calculation of the interest provision that is

applicable to the FCR and CCR true-ups.

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in July 2007.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Appendix I, pages 2 and 3, show the calculation of the FCR Estimated/Actual True-up amount. The estimated/actual true-up amount for the period January 2007 through December 2007 is an under-recovery, including interest, of $49,425,979 (Appendix I, Page 3, Column 13, Line C7 plus C8).

Appendix I, pages 2 and 3 also provide a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines B1 through B3), Jurisdictional Fuel Revenues (line C1 through C3), the

True-up and Interest Provision for this period (lines C4 through C10), and the End of Period True-up amount (line C11).

The data for January 2007 through June 2007, columns (1) through (6) reflects the actual results of operations, and the data for July 2007 through December 2007, columns (7) through (12) are based on updated estimates.

The true-up calculations follow the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" filed monthly with the Commission.

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes, they were.

Q. What is FPL's total under-recovery?

A. FPL's total under-recovery is $103,170,537. This consists of the $49,425,979 estimated/actual under-recovery for 2007 plus the final under-recovery of $53,744,558 for the period ending December 2006 filed on March 1, 2007. This total under-recovery of $103,170,537 is to be carried forward and included in the fuel factor for January through December 2008.

Q. Please summarize the variance schedule provided as page 4 of Appendix I.

A. The variance calculation of the Estimated/Actual data compared to the original projections for the January 2007 through December 2007 period is provided in Appendix I, Page 4. FPL's filing dated October 24, 2006 projected Jurisdictional Total Fuel and Net Power Transactions to be $6.008 billion for January through December 2007 (See Appendix I, Page 4, Column 2, Line C6). The estimated/actual Jurisdictional Total Fuel Cost and Net Power Transactions are now projected to be $5.945 billion for the period January through December 2007 (Actual data for January through June 2007 and revised estimates for July through December 2007) (See Appendix I, Page 4, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Cost and Net Power Transactions are $63.1 million or 1.0% lower than originally projected (See Appendix I, Page 4, Column 3, Line C6).

Jurisdictional Fuel Revenues for 2007 are $ 108.9 million lower than originally projected (Appendix I, Page 4, Column 3, Line C3). Combining the $63.1 million of lower costs with the $108.9 million of lower revenues, plus interest, results in the $49.4 million under-recovery.

Q. Please explain the variances in Jurisdictional Total Fuel Costs and Net Power Transactions.

A. As shown on Appendix I, Page 4, Line C6, the variance in Jurisdictional Total Fuel Costs and Net Power Transactions of $63.1

million is a 1.0% decrease from projections. The primary reason for this variance is lower than projected Fuel Costs of System Net Generation and lower Energy Costs of Economy Purchases, which is somewhat offset by higher than projected Purchased Power Costs and lower than projected Power Sold.

There is a $96.4 million or 1.7% decrease in the Fuel Cost of System Net Generation due primarily to lower than projected residual oil costs offset somewhat by higher than projected natural gas costs. Residual oil costs are currently projected to be $392.5 million (36.5%) lower than the original filing. The unit cost of residual oil in the estimated/actual period is $9.50 per MMBTU or $0.01 (0.1%) higher than the $9.49 per MMBTU included in the original filing. Additionally, the estimated/actual heavy oil consumption is 36.5% less than the original projection. Natural gas costs are currently projected to be $270.2 million (6.2%) higher than the original filing. Although the unit cost of natural gas in the estimated/actual period is $9.63 per MMBTU or $0.55 (5.4%) lower than the $10.18 per MMBTU included in the original filing, consumption of natural gas has increased by 12.2% compared to the original projections. Projections for generation by fuel type for the period July 2007 through December 2007 are included in Appendix I, Schedule E3. Additionally, there is a $45.3 million decrease in the Energy Cost of Economy Purchases due to lower than projected economy purchases and lower than

projected market prices for power. Projected Economy energy purchases for the period July 2007 through December 2007 are provided in Appendix I, Schedule E9.

These decreases in fuel costs and economy purchases are partially offset by a $27.3 million increase in the Fuel Cost of Purchased Power due primarily to higher than projected cost of purchased power. Projections for Fuel Cost of Purchased Power for the period July 2007 through December 2007 are provided in Appendix I, Schedule E7. Additionally, there is a $45.3 million variance for the Fuel Cost of Power Sold primarily due to lower overall fuel costs, higher than projected off-peak sales during the first quarter of 2007 and lower than projected off-system MWh sales. Projections for Power Sold for the period July 2007 through December 2007 are provided in Appendix I, Schedule E6.

Q. What is the appropriate estimated benchmark level for calendar year 2008 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI?

A. For the forecast year 2008, the three-year average threshold consists of actual gains for 2005, 2006, and January through June 2007, and estimates for July through December 2007 (see below). Gains on sales in 2008 are to be measured against this three-year average threshold, after it has been adjusted with the true-up filing (scheduled

to be filed in March 2008) to include all actual data for the year 2007.

2005	$21,022,022
2006	$19,967,227
2007	$22,054,662
Average threshold	$21,014,637

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Appendix II, Pages 2 and 3 show the calculation of the CCR Estimated/Actual True-up amount. The calculation of the Estimated/Actual True-up for the period January 2007 through December 2007 is an under-recovery of $15,232,599 including interest (Appendix II, Page 3, Column 13, Lines 17 plus 18).

Q. *Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this Docket?*

A. Yes, it is.

Q. Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?

A. Yes. Appendix II, Page 4, shows the Estimated/Actual capacity charges and applicable revenues (January through June 2007 reflects actual data and the data for July through December 2007 is

based on updated estimates) compared to the original projections for the January 2007 through December 2007 period, filed September 1, 2006.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 4, Column 3, Line 13, the variance related to capacity charges is a $4.7 million increase. The primary reasons for this variance is a $2.4 million increase in short-term capacity payments, a $1.4 million increase in Capacity Payments to Cogenerators, and a $2.5 million increase in Transmission of Electricity by others, offset by $2.2 million decrease in Incremental Power Plant Security Costs. Short Term Capacity Payments are higher than originally projected due to higher than projected unit costs. The increase in Capacity Payments to Cogenerators is primarily due to slightly better capacity factor performance from QF's than originally projected. The increase in Transmission of Electricity by Others is due to higher than originally projected costs. The decrease in Security Costs is due primarily to the rescheduling of the NERC Cyber Security Standards costs from 2007 to 2008.

In addition to the cost variances, Page 4, Column 3, Line 14, Capacity Cost Recovery revenues, net of revenue taxes, are $8.9 million lower than originally projected. The $4.7 million higher costs plus the $8.9 million revenue variance, plus interest, results in an estimated/actual 2007 true-up amount of $15.2 million under-

recovery (Appendix II, Page 4, Column 3, Lines 17 plus 18). This under-recovery of $15.2 million plus the final 2006 under-recovery of $4.0 million filed on March 1, 2007 results in an under-recovery of $19.2 million to be carried forward to the 2008 capacity factor.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 070001-EI

September 4, 2007

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present for Commission review and approval the Fuel Cost Recovery (FCR) factors for the period January 2008 through December 2008.
- I present for Commission review and approval a revised 2007 FCR estimated/actual true-up amount, which has been updated to include July actual data and which is incorporated into the calculation of the 2008 FCR Factors.
- I present for Commission review and approval the Capacity

Cost Recovery (CCR) factors for the period January 2008 through December 2008.

- I present for Commission review and approval a revised 2007 CCR estimated/actual true-up amount, which has been updated to include July actual data and which is incorporated into the calculation of the 2008 CCR Factors.
- I present for Commission review and approval FPL's projected incremental security costs for 2008, to be recovered through the CCR Clause.
- Finally, I provide on pages 70-71 of Appendix II FPL's proposed COG tariff sheets, which reflect 2008 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. They are as follows:

- KMD-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D E1-E, E2, E10, H1, and pages 8a-8c and 70-71 included in Appendix II
- KMD-6 -- the entire Appendix III

Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FUEL COST RECOVERY CLAUSE

Q. What is the proposed levelized fuel cost recovery (FCR) factor for which the Company requests approval?

A. 5.553¢ per kWh. Schedule EI, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 9 and 10 of Appendix II shows the monthly fuel factors for January 2008 through December 2008 and also the twelve-month levelized FCR factor for the period.

Q. Has the Company developed levelized FCR factors for its Time of Use rates?

A. Yes. Schedule E1-D, Page 6a of Appendix II, provides a twelve-month levelized FCR factor of 6.011¢ per kWh on-peak and 5.354¢ per kWh off-peak for our Time of Use rate schedules. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are provided on Schedule E-1D, Page 6b of Appendix II. The SDTR was implemented pursuant to the Stipulation and Settlement Agreement approved in Docket No. 050045-EI, which incorporates a different on-peak period during the months of June through September.

FCR factors by rate group for the periods January through December 2008 are presented on Schedule E1-E, Pages 7a and 7b of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 7b of Appendix II.

Q. Were these calculations made in accordance with the procedures approved in predecessors to this Docket?

A. Yes.

Q. Has FPL calculated the residential fuel charges using the inverted rate structure?

A. Yes.

Revised 2007 FCR Estimated/Actual True-up

Q. Has FPL revised its 2007 FCR Estimated/Actual True-up amount that was filed on August 6, 2007 to reflect July actual data?

A. Yes. The 2007 FCR Estimated/actual True-up amount has been revised to an under-recovery of $25,577,700 reflecting July actual data. The calculation of the revised 2007 FCR Estimated/actual true-up amount is shown on Revised Schedule E1-B, on Pages 4a-4b of Appendix II.

Q. What is the revised net true-up amount that FPL is requesting to include in the FCR factor for the January 2008 through December 2008 period?

A. FPL is requesting approval of a net true-up under-recovery of $79,322,258. This $79,322,258 under-recovery represents the revised estimated/actual under-recovery for the period January 2007 through December 2007 of $25,577,700 plus the final true-up under-recovery of $53,744,558 that was filed on March 1, 2007 for the period January 2006 through December 2006. This $79,322,258

under-recovery is to be included for recovery in the FCR factor for the January 2008 through December 2008 period.

Q. What adjustments are included in the calculation of the levelized FCR factor shown on Schedule E1, Page 3 of Appendix II?

A. As shown on line 29 of Schedule E1, Page 3 of Appendix II, the total net true-up to be included in the 2008 factors is a revised under-recovery of $79,322,258. This amount divided by the projected retail sales of 111,773,808 MWH for January 2008 through December 2008 results in an increase of .0710¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Frank Irizarry, filed on April 1, 2007, calculated a reward of $9,001,300 for the period ending December 2006, which is being applied to the January 2008 through December 2008 period. This $9,001,300 reward divided by the projected retail sales of 111,773,808 MWh during the projected period results in an increase of .0081¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

~~Turkey Point Unit 3 Outage Extension (Pressurizer Piping)~~

Q. In FPL witness Terry Jones' Testimony, he describes the 2006 Turkey Point Unit 3 outage extension for the pressurizer piping incident. What regulatory treatment did the Commission approve last year for the replacement power costs resulting

from that outage extension?

A. Because sensitive investigations by FPL, the FBI and the NRC concerning the drilled hole in the pressurizer piping were in progress at the time of last year's fuel adjustment proceedings, the Commission deferred review of the outage extension to this year's proceedings. Consistent with its prior precedent, the Commission approved FPL's request to recover through the 2007 FCR factor the approximately $6 million of replacement power costs associated with the outage extension, subject to potential refund with interest if the Commission were to determine subsequently that FPL is not entitled to recover those costs.

Q. What standard has the Commission used to determine whether utilities may recover replacement power costs associated with nuclear unit outages?

A. The Commission has consistently based that determination on whether a utility's actions were prudent in whatever circumstances led to the need for replacement power. These prudence determinations essentially look to whether a utility acted reasonably based on the information available to it at the time, without the benefit of hindsight. So long as a utility's actions are prudent by this measure, the utility is permitted to recover the replacement power costs.

Q. Do you believe that this prudence standard is appropriate for determining whether replacement power costs may be

recovered?

a. Yes, I do. Replacement power costs constitute out-of-pocket fuel and/or purchased power costs actually incurred by a utility in providing electric service to its customers. As such, they are properly recoverable through the FCR Clause just like any other power costs, unless they are shown to have been unnecessarily incurred because the utility could have avoided them had it acted reasonably.

Q. Should FPL be entitled to recover the replacement power costs associated with the 2006 Turkey Point Unit 3 outage extension under the prudence standard?

A. Yes. As FPL witness Jones explains in his testimony, FPL complied fully with NRC requirements and industry standards in order to prevent improper access and deliberate criminal acts, and took extensive actions to swiftly and effectively investigate and inspect both Turkey Unit 3 and Unit 4 after the drilled hole in the pressurizer piping was discovered, enabling FPL to expeditiously return the plant to service with minimal disruption in production. FPL's actions at each step in this process were unquestionably reasonable and prudent.

Q. Would it be unfair to deny FPL recovery of its replacement power costs even though its actions were prudent?

A. Yes. To deny recovery of replacement power costs even where a utility has acted prudently would be completely inconsistent with the purpose of the FCR Clause and would essentially make the utility a guarantor of

the reliability of its nuclear plants, with no corresponding reward for taking on this large risk. Such a policy would create a major disincentive to investments in new nuclear capacity which FPL believes is important to help ensure energy security and fuel diversity.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2007 CCR Estimated/Actual True-up amount that was filed on August 6, 2007 to reflect July actual data?

A. Yes. The 2007 CCR Estimated/actual True-up amount has been revised to an under-recovery of $15,561,009 reflecting July actual data. The calculation of the revised 2007 CCR Estimated/actual true-up amount is shown on page 3b of Appendix III.

Q. What is the revised net true-up amount that FPL is requesting to include in the CCR factor for the January 2008 through December 2008 period?

A. FPL is requesting approval of a net true-up under-recovery of $19,591,292. This $19,591,292 under-recovery represents the revised estimated/actual under-recovery for the period January 2007 through December 2007 of $15,561,009 plus the final true-up under-recovery of $4,030,283 that was filed on March 1, 2007 for the period January 2006 through December 2006. This $19,591,292 under-recovery is to be included for recovery in the CCR factor for the January 2008 through December 2008 period.

Q. Have you prepared a summary of the requested capacity

payments for the projected period of January 2008 through December 2008?

A. Yes. Page 3 of Appendix III provides this summary. Total Recoverable Capacity Payments are $566,444,416 (line 16) and include payments of $205,560,816 to non-cogenerators (line1), Short-term Capacity Payments of $48,647,490 (line 2), payments of $323,621,136 to cogenerators (line 3), and $3,020,012 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4), $33,297,815 in Incremental Power Plant Security Costs (line 6), and $6,034,121 for Transmission of Electricity by Others (line 7). This amount is offset by $5,456,439 of Return Requirements on SJRPP Suspension Payments (line 5), by Transmission Revenues from Capacity Sales of $3,760,758 (line 8), and by $56,945,592 of jurisdictional capacity related payments included in base rates (line 12). The resulting amount is then increased by a net under-recovery of $19,591,292 (line 13). The net under-recovery of $19,591,292 includes the final under-recovery of $4,030,283 for the January 2006 through December 2006 period that was filed with the Commission on March 1, 2007, plus the estimated/actual under-recovery of $15,561,009 for the January 2007 through December 2007 period, which includes actual data for January through July 2007 and revised estimates for August through December 2007.

Incremental Power Plant Security

Q. Has FPL included a projection of its 2008 Incremental Power Plant Security Costs in calculating its Capacity Cost Recovery (CCR) Factors?

A. Yes. FPL has included $33,297,815 on Appendix III, page 3, Line 6 for projected 2008 Incremental Power Plant Security Costs in the calculation of its CCR Factors. Section 14 of FPL's 2005 Rate Case Stipulation contemplates the continued use of the CCR Clause to recover incremental power plant security costs throughout the term of the stipulation. Of the total amount of projected 2008 costs, $29,527,430 is for nuclear power plant security, which is discussed in Mr. Jones' testimony. $1,420,104 is for fossil power plant security and $2,350,281 is for the North American Reliability Council (NERC) Cyber Security Standards. All of the incremental security costs that FPL has included in the calculation of the CCR Factors are post 9/11 power plant-related security measures required by the Nuclear Regulatory Commission, the Maritime Transportation Act, Coast Guard rules, NERC and/or recommendations from the Department of Homeland Security authorities. These costs are not reflected in base rates. They are tracked and segregated by work order and charged only to the CCR clause.

Calculation of CCR Factors

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 4 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Have you prepared a calculation of the proposed CCR factors by rate class?

A. Yes. Page 5 of Appendix III presents this calculation.

Q. What effective date is the Company requesting for the new FCR and CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2008 through December 2008. This will provide for 12 months of billing on the CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective January 2008?

A. The Residential 1,000 kWh Bill is $102.49.This includes a base charge of $39.37, the fuel cost recovery charge is $52.27, the Capacity Cost Recovery charge is $5.46, the Conservation charge is $1.45, the Environmental Cost Recovery charge is $0.40, the Storm charge is $0.98 and the Gross Receipts Tax is $2.56. A comparison of the current Residential (1,000 kWh) Bill to FPL's 2008 projected Residential (1,000 kWh) Bill is presented in Schedule E10, Page 68

of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BUTLER: Next FPL had testimony prefiled of Witness Pamela Sonnelitter, which was the results testimony on GPIF, but that was subsequently adopted by Mr. Irizarry. And I suppose the appropriate thing to do would be to ask for the insertion of both Ms. Sonnelitter's testimony as adopted and Mr. Irizarry's testimony concerning GPIF. And they had Exhibits 22 and 23.

CHAIRMAN EDGAR: Okay. So the prefiled testimony of Witness Sonnelitter and Witness Irizarry --

MR. BUTLER: Irizarry.

CHAIRMAN EDGAR: -- Irizarry, thank you, will be entered into the record as though read, as will Exhibits 22 and 23.

(Exhibits 22 and 23 marked for identification and admitted into the record.)

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF PAMELA SONNELITTER

DOCKET NO. 070001-EI

APRIL 2, 2007

Q. Please state your name and business address.

A. My name is Pamela Sonnelitter, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Would you please state your present position with Florida Power and Light Company (FPL).

A. I am the General Manager of Business Services in the Power Generation Division of FPL

Q. Have you previously testified in the predecessor to this Docket?

A. Yes, I have

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report the actual performance relative to the Equivalent Availability Factor (EAF)

and Average Net Operating Heat Rate (ANOHR) for the thirteen (13) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-05-1252-FOF-EI issued December 23, 2005, for the period January through December 2006, and I have performed the reward/penalty calculations prescribed by the GPIF Manual based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control an exhibit in this proceeding?

A. Yes, I have. It consists of one exhibit, PS -1.

Page 1 of PS-1 is an index to the contents of the exhibit.

Q. What is the incentive amount you have calculated for the period January through December, 2006?

A. I have calculated a GPIF incentive reward of $9,001,300.

Q. Please explain how the GPIF reward amount is calculated.

A. The steps involved in making this calculation are provided in PS-1. Page 2 of PS-1 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.16 corresponding to a GPIF reward of $9,001,300. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (ANOHR and EAF), the weighting factors, and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the thirteen (13) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Page 7 shows the adjustments to ANOHR. For each of the thirteen (13) units, it shows, in columns 2 through 4, the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Q. Are there any changes to the targets approved through Commission Order No. PSC-05-1252-FOF-EI?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the January through December, 2006 period.

A. The primary reason that FPL will receive a reward for the period was that Scherer 4, St. Lucie Nuclear Units 1 & 2, and Turkey Point Nuclear Units 3 & 4 adjusted availability was better than targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward.

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 91.3% compared to its target of 86.0%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,171,670.

Turkey Point Unit 4 operated at an adjusted actual EAF of 89.7% compared to its target of 86.8%. This results in a +9.67 point reward, which corresponds to a GPIF reward of $2,058,434.

St. Lucie Unit 1 operated at an adjusted actual EAF of 99.9% compared to its target of 93.6%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,801,142.

St. Lucie Unit 2 operated at an adjusted actual EAF of 80.9% compared to its target of 75.8%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,001,694.

Q. Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,063 Btu/kWh compared to its target of 11,078 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,032 Btu/kWh compared to its target of 11,072 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,852 Btu/kWh compared to its target of 10,870 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,845 Btu/kWh compared to its target of 10,931 Btu/kWh. This results in a +2.13 point reward, which corresponds to a GPIF reward of $67,380.

In total, the nuclear units' heat rate performance results in a GPIF reward of $67,380.

Q. What is the total GPIF incentive reward for FPL's nuclear units?

A. $9,100,321

Q. Ms. Sonnelitter, would you summarize the performance of FPL's fossil units?

A. Yes. Regarding EAF performance, seven (7) of the nine (9) fossil generating units performed better than their availability targets, while the remaining two units performed worse than their targets. The combined fossil units' availability performance results in a GPIF reward of $828,561.

Regarding ANOHR, three (3) out of the nine (9) fossil units operated with an ANOHR that was above the ± 75 Btu/kWh

deadband resulting in a penalty. The remaining six (6) units operated with ANOHRs that were within the ± 75 Btu/kWh deadband, and they will receive no incentive reward or penalty. The combined fossil units' heat rate performance results in a GPIF penalty of $927,581.

Q. What is the total GPIF penalty for FPL's fossil units?

A. $99,020

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF FRANK IRIZARRY

DOCKET NO. 070001-EI

SEPTEMBER 4, 2007

Q. Please state your name and business address.

A. My name is Frank Irizarry and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Would you please state your present position with Florida Power and Light Company (FPL).

A. I am the Director of Production Assurance and Business Services in the Power Generation Division of FPL.

Q. Please describe your educational background and business experience.

A. I received a Bachelors degree in Industrial Engineering from Georgia Tech in 1982 and a Masters of Business Administration from Nova Southeastern University in 1988. I am also a Registered Professional Engineer in Florida and have held my registration for over twenty years. I have been employed with FPL since 1985 and between 1985 and 2002, I have held a variety of administrative, technical, maintenance, and operating positions at one nuclear site and various fossil plants in Florida. Between 2002 and through my current

position, I have held business unit support positions in Business Services, Central Maintenance, and the Integrated Supply Chain. Prior to joining FPL, I worked as an Industrial and Production Engineer with ALCOA aluminum company for approximately three and a half years.

Q. Mr. Irizarry, are you adopting the testimony of FPL witness Pamela Sonnelitter entitled "Generating Performance Incentive Factor, Performance Factor Results for January through December 2006" as your own?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the target unit equivalent availability factors (EAF) and the target unit average net operating heat rates (ANOHR) for the period of January through December, 2008, for use in determining the Generating Performance Incentive Factor (GPIF).

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control, an exhibit in this proceeding?

A. Yes, I have. It consists of one document, FI -2. The first page of this document is an index to the contents of the document. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2008 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December, 2008, FPL projects a weighted system equivalent planned outage factor of 5.4% and a weighted system equivalent unplanned outage factor of 7.1%, which yield a weighted system equivalent availability target of 87.5%. The targets for this period reflect planned refueling outages for two nuclear units. FPL also projects a weighted system average net operating heat rate target of 8,924 Btu/kWh for the period January through December, 2008. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit PS-2, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for the 13 generating units which FPL proposes to be considered as GPIF units for the period of January through December, 2008. All of these targets have been derived utilizing the methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor (EUOF). The EPOF for each unit is determined by the length of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that will materially affect the predicted heat rate. A regression equation that best fits the data is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the POWERSYM model. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or

degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. The GPIF units were selected in accordance with the GPIF Manual using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period. The 13 units which FPL proposes to use for the period of January through December 2008 represent the top 81.2% of the total forecasted system net generation for this period excluding three units: Martin Unit 8, Manatee Unit 3, and Turkey Point Unit 5. These three units were excluded from the GPIF calculation because there is insufficient historical data to include them. The conversion of Martin Unit 8 to combined cycle in 2005 constitutes a major design change affecting both the generation capacity and the performance of this unit. As a result, its future performance is not yet comparable to its historical performance. Manatee Unit 3 and Turkey Point Unit 5 are new units for 2005 and 2007 respectively. Consistent with the GPIF Manual, the above mentioned units will be excluded from the GPIF calculations until we have enough operating history to use in projecting future performance.

Q. Do FPL's EAF and ANOHR performance targets represent a reasonable level of generation efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BUTLER: I believe that wraps it up for FPL, I think. And please correct me if I'm missing anything, but I believe that the only other, the only remaining exhibit is the one that we have identified as 48, which would be our late-filed exhibit concerning the hedging percentages.

CHAIRMAN EDGAR: That, that is the way it appears to me.

MR. BUTLER: Thank you.

CHAIRMAN EDGAR: Okay. We will go on lunch break here in a moment. When we come back, we will address the, described to be late-filed exhibits, and then we will begin with Witness Ball for Gulf. And can we come back at 1:30? See if we can get this -- okay. We will be on lunch break until 1:30. Thank you.

(Lunch recess taken.)

CHAIRMAN EDGAR: And I call this hearing back to order.

We are back from lunch break. And I believe when we went on break, we had decided that we would take up the to be late-filed exhibits when we first came back, so let's begin there.

Ms. Bennett.

MS. BENNETT: Madam Chair, my understanding is that each of the utilities now has the information which was requested earlier and would be prepared to present it. It is

confidential for each of the utilities, and so as we discuss the information we need to carefully word any questions that we might have. We might start with Progress and then move to Florida Power and Light, then Gulf, and then TECO.

CHAIRMAN EDGAR: Okay. Let's begin there.

MR. BURNETT: Madam Chair, just as a matter of procedure, if I can address this.

My understanding is we will hand out copies to all five Commissioners, a copy to staff, and then a copy to any non-public entity party that we have signed a confidentiality agreement with as well as the Office of Public Counsel. The Commission will have those for review, then we will pick them back up and then officially file a copy with the Clerk's Office tomorrow, along with a written notice of intent.

CHAIRMAN EDGAR: That is my understanding.

Commissioners, any questions about that process? No. Okay.

MR. BURNETT: Thank you.

CHAIRMAN EDGAR: Commissioners, as we discussed and as is obvious from the labeling, this is confidential information. There is the opportunity, though, to ask questions if they are in keeping with keeping the confidential material confidential.

So any questions for Progress at this time? No. Okay.

Ms. Bennett.

MS. BENNETT: No questions. We would ask that this be moved into the record as Exhibit 49.

CHAIRMAN EDGAR: This exhibit, which had previously been Numbered 49, will so be numbered and labeled, "Progress Hedging Percentages Financial and Fiscal 2007," and marked for the record as confidential.

Commissioner Argenziano, do you have any question about this information for Progress at this time?

COMMISSIONER ARGENZIANO: No.

CHAIRMAN EDGAR: Okay. All right. Marked and entered.

(Exhibit 49 marked for identification and admitted into evidence.)

MS. BENNETT: If the Commissioners are finished and the parties are finished looking at it, we could have Mr. Burnett collect this, and then have Mr. Butler pass out Florida Power and Light's exhibit.

CHAIRMAN EDGAR: Commissioners, are you ready for this to be collected, or do you need more time?

COMMISSIONER ARGENZIANO: Okay.

MR. BUTLER: Madam Chairman.

CHAIRMAN EDGAR: Yes, sir.

MR. BUTLER: I'm going to have to ask, if I may, that we go last. We are still, literally, getting the exhibit

delivered from our Tallahassee office over here to the Commission to be able to distribute, so if we could --

CHAIRMAN EDGAR: We can come back to you.

MR. BUTLER: Thank you.

CHAIRMAN EDGAR: Okay.

MR. BURNETT: May I approach the bench?

CHAIRMAN EDGAR: Yes, you may. Thank you.

(Pause.)

CHAIRMAN EDGAR: Mr. Badders.

MR. BADDERS: Thank you.

Russell Badders on behalf of Gulf Power. Our exhibit is actually not confidential, and we can pass it out to all the parties and the Commissioners, if you would like us to.

CHAIRMAN EDGAR: Yes, please.

MR. BADDERS: And I will note that our Witness Ball is the next witness, and he can address questions related to this.

CHAIRMAN EDGAR: Thank you.

(Pause.)

CHAIRMAN EDGAR: As indicated, this is Exhibit 50, not confidential. We'll go ahead --

(Exhibit 50 marked for identification and admitted into the record.)

MS. BENNETT: And we would ask that that be entered into the record as Exhibit 50. And it is nonconfidential, so

we can ask questions.

CHAIRMAN EDGAR: So we will go ahead and enter this into the record as Exhibit 50. And with the understanding, Commissioners, if there are questions related to this information, the next witness would be an appropriate person to address those to.

And, TECO.

MR. BEASLEY: Yes, Madam Chair. Ours is confidential. I'll be happy to distribute it to the Commissioners and staff.

CHAIRMAN EDGAR: Let's go ahead and do that. Thank you.

(Pause.)

CHAIRMAN EDGAR: And this would be Exhibit 51.

Commissioners, any questions for TECO's counsel at this point?

COMMISSIONER CARTER: (Inaudible. Microphone off.)

MR. BEASLEY: That's my best lawyer's handwriting.

CHAIRMAN EDGAR: Ms. Bennett.

MS. BENNETT: We would ask that that be moved into the record as Exhibit 51, and it is confidential.

CHAIRMAN EDGAR: So moved.

(Exhibit 51 marked for identification and admitted into the record.)

MR. BEASLEY: We will submit that tomorrow with the

Commission's Clerk's Office under a confidentiality agreement.

CHAIRMAN EDGAR: Thank you.

MR. BEASLEY: May I approach and collect?

CHAIRMAN EDGAR: Yes, please.

(Pause.)

CHAIRMAN EDGAR: Mr. Butler, you're last.

MR. BUTLER: We have resorted to handwriting it and copying it in the Clerk's Office to get you the information as quickly as possible. The FPL person is over in the Clerk's Office at the moment making the copies. Do you want to move on --

CHAIRMAN EDGAR: Let's move on and see what we can get done. And we will come back to you, if that is satisfactory to everyone. Thank you.

Okay. Then I think, Ms. Bennett, unless you have something else, we are ready for the next witness.

MS. BENNETT: I believe we are ready for the next witness.

MR. BADDERS: On behalf of Gulf Power, we'll call Witness Ball to the stand.

CHAIRMAN EDGAR: Thank you.

MR. BADDERS: And I'll note for the record, he was present this morning when the witnesses were sworn.

CHAIRMAN EDGAR: And as I mentioned this morning, we have made some changes to our sound system because we had had

difficulty recently. And it's still being tweaked; so everybody, if you would, make sure that it sounds like you are on mike, and, if not, of course we will make some adjustments.

HERBERT R. BALL

was called as a witness on behalf of Gulf Power Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BADDERS:

Q Mr. Ball, please state your name and business address for the record?

A My name is Herbert R. Ball. My business address is One Energy Place, Pensacola, Florida 32520.

Q By whom are you employed and in what capacity?

A I'm employed by Southern Company Services, Incorporated, and my capacity is Fuel Manager for Gulf Power Company.

Q Are you the same H.R. Ball who prefiled Direct Testimony on March 1, 2007, consisting of 11 pages; August 6, 2007, consisting of 11 pages; and on September 4, 2007, consisting of 10 pages?

A Yes, I am.

Q Do you have any changes to that testimony as prefiled?

A No, I do not.

Q If I were to ask you the same questions today, would

your answers be the same?

A Yes.

MR. BADDERS: We ask that those three pieces of prefiled testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony as referenced will be entered into the record as though read.

MR. BADDERS: I would also note that Mr. Ball has three exhibits -- I mean, two exhibits to his testimony that have been previously identified as Exhibits 27 and 28.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 070001-EI
Date of Filing: March 1, 2007

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

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System (SES). I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2006 through December 31, 2006. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Ball's Exhibit consisting of two schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2006 through December 2006, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $410,603,416 or 16.61% above the projected amount of $352,122,170. Actual net energy was 12,573,246,757 KWH compared to the projected net energy of 12,466,963,000 KWH or 0.85% above projections. The resulting actual average cost of 3.2657 cents per KWH was 15.62% above the projected cost of 2.8244 cents per KWH. The higher total fuel and net power transaction expense is attributed to higher market coal prices, a higher percentage of energy generated from natural gas fired resources, and a lower quantity and price for power sales than projected for the period. This information is from Schedule A-1, period to date, of the Monthly Fuel Filing for the month of December 2006.

Q. During the period January 2006 through December 2006 how did Gulf Power Company's recoverable fuel expenses compare with the projected expenses?

A. Gulf's recoverable fuel cost of net generation was $505,235,341 or 1.55% above the projected amount of $497,510,274. Actual generation was 16,349,407 MWH compared to the projected generation of 17,029,410 MWH or 3.99% below projections. The resulting actual average fuel cost of 3.0902 cents per KWH was 5.77% above the projected cost of 2.9215 cents per KWH. The higher total fuel expense is attributed to the higher cost of coal for the period and a greater percentage of energy generated from natural gas fired resources than projected. Fuel cost for coal including boiler lighter was $2.51 per MMBTU or 9.13% higher than the estimated amount of $2.30 per MMBTU. Fuel cost for gas was $8.66 per

MMBTU or 15.35% lower than estimated amount of $10.23 per MMBTU. The percentage of energy generated from natural gas fired resources was 13.05% which was 12.69% higher than the estimate of 11.58%. This information is from Schedule A-3, period to date, of the Monthly Fuel Filing for the month of December 2006.

Q. How much spot coal did Gulf Power purchase during the period?

A. Excluding Plant Scherer Unit 3, Gulf purchased 3,542,177 tons of coal or 60% of its total coal purchased on the spot market. Schedule 1 of my exhibit consists of a list of contract and spot coal purchases for the period.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $386,609,116 (sum of lines 17 & 30 period to date on the December 2006, Schedule A-5) compared to the projected cost of $362,919,558 or 6.53% above projected. The higher cost was due to a greater quantity and higher prices for spot coal purchases than projected for the period.

Q. How did the total projected cost of coal burned compare to the actual cost?

A. The total cost of coal burned was $370,343,817 (the sum of lines 21 and 34 period to date on the December 2006, Schedule A-5). This is 4.42% higher than our projection of $354,659,995. On a per unit basis, the cost of coal burn including boiler lighter was $2.51 per MMBTU or 9.13%

higher than the estimated amount of $2.30 per MMBTU. The higher per unit cost of coal is attributed to the unanticipated need to replace lower priced contract coal with higher priced spot coal purchases during the period.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total cost of natural gas burned for generation was $132,676,599 (line 47 period to date on the December 2006, Schedule A-5). This is 5.29% below our projection of $140,085,500. The decrease can be attributed to lower than forecasted market prices for natural gas. On cost per unit basis, the actual gas burn cost was $8.65 per MMBTU which is 17.38% lower than the projected burn cost of $10.47 per MMBTU.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 7,420,000 MMBTU of natural gas in 2006 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (7,420,000 MMBTU) of gas

hedged was hedged using these financial instruments as reflected on Schedule 2 of my exhibit.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. Schedule 2 of my exhibit consists of a table of all natural gas hedge transactions and associated costs. No fees, commissions, or option premiums were paid. Gulf's 2006 hedging program resulted in a net financial loss of $18,820,316 (hedging settlement costs plus support costs from lines 2 and 3 of Schedule A-1, December period-to-date).

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement filed with the Florida Public Service Commission on April 3, 2006?

A. Yes, Gulf Power's fuel strategy in 2006 complied with the Risk Management Plan, and the actual results achieved compared favorably with the projected results in the plan. Supply of all fuel types and associated transportation to Gulf's generating plants are secured through a combination of long term contracts and spot purchase orders as specified in the plan. The result was that Gulf's generating plants had an adequate supply of fuel available at all times to meet the electric generation demands of its customers. Fuel cost volatility was mitigated by compliance with the Risk Management Plan. Since Gulf purchases physical natural gas requirements at market price, the objective of the financial hedging program is to reduce upside price risk to Gulf's

customers in a volatile price market for natural gas. Gulf uses physical hedges to reduce price volatility in the coal procurement program. In 2006, Gulf's average cost of fuel consumed was $3.09 per MMBTU. This was 4.75% higher than the original projection of $2.95 per MMBTU. Gulf was able to hold per unit fuel costs to very reasonable levels for its customers during a period of coal supply disruptions and volatile market fuel prices by following its Fuel Risk Management Plan.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?

A. Yes, Gulf's coal supply program is based on a mixture of long term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive

pricing and reliable supply.

Q. During the period January 2006 through December 2006 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is $143,801,950 or 15.95% below the projected amount of $171,084,000. Total kilowatt hours of power sales was 4,992,979,347 KWH compared to estimated sales of 5,119,655,000 KWH or 2.47% below projections. The resulting average fuel cost of power sold was 2.8801 cents per KWH or 13.81% below the projected amount of 3.3417 cents per KWH. This information is from Schedule A-1, period to date, of the Monthly Fuel Filing for the month of December 2006.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of power sold and the current projection?

A. The lower total credit to fuel expense from power sales is attributed to a lower amount of KWH sold and lower replacement fuel costs than originally projected. Lower market prices for natural gas during the period reduced the fuel reimbursement rate ($/MWH) for power sales.

Q. During the period January 2006 through December 2006 how did Gulf Power Company's recoverable fuel cost of purchased power compare with the projection?

A. Gulf's recoverable fuel cost of purchased power for the period was

$30,902,609 or 20.57% above the estimated amount of $25,631,000. Total kilowatt hours of purchased power were 1,216,819,104 KWH compared to the estimate of 557,208,000 KWH or 118.38% above projections. The resulting average fuel cost of purchased power was 2.5396 cents per KWH or 44.79% below the estimated amount of 4.5999 cents per KWH. This information is from Schedule A-1, period to date, of the Monthly Fuel Filing for the month of December 2006.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of KWH at attractive prices to supplement its own generation to meet load demands. The average fuel cost of energy purchases per KWH are lower than projected as a result of lower cost energy being made available to Gulf for purchase during the period and lower natural gas market prices reducing the fuel cost of system pool resources.

Q. During the period January 2006 through December 2006, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2006 through December 2006 recovery period, shown on line 3 of Schedule CCA-2, was $29,733,736. Gulf's projected net purchased power capacity cost for the same period was $29,458,820, as indicated on Line 3 of Schedule CCE-1,

filed September 16, 2005. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is less than 1% or essentially on target with our net position.

Q. Was Gulf's actual 2006 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC, a Federal Energy Regulatory Commission approved contract, in which Gulf has been a participant for many years. Gulf's participation in the integrated SES that is governed by the IIC has produced substantial benefits for Gulf's territorial customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews.

Per contractual agreement, Gulf and the other SES operating companies are obligated to provide for the continued operation of its electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner.

The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2006, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve

levels are available to provide reliable electric service to territorial customers. This cost has been properly allocated to Gulf per the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
H. R. Ball
Docket No. 070001-EI
Date of Filing: August 6, 2007

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January, 2007 through December, 2007 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January, 2007 through June, 2007 and newly projected fuel and net power transaction costs for July, 2007 through December, 2007. Projected capacity costs for July through December remain as originally filed. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. During the period January, 2007 through December, 2007 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $425,399,828 which is $3,061,029 or 0.72% above the original projected amount of $422,338,799. The resulting average fuel cost is projected to be 3.3937 cents per KWH or 2.12% above the original projection of 3.3233 cents per KWH. The higher total fuel expense and average per unit fuel cost is attributed to a combination of lower than projected fuel prices for the period which are reflected in both the fuel cost of generation and the fuel cost of purchased power offset by lower fuel revenue from power sales for the period. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 20.

Q. During the period January, 2007 through December, 2007 how will Gulf Power Company's recoverable fuel cost of system net generation compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable fuel cost of system net generation for the period is $577,586,046 which is $6,777,368 or 1.16% below the original projected amount of $584,363,414. Total net system generation is expected to be 17,514,719 MWH compared to the original projected generation of 17,529,530 MWH or 0.08% below projections. The resulting average fuel cost is expected to be 3.2977 cents per KWH or 1.08% below the original projected amount of 3.3336 cents per KWH. This current

projection of fuel cost of system net generation is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 1.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of system net generation and the current projection?

A. The lower total fuel expense is due to lower than projected average per unit fuel costs. Delivered coal and natural gas prices per MMBTU are projected to remain below original projections for the remainder of the period.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2007?

A. The total fuel cost of system net generation was $267,607,934 which is $13,425,894 or 4.78% lower than the projection of $281,033,828. On a fuel cost per KWH basis, the actual cost was 3.2606 cents per KWH, which is 1.06% lower than the projection of 3.2956 cents per KWH. This lower cost of system generation on a cents per KWH basis is due to a combination of fuel cost in $/MMBTU being 1.51% lower than projected and heat rate (BTU/KWH) of the generating units operating being 0.50% higher than projected. This information is found on Schedule A-1, Period to Date and Schedule A-3 of the June, 2007 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2007?

A. The total cost of coal burned (including boiler lighter) was $190,374,001 which is $26,584,151 or 12.25% lower than our projection of $216,958,152.

On a fuel cost per KWH basis, the actual cost was 2.717 cents per KWH which is 2.93% lower than the projected cost of 2.799 cents per KWH. The lower than projected cost of coal burned and cost of coal fired generation is due to coal prices being 5.13% lower than projected on a $/MMBTU basis. This information is found on Schedule A-3 of the June, 2007 Monthly Fuel Filing.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2007?

A. The total cost of natural gas burned for generation was $77,206,561 which is $13,130,885 or 20.49% higher than Gulf's projection of $64,075,676. The total cost of natural gas burned for generation is higher than projected due to net generation from gas fired units being 54.73% greater than projected. On a cost per unit basis, the actual cost of gas fired generation was 6.43 cents per KWH which is 22.15% lower than the projected cost of 8.26 cents per KWH. The cost per KWH for gas fired generation is lower than projected due to lower natural gas prices. Natural gas prices were 24.09% lower than projected on a $/MMBTU basis. This information is found on Schedule A-3 of the June, 2007 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 2,250,000 MMBTU of natural gas for the period January, 2007 through June, 2007 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (2,250,000 MMBTU) of gas hedged was hedged using these financial instruments.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were paid. Gulf's gas hedging program has resulted in a net financial loss of $3,650,094 for the period January through June, 2007.

Q. During the period January, 2007 through December, 2007 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of power sold for the period is $182,601,235 or 7.73% below the original projected amount of $197,895,521. Total megawatt hours of power sales is expected to be 5,650,384,198 KWH compared to the original projection of 5,509,506,000 KWH or 2.56% above projections. The resulting average fuel cost of power sold is expected to be 3.2317 cents per KWH or 10.03% below the original projected amount of 3.5919 cents per KWH. This current projection of fuel

cost of power sold is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 18.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of power sold and the current projection?

A. The lower total credit to fuel expense from power sales is attributed to lower replacement fuel costs than originally projected. Lower market prices for natural gas during the period have reduced the fuel reimbursement rate (cents/KWH) for power sales.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2007?

A. The total fuel cost of power sold was $74,507,234 which is $20,985,766 or 21.98% less than our projection of $95,493,000. On a fuel cost per KWH basis, the actual cost was 2.7282 cents per KWH which is 21.24% below the projected cost of 3.4640 cents per KWH. This information is found on Schedule A-1, Period to Date of the June, 2007 Monthly Fuel Filing.

Q. During the period January, 2007 through December, 2007 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $24,429,398 or 22.60% below the original projected amount of $31,564,000. The total amount of purchased power is expected to be 611,594,786 KWH compared to the original projection of 575,829,000 KWH

or 6.21% above projections. The resulting average fuel cost of purchased power is expected to be 3.9944 cents per KWH or 27.13% below the original projected amount of 5.4815 cents per KWH. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 12.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The lower total fuel cost of purchased power is attributed to a combination of Gulf purchasing a greater amount of energy to supplement its own generation to meet load demands but at a much lower price per KWH than originally projected. Replacement fuel costs for purchased power are lower as a result of forecasted natural gas market prices being lower than projected for the period.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2007?

A. The total fuel cost of purchased power was $8,242,397 which is $7,595,603 or 47.96% lower than our projection of $15,838,000. The lower than anticipated purchased power expense is due to the actual price per KWH for purchases being well below the projected price during the first six months of the year. On a fuel cost per KWH basis, the actual cost was 1.9322 cents per KWH which is 62.32% lower than the projected cost of 5.1276 cents per KWH. This information is found on Schedule A-1, Period to Date of the June, 2007 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30, 2007 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes, Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes, Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from

qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery account so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2007 through December 2007, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 3 of Schedule CCE-1b in the exhibit to Witness Martin's testimony, Gulf's total current net capacity payment projection for the January 2007 through December 2007 recovery period is $30,554,825. Gulf's original projection for the period was $32,623,193 and is shown on Line 3 of Schedule CCE-1 filed in September, 2006. The difference between these projections is $2,068,368 or 6.34% lower than the original projection of net capacity payments and represents the difference between actual capacity payments year to date June 2007 and the original projection for this period.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 070001-EI
Date of Filing: September 4, 2007

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2008 through December 31, 2008. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have prepared an exhibit that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections.

Counsel: We ask that Mr. Ball's exhibit , consisting of one schedule, be marked as Exhibit No. _____ (HRB-2).

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2008 through December 2008 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $433,719,593. This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, line 20.

Q. How does the total projected fuel and net power transactions cost for the 2008 period compare to the projected fuel cost for the same period in 2007?

A. The total updated cost of fuel and net power transactions for 2007, reflected on Schedule E-1B-1, line 21 of Witness Martin's testimony, is projected to be $425,399,828. The projected total cost of fuel and net power transactions for the 2008 period reflects an increase of $8,319,765 or 1.96% over the same period in 2007. On a fuel cost per KWH basis, the 2007 projected cost is 3.3937 cents per KWH and the 2008 projected fuel cost is 3.3648 cents per KWH, which is a decrease of 0.0289 cents

per KWH or .85%.

Q. What is Gulf's projected recoverable fuel cost of net generation for the period?

A. The projected total cost of fuel to meet system net generation needs in 2008 is $626,630,546. The projection of fuel cost of system net generation for 2008 is captured in the exhibit to Witness Martin's testimony, Schedule E-1, line 1.

Q. How does the total projected fuel cost of net generation for the 2008 period compare to the projected fuel cost for the same period in 2007?

A. The total updated cost of fuel to meet 2007 system net generation needs, reflected on Schedule E-1B-1, line 1 of Witness Martin's testimony, is projected to be $577,586,046. The projected total cost of fuel to meet system net generation needs for the 2008 period reflects an increase of $49,044,500 or 8.49% over the same period in 2007. Total system net generation in 2008 is projected to be 17,586,010 MWH, which is 71,291,000 KWH or 0.41% higher than is currently projected for 2007. On a fuel cost per KWH basis, the 2007 projected cost is 3.2977 cents per KWH and the 2008 projected fuel cost is 3.5632 cents per KWH, which is an increase of 0.2655 cents per KWH or 8.05%. This higher projected total fuel expense and average per unit fuel cost is the result of increased utilization of Gulf's gas-fired generating resources thereby increasing the percentage of higher cost natural gas in the generation mix.

Q. Does the 2008 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under existing coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect the customer from fuel price spikes?

A. Natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indexes.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2007 through 2008?

A. Gulf has adequate natural gas financial hedges in place for 2007 to mitigate price risk. Gulf currently has gas and purchased power hedges in place for 2008 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer

and protect against unanticipated dramatic price increases in the natural gas market.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that considers both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the IIC. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for

supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm transportation capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements. Details of Gulf's natural gas procurement strategy are included in the "Risk Management Plan for Fuel Procurement" on file in this docket.

Q. What is Gulf's projected recoverable fuel cost of power sold for the period?

A. Gulf's projected recoverable fuel cost of power sold is $213,447,000. This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, line 18.

Q. How does the total projected recoverable fuel cost of power sold for the 2008 period compare to the projected recoverable fuel cost of power sold for the same period in 2007?

A. The total projected recoverable fuel cost of power sold in 2007, reflected on Schedule E-1B-1, line 19 of Witness Martin's testimony, is projected to be $182,601,235. The projected recoverable fuel cost of power sold in 2008 represents an increased credit of $30,845,765 or 16.89%. Total quantity of power sales in 2008 is projected to be 5,188,854,000 KWH, which is 461,530,198 KWH or 8.17% less than currently projected for 2007. On a fuel cost per KWH basis, the 2007 projected cost is 3.2317 cents per KWH and the 2008 projected fuel cost is 4.1136 cents per KWH, which is an increase of 0.8819 cents per KWH or 27.29%. This

higher total credit to fuel expense from power sales is attributed to a higher fuel reimbursement rate (cents per KWH) for power sales as a result of a greater percentage of sales being made from higher-cost gas-fired generation resources.

Q. What is Gulf's projected purchased power recoverable cost for energy purchased for the period?

A. Gulf's projected recoverable cost for energy purchases is $17,616,000. This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, line 12

Q. How does the total projected purchased power cost for the 2008 period compare to the projected purchased power cost for the same period in 2007?

A. The total updated cost of purchased power to meet 2007 system needs, reflected on Schedule E-1B-1, line 13 of Witness Martin's testimony, is projected to be $24,429,398. The projected cost of purchased power to meet system needs in 2008 is $6,813,398 or 27.89% less than is currently projected for 2007. The total quantity of purchased power in 2008 is projected to be 417,436,000 KWH, which is 194,158,786 KWH or 31.75% lower than is currently projected for 2007. On a fuel cost per KWH basis, the 2007 projected cost is 3.9944 cents per KWH and the 2008 projected fuel cost is 4.2200 cents per KWH, which represents an increase of 0.2256 cents per KWH or 5.65%. This higher average fuel price of purchased power is attributed to a higher fuel reimbursement rate (cents

per KWH) as a result of a greater percentage of purchases from higher-cost natural gas fired generation resources.

Q. What are Gulf's projected recoverable capacity payments for the period?

A. The total recoverable capacity payments for the period are $26,894,321. This amount is captured in Witness Martin's testimony on line 9 of Schedule CCE-1. Schedule CCE-4 of Ms. Martin's testimony lists the long-term power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting capacity dollar amounts. Also included on Schedule CCE-4 is a total of the revenues produced by several market-based service agreements between the Southern Electric System operating companies and entities outside the system that are included in Gulf's 2008 projection. The total capacity cost included on Schedule CCE-4 is shown on line 1 of Schedule CCE-1.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $200,000 in its capacity cost recovery projection. This amount is captured in Witness Martin's testimony on line 2 of Schedule CCE-1.

Q. How does the total projected net capacity cost for the 2008 period compare to the projected net capacity cost for the same period in 2007?

A. Gulf's 2008 Projected Jurisdictional Capacity Payments, found on

Schedule CCE-1, line 5 of Witness Martin's testimony, are projected to be $28,968,564 or 1.90% lower than the current estimate of $29,530,847 (Schedule CCE-1B, line 5) for 2007 that was filed in Ms. Martin's estimated/actual true-up testimony in this docket on August 6, 2007. This decrease is a result of a reduction in the capacity reserve purchase rate under the provisions of the IIC. The average cost of SES operating companies' peaking power resources used to determine the reserve sharing rates is projected to be lower during the 2008 period.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

BY MR. BADDERS:

Q Mr. Ball, do you have any changes to those exhibits?

A No, I do not.

Q At this time, Mr. Ball, please summarize your testimony.

A My responsibility at Gulf Power is to manage the fuel program in a manner that accomplishes the primary objectives of providing a reliable supply of fuel to Gulf's generating plants at the lowest practical cost in the right quantity to minimize supply risk and with the right quality to meet both operational and environmental obligations.

Gulf's primary source of fuel for generation of electricity is coal. Gulf purchases coal using a combination of short and long-term supply agreements that incorporates specific quality specifications in the contract terms. The combination of short and long-term agreements is designed to limit supply risk while allowing flexibility of supply to respond to potential changes in annual burn quantity. The short-term agreements are priced at market and the price is fixed over the term of the agreement. The long-term agreements are priced using a competitive bid process, and the price certain nature of these agreements provide a fiscal cost hedge to protect against potential large increases in market price.

Natural gas comprises a much smaller percentage of Gulf's fuel supply quantity, but represents a significant

percentage of the cost of the fuel program to Gulf's customers. Gulf's strategy for the procurement of natural gas is to contract for supply using long-term agreements priced at market through the indexing of contract gas price to daily published market pricing. The goal is to provide gas suppliers market price to assure reliable gas supply during normal supply conditions, and to rely on natural gas storage for gas supply during periods of market supply disruptions. Gulf hedges the price of the percentage of these natural gas purchase quantities using financial hedges.

The objective of the financial hedging program is to provide price certainty for a portion of Gulf's annual gas requirements in order to limit the volatility of market gas pricing and to limit the risk to the customer for incurring potential higher cost associated with large market price increases during periods of market supply disruptions. We believe that these coordinated coal and gas procurement strategies prudently accomplish the primary objectives of Gulf's fuel program.

MR. BADDERS: We tender the witness for cross examination.

CHAIRMAN EDGAR: Thank you. Other questions on cross for this witness? No. No.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Ball, do you project gains or losses in your hedging transactions for 2007?

A We are projecting a loss in the hedging program for 2007.

Q And what will be the amount of that loss?

A Year-to-date the loss in the program is $7,946,255. We also have a mark-to-market for the remainder and that is through October 31st -- for the reminder of the year we project as of 10/31/2007, an additional loss of $960,900.

Q In round terms, $8 million for the year?

A More closely to 9.

Q When you say that your financial hedges are based upon market price, how do you determine what the market price is?

A The market price that we are using to settle hedges is NYMEX last day Henry Hub market price.

Q And that can be -- you can today using NYMEX Henry Hub price for July of 2008?

A That's correct, yes.

Q When you enter into a financial hedge, do you purchase your contract through the NYMEX, or do you use bilateral contracts?

A We purchase our financial hedging contracts through creditworthy counterparties, primarily large financial

institutions.

Q And that is called the over-the-counter market?

A No, I would not describe it as over the counter.

Q Do you know the policy that underlies why your company uses bilateral transactions rather than exchange transactions?

A The primary reason we use these large financial institutions with which to hedge these gas contracts with is mostly for creditworthiness of the counterparties. We have a very rigorous risk management organization that look at each of these counterparties and assure that they creditworthy enough to meet the obligations of the hedge once it settles.

Q Are you aware that the NYMEX also has a methodology to ensure creditworthiness?

A I'm not extremely familiar with it, but I would assume that they would, yes.

MR. McWHIRTER: That's all the questions that I have.

CHAIRMAN EDGAR: Any questions from staff?

MR. YOUNG: Two questions, Madam Chairman.

CROSS EXAMINATION

BY MR. YOUNG:

Q How long has Gulf been hedging?

A I'm sorry.

Q How long has Gulf been using hedging activities?

A Hedging activities can extend out, I believe it's 42

months into the future. So we are essentially hedging currently into 2010.

Q And for 2006, your hedging activities resulted in a loss of approximately $18.8 million, correct?

A That is correct.

MR. YOUNG: No further questions, Madam Chairman.

CHAIRMAN EDGAR: Commissioners, any questions for this witness?

Commissioner Carter.

COMMISSIONER CARTER: The discussion we have been having on hedging this morning and this afternoon revolved around beginning in -- I think it was '01 and '02 or something like that, is that correct?

THE WITNESS: That is correct, Commissioner.

COMMISSIONER CARTER: And Gulf has been a part of this process since then?

THE WITNESS: Since 2002, Commissioner, yes.

COMMISSIONER CARTER: Thank you.

CHAIRMAN EDGAR: Any questions on redirect?

MR. BADDERS: No redirect.

CHAIRMAN EDGAR: No redirect. Okay. Let's take up the exhibits.

MR. BADDERS: Yes. We would move Exhibits 27, 28, and 47.

CHAIRMAN EDGAR: Okay. Exhibits 27, 28 --

MR. BADDERS: And 47 is the composite exhibit from this morning.

CHAIRMAN EDGAR: Thank you. Yes, and 47. Thank you. Okay.

Exhibits, 27, 28, and 47 will be moved into the record.

(Exhibits 27, 28, and 47 admitted into the record.)

CHAIRMAN EDGAR: The witness is excused. Thank you.

MR. BADDERS: Thank you.

CHAIRMAN EDGAR: Okay. Let's take up your next witnesses that have been excused previously.

MR. BADDERS: The next witness who has been excused is R.J. Martin. We would ask that her testimony be entered into the record as though read, and she has two exhibits. Exhibit 29 and 31. Oh, and 30, I'm sorry.

CHAIRMAN EDGAR: Okay. The prefiled testimony of Witness Martin will be entered into the record as though read, and the accompanying exhibits, 29, 30, and 31 will also be entered into the record at this time.

(Exhibits 29, 30, and 31 admitted into the record.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070001-EI
Date of Filing: March 1, 2007

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes.

Counsel: We ask that Ms. Martin's Exhibit consisting of five schedules be marked as Exhibit No. _____ (RJM-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2006 through December 2006 and the Purchased Power Capacity Cost true-up calculations for the period of January 2006 through December 2006 set forth in your exhibit?

A. Yes. These documents were prepared under my direction.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes.

Q. What is the amount related to the period of January through December 2006 to be refunded or collected through the fuel cost recovery factors in the period January 2008 through December 2008?

A. A net amount to be collected of $30,800,849 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $30,800,849 was calculated by taking the difference in the estimated January 2006 through December 2006 under-recovery of $26,505,347 and the actual under-recovery of $57,306,196, which is the sum of the Period-to-Date amounts on lines 7 and 8 shown on Schedule A-2, page 2, of the monthly filing for December 2006. The estimated true-up amount for this period was approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006. Additional details supporting the approved estimated true-up amount are included on revised Schedules E1-A and E1-B filed September 1, 2006.

Q. Ms. Martin, has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2007?

A. Yes.

Q. What is the actual threshold for 2007?

A. Based on actual data for 2004, 2005, and now 2006, the threshold is calculated to be $3,395,987.

Q. The Commission approved Gulf's hedging program in October 2002. What incremental hedging support costs related to administering Gulf's approved hedging program is Gulf seeking to recover for 2006?

A. Gulf has included $105,754, as shown on Schedule A-1, Period-to-Date, of the monthly fuel filing, for incremental hedging support costs related to

administering the approved hedging program during the 2006 recovery period.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements in the 2006 recovery period?

A. Yes. On Schedule A-1, Period to Date, of the December 2006 monthly fuel filing, Gulf has recorded a net loss of $18,714,562 related to hedging activities in 2006. Mr. Ball will address the details of those hedging activities in his testimony.

Q. Ms. Martin, you stated earlier that you are responsible for the Purchased Power Capacity Cost Recovery true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the Purchased Power Capacity Cost Recovery true-up calculation for the period January 2006 through December 2006.

Q. What is the amount related to the period of January through December 2006 to be refunded or collected in the period January 2008 through December 2008?

A. An amount to be refunded of $458,084 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $458,084 was calculated by taking the difference in the estimated January 2006 through December 2006 under-recovery of $223,116 and the

actual over-recovery of $234,968, which is the sum of lines 9 and 10 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006. Additional details supporting the approved estimated true-up amount are included on revised Schedules CCE-1A and CCE-1B filed September 1, 2006.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2006 through December 2006. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2006 through December 2006. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Please describe Schedule CCA-4 of your exhibit.

A. Schedule CCA-4 provides additional details related to Line 1 of Schedule CCA-2.

Q. Ms. Martin, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070001-EI
Date of Filing: August 6, 2007

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Ms. Martin's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (RJM-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2007 through December 2007 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2007 through December 2007 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Ms. Martin, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2008 through December 2008?

A. The fuel cost recovery true-up for this period is an increase of .3706¢/kwh.

As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2007 period of $12,525,950, plus a final under-recovery for the January through December 2006 period of $30,800,849 (see Schedule 1 of Exhibit RJM-1 in this docket filed on March 1, 2007). The resulting total under-recovery of $43,326,799 will be included for recovery during 2008.

Q. Ms. Martin, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1a, CCE-1b and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2008 through December 2008 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2008 through December 2008?

A. The true-up for this period is a decrease of .0179¢/kwh as shown on Schedule CCE-1a. This includes an estimated over-recovery of $1,635,509 for January 2007 through December 2007. It also includes a final over-recovery of $458,084 for the period of January 2006 through December 2006 (see Schedule CCA-1 of Exhibit RJM-1 in this docket filed March 1, 2007). The resulting total over-recovery of $2,093,593 will be refunded to customers during 2008.

Q. Ms. Martin, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070001-EI
Date of Filing: September 4, 2007

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2008 through December 2008. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2008 through December 2008.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit consists of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Martin's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RJM-3).

Q. Ms. Martin, what is the levelized projected fuel factor for the period January 2008 through December 2008?

A. Gulf has proposed a levelized fuel factor of 3.954¢/kwh. This factor is based on projected fuel and purchased power energy expenses for January 2008 through December 2008 and projected kwh sales for the same period, and includes the true-up and GPIF amounts. This levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2008 is .016¢/kwh more or .41 percent higher than the levelized fuel factor for 2007 upon which current fuel factors are based.

Q. Please explain the calculation of the true-up amount included in the levelized fuel factor for the period January 2008 through December 2008.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $43,326,799 to be collected during 2008 includes an estimated under-recovery for the January through December 2007 period of $12,525,950, plus a final under-recovery for the January through December 2006 period of $30,800,849. The estimated under-recovery for the January through December 2007 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2006 through December 2006?

A. The GPIF result is shown on Line 32 of Schedule E-1 as a decrease of .0018¢/kwh, thereby penalizing Gulf $205,097.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 30 of Schedule E-1.

Q. Ms. Martin, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Martin, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.975¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Ms. Martin, how were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2008 through December 2008. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2007 and how would the change affect the cost of 1,000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2007 is 3.959¢/kwh compared with the proposed factor of 3.975¢/kwh. For a residential customer who uses 1,000 kwh in January 2008, the fuel portion of the bill would increase from $39.59 to $39.75.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2008 through December 2008.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2008 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $3,418,060 has been calculated for 2008. The actual gains for 2005, 2006, and the estimated gains for 2007 on all non-separated sales have been averaged to determine the minimum projected threshold for 2008 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2008 for the months of January through December.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, Schedule CCE-2, and Schedule CCE-4 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2008 through December 2008.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2008 through December 2008 is $30,043,645. The jurisdictional amount is $28,968,564. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. Has there been any change that would affect the capacity clause estimated true-up for 2007 filed by Gulf on August 6, 2007?

A. No. There have been no changes to the estimated true-up for 2007.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last rate case and approved by the Commission in

Order No. PSC-02-0787-FOF-EI issued June 10, 2002, in Docket No. 010949-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2006 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kwh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kwh will be $2.71.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2008 and continuing through the last billing cycle of December 2008.

Q. Ms. Martin, does this conclude your testimony?

A. Yes.

MR. BADDERS: The next witness will be L.S. Noack. She also has two exhibits. At this time we would ask to have her testimony inserted into the record as though read, and we would move Exhibits 32 and 33 into the record.

CHAIRMAN EDGAR: Thank you. The prefiled testimony of Witness Noack will be entered into the record as though read, as well as Exhibits 32 and 33.

(Exhibits 32 and 33 admitted into the record.)

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

L. S. Noack

Docket No. 070001-EI

Date of Filing: April 5, 2007

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

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf

Power Company. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2006, through December 31, 2006.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Ms. Noack's Exhibit, consisting of five schedules, be marked for identification as Exhibit No. ____(LSN-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 16 through 31 of Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Were average net operating heat rate (ANOHR) targets that include the BTU/LB independent variable approved in FPSC Order No. PSC-99-2512-FOF-EI used for Plant Daniel Units 1 and 2 for this period?

A. Yes. The target heat rate equations for Plant Daniel Units 1 and 2 included the BTU/LB independent variable originally approved in FPSC Order No. PSC-99-2512-FOF-EI. The use of this BTU/LB variable has been incorporated in this filing to account for the change in fuel mix at Plant Daniel, which was previously noted in the GPIF Target Filing for 2006 that was submitted to the FPSC on September 16, 2005, as well as the GPIF Results Filing for 2005 that was submitted to the FPSC on April 3, 2006. The actual monthly BTU/LB parameters used are shown on pages 8 and 9 of Schedule 3. All results for Plant Daniel Units 1 and 2 reflect the use of this variable.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 15 of Schedule 5. Pages 3 through 10 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-05-1252-FOF-EI is on page 11 of Schedule 2. The results are: Crist 4, -2.50 points; Crist 5, +10.00 points; Crist 6, +9.66 points; Crist 7, +10.00 points; Smith 1, -10.00 points; Smith 2, +10.00 points; Daniel 1, +10.00 points; and Daniel 2, -4.67 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 9 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target bases. These equations, submitted in September 2005, are shown on page 20 of Schedule 3. As calculated on page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: -10.00 for Crist 4, -8.01 for Crist 5, -3.13 for Crist 6, -9.74 for Crist 7, 0.00 for Smith 1, -0.34 for Smith 2, +2.22 for Daniel 1, and +3.32 for Daniel 2.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was -0.84, as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $205,097.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $205,097 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

L. S. Noack

Docket No. 070001-EI

Date of Filing: September 4, 2007

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

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf

Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

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

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2008 through December 31, 2008.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared one exhibit consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Counsel: We ask that Ms. Noack's exhibit consisting of three schedules be marked for identification as Exhibit_(LSN-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Units 4, 5, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2, continue to be the Company's GPIF units. The projected net generation from these units, which represent all of Gulf's qualifying base and intermediate load units for GPIF, is approximately 80% of Gulf's projected net generation for 2008.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for

the performance period January 1, 2008 through December 31, 2008?

A. I would like to refer you to page 47 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf. For Daniel Units 1 and 2, the use of the Btu/lb independent variable that was stipulated and approved in Commission Order PSC-99-2512-FOF-EI and used in the 2006 GPIF Target Filing, Docket No. 060001-EI, was evaluated. However, the results of the regression analyses indicated that the Btu/lb variable was not statistically significant for this performance period and was, therefore, not included in the target heat rate equations for Daniel Units 1 and 2.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 43 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 44 through 46 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on page 47 of Schedule 1 of your exhibit, calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Ms. Noack, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Ms. Noack, would you please summarize your testimony?

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 4, 5, 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2008 through December 31, 2008.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 47 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 20 through 35 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

Q. Ms. Noack, does this conclude your testimony?

A. Yes.

CHAIRMAN EDGAR: Okay. That brings us to the next witness, which will be TECO. I'm showing that the first TECO witness is excused, and then the next witness is here, and we will hear from -- before we do that, Mr. Butler, do I see that you may be ready to go back a bit?

MR. BUTLER: I am, yes. I can distribute Late-filed Exhibit 48, which is FPL's response to the question on hedging.

CHAIRMAN EDGAR: Let's go ahead and do that. Thank you.

Commissioners, again, as with the discussion just a bit earlier, this is confidential information, as it is labeled, and so we cannot ask questions that would make the confidential information unconfidential. But there is the opportunity to ask general questions, I believe. So are there any questions for Mr. Butler at this time? Is that a no?

Okay. Then I will give you a few moments, and in a few moments we will ask Mr. Butler to collect the information with the understanding that he will follow through on the procedure as earlier described. And as we have marked this as 48 earlier, we can go ahead and enter that.

(Exhibit 48 admitted into the record.)

CHAIRMAN EDGAR: Commissioners, is there a desire for additional time with this information or are you ready to relinquish it? Okay. Commissioner, are you good? Okay.

MR. BUTLER: May I approach the bench?

CHAIRMAN EDGAR: You may.

MS. BENNETT: And, Madam Chair, we would ask that that be introduced as Exhibit 48.

CHAIRMAN EDGAR: I think we just did that.

MS. BENNETT: I'm sorry.

CHAIRMAN EDGAR: That's okay.

Mr. Beasley.

MR. BEASLEY: Yes, Madam Chair. As you pointed out, our first witness, Benjamin Smith, has been excused from the hearing. I would ask that his projection testimony submitted September 4th, 2007, be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of Witness Smith will be entered into the record as though read.

MR. BEASLEY: And he had no exhibit.

BEFORE THE 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 Fuel Services and Systems 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 Strategic Fuels and Power Services in the Fuel Services and Systems group. My responsibilities are to evaluate, pursue, and negotiate short- and long-term purchase and sale opportunities within the wholesale power market, as well as assist in the evaluation of the processes used to value such 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 this Commission?

A. Yes. I testified before this Commission in Docket No. 030001-EI and 040001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales. I also submitted written testimony in Docket No. 050001-EI and 060001-EI.

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 customer energy and demand. Purchases are made to achieve reserve margin requirements, to meet customers' needs, to supplement generation during unit outages, and for economical purposes. When there is a purchased power need, the company aggressively shops for wholesale capacity and/or energy by 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 and/or energy products to credit worthy counterparties. The company has wholesale power purchase and sales transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's purchases and sales 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 sales activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale sales and purchases with the goal of capitalizing on opportunities to reduce costs to its customers. 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. Tampa Electric continually strives to improve its knowledge of markets and the available opportunities to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power and market conditions allow is available on Tampa Electric's system.

Q. Please describe Tampa Electric's 2007 wholesale energy purchases.

A. Tampa Electric assessed the wholesale energy market and entered into long- and short-term purchases based on price and availability of supply. Approximately 13 percent of the expected energy needs for 2007 will be met using purchased power, which includes economy purchases, the existing firm purchased power agreements with Hardee Power Partners and qualifying facilities, a Calpine 170 MW peaking purchase and a Progress Energy Florida 50 to 75 MW system average purchase. The company's purchases also included a 35 to 40 MW short-term firm purchase from Okeelanta, a 158 MW short-term firm purchase from Reliant in the spring and another 158

MW short-term firm purchase from Reliant in the summer. The 170 MW purchase from Calpine began May 2006 and continues through April 2011. As described in my September 2005 testimony and approved by the Commission in Docket No. 050001-EI, this purchase is from Calpine's natural gas-fired facilities in Auburndale, Florida and was entered into to meet Tampa Electric's peaking system needs. The purchase from Progress Energy Florida, which was a 50 MW purchase from January 2006 through March 2007, was extended for the period of April through November 2007 at a total of 75 MW. The fuel charge for this purchase is equal to Progress Energy Florida's system average fuel cost. Its estimated savings to customers is projected to be $0.5 million for 2007.

The 35 to 40 MW purchase from Okeelanta was 40 MW for the period of January through March and 35 MW for the period of April 2007. It was a must-take purchase secured to meet the company's 20% firm reserve margin requirement as well as to support load service during the spring Big Bend Unit 4 SCR installation outage. The first 158 MW Reliant purchase was for the period of February through May and was also secured to support load service during the Big Bend Unit 4 SCR installation outage. The second 158 MW Reliant purchase was for the

period of June through August 2007 and was secured to meet the company's 20 percent firm reserve margin requirement. All of these purchases provided supply reliability and helped reduce price volatility.

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. Has Tampa Electric entered into any other wholesale energy purchases?

A. Yes, it has. Tampa Electric has finalized the purchase of 121 MW of intermediate, natural-gas fired capacity with Pasco Cogen for the period of January 2009 through December 2018. This purchase has an estimated savings to customers of $13 million over the life of the contract. As previously stated, Tampa Electric continues to evaluate economic combinations of forward purchases to reduce the overall cost to customers as well as make reliability purchases whenever necessary.

For 2008, the company expects to meet approximately 12 percent of its customers' energy needs through purchased power, which includes economy purchases, the existing firm purchased power agreements with Hardee Power Partners, qualifying facilities and Calpine.

Q. Does Tampa Electric plan to enter into any other new purchased power agreements during its upcoming Big Bend Station SCR installation outages?

A. As mentioned previously, Tampa Electric purchased power from both Okeelanta and Reliant during the spring 2007 Big Bend Unit 4 SCR installation outage, which began in February and continued through May 2007. For the upcoming SCR installation outages on Big Bend Units 1-3, Tampa Electric is monitoring and engaging the marketplace for power purchase opportunities. The company will evaluate economic combinations of forward purchases during the outages to reduce the overall cost to customers. The SCR installation outages for Big Bend Units 3, 2 and 1 are scheduled to begin November 2007, December 2008 and November 2009, respectively, and are projected to last approximately four months each.

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 products and considers such products to be physical hedges. The company has engaged only in physical hedging for wholesale transactions because the availability of financial instruments for power within the Florida market is limited. The Florida market currently operates through bilateral contracts between various counterparties, and there is no Florida trading hub where standard financial transactions can occur with enough volume for 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 instead, employs a diversified power supply strategy, which includes self-generation and long- and short-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 2007?

A. Yes, Tampa Electric expects its physical hedges to continue to reduce its customers' purchased power price risk. For example, during the summer of 2007, Tampa Electric executed an agreement with Reliant Energy. The purchase from Reliant Energy was a cost-based call option on peaking power. This agreement reduces the purchased power price risk for Tampa Electric customers.

The Calpine and Progress Energy Florida purchases serve as both a physical hedge and reliable source of economical power in 2007. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by the volatility of natural gas prices.

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

for the year 2007 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. Tampa Electric continues to utilize a purchased power risk management strategy that includes monitoring storm activity; evaluating the impact of the storm on the wholesale market; purchasing power on the forward market for reliability and economics; evaluating geographic location and transmission availability; reviewing the seller's fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases during hurricanes. Absent the threat of a hurricane and for all other months of the year, the company's purchased power strategy for evaluating economic combinations of long- and short-term purchase options remains unchanged.

Q. Please describe Tampa Electric's wholesale energy sales for 2007 and 2008.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2007. The gains from the non-separated sales are returned to customers through

the fuel adjustment clause, up to the three-year rolling average threshold of $895,111. Other than its pre-existing separated sales, the company has made no sales for 2008.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale energy market to identify and take advantage of opportunities in the wholesale electric power market, and those efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and long- and short-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, and enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the developing Florida wholesale electric 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.

MR. BEASLEY: Our next witness will testify, Ms. Joann Wehle. I would call her to the stand.

And I believe, Ms. Wehle, you have been sworn, is that correct?

THE WITNESS: Yes, that's correct.

JOANN T. WEHLE

was called as a witness on behalf of Tampa Electric Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Would you please state your name, your business address, and your position with Tampa Electric Company?

A My name is Joann Wehle. I'm the Director of Wholesale Marketing and Fuels for Tampa Electric; P.O. Box 111, Tampa, Florida, 33601.

Q Thank you.

Ms. Wehle, did you prepare and submit a document entitled Prepared Direct Testimony of Joann T. Wehle, dated April 2, 2007?

A Yes, I did.

Q Did you also submit prepared Direct Testimony dated September 4, 2007?

A Yes, I did.

Q If I were to ask you the questions contained in those two testimonies, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Wehle's prepared direct testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled direct testimony will be entered into the record as though read.

BY MR. BEASLEY:

Q Ms. Wehle, did you also prepare the Exhibit JTW-1, a one-page exhibit that accompanied your April 2, 2007, testimony?

A Yes, I did.

Q I believe that has been marked Exhibit 43 on the Composite Exhibit List. Did you also prepare and submit Exhibit JTW-2, another one-page exhibit that accompanied your September 4, 2007, prepared testimony?

A Yes, I did.

MR. BEASLEY: And, Madam Chair, that has been marked Exhibit 44 in the Composite Exhibit List.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 4/2/07

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 of the Wholesale Marketing and Fuels Department.

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, 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 present, for the Florida Public Service Commission's ("FPSC" or "Commission") review, information regarding the 2006 performance of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI. In addition, I will present details regarding the appropriateness for recovery of $210,649 in incremental operations and maintenance ("O&M") expenses associated with hedging activities.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. Exhibit No. ___ (JTW-1) was prepared under my direction and supervision. My exhibit shows Tampa Electric's calculation of its 2006 incremental hedging O&M expenses.

Q. What is the source of the data you present in your testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the source of the data is books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What were the results of Tampa Electric's risk management activities in 2006?

A. As outlined in Tampa Electric's annual Risk Management Plan most recently filed on September 1, 2006 in Docket No. 060001-EI, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In an effort to limit exposure to market price fluctuations of natural gas, Tampa Electric established a hedging program. Over time, the program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

On April 2, 2007 Tampa Electric filed its annual risk management report, which describes the outcomes of its 2006 risk management activities. The report indicates that Tampa Electric's 2006 hedging activities resulted in a net loss of $54 million; however, Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. As shown in the table on page 3 of the Risk Management Report filed on April 2, 2007, the difference between the high and low natural gas market prices was $7.23 per MMBtu; however, the natural gas hedge price difference was reduced to $1.21 per MMBtu. Thus, Tampa Electric achieved a significant reduction in natural gas price volatility for its customers by using financial hedges.

Q. Did Tampa Electric enhance its physical hedging activities for natural gas?

A. Yes, Tampa Electric has been improving its physical access to natural gas supply since Bayside Power Station began commercial operation in 2003. Tampa Electric diversified its receipt points for natural gas along the Gulf Coast, acquired pipeline capacity on the Gulfstream interstate pipeline to supplement its capacity on Florida Gas Transmission and entered into a natural gas storage

arrangement with Bay Gas Storage. In 2006, Tampa Electric implemented additional physical hedging for natural gas by increasing storage capacity to 225,000 MMBtu. The storage provides Tampa Electric with improved access to "intraday" natural gas to meet operational needs, provides improved hurricane coverage, allows the company to cost-effectively manage swings in gas supply needs during extreme weather conditions, weekends and holidays.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports. Nucleus is also used for contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2006?

A. Tampa Electric's incremental natural gas hedging activities protected customers from price volatility for [redacted] of the natural gas used in the company's generating stations. The net result of natural gas hedging activity in 2006 was a loss of $54 million, when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2006?

A. No, Tampa Electric did not use financial hedges for other commodities primarily because of its fuel mix.

Tampa Electric's generation is comprised mostly of coal and natural gas. The price of coal is relatively stable compared to the prices of oil and natural gas. In addition, financial hedging instruments for the primary coal Tampa Electric burns, high sulfur Illinois Basin coal, do not exist.

Tampa Electric consumes a small amount of oil. However, its low and erratic usage pattern makes price hedging of oil consumption impractical; therefore, the company did not use financial hedges for oil.

The company did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist in Florida.

Q. Did Tampa Electric use physical hedges for other commodities?

A. Yes, Tampa Electric used physical hedges in managing its coal supply. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. In previous years Tampa Electric has been able to take advantage of contractual volume flexibility to seek out favorable spot market pricing. Those agreements have expired, and volume flexibility was not available for the replacement contracts.

Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Commission Order No. PSC-02-1484-FOF-EI, in Docket No.

011605-EI states:

> "Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas."

Therefore, Tampa Electric's request for recovery is in accordance with the aforementioned order.

Q. Are you requesting recovery of incremental hedging O&M costs?

A. Yes, Tampa Electric requests recovery of $210,649 that the company incurred as incremental O&M expenses. The Commission, in Order No. PSC-02-1484-FOF-EI, states:

> "Each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative

financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006 or the time of the utility's next rate proceeding, whichever comes first."

Tampa Electric established its base year expenses according to the portion of the employee's time and related expenses for hedging in 2001. The 2006 actual costs were then calculated using the same methodology. Tampa Electric's calculation of the incremental expenses as well as base year expenses and 2006 actual expenses are shown in my Exhibit No._____ (JTW-1).

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 9/4/07

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 2008 risk management plan submitted concurrently in this docket. Finally, I will present the calculation of waterborne transportation costs submitted for recovery.

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 and 031033-EI as well as the annual fuel and purchased cost recovery dockets from 2001 through 2007. I have also recently filed testimony in Tampa Electric's petition to determine need for the Polk Unit 6 electrical power plant, Docket No. 070467-EI. 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.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes. Exhibit No. ____ (JTW-2) describes the calculation of the 2006 waterborne transportation costs disallowance.

2008 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2008?

A. In 2008, Tampa Electric expects its fuel mix to be comparable to 2007. In 2008, natural gas-fired and coal-fired generation is expected to be 45 percent and 55 percent of total generation, respectively. Generation from No. 2 oil and No. 6 oil is less than one percent of the total 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. The company's portfolio consists of a blend of pre-arranged base load, intermediate and swing supply along 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 trades for physical natural gas supply with many approved counterparties, enhancing liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indexes, increasing portfolio diversification.

Tampa Electric 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 minimize costs to its customers. Additionally, Tampa Electric's risk management activities improve the company's natural gas procurement activities by reducing natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas

transportation arrangements.

A. Tampa Electric currently receives natural gas transportation to its plants on the Florida Gas Transmission ("FGT") pipeline. The company diversified its transportation assets when it entered into a cost-effective contract with Gulfstream Natural Gas Pipeline, LLC ("Gulfstream") that will provide firm natural gas transportation directly to Tampa Electric's H. L. Culbreath Bayside Station ("Bayside Station") from Manatee County, via a 28-mile lateral pipeline. Tampa Electric anticipates completion of the lateral pipeline in early 2008. The transportation agreement with Gulfstream adds a second pipeline to Tampa Electric's capacity portfolio and improves the company's ability to meet natural gas hourly and daily 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. When Bay Gas Storage completes expansion of its facilities in 2008, Tampa Electric will increase its storage capacity to 750,000 MMBtu, which provides enhanced access to natural gas in the event of severe weather or other events that disrupt

supply. 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 in FGT Zone 3 and provide access to lower priced gas supply.

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 coal, petroleum coke, and lower sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as sulfur content, Btu/lb, ash, fusion temperature and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, price, availability, and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bilateral, long-, intermediate-, and short-term contracts 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 in market monitoring and in 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 by displacing higher cost options.

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2008 delivery?

A. Yes, it has. To mitigate price volatility and ensure reliability of supply, Tampa Electric has contracted for a significant portion of its expected coal needs through bilateral agreements with coal suppliers. Approximately two thirds of the company's expected 2008 coal requirements are already under contract. Tampa Electric has also entered into contracts for approximately [redacted] percent of the company's expected natural gas needs for the winter of 2007 and through 2008.

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 monitors and adjusts fuel volumes it accepts within contractually allowed maximum and minimum amounts in accordance with the price of fuel available on the spot market, to take advantage of the lowest available prices. 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.

Projected 2008 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 PIRA Energy Group, Hill & Associates, 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, blended with current PIRA price forecasts form the basis of the natural gas, No. 6 oil and No. 2 oil price forecasts. The commodity price projections are adjusted to incorporate expected transportation costs and quality adjustments. These adjustments are specific to the power plants to which the fuel will be delivered and the locations from which it is transported.

Coal prices and coal transportation prices are projected using information from industry-recognized consultants 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, associated transportation costs, inventory effects, and analysis performed on coal inventory.

Q. How do the 2008 projected fuel prices compare to the fuel prices projected for 2007?

A. The entire industry, including Tampa Electric, has experienced rising fuel prices since 2003, and projected fuel prices for 2008 are expected to remain at these levels due to the demand on natural resources. The global economy and the increasing industrialization of countries like China have

affected the global balance of natural resources such as natural gas, oil, and coal. In particular, crude oil prices have soared to well over $70 per barrel, due to factors such as the turmoil in the Middle East, fears of additional hurricane activity near the U.S. coastline and growth in demand for refined products. Similarly, the transportation costs for commodities have increased as the fuel used in transportation increased in price.

Q. What are the market drivers of the expected 2008 increase in the price of natural gas?

A. Of the fuels utilized by Tampa Electric, natural gas has experienced the greatest increase in price over the last several years. In addition to price pressures from natural gas and crude oil, the market drivers include increased demand from natural-gas fired generation, declining natural gas production in North America, delayed liquefied natural gas projects, concerns about the adequacy of natural gas in storage, and concerns about production losses due to tropical storm activity. A return to a normal or more active storm season in the summer of 2007 coupled with normal winter weather in 2007/2008 is expected to increase natural gas prices in 2008 compared to 2007.

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

A. Coal prices correlate with the prices of other fuels since coal mining utilizes petroleum products, steel, and lumber in its production processes; therefore, coal prices have increased in conjunction with increases in the prices of these products and other fuels. Costs of SO_2 allowances also contribute to the higher prices for lower sulfur coals and coal in general. Thus, Tampa Electric expects higher coal prices to continue through 2008. Fortunately, Tampa Electric's use of high sulfur coal from the Illinois Basin in its scrubbed units at Big Bend has shielded Tampa Electric from some of the extreme price volatility experienced in low sulfur coal prices.

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

A. Yes. Tampa Electric has provided an analysis in which 2008 natural gas prices are 35 percent higher or lower than the base forecast. The causes of potential price uncertainty include weather, political turmoil, global economics, commodity production, and transportation issues.

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 simultaneously in this docket.

Q. Does Tampa Electric's risk management strategy help to mitigate natural gas price risk?

A. Yes. To help protect customers from price volatility, Tampa Electric may purchase over-the-counter natural gas swaps, options and collars. A swap is a financial derivative that provides a "fixed for floating" position. Tampa Electric, the buyer pays a fixed price for the natural gas, which has a floating value until cash settlement. Swaps allow Tampa Electric to lock in known natural gas prices and avoid upward price volatility. The transaction costs of swaps are embedded in the price of the commodity.

Options give Tampa Electric the right, but not the obligation, to buy (call) or sell (put) natural gas at a predetermined price for a given future month. Tampa Electric pays a premium at the time of the option purchase for this

right.

Collars are combinations of call options (caps) and put options (floors) that limit prices within a certain range. An option is the right, but not the obligation, to buy (call) or sell (put) natural gas at a pre-determined price. With a collar, the company knows that its future prices will remain within the predetermined boundaries established by the call and put options.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2007 and 2008 natural gas requirements?

A. Yes. Tampa Electric has hedged a significant portion of its 2007 natural gas supply needs and a portion of its expected 2008 natural gas supply needs. 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 is provided in the Risk Management Plan.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2007 and 2008 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.

Q. Have recent increases in the market price of natural gas affected the percentage of Tampa Electric's natural gas requirements that the company has hedged or plans to hedge?

A. No. The volume hedged is driven primarily by expected natural gas consumption levels and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a prescribed percentage range. Price is not a component of the current plan since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through August 2007 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.

Coal Transportation Costs

Q. Did Tampa Electric calculate the waterborne transportation costs submitted for cost recovery in accordance with the Commission's Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999"), issued in Docket No. 031033-EI on October 12, 2004?

A. Yes. The waterborne transportation costs that Tampa Electric is seeking to recover are the adjusted rates per ton for each upriver terminal as well as the adjusted ocean barge transportation rate. The company calculates the adjusted rates as described in Order No. 04-0999. The river rate is adjusted using the following formula:

$$\frac{\text{(Weighted average rate per ton for all upriver terminals - \$1/ton)}}{\text{Weighted average rate per ton for all upriver terminals}} \times \text{Contract rate for specific upriver terminal}$$

The ocean rate is reduced by [redacted] per ton for shipments from the Davant, Louisiana terminal and [redacted] per ton for petroleum coke shipments from Texas, as prescribed by the Commission order.

For 2006, Tampa Electric's adjustment to its total waterborne transportation costs totaled $15,314,802. The total 2006 adjustment recorded in Tampa Electric's final true-up filing, submitted in this docket on March 1, 2007, was calculated using the actual tons of coal and petroleum coke shipped in 2006 and the methodology required by Order No. 04-9999. These calculations are shown in Exhibit No. ____ (JTW-2), Document No. 1. Therefore, Tampa Electric's 2006 adjusted coal transportation costs are appropriate for recovery through the Fuel and Purchased Power Cost Recovery Clause.

Likewise, the expected 2007 and 2008 waterborne transportation costs have been adjusted using this same methodology according to Order No. 04-0999 and will be revised to reflect the actual tons shipped and associated calculated disallowances as part of the normal true-up process. Accordingly, it is also appropriate for Tampa Electric to recover its allowable 2007 and 2008 projected transportation expenses included in the fuel clause for coal transportation.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Wehle, could you summarize your testimony for us?

A Yes. Good afternoon, Commissioners. My name is Joann Wehle. I'm the Director of Wholesale Marketing and Fuels for Tampa Electric Company.

My direct testimony addresses a variety of fuel-related issues, including the mitigation of price risk associated with natural gas purchases. As noted in the company's risk management plan filings with the Commission, our hedging plan approved by our company's risk authorizing committee, describes the company's strategies to reduce natural gas price volatility using a disciplined nonspeculative approach for our customers.

Since the inception of our hedge program, Tampa Electric has reviewed its position and in 2005 enhanced features of the plan to increase the length and volumes that can be hedged under the plan. The company has consistently applied the plan to our natural gas needs for the benefit of our customers by limiting exposure to the volatile nature of natural gas price swings in the marketplace.

This concludes my summary.

Q Ms. Wehle, did you also sponsor what has been marked as Exhibit 51 in this proceeding?

A Yes.

MR. BEASLEY: Thank you.

We tender Ms. Wehle for questions.

CHAIRMAN EDGAR: Any questions on cross? No. No. Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Wehle, what do you project your experience will be on gains and losses for the year 2007?

A Year-to-date through September of this year we had experienced a $45 million loss associated with that, and by the end of the year we anticipate that we will be at roughly a $54 million loss.

Q You heard Mr. Ball use the mark-to-market, what does that term mean?

A Basically, it is the settlement of your derivatives where they are actually marked to whatever the current market is at that settlement date.

Q And that's important for derivatives that go out a number of years into the future and you haven't reached a strike date on those derivatives yet?

A It is important for derivatives that go out into the future. Not just years into the future, but any time into the future.

Q If it's not confidential, how far out into the future does your company go when it buys financial hedges?

A That is not confidential. We hedge 24 months out

into the future.

Q So when you project a loss for the year, you evaluate the contracts that may mature two years from now and see what their present value is in making that determination?

A No, sir. In evaluating where we would stand at the end of the year, we would look through our hedging program through the end of the year, not out into the future beyond that.

Q But you look at a contract that may be two years in the future to determine the value of that contract as part of your loss, don't you?

A For that given time frame those would be considered unrealized losses. What we talked about in your first set of questions are where did we anticipate our realized losses would be for the year.

Q I see. Do you know what your unrealized losses are for 2007 to date, as opposed to your realized losses?

A Again, our realized losses to date are $45 million through September, and we anticipate another $9 million of unrealized losses at this point that will be realized at the end of December.

Q And those losses are determined by looking at the futures market price for a contract of natural gas?

A That is correct.

Q And where do you find that futures contract price?

A On the NYMEX exchange.

Q And that's the only exchange you use?

A That's correct.

Q Do you engage in buying and selling hedges through the NYMEX exchange, or do you do it with bilateral contracts?

A We do it with bilateral. We purchase bilateral contracts hedges. We do not sell hedges.

Q There's no circumstance under which you would sell a hedge?

A The only circumstance that we would look at doing that is if we were trying to enter into some kind of a collar where you would probably buy a ceiling and sell a floor.

Q And why do you do that?

A In order to collar the range that your prices can move within.

Q Do you know what your company's policy is with respect to why you use bilateral contracts with banks rather than dealing through the open market exchange?

A Again, that would probably be more appropriate for our risk authorizing director, or risk oversight director to discuss. But I do agree with, as Mr. Yupp had stated, there is a lot of liquidity in a bilateral market.

Q He called it the over-the-counter market. Do you call it that as well?

A Yes, we do.

Q Are you familiar at all with your company's conservation programs?

A No, I'm not.

Q Are you familiar with price elasticity as it applies to your customers?

A I understand how appropriate price signals could incentivize someone to change their habits, if that's your question.

Q That's correct. But my question relates to are you familiar with the price elasticity of the customers of your company with respect to purchasing electricity?

A I'm not familiar with that, no.

MR. McWHIRTER: That's all the questions I have of this witness.

CHAIRMAN EDGAR: Other questions from staff?

MR. YOUNG: No questions.

MS. BENNETT: Oh. I'm sorry, I do have a couple of questions.

CHAIRMAN EDGAR: Okay. Price signaling problems here. Go ahead.

CROSS EXAMINATION

BY MS. BENNETT:

Q Ms. Wehle, I'm given to understand that TECO's policy for hedging is also for price stability, is that correct?

A It's to reduce volatility.

Q Price volatility. We heard Mr. Yupp earlier talk about inter versus intra-year stability. Is TECO focused on inter or intra-year stability for price volatility for its customers?

A We are interested in both. Given the fact that our program spans 24 months, we are interested in both intra and inter-price stability.

Q You previously testified that in 2007 it was a 54 million anticipated loss. And what is your 2006 loss?

A If you'll give me a minute, I can -- our 2006 actual realized loss was also $54 million.

MS. BENNETT: I have no other questions of this witness.

CHAIRMAN EDGAR: Commissioners, any questions for this witness?

No.

Any redirect?

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Wehle, do you know if the company expects to realize an unrealized gain or loss for 2008?

A Yes. We anticipate that we will have gains in 2008.

MR. BEASLEY: That is all the redirect I have. I would like to move the admission of Exhibits 43 and 44, and I believe that staff has already moved 51.

CHAIRMAN EDGAR: Exhibit 43 and 44 will you moved into the record at this time.

MR. BEASLEY: Thank you.

(Exhibits 43 and 44 admitted into the record.)

CHAIRMAN EDGAR: And the witness can be excused. Thank you.

MR. BEASLEY: Thank you. Madam Chair, our next two witnesses have also been excused. They are Mr. Carlos Aldazabal, who has filed true-up and projection prepared direct testimony. I would ask that his testimonies be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of Witness Aldazabal will be entered into the record as though read.

MR. BEASLEY: Thank you. And I would move his Exhibits 34 through 40 as listed on the Composite Exhibit List.

CHAIRMAN EDGAR: And accompanying Exhibits 34, 35, 36, 37, 38, 39, and 40 will also be moved into the record at this time.

(Exhibits 34 through 40 admitted into the record.)

MR. BEASLEY: I would also ask that Mr. David Knapp's true-up and projection testimonies be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of Witness Knapp will be entered into the record as though read.

MR. BEASLEY: And I would move the admission of the

exhibits that witness sponsors, which are Exhibits 41 and 42.

CHAIRMAN EDGAR: Exhibits 41 and 42 will be entered into the record at this time.

(Exhibits 41 and 42 admitted into the record.)

MR. BEASLEY: And Tampa Electric has completed its case.

CHAIRMAN EDGAR: Thank you.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 3/1/07

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 Manager, 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 from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 12 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 was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2006 through December 2006 for both the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause ("capacity clause"). I also present the wholesale incentive benchmark for January 2007 through December 2007 as well as the actual incremental operation and maintenance ("O&M") security alert and hedging expenses for the period January 2006 through December 2006.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business

in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (CA-1), consisting of four documents which are described in my testimony, was prepared under my direction and supervision.

CAPACITY COST RECOVERY CLAUSE

Q. What is the final true-up amount for the Capacity Cost Recovery Clause for the period January 2006 through December 2006?

A. The final true-up amount for the capacity clause for the period January 2006 through December 2006 is an under-recovery of $2,666,246.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2006

Through December 2006", provides the calculation for the final under-recovery of $2,666,246. The actual capacity cost under-recovery, including interest was $3,627,197 for the period January 2006 through December 2006 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $960,951 actual/estimated under-recovery approved in Order No. PSC-06-1057-FOF-EI issued December 22, 2006 in Docket No. 060001-EI, results in a final under-recovery for the period of $2,666,246 as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2008 through December 2008.

Q. What is the estimated effect of this $2,666,246 under-recovery for the January 2006 through December 2006 period on residential bills during January 2008 through December 2008?

A. The $2,666,246 under-recovery will increase a 1,000 kWh residential bill by approximately $0.16.

Incremental Security Alert Expenses

Q. What were Tampa Electric's actual 2006 incremental O&M costs for security alert expenses as a result of the

events of September 11, 2001?

A. As shown in Document No. 1, Page 2 of 4, line 4, Tampa Electric incurred $587,570 for incremental O&M security expenses for measures taken by the company to protect its generating facilities for the period January 2006 through December 2006.

Q. How did the actual incremental O&M security costs compare to the costs included in the 2006 Actual/Estimated capacity filing?

A. Actual incremental O&M security costs were $17,086 lower than projected in the 2006 Actual/Estimated capacity filing.

Q. Is Tampa Electric's methodology used to calculate incremental security costs consistent with the one described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003.

A. Yes. To calculate incremental security costs, Tampa Electric compared its actual total O&M security expenses to baseline expenses or pre-9/11 annual security expenses. All incremental O&M security costs were

separately identified and any savings gained through the implementation of any security related projects were credited pursuant to the method described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Q. What is the final true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2006 through December 2006?

A. The final fuel clause true-up for the period January 2006 through December 2006 is an under-recovery of $2,349,844. The actual fuel cost under-recovery, including interest, was $160,126,823 for the period January 2006 through December 2006. This $160,126,823 amount, less the $157,776,979 actual/estimated under-recovery amount approved in Order No. PSC-06-1057-FOF-EI, issued December 22, 2006 in Docket No. 060001-EI results in a net under-recovery amount for the period of $2,349,844.

Q. What is the estimated effect of the $2,349,844 under-recovery for the January 2006 through December 2006 period on residential bills during January 2008 through December 2008?

A. The $2,349,844 under-recovery would increase a 1,000 kWh residential bill by approximately $0.12.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2006 Through December 2006". It shows the calculation of the final fuel under-recovery of $2,349,844.

Line 1 shows the total company fuel costs of $965,306,536 for the period January 2006 through December 2006. The jurisdictional amount of total fuel costs, which includes the Commission ordered waterborne coal transportation expense disallowance, is $917,646,491, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $43,361,999 under-recovered fuel costs for the period, combined with the interest, true-up collected and the prior period true-up shown on lines 5, 6 and 7, respectively, constitute the actual under-recovery of $160,126,823 shown on line 8. The

$160,126,823 actual under-recovery amount less the $157,776,979 actual/estimated under-recovery amount shown on line 9, results in a final $2,349,844 under-recovery amount for the period January 2006 through December 2006 as shown on line 10.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual vs. Original Estimates for the Period January 2006 Through December 2006", shows the calculation of the actual under-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2006 through December 2006?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $10,919,677 more than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2006 through December 2006?

A. As shown on line C3 of Document No. 3, the company collected $41,164,789 or 4.5 percent less jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 through A9 for the months of January 2006 through December 2006. Also included is a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, A9 and A12 for the period January 2006 through December 2006.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2007, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2007 benchmark is $895,111, which is the three-year average of $1,049,937, $878,238, and $757,156 actual gains on non-separated wholesale sales, excluding emergency sales, for 2004, 2005 and 2006, respectively.

Hedging Transaction and Incremental O&M Costs

Q. Did Tampa Electric prudently incur incremental O&M expenses for initiating and/or maintaining its non-speculative financial hedging program in 2006?

A. Yes. Tampa Electric prudently incurred $210,649 for incremental O&M hedging expenses. An itemization of the incremental O&M expenses by category will be provided as an exhibit to the direct testimony of Tampa Electric witness J. T. Wehle, which will be filed April 5, 2007 in this docket.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 8/6/07

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 Manager, 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 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 12 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I

was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2007 through December 2007 fuel and purchased power and capacity true-up amounts to be recovered in the January 2008 through December 2008 projection period. My testimony addresses the recovery of fuel and purchased power costs, capacity costs and incremental O&M security costs for the year 2007, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2008 fuel and purchased power costs and capacity cost recovery factors.

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

A. Yes. I have prepared Exhibit No. ____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased

power cost recovery true-up amount for the period January 2007 through December 2007. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2007 through December 2007. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2008 through December 2008 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2008 through December 2008 is an over-recovery of $15,392,712.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2008 through December 2008 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2008 is the sum of the final true-up amount for the period January 2006 through December 2006 and the actual/estimated true-up

amount for the period January 2007 through December 2007.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2006?

A. The true-up was an under-recovery of $2,349,844. The actual fuel cost under-recovery, including interest and the waterborne transportation cost adjustment, was $160,126,823 for the period January 2006 through December 2006. The $160,126,823 amount, less the actual/estimated under-recovery amount of $157,776,979 approved in Order No. PSC-06-1057-FOF-EI issued December 22, 2006 in Docket No. 060001-EI results in a net under-recovery amount for the period of $2,349,844.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2007 through December 2007?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $17,742,556 for the January 2007 through December 2007 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2008 through December 2008 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2008 through December 2008 is an under-recovery of $23,796,584 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2008 through December 2008 capacity cost recovery factors?

A. Tampa Electric calculated the net true-up amount to be recovered in 2008 in the same manner as previously described for the fuel and purchased power cost recovery net true-up amount. The net true-up amount to be recovered in the 2008 capacity cost recovery factors is the sum of the final true-up amount for 2006 and the actual/estimated true-up amount for January 2007 through December 2007.

Q. What did Tampa Electric calculate as the final capacity

cost recovery true-up amount for 2006?

A. The true-up was an under-recovery of $2,666,246. The actual capacity cost under-recovery including interest was $3,627,197 for the period January 2006 through December 2006. The $3,627,197 amount, less the actual/estimated under-recovery amount of $960,951 approved in Order No. PSC-06-1057-FOF-EI issued December 22, 2006, in Docket No. 060001-EI results in a net under-recovery amount for the period of $2,666,246 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2007 through December 2007?

A. The actual/estimated true-up amount is an under-recovery of $21,130,338 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. Are incremental security O&M costs included for cost recovery through the capacity clause?

A. Yes. Given the Commission's previous authorization to recover incremental security O&M costs arising as a

result of the extraordinary circumstances of the terrorist attacks of September 11, 2001, Tampa Electric's incremental security O&M costs are included for recovery through the capacity clause. Therefore, as shown on Exhibit No. ____ (CA-2), Document No. 2, Page 4 of 5 the company requests recovery of $972,371, after jurisdictional separation, for 2007 actual/estimated incremental security O&M expenses.

Q. How does this amount vary from the original projection?

A. The actual/estimated incremental security O&M expenses are $303,609 greater than the original projected costs. The variance is primarily due to the inclusion of incremental costs associated with North American Electric Reliability Council ("NERC") Cyber Security Standards CIP-002-1 through CIP-009-1, effective June 1, 2006. The NERC standards were implemented to address concerns with cyber security as a result of the September 11, 2001 terrorist attacks and are not presently recovered through base rates.

Q. Why were compliance costs associated with NERC Cyber Security Standards not included in the 2007 projection filing?

A. As previously stated the NERC standards became effective June 1, 2006, with an implementation schedule of 2007 through 2010. At the time of the 2007 projection filing Tampa Electric had not completed an analysis to determine the requirements and associated costs to implement the NERC standards. The detailed analysis was completed in the fourth quarter of 2006, and costs associated with the standards began to occur in the second quarter of 2007.

Q. Did Tampa Electric evaluate and calculate its incremental "post-9/11" security project costs according to the detailed guidelines provided in Order No. PSC-03-1461-FOF-EI filed in Docket No. 030001-EI on December 22, 2003?

A. Yes. The first test is to determine if the company has any O&M expenses for incremental security projects included in the Minimum Filing Requirements ("MFR") that established its current base rates and to remove any such expenses from the calculation of incremental expenses. None of Tampa Electric's post-9/11 increased security costs were included in MFRs that established its base rates as the company's last base rate proceeding was approved in 1993, before the terrorist attacks occurred. The second test is to identify any project costs that are

reflected elsewhere in the company's base rates and remove them. Tampa Electric identified such project costs for security and credited the savings to the total incremental security expense. Finally, the third test is to determine if the project will result in any offsetting O&M savings and credit any savings to the project to reduce its total cost. Tampa Electric has evaluated its incremental security O&M expenses for related O&M savings and credited the savings against total incremental security O&M expenses. The calculation of incremental security O&M costs is shown on Exhibit No. ____ (CA-2), Document No. 2, page 4 of 5.

Q. Were Tampa Electric's base year "post-9/11" security costs adjusted for retail energy sales growth as required by Order No. PSC-03-1461-FOF-EI?

A. Yes. After adjusting the base year total by energy sales growth, the baseline that should be used to calculate 2007 incremental security costs is $2,232,959. The calculation of the baseline security O&M expense amount is shown on Exhibit No. ____ (CA-2), Document No. 2, page 4 of 5.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 9/4/2007

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 Manager, 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 12 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I

was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

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 and the projected wholesale incentive benchmark for January 2008 through December 2008. In addition, I will address the 2008 projected incremental security costs as a result of the September 11, 2001 attacks as well as the appropriate base amount and period for calculating incremental security costs. 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 2008.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of two documents, was prepared under my direction and

supervision. Document No. 1 of Exhibit No. ____ (CA-3) is furnished as support for the projected capacity cost recovery factors. 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 2008 through December 2008 as well as Schedule H1 for January through December, 2005 through 2008.

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, Projected Capacity Cost Recovery.

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.

The company is also requesting recovery of incremental security expenses as a result of the events of September 11, 2001, as authorized in previous years. As shown in Exhibit No. ____ (CA-3), Document No. 1, Tampa Electric requests recovery of $1,997,986, after jurisdictional separation, for estimated expenses in 2008.

Q. Were Tampa Electric's base year "post-9/11" security costs adjusted for retail energy sales growth as required by Order No. PSC-03-1461-FOF-EI, filed in Docket No. 030001-EI on December 22, 2003?

A. Yes. Tampa Electric's 2007 actual adjusted base year total security O&M costs were $2,232,959. After adjusting this amount for expected energy sales growth, a $2,293,026 baseline was used to calculate Tampa Electric's 2008 incremental security costs. This calculation is shown on Exhibit No. ____ (CA-3), Document No. 1, page 4 of 5.

Q. Please summarize the proposed capacity cost recovery factors by rate schedule for January 2008 through December 2008.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kWh)
Average Factor	0.428
RS	0.517
GS and TS	0.496
GSD, EV-X	0.415
GSLD and SBF	0.353
IS-1, IS-3, SBI-1, SBI-3	0.032
SL-2, OL-1 and OL-3	0.063

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 5.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.428 cents per kWh compare to the factor for January 2007 through December 2007?

A. The proposed capacity cost recovery factor is 0.157 cents per kWh (or $1.57 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.271 cents per kWh for the January 2007 through December 2007 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the base fuel and purchased power cost recovery factor for the year 2008?

A. The appropriate amount for the 2008 period is 5.219 cents per kWh before the normal application of factors that adjust for variations in line losses. Schedule E1 of Exhibit No. ____ (CA-3), Document No. 2, Fuel Projection, shows the appropriate value for the total fuel and purchased power cost recovery factor as projected for the period January 2008 through December 2008.

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 $1,439,819, 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 2007 through December 2007 period. The net true-up amount for this period is an over-recovery of $15,392,712.

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 2008 through December 2008.

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

A. Schedule E1-E presents the standard, on-peak and off-peak fuel adjustment factors after adjusting for variations in line losses.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by rate schedule for January 2008 through December 2008.

A.

Rate Schedule	**Fuel Charge Factor (cents per kWh)**	
Average Factor	5.219	
RS, GS and TS	5.241	
RST and GST	6.344	(on-peak)
	4.668	(off-peak)
SL-2, OL-1 and OL-3	4.920	
GSD, GSLD, and SBF	5.221	
GSDT, GSLDT, EV-X and SBFT	6.320	(on-peak)
	4.650	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	5.084	

Rate Schedule	Fuel Charge Factor (cents per kWh)
IST-1, IST-3, SBIT-1, SBIT-3	6.154 (on-peak)
	4.528 (off-peak)

Q. How does Tampa Electric's proposed average fuel adjustment factor of 5.219 cents per kWh compare to the average fuel adjustment factor for the January 2007 through December 2007 period?

A. The proposed fuel charge factor is 0.678 cents per kWh (or $6.78 per 1,000 kWh) lower than the average fuel charge factor of 5.897 cents per kWh for the January 2007 through December 2007 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2008 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events. These are 1) the company's wholesale purchases; and 2) Tampa Electric's recovery of waterborne coal transportation costs as required in Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999") issued October 12, 2004 in Docket No. 031033-EI.

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

A. Tampa Electric entered into or continued several cost-effective purchase agreements with Progress Energy Florida, Reliant Energy, Okeelanta and Calpine Energy Services, L.P. The purchases improve supply reliability for retail ratepayers in 2007 and 2008 at reasonable and prudent costs. The direct testimony of Tampa Electric witness B. F. Smith describes the purchases and demonstrates that the costs associated with the purchased power agreements are prudent and appropriate for recovery through the Fuel and Purchased Power and Capacity Cost Recovery Clauses.

Tampa Electric also intends to enter into purchase agreements to replace lost generation capacity during the planned 2008 Big Bend scrubber outage.

Q. Please describe the second event.

A. The calculation of the 2008 fuel and purchased power factor reflects Tampa Electric's recovery of waterborne coal transportation costs as required in Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999") issued October 12,

2004 in Docket No. 031033-EI. Tampa Electric adjusted fuel expense for the disallowance of costs required by FPSC Order No. 04-0999, which specifies that a portion of the costs incurred by Tampa Electric under the current contract with TECO Transport is not reasonable for cost recovery. The annual adjustment to the company's fuel cost recovery is projected to be $15,315,380 in 2008. This adjustment will be trued up to reflect the actual tons shipped and associated calculated disallowances as part of the normal true-up process.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2008?

A. The company's projected 2008 benchmark is $1,181,573, which is the three-year average of $878,238, $757,156 and $1,909,325 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2005, 2006 and 2007 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2008 from non-separated wholesale sales to exceed its 2008 wholesale incentive benchmark?

A. Yes. Tampa Electric anticipates that sales will exceed the projected benchmark by $1,005,727 of which 80 percent or $804,582 will flow back to ratepayers.

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 $0.16 beginning January 2008. 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 the first billing cycle for January 2008.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 9/4/2007
REVISED: 10/11/2007

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

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

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department,

where I led a team that provides engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities. In December 2006, I transferred to the Operations Planning area of the Resource Planning, and in September 2007, I was promoted to Supervisor. I provide engineering and technical support for the daily operations of Tampa Electric's generating facilities.

Q. What is the purpose of your testimony?

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

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

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

GPIF Calculations

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

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

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

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

Q. Did Tampa Electric identify any outages as outliers?

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

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2008 period. A range of potential improvements and degradations were determined for each of these parameters.

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

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

To give an example for the 2008 period, the projected

Equivalent Unplanned Outage Factor for Big Bend Unit 2 is 13.96 percent, and the Planned Outage Factor is 8.74 percent. Therefore, the target equivalent availability factor for Big Bend Unit 2 equals 77.29 percent or:

$$100\% - [(13.96 + 8.74\%)] = 77.29\%$$

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

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

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

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

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

EAF_{MAX} = 100% - [0.8 (13.96%) + 0.95 (8.74%)] = 80.52%

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

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

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

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

Again, continuing with the Big Bend Unit 2 example,

EAF_{MIN} = 100% - [1.4 (13.96%) + 1.10 (8.74%)] = 70.83%

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

REVISED 10/11/2007

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

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

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

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

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

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

A. Graphs for both factors, adjusted for planned outages, versus time were prepared. Monthly data and 12-month ending average data were recorded. For each unit the most current 12-month ending value, June 2007, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 22.62 percent for Big Bend Unit 4. The Equivalent Unplanned Outage Factor for Big Bend Unit 4 is verified by the data shown on page 17, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

REVISED 10/11/2007

$$EUOF = \frac{(1,533 + 454)}{8,784} \times 100 = 22.62\%$$

Relative to Big Bend Unit 4, the EUOF of 22.62 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 23.38 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 3.83 percent. Therefore, the target equivalent availability for this unit is 72.79 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 13.96 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 8.74 percent. Therefore, the target equivalent availability for this unit is 77.29 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 26.00 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is

26.50 percent. Therefore, the target equivalent availability for this unit is 47.50 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 22.62 percent. The unit will have a planned outage in 2008, and the Planned Outage Factor is 3.83 percent. Therefore, the target equivalent availability for this unit is 73.55 percent.

Polk Unit 1

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

Bayside Unit 1

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

Bayside Unit 2

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

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 68.80 percent is shown on Page 5 of Document No. 1. This target is similar to the January through December 2006 GPIF period.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since the units in the GPIF are usually baseload units, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the

Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 4 on page 17 of Document No. 1. During the months of January through October and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the month of November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to a scheduled planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit parameters, which are subsequently converted to factors. Therefore,

$$FOF + MOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data

required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

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

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for

each unit. This information is shown on pages 33 through 39 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2008 period.

A. The heat rate target for Big Bend Unit 1 is 10,908 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±313 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,693

Btu/Net kWh with a range of ±297 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,657 Btu/Net kWh, with a range of ±695 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,837 Btu/Net kWh with a range of ±627 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,607 Btu/Net kWh with a range of ±822 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,320 Btu/Net kWh with a range of ±129 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,359 Btu/Net kWh with a range of ±117 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting

factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $1,115,479,000 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 $49,686,335 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit 1, the weighting factor for equivalent availability is 11.54 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the

equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 1, page 7, if the unit operates at 77.7 percent equivalent availability, fuel savings would equal $5,731,400, 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 $49,686,335. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

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

Q. Are there any other constraints set forth by the

Commission regarding the magnitude of incentive dollars?

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

Q. Please summarize your testimony on the GPIF.

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

$$GPIP = (0.1154\ EAP_{BB1} + 0.0422\ EAP_{BB2} + 0.1289\ EAP_{BB3} + 0.1266\ EAP_{BB4} + 0.0957\ EAP_{PK1} + 0.0324\ EAP_{BAY1} + 0.0023\ EAP_{BAY2} + 0.0340\ HRP_{BB1} + 0.0370\ HRP_{BB2} + 0.0540\ HRP_{BB3} + 0.0841\ HRP_{BB4} + 0.0642\ HRP_{PK1} + 0.0881\ HRP_{BAY1} + 0.0952\ HRP_{BAY2})$$

Where:

GPIP = Generating Performance Incentive Points.

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

Polk Unit 1 and Bayside Units 1 and 2.

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

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

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

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department,

where I led a team that provides engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities. In December 2006, I transferred to the Operations Planning area of the Resource Planning department, where I provide engineering and technical support for the daily operations of Tampa Electric's generating facilities.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the GPIF for the period January 2006 through December 2006. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (DRK-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2006 - December 2006, True-up" is consistent with the GPIF Implementation Manual previously approved by the

Commission. In addition, Document No. 2 provides the company's Actual Unit Performance Data for the 2006 period.

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

A. Five of the company's units are included. They are Big Bend Station Units 1, 2, 3, and 4 and Polk Station Unit 1.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2006 through December 2006 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 28. Based upon 2.617 GPIF points, the result is a reward amount of $1,439,819 for the period.

Q. Please proceed with your review of the actual results for the January 2006 through December 2006 period.

A. On Document No. 1, page 3 of 28, the actual average common equity for the period is shown on line 14 as $1,399,297,816. This produces the maximum penalty or

reward amount of $5,501,411 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the five units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 28, column 2, directly applicable to the GPIF table?

A. No. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 28. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 1,344.0 planned outage hours were originally scheduled for 2006. Actual outage activities required 1,621.4 planned outage hours. Consequently, the actual equivalent availability of 55.2% is adjusted to 57.4% as shown on Document No. 1, page 7 of 28.

Big Bend Unit No. 2

On this unit, 336.0 planned outage hours were originally scheduled for 2006. Actual outage activities required 0.0 planned outage hours. Consequently, the actual equivalent availability of 82.8% is adjusted to 79.7% as shown on Document No. 1, page 8 of 28.

Big Bend Unit No. 3

On this unit, 840.0 planned outage hours were originally scheduled for 2006. Actual outage activities required 695.7 planned outage hours. Consequently, the actual equivalent availability of 61.9% is adjusted to 60.8% as shown on Document No. 1, page 9 of 28.

Big Bend Unit No. 4

On this unit, 504.0 planned outage hours were originally scheduled for 2006. Actual outage activities required 728.3 planned outage hours. Consequently, the actual

equivalent availability of 74.7% is adjusted to 76.7% as shown on Document No. 1, page 10 of 28.

Polk Unit No. 1

On this unit, 384.1 planned outage hours were originally scheduled for 2006. Actual outage activities required 1,054.6 planned outage hours. Consequently, the actual equivalent availability of 78.8% is adjusted to 85.6%, as shown on Document No. 1, page 11 of 28.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 28, column 4. This number is entered into the respective Generating Performance Incentive Point ("GPIP") table for each particular unit on pages 22 of 28 through 26 of 28. Page 4 of 28 summarizes the equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for

Big Bend Units 1, 2, 3, and 4 and Polk Unit 1 are shown on Document No. 1, page 6 of 28. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 28. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 22 of 28 through 26 of 28. Page 4 of 28 summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric for the January 2006 through December 2006 period?

A. This is shown on Document No. 1, page 28 of 28. Essentially, the weighting factors shown on page 4 of 28, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 28, column 4, are substituted within the equation. The resulting value, 2.617, is then entered into the GPIF table on page 2 of 28. Using linear interpolation, the reward amount is $1,439,819.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN EDGAR: Ms. Christensen. The witness was withdrawn. And the rebuttal witnesses were withdrawn, as well, Mr. Butler.

And, Ms. Bennett.

MS. BENNETT: It appears that we have entered all of the prefiled testimony and exhibits into the record, as well as the late-filed exhibits and the additional stipulations. Those stipulations are in addition to those that were found in the prehearing order that was issued October 30th. And prior to beginning the bench decision, I believe staff would appreciate about a 20-minute recess in order to come back to with you a recommendation.

CHAIRMAN EDGAR: Okay. It is about 2:18 by the clock on the wall, so, do you want to say 2:40? Does that give you enough time?

MS. BENNETT: I'm getting the nod yes.

CHAIRMAN EDGAR: Commissioners, does that work, if our staff is intending to put their thoughts together and collected? And then when we come back, staff will be recommending, as mentioned, a bench decision, so we will move forward at that point in time. And we will be on break until 2:40 by the clock on the wall.

(Recess.)

CHAIRMAN EDGAR: Okay. We will go back on the record. And when we had taken a short break, I think we were

at the point where we were going to look to our staff to give us some recommendations.

Ms. Bennett.

MS. BENNETT: Madam Chairman, the first item is the stipulated issues. I would suggest that the Commission, if they have questions of staff on the stipulated issues, if not we can begin to take up the vote on those stipulated issues.

CHAIRMAN EDGAR: Commissioners, I believe you have before you a list that was compiled by our staff just of all of the issues that have been stipulated. We can work our way through that one-by-one, or we can take them as a group or in subgroups. Are there any questions about the issues generally or specifically? No questions at this time. Okay.

Commissioners, are you comfortable if we take them up as a group, or is there a desire to go through them individually?

COMMISSIONER CARTER: Madam Chair.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: I suggest we just take them up as a group and we just deal with the changes or whatever corrections or revisions, if that's appropriate.

CHAIRMAN EDGAR: Okay. And, again, seeing no objection or questions from other members at this time, we can take them up as a group. And, again, I think you all have this in front of you. I will run through it real quick. We have

Issue 1 for FPUC; Issue 2, FPUC; Issue 3, FPUC; Issue 4, all five, and that is as down the list. Does everybody have that? Okay.

Then is there a motion to adopt the stipulated issues as listed on the checklist before you?

COMMISSIONER CARTER: So moved.

COMMISSIONER SKOP: Second.

CHAIRMAN EDGAR: Seeing no questions, all in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed? Show it adopted. Thank you.

And that will bring us to the second list of nonstipulated issues, and we will ask our staff to give us a recommendation one-by-one.

Ms. Bennett.

MS. BENNETT: Madam Chair, Mr. Matlock has a recommendation on Issue 12B.

MR. MATLOCK: Commissioners, Issue 12B is has PEF adequately mitigated the price risk for natural gas, residual oil, and purchased power for the years 2006 through 2008? Based on the testimony of Witness McCallister and the evidence presented in this hearing, staff recommends that PEF has adequately mitigated the price risk for the months September through December 2006, and that PEF's 2008 risk management plan

also is adequate.

In the 2006 fuel and purchased power hearing, the Commission approved staff's position that PEF had adequately mitigated the price risk through September 1st, 2006. In this proceeding, staff prefers to defer having a position regarding PEF's efforts for all of the months in 2007 until PEF has filed its results for 2007. The filing will be in the risk management report which will be filed in April of 2008.

Staff prefers to withhold its recommendation for 2007 until after that filing is made and to make a recommendation for all of 2007 in next year's hearing. Staff makes its recommendation based on PEF's efforts to minimize price volatility rather than on whether PEF incurred gains or losses in 2006. Staff feels that the minimization of price volatility as a fuel procurement objective is beneficial to PEF's customers.

CHAIRMAN EDGAR: Commissioner Skop, did you have a question?

COMMISSIONER SKOP: I do, Madam Chair, but at the appropriate time. If staff is completed, I do have a question.

I guess my concern would be with respect to staff's recommendation and maybe we need some vetting between my colleagues and I, but it seems like it's reframing or recasting the issue as it was presented to the extent that it is carving out certain things, if I heard that correctly. And maybe I

didn't. But it seems that instead of the aggregate from 2006 through 2008, it is now bifurcating issues on the basis of specific years instead of the way the issue was presented.

MS. BENNETT: Yes, it is. And staff has changed its recommendation from the prior year to this year. What we have experienced is the -- in 2007 we do not have the complete year's data in, and staff would prefer to look at the entire year's data, not just the actual data until July, and then the completed data until December. You are actually making a prudence determination, and we would prefer to make that prudence determination based upon the actual data once it is completely filed.

CHAIRMAN EDGAR: For 2007.

MS. BENNETT: For 2007. For 2006, staff is comfortable with the costs as reported by Progress. We have also reviewed the plans, and for 2008 we are comfortable with the plan for hedging that Progress has filed.

CHAIRMAN EDGAR: Commissioner Skop, follow up?

COMMISSIONER SKOP: Yes. Thank you, Madam Chair.

Again, I understand what staff is saying, and perhaps it will take a moment for me to have that sink in, but, again, I was just looking at the way the issue was framed as it is presented, 2006 through 2008, and I'm kind of wondering, you know, should that issue have been drafted appropriately at the time, knowing that we may or may not have the information that

apparently we don't have. But, moreover, too, with respect to I would like to get some clarification from counsel, it's also my understanding, based upon reading the past order, that I don't necessarily know if, in fact, we are making a blanket prudency determination as opposed to just merely approving the costs as presented. And I need to get a little bit of clarification on that. Because maybe it was just the context in which you stated it, but that is not my understanding of what we are doing. And I may be mistaken.

CHAIRMAN EDGAR: Commissioner McMurrian.

COMMISSIONER McMURRIAN: I would second, especially that last thought about the prudence. Based on prior discussions with staff on these issues, and probably in separate dockets, as well, my understanding was that if we were going to identify it as a prudence issue, the issue would state such. So I am happy to discuss whether this is a prudence determination or not, but I just wasn't aware.

MR. McNULTY: Commissioner -- I'm not sure if this one is working. Can you hear me? Okay.

Commissioner, to address your question, I think if we go back to the original order that is behind all of our hedging activities that have been approved by the Commission, that the term -- basically, it states as a footnote on the last page that the Commission will review the prudence of the activities, the hedging activities of the utilities in the context of our

annual proceedings. It doesn't specify which years will be reviewed as part of that prudence review. It doesn't say your final trip year, your actual trip year, and your projected year will all be reviewed in terms of prudence, but it does say a prudence determination will be made.

What staff has presented here today is that we feel as though we can specify that the last three months of 2006, that the companies collectively were prudent in their hedging programs. We also have put forth today that we believe we have reviewed the 2008 hedging plans and state that our position or our recommendation to you that those hedging plans are prudent in how they have been formed.

What we have a little bit of difficulty with, and perhaps the position or that the issue could have been framed a little bit more optimally than it has been, is that we can't really say whether or not the company was prudent in the results of its hedging program for 2008. That's not possible. We can't do it for the last three or four months of 2007. So there is some difficulty with perhaps the way that the issue was framed. I'm not sure what to do about that from a legal perspective, but I can say that, you know, that was some of the thinking behind the recommendation that you heard today.

CHAIRMAN EDGAR: Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you.

And just to follow up, you are saying that your

comfort level of 2007, or the lack of comfort level you have with 2007 is because you don't have all the data you believe that you need in order to make a prudence determination as opposed to just recovery of costs?

MR. McNULTY: That's correct.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN EDGAR: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

Again, one of the questions I have -- and, again, I do thank staff for providing the order with respect to hedging activity. And I have just now reviewed the footnote or the asterisk note on the Attachment A on Page 7 about the Commission will review the prudence of hedging transactions, but I am also trying to distinguish how this order impacts the language in the Order Number 12645, which is a little bit older, but basically speaks to, you know, prudency on specific requests. I think they are in harmony, and I do think that perhaps that they don't conflict to the extent that it specifically states that the prudency of the hedging will be reviewed annually in the later order as opposed to the prior order which speaks generally. So, I am getting some comfort level with it. But, again, I think the discussion we are having with respect to any problems between my colleagues may be beneficial here.

CHAIRMAN EDGAR: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you. And while I understand the concern that Commissioner Skop and McMurrian raise, I do commend staff. I wouldn't want you to deem something prudent without having that information before you, so I understand that and agree with that position.

CHAIRMAN EDGAR: Ms. Hilton, did you have something that you would like to add?

MS. HILTON: I'm not sure if it would help or not. Just because the issue is framed so that the Commission is being asked to consider and bless the costs, or the price risk for 2006 through 2008 doesn't mean that you have to do that. I think what staff is recommending is that they are comfortable for you to address that portion of 2006 in the plan for 2008, but because we don't feel that there is enough information to address the other years, I think that is perfectly acceptable under our process and procedures.

CHAIRMAN EDGAR: Commissioners, any further questions for our staff or discussion?

Commissioner Carter.

COMMISSIONER CARTER: A point of clarification, Ms. Hilton. As I understand it, and I could be wrong, but as I understand it, what your recommendation is is that we will deal with the years that we actually have the numbers for versus '07, which we don't have the numbers for, so we will be making a determination on the '06 numbers.

However, for '08, what we are doing is just making a determination on the plan itself and not any degree of whether or not the numbers are there. We don't really have any numbers there, it is just a matter of the plan itself, is that correct?

MS. BENNETT: Yes. What your vote will be is that 2006, you are looking at -- staff is recommending that you find the numbers be prudent or are prudent for 2006 for the last three months and that the plan is adequate for 2008. And we would not address 2007 until next year when all of the numbers are in for 2007. Did I answer your question?

COMMISSIONER CARTER: If I may? Ms. Hilton, I may be way far afield, but it won't be the first time. In the event that there are more credible numbers later on, or I shouldn't say credible, more specific numbers later on in the context of true-up or something like that, would we have access to that, or are we beyond that. Or am I talking about apples and grapefruit?

MR. McNULTY: In 2008, you are going to get a final report that will be part of the final true-up testimony that will identify specific information that's provided for in the hedging order we have been discussing. That information will be provided by each utility that engaged in hedging as part of the hedging stipulation of 2002. So you will have an opportunity to look at those actual results, and at that point you will have a full picture of 2007 results. You will have

all the data that is specified in that order, which you don't have today.

COMMISSIONER CARTER: Thank you, Madam Chair. I just wanted to make sure that we had an opportunity to make full, you know, evaluation and examination of all of the numbers and all like that. So I think that based upon where we are now, I understand where staff is coming from.

CHAIRMAN EDGAR: Thank you.

Commissioner McMurrian.

COMMISSIONER McMURRIAN: One more. Since every year we have these hearings about the same time, and we have taken up these types of issues before, what have we done in the past when we are in November of that particular year and we are looking at these costs? Have we deferred this in the past, or do we normally essentially go with what we have for the current year and make a determination?

MS. BENNETT: I can speak to last year's, and last year we approved through September of 2006. We had the numbers and had reviewed those numbers for up to September of 2006. I'm not certain about the prior year without looking what we have done in the prior three years.

MR. McNULTY: I believe we have reviewed up to a certain point in time in the year. Whether it's exactly September or some close month to it, it has been reviewed in that way.

CHAIRMAN EDGAR: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

I think I have a handle on this and at the appropriate time I think I would be willing to make a motion encompassing what staff has recommended.

CHAIRMAN EDGAR: I think we have a few more questions.

Commissioner McMurrian.

COMMISSIONER McMURRIAN: Does staff have a lack of comfort with the numbers through September 2007? I'm just trying to understand why we have the departure from how we have done it in the past. I'm not uncomfortable departing from how we have done in the past, I just want to understand the difference, because I realize we are about at the same point of the year where we were before when we approved it through September of 2006.

MR. MATLOCK: Staff is not uncomfortable with anything that we know or anything that we have seen. We just feel that the complete year with the additional information for the year and that information also being for a complete year would be more -- a recommendation on it could be made more thoroughly if it were to be dealt with in that way. We don't know of anything bad about 2007 as far as the utilities, the work the utility has done. It's just a timing matter. And we feel that 2007 can be dealt with better by doing it that way.

CHAIRMAN EDGAR: Okay. Hold on a second. I may have a question, too. And, Commissioner Argenziano, I know you do, so, please.

COMMISSIONER ARGENZIANO: I think it's more of a comment. I don't know how you can deem something prudent without having the complete information. So I am uncomfortable without having all of that information to say that it is done with prudence without having all of that information. Despite how it may have been done with all respect in the past, I am here now. And I think that's what staff is relaying to me and that is what I am taking from it, there is not enough information to say, put my stamp on it today to say that it is prudent, even though it may be. Everything may be fine. I would feel more comfortable in stamping something prudent knowing all the information, and I believe that is where staff is coming from. Thank you.

CHAIRMAN EDGAR: And I guess I may be missing something, so, if you would, go over this for me one more time. I'm going to blame it on the cough drops or something. My memory and from what you have described of what we did last year was to approve, as you pointed out, for '06 from January through August, basically. But this year for '07, for January through August or September, or whatever the cutoff would be with the numbers, you are recommending a different treatment. And what I'm not understanding exactly is what is different

this year than last year or what is to be gained or lost. So if you could elaborate on that point for me a little more, please.

MR. MATLOCK: Staff would just see more complete information about the first eight months of '07 when it sees the same information for the last four months of '07, and this will come in the filing of the 2007 results when the true-up filings come in early next year. There's not really anything different about this year that causes staff to want to make this change.

CHAIRMAN EDGAR: Okay. Commissioner McMurrian.

COMMISSIONER McMURRIAN: I think I understood what Mr. Matlock said. Once you get to the end of the year, you will have more information filed with respect to those later months that will shed, perhaps, additional light even on the first eight months. So it's not that we have a complete picture of the first eight months right now. But until we get the information with respect to the later months, it may give us more information about respect to the first eight.

MR. MATLOCK: Yes, ma'am.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN EDGAR: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

And I think that it's becoming clearer by the moment, and in terms of --

CHAIRMAN EDGAR: Are you sure about that?

COMMISSIONER SKOP: Well, I'm not one for surprises or changes in the way that -- you know, as I have stated before, I am all about precedent and procedure. But I think Commissioner Argenziano raises a good issue, and pursuant to the older order, the 12645, and I quote, "But we will not adjudicate the question of prudence nor consider ourselves bound to do so until all relevant facts are analyzed and placed before us." So I think she raises a good point there.

Although that order seems to give us a little bit more discretion in terms of prudency review, the order with respect to hedging activities also states that we will make a prudency determination. So, again, I don't think they are intentioned. I think they are complimentary to each other. But if we don't have all the information, I don't think we are precluded from necessarily having to render a prudency determination under the latter order. So, again, we will get in my comfort level that there is no tension between the two orders; but, again, without having looked at the hedging order previously, I would have assumed that the prior order governed.

But I do have a comfort level with what staff is proposing and wish that we, as Commissioner McMurrian mentioned, and also I think as you articulated about departing from the way we have done things in the past, because, again, a part of regulatory certainty is stability and predictable

results, and we seem to be departing maybe from what we have done previously. I wasn't here, this is my first hearing, but it does seem somewhat sound and reasonable. If we don't have complete information, then it would be difficult to render that prudency determination. But, again, I am a little bit concerned by the departure, although I do understand staff's position and would be supportive of it.

CHAIRMAN EDGAR: Commissioners, further comments or questions? No.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

If there are no further questions, I would like to try and frame staff's recommendation into a motion. With respect to, I believe -- and, staff, I've lost my page, but I believe this is Issue 12B, is that correct?

MS. BENNETT: Yes.

COMMISSIONER SKOP: With respect to Issue 12B, I would like to amend the issue to incorporate staff's recommendation, and that would be basically a prudency determination with respect to the last three months of 2006, withholding of prudency determination for 2007 until such time as we get complete data. And, like I said, it would be deferred until 2008. And for 2008, prudency of the plant only and not the results for 2008.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: Okay. Commissioners, we have a motion and a second in favor of the recommendation from our staff. Is there further discussion? Seeing none. All in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

And that brings us to 13B.

MR. MATLOCK: Commissioners, staff's position on Issue 13B for FPL is identical to its position on 12B.

CHAIRMAN EDGAR: Got it.

Commissioners, any question of our staff? Is there a motion?

COMMISSIONER ARGENZIANO: Move it.

CHAIRMAN EDGAR: Commissioner Argenziano has made a motion in favor of the staff recommendation.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: And there is a second. Any questions? Seeing none. All in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: All opposed?

Show it adopted.

Which brings us to 15A.

MR. MATLOCK: Staff's position on Issue 15A for Gulf is identical to its positions on Issues 12B and 13B.

COMMISSIONER SKOP: Second.

CHAIRMAN EDGAR: Commissioners, we have a motion in favor of the staff recommendation and a second for Issue 15A. All in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed? Show it adopted.

And that brings us to 16A.

MR. MATLOCK: Staff's position on Issue 16A for TECO is identical to its position on the last three issues.

CHAIRMAN EDGAR: Thank you. Commissioners? Okay. Discussion? No.

All in favor of the staff recommendation for 16A say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted. Thank you.

And, Commissioners, my understanding is that Issues 1, 2, 3, 5, 6, and 8 as relates to Progress, Gulf, and TECO are fallout issues from the decisions that we have just made, and I will ask our staff to elaborate.

MR. LESTER: Pete Lester with staff.

Issue 1 is what are the appropriate fuel adjustment true-up amounts for the period January 2006 through December 2006? And staff recommends that the Commission approve the amounts for each utility for this issue as

presented in the prehearing order.

CHAIRMAN EDGAR: Commissioners, any questions for our staff, or discussion?

Seeing none, is there a motion?

COMMISSIONER SKOP: Motion to move staff recommendation.

CHAIRMAN EDGAR: A motion for the staff recommendation. All in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

MR. LESTER: Issue 2 is what are the appropriate fuel adjustment true-up amounts for the period January 2007 through December 2007? Staff recommends that the Commission approve the amounts for each utility for this issue as presented in the prehearing order.

COMMISSIONER SKOP: A motion to move staff.

CHAIRMAN EDGAR: There's a motion and a second for the staff recommendation on Issue 2. All in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

MR. LESTER: Issue 3 is what are the appropriate total fuel adjustment true-up amounts to be collected and refunded from January 2008 to December 2008?

And staff recommends that the Commission approve the amounts for each utility for this issue as presented in the prehearing order.

COMMISSIONER SKOP: So moved.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: All in favor of the staff recommendation for Issue 3 say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

5.

MR. LESTER: Issue 5 is what are the appropriate projected net fuel and purchased power cost-recovery amounts to be included in the recovery factor for the period January 2008 through December 2008?

And, once again, staff recommends that the Commission approve the amounts for each utility for this issue as presented in the prehearing order.

COMMISSIONER SKOP: So moved.

CHAIRMAN EDGAR: Commissioners, all in favor of the motion for the staff recommendation on Issue 5 say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

MS. DRAPER: Commissioners, Elizabeth Draper with

staff.

Issue 6 reads what are the appropriate levelized fuel cost-recovery factors for the period January 2008 through December 2008? Staff recommends that you approve the factors for each utility as stated in the prehearing order.

COMMISSIONER SKOP: So moved.

CHAIRMAN EDGAR: All in favor of the staff recommendation for Issue 6 say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

And I believe that brings us to our last issue, Number 8.

MS. DRAPER: Yes. Issue 8, our final issue, what are the appropriate fuel cost-recovery factors for each rate class or delivery voltage level class adjusted for line losses?

And, again, it is staff's recommendation that you approve the factors for each utility as stated in the prehearing order.

COMMISSIONER SKOP: So moved.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: Commissioners, all in favor of the staff recommendation for Issue 8 say aye.

(Unanimous affirmative vote.)

CHAIRMAN EDGAR: Opposed?

Show it adopted.

And that was our last issue. Are there any other matters?

MS. BENNETT: There are none, Commissioner. The final order in this case will be issued by November 26th, 2007.

CHAIRMAN EDGAR: Okay. That concludes our business for today.

Thank you to our staff and to all of the parties for all the work that went into getting us to this point. And we adjourned.

(The hearing concluded at 3:13 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTERS

COUNTY OF LEON)

WE, JANE FAUROT, RPR, and LINDA BOLES, RPR, CRR, Official Commission Reporters, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision; and that this transcript constitutes a true transcription of our notes of said proceedings.

WE FURTHER CERTIFY that we are not a relative, employee, attorney or counsel of any of the parties, nor are we a relative or employee of any of the parties' attorneys or counsel connected with the action, nor are we financially interested in the action.

DATED THIS 15th DAY OF NOVEMBER, 2007.



JANE FAUROT, RPR
FPSC Official Commission Reporter
(850) 413-6732



LINDA BOLES, RPR, CRR
FPSC Official Commission Reporter
(850) 413-6734

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
Staff				
1		Exhibit List- 1	Comprehensive Exhibit List	✓
2		Staff Composite Exhibit - 2	**Progress Energy of Florida, Inc.** 1. PEF's Response to Staff's Second Set of Interrogatories (Nos. 11 & 12 w/ Attachment A). **Florida Power & Light Company** 2. FPL's Response to Staff's Second Set of Interrogatories (No. 11). 3. FPL's Response to Staff's Fourth Set of Interrogatories (Nos. 31 - 41). 4. FPL's Response to Staff's Second Request for Production of Documents (No. 12). **Florida Public Utilities Company** 5. FPUC – Audit Finding No. 1 Subject: Deposits on New Contracts Reported as Expense. **Gulf Power Company** 6. Gulf's Response to Staff's Second Set of Interrogatories (No. 11). 7. Gulf's Response to Staff's Third Set of Interrogatories (Nos. 12 - 16).	✓

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 1
COMPANY FPSC Staff
WITNESS Comprehensive Exhibit List
DATE 11-06-07

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			8. Gulf Power Company Monthly Fuel Filings for January 2006 – December 2006 ("A" Schedules). **Tampa Electric Company** 9. TECO's Response to Staff's Second Set of Interrogatories (Nos. 11 – 32). 10. Late Filed Deposition Exhibit No. 5 of TECO witness Joann T. Wehle.	
3		CONFIDENTIAL Staff Composite Exhibit – 3	**Progress Energy Florida** 1. PEF's Response to Staff's Third Set of Interrogatories (No. 26) (DN 09607-07). **Florida Power & Light Company** 2. FPL's Response to Staff's Second Set of Interrogatories (No. 12) (DN 09053-07). 3. FPL's Response to Staff's Third Set of Interrogatories (No. 16) (DN 09657-07). 4. FPL's Response to Staff's Second Request for Production of Documents (Nos. 9 & 13) (DN 09819-07). 5. Late Filed Panel Deposition Exhibit No. 3 to FPL witnesses Dubin/Yupp/Jones taken 10/30/07.	✓

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			Gulf Power Company 6. Gulf's Risk Management Plan (DN 02925-07). **Tampa Electric Company** 7. Confidential portions of TECO's Risk Management Report (DN 07996-07). 8. TECO's Risk Management Plan (DN 02854-07).	
Testimony Exhibit List				
PROGRESS ENERGY FLORIDA, INC.				
4	Will Garrett	WG-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2006)	✓
5	Will Garrett	WG-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2006)	✓
6	Will Garrett	WG-3T	Schedules A1 through A3, A6 and A12	✓
7	Lori Cross	LC-1R	Estimated/Actual true-up Schedules for period 1/07 through 12/07	✓
8	Lori Cross	LC-1P	Projection factors for January to December 2008.	✓
9	Joseph McCallister	JM-1T	2006 Hedging Information as required by Order No. PSC-02-1484-FOF-EI	✓
10	Joseph McCallister	JM-1P	2008 Risk Management Plan	✓
11	Robert M. Oliver	RMO-1T	GPIF Reward/Penalty Schedules for 2006	✓
12	Robert M. Oliver	RMO-1P	GPIF Targets/Ranges Schedules (for Jan – Dec. 2008)	✓

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
FLORIDA POWER & LIGHT COMPANY				
13	G. Yupp	GJY-1	2006 Hedging Activity	✓
14	G. Yupp	GJY-2	Fuel Cost Recovery and Capacity Cost Recovery Projections	✓
15	T.O. Jones	TOJ-1	Turkey Point Outage Extension Fuel Cost Recovery and Capacity Cost Recovery Projections	withdrawn
16	K. M. Dubin	KMD-1	Fuel Cost Recovery and Capacity Cost Recovery 2006 Final True-up	✓
17	K. M. Dubin	KMD-2	Fuel Cost Recovery and Capacity Cost Recovery 2006 Final True-up	✓
18	K. M. Dubin	KMD-3	Fuel Cost Recovery and Capacity Cost Recovery 2007 Estimated/Actual True-Up	✓
19	K. M. Dubin	KMD-4	Fuel Cost Recovery and Capacity Cost Recovery 2007 Estimated/Actual True-U	✓
20	K. M. Dubin	KMD-5	Fuel Cost Recovery and Capacity Cost Recovery 2008 Projections	✓
21	K. M. Dubin	KMD-6	Fuel Cost Recovery and Capacity Cost Recovery 2008 Projections	✓
22	P. Sonnelitter* * The exhibits filed by witness Sonnelitter will be adopted and sponsored by witness Irizarry	PS-1	2006 GPIF Performance Results	✓
23	F. Irizarry	FI-2	2008 GPIF Incentive Factor Targets and Ranges	✓

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
FLORIDA PUBLIC UTILITIES COMPANY				
24	Cheryl Martin* * The exhibits filed by witness Martin will be adopted and sponsored by witness Khojasteh.	CMM-2	Schedules M1, F1, and E1-B (for the Marianna and Fernandina Beach Divisions)	✓
25	Cheryl Martin* * The exhibits filed by witness Martin will be adopted and sponsored by witness Khojasteh.	CMM-2	Schedules E1-A, E1-B, and E1-B1(for the Marianna and Fernandina Beach Divisions)	✓
26	Mehrdad Khojasteh	MK-1	Schedules E1, E1-A, E2, E7 and E10 for the Marianna Division and Schedules E1, E1-A, E2, E7, E8 and E10 for the Fernandina Beach Division	✓
GULF POWER COMPANY				
27	H. R. Ball	HRB-1	Coal Suppliers and Hedging Transactions, January 2006 - December 2006	✓
28	H. R. Ball	HRB-2	Projected vs. Actual Fuel Cost of Net Generation, March 1997 - December 2008	✓
29	R. J. Martin	RJM-1	Calculation of Final True-Up January 2006 – December 2006	✓
30	R. J. Martin	RJM-2	Estimated True-Up, January 2007 – December 2007	✓
31	R. J. Martin	RJM-3	Projection, January 2008 – December 2008	✓
32	L. S. Noack	LSN-1	Gulf Power Company GPIF Results, January 2006 - December 2006	✓
33	L. S. Noack	LSN-2	Gulf Power Company GPIF Targets and Ranges, January 2008 - December 2008	✓
TAMPA ELECTRIC COMPANY				
34	Carlos Aldazabal	CA-1	Fuel Cost Recovery January 2006 - December 2006	✓

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
35	Carlos Aldazabal	CA-1	Capacity Cost Recovery January 2006 - December 2006	✓
36	Carlos Aldazabal	CA-2	Fuel Cost Recovery, Projected January 2007 – December 2007	✓
37	Carlos Aldazabal	CA-2	Capacity Cost Recovery, Projected January 2007 – December 2007	✓
38	Carlos Aldazabal	CA-3	Fuel Cost Recovery, Projected January 2008 – December 2008	✓
39	Carlos Aldazabal	CA-3	Capacity Cost Recovery, Projected, January 2008 – December 2008	✓
40	Carlos Aldazabal	CA-3	2008 Incremental Security Costs	✓
41	David R. Knapp	DRK-1	Generating Performance Incentive Factor Results January 2006 – December 2006	✓
42	David R. Knapp	DRK-2	Generating Performance Incentive Factor Estimated January 2008 – December 2008	✓
43	Joann T. Wehle	JTW-1	Calculation of 2006 Incremental Hedging Operations and Maintenance Costs	✓
44	Joann T. Wehle	JTW-2	2006 Waterborne Transportation Cost Adjustment	✓
OFFICE OF PUBLIC COUNSEL				
45	Aaron L. Rothschild	ALR-1	Resume of Aaron L. Rothschild	with

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed
46		Staff	Docket No 070001-EI November 6, 2007 Additional Stipulations	✓
47		Gulf	Gulfs Responses to Staffs 1st & 4th Interrogatories	✓

HEARING EXHIBITS

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed
48	Napp	FPL	FPL Hedging hedging v. spot hedging v. long term percentages (financial/physical 2007)	✓
49		PEF	" "	✓
50		Gulf	GULF HEDGING " "	✓
51		TECO	TECO " "	✓

To B

Late Filed

"

"

"

HEARING EXHIBITS				
Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed

RECEIVED-FPSC
07 NOV -7 AM 10:52
COMMISSION
CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 2
COMPANY FPSC Staff
WITNESS Staff Composite Exhibit-2
DATE 11-06-07

EXHIBIT NO. 2

DOCKET NO: 070001-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA
FLORIDA POWER & LIGHT CO.
FLORIDA PUBLIC UTILITIES CO.
GULF POWER COMPANY
TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT-2 OF STIPULATED NON-CONFIDENTIAL **(Redacted)** DOCUMENTS:

Progress Energy of Florida, Inc.

1. PEF's Response to Staff's Second Set of Interrogatories (Nos. 11 & 12 w/ Attachment A).

Florida Power & Light Company

2. FPL's Response to Staff's Second Set of Interrogatories (No. 11).

3. FPL's Response to Staff's Fourth Set of Interrogatories (Nos. 31 - 41).

4. FPL's Response to Staff's Second Request for Production of Documents (No. 12).

Florida Public Utilities Company

5. FPUC – Audit Finding No. 1 Subject: Deposits on New Contracts Reported as Expense.

Gulf Power Company

6. Gulf's Response to Staff's Second Set of Interrogatories (No. 11).

7. Gulf's Response to Staff's Third Set of Interrogatories (Nos. 12 - 16).

8. Gulf Power Company Monthly Fuel Filings for January 2006 – December 2006 ("A" Schedules).

Tampa Electric Company

9. TECO's Response to Staff's Second Set of Interrogatories (Nos. 11 – 32).

10. Late Filed Deposition Exhibit No. 5 of TECO witness Joann T. Wehle.

PROFFERED BY: STAFF

Progress Energy's Responses to

Staff's 2nd ROGS Nos. 11-12 (with Attachment A)

070001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 070001-EI

Submitted for Filing: October 2, 2007

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 11-20)

Progress Energy Florida, Inc. ("PEF"), responds to STAFF's Second Set of Interrogatories to PEF (Nos. 11-20), as follows:

INTERROGATORIES

11. Please provide a response to Audit Finding No. 1 to the PEF Capacity Clause Audit, Audit Control No. 07-022-2-4. Include information on how the proposed adjustment will be made.

Answer: PEF inadvertently overstated its incremental NRC fee by $104,520 in its true-up filings. The authorized amount recoverable for NRC quarterly dues is $249,240 ($402,000 x 62%) and at the end of the 3rd quarter, $301,500 had been posted to the incremental security account; therefore, an adjustment was required for $52,260. The adjusting entry was incorrectly posted, increasing the incremental security rather than decreasing the recoverable incremental security. This correction will be made in 2007 and is included in the 2007 true-up filing.

12. For each month of 2006, please provide the commodity cost, transportation cost, hedging gain/loss and total cost for natural gas.

Answer: Please see Attachment A.

Docket No. 070001-EI
Staff's 2nd Set of Interrogatories
Witness: Cindy Lee
Question #12

Progress Energy Florida
Natural Gas Cost / Hedging Gain/Loss

Month	Commodity Cost	Transportation Cost	Total Natural Gas Cost [2]	Total Hedging Gain/(Loss) [1]
January-06	$30,212,813	$4,789,387	$35,002,200	$21,269,603
February-06	$22,155,433	$4,115,467	$26,270,900	$9,166,215
March-06	$39,779,157	$4,699,043	$44,478,200	$5,030,510
April-06	$45,984,416	$4,553,184	$50,537,600	$2,013,430
May-06	$43,841,406	$5,642,494	$49,483,900	$8,206,286
June-06	$67,636,580	$6,049,020	$73,685,600	$961,161
July-06	$61,929,974	$7,132,026	$69,062,000	($2,655,705)
August-06	$60,634,174	$6,839,226	$67,473,400	$8,093,509
September-06	$57,438,350	$6,018,650	$63,457,000	$9,643,062
October-06	$32,244,882	$4,875,218	$37,120,100	($6,751,052)
November-06	$32,029,795	$3,917,505	$35,947,300	$1,186,779
December-06	$22,919,136	$4,373,964	$27,293,100	$5,903,020
Total	$516,806,115	$63,005,185	$579,811,300	$62,066,818

[1] The hedging gains and losses are included in the commodity costs for the respective months.
[2] Total natural gas costs on this exhibit have small rounding variances from Schedule A-3.

Attachment A

Florida Power & Light Company's Responses to

STAFF'S 2ND ROGS No. 11

070001

Q.

Please provide a response to Audit Finding No. 1 in the FP&L Capacity Clause Audit-Audit Control No. 07-022-4-3.

A.

Due to the specialized nature of the two positions in question, FPL must offer competitive compensation packages to attract highly qualified people to perform the job function. Relocation assistance was included as part of the compensation. In the past five years, the South Florida housing market values had substantially increased resulting in increased relocation costs. Depending upon the level of the position and geographic location of the person moving to South Florida, it has not been unusual for FPL to incur relocation costs in the range identified in Audit Finding No. 1. The increased costs are primarily attributable to the closing costs associated with both the sale and purchase of a home.

In recent years, FPL has incurred closing costs for the sale of an employee's existing home averaging 10% of the value of the home. Additionally, closing costs for the purchase of an employee's new home have amounted to an average of 4% of the value of the new home. Assuming for the purpose of illustration that the values of both the existing and new homes were $500,000, the associated closing costs would total $70,000. When you combine this cost with the cost for customary expenses such as temporary living and moving expenses for vehicle and household items, relocation costs could easily exceed $100,000.

Florida Power & Light Company's Responses to

Staff's Fourth Set of Interrogatories Nos. 31 - 41

070001

Q.

Page 18 of Mr. Terry Jones' prefiled testimony states that the "pressurizer piping incident" was a criminal act. Was the individual responsible for the criminal act ever identified?

A.

FPL has been advised by the Federal Bureau of Investigation that the FBI has identified an individual that the FBI believes is responsible for the pressurizer piping incident. At this time, however, the FBI has not shared with FPL the information that led to its identification of that individual.

Q.

If your response to Interrogatory No. 31 is Yes, was the individual responsible for the criminal act arrested and charged with a crime?

A.

Refer to confidential Exhibit TOJ-1 for details associated with the individual.

Q.

If your response to Interrogatory No. 31 is Yes, has FPL identified the contractor that employed the individual responsible for the criminal act?

A.

Yes.

Q.

What type of assurances (bond, surety, or other guarantee), did FPL require of the contractor that employed the individual responsible for drilling the hole in the pressurized pipe? In your response to this interrogatory, include the type of guarantee, the amount of the guarantee, and the acts covered by the guarantee.

A.

There is no performance bond requirement in the Contract. The Contract contains warranty protection related to the Work performed by the contractor. The Work must be provided in conformance with the specifications and other descriptions and requirements set forth in the Contract; in accordance with standards of care, skill and diligence consistent with recognized and sound industry practices, procedures and techniques; delivered to FPL free from faulty design; constructed utilizing new materials and/or equipment free from faults and defects; fabrication and workmanship be of the kind, size, quality, design, capability, and materials to meet in all respects the requirements and operating conditions specified in the Contract; suitable for the use intended; in conformance with all applicable laws, regulations, codes, and applicable trade practices; and conveyed with free and clear title.

Q.

If no assurances were required of the contractor, explain why not.

A.

N/A. See the response to answer to Interrogatory No. 34.

Q.

If the answer to Interrogatory No. 31 is Yes, was the individual who drilled the hole also bonded or did he provide some other performance guarantee to either FPL or the contractor? Please describe the type of guarantee, the amount of the guarantee, and the acts covered by the guarantee.

A.

No other bonding or performance guarantee applied to the individual referenced in the answer to Interrogatory 31. See also the response to Interrogatory No. 34.

Q.

Has FPL sought to recover any cost associated with the pressurizer piping incident repairs from the individual who caused the damage; or the contractor that employed the individual that might be responsible for the damage; or from any bond or guarantee posted by the contractor or individual?

A.

No. Until FPL has access to the FBI's information that is the basis for its identification of the individual who drilled the hole, FPL is not in a position to demonstrate either the individual's or the contractor's responsibility to the level of proof required to pursue claims for recovery.

Q.

If your response to Interrogatory No. 37 is Yes, what is the status of FPL's attempt to recover the cost from the contractor, the individual responsible for drilling the hole; or the insurance, bond, guarantee, or surety?

A.

N/A. See response to Interrogatory No. 37.

Q.

Does FPL carry insurance to recover cost resulting from acts of vandalism, employee misconduct, criminal acts, or employee mistakes?

A.

FPL carries property insurance which would have responded to the Turkey Point pressuriser piping incident had the direct costs of repair exceeded the deductible. Because the direct cost of repair was less than the deductible, the insurer was not put on notice of this claim and did not investigate the claim.

FPL also carries Accidental Outage Insurance which would have paid a weekly liquidated damage amount in the event of an extended outage attributable to an insured property loss. This policy did not apply to the subject incident because the outage fell well below the deductible.

Q.

If your response to Interrogatory No. 39 is Yes, what is the company's deductible under this policy?

A.

The deductible under FPL's Property Policy is $1 million.

The deductible under FPL's Accidental Outage Policy is twelve (12) weeks. For this policy to provide coverage, an accidental outage must be directly attributable to an insured property incident and must be longer than twelve (12) weeks in duration.

Q.

On a prospective basis, how does FPL propose to financially indemnify its customers from negligence and sabotage that may result from FPL contracted workers?

A.

In order to minimize the potential for this type of event, FPL has taken, and will continue to take, great care in evaluating potential contract workers for access to our nuclear facilities and then supervising the contract workers who are granted access. These precautions are discussed in the pre-filed testimony of FPL witness Terry Jones. In the unlikely event that negligence or sabotage occurs in spite of the precautions, FPL will pursue available sources for recovery of resulting damages.

Florida Power & Light Company's Responses to

Staff's Second Request for Production of Documents No. 12

070001

Q.

In Mr. Terry Jones' prefiled direct testimony, Mr. Jones referenced that the FBI has investigated the pressurizer piping incident. Please provide a complete copy of the FBI report documenting its findings in its investigation

A.

FPL has been briefed by the FBI but does not have access to the FBI report.

FPUC
Audit Finding No. 1
Subject: Deposits on New Contracts Recorded As Expense

070001

AUDIT FINDING NO. 1

SUBJECT: DEPOSITS ON NEW CONTRACTS RECORDED AS EXPENSE

SUMMARY: In December 2006, the utility recorded refundable customer deposits paid to the new supplier as expenses instead of in an asset account for customer deposits.

STATEMENT OF FACTS: In December 2006, the utility booked a journal entry number 5.14 of $130,306 to Marianna Other Fuel Expense Account 114.4010.557. They booked the same entry to Fernandina for $187,530 to Fernandina Other Fuel Expense Account 115.4010.557. The entry indicated that the deposit was for a survey that was to be done and some might be refunded. Further investigation revealed that these payments were actually a refundable deposit being held in the event that Florida Public Utilities did not pay its bill. As such, the amount should be recorded as an asset. If these amounts are removed, interest expense for Marianna decreases by $285 and by $410 for Fernandina. Therefore, the total change to the fuel true-up is a decrease of the under-recovery of $130,592 for Marianna and $187,940 for Fernandina.

EFFECT ON THE GENERAL LEDGER: The following entry should be made:

114.1860.21	Deferred Fuel Costs		$130,592
114.4010.551	True-Up Expense	$130,592	
115.1860.21	Deferred Fuel Costs		$187,940
115.4010.551	True-Up Expense	$187,940	
114.1340.1	Other Special Deposits	$130,306	
115.1340.1	Other Special Deposits	$187,530	
114.4010.557	Other Fuel Expenses		$130,306
115.4010.557	Other Fuel Expenses		$187,530

EFFECT ON THE FILING: The original under-recovery of $373,051 for Marianna should be reduced by $130,592 to $242,459. The original under-recovery of $807,694 for Fernandina should be reduced by $187,940 to $619,754.

Gulf Power Company's Responses to

STAFF'S 2nd ROGS No. 11

070001

11. For each month of 2006, please provide the commodity cost, transportation cost, hedging gain/loss, and total cost for natural gas.

ANSWER:

The following amounts represent the costs of natural gas purchased plus any hedging gains or losses:

YEAR 2006	PURCHASE QUANTITY (MMBTU)	TOTAL COST ($)	COMMODITY COST ($)	TRANSPORTATION COST ($)	STORAGE COST ($)	HEDGING (GAIN)/LOSS ($)
JAN	946,274	9,221,106	8,220,137	817,190	131,739	52,040
FEB	807,685	8,156,683	6,625,392	506,176	130,148	894,967
MAR	794,710	9,013,596	5,781,916	732,254	129,676	2,369,750
APR	914,578	9,971,788	7,271,661	1,595,220	128,507	976,400
MAY	1,311,815	12,145,305	8,671,010	1,996,049	129,401	1,348,845
JUN	1,369,363	13,543,174	9,590,900	1,944,188	128,796	1,879,290
JUL	1,565,449	16,148,497	10,917,412	2,079,863	130,465	3,020,757
AUG	1,981,477	21,256,014	17,072,464	2,093,714	128,860	1,960,976
SEP	1,618,665	13,669,331	8,513,988	2,209,265	129,678	2,816,400
OCT	1,777,923	14,479,475	10,539,680	2,291,295	132,867	1,515,633
NOV	1,184,521	10,797,444	9,067,311	744,653	128,869	856,611
DEC	1,171,369	10,665,569	8,937,108	576,543	129,025	1,022,893
TOTAL	15,443,829	149,067,982	111,208,979	17,586,410	1,558,031	18,714,562

Gulf Power Company's Responses to

Staff's Third Set of Interrogatories Nos. 12 - 16

070001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	Docket No. 070001-EI Date Filed: October 17, 2007

GULF POWER COMPANY'S NOTICE OF SERVING RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 12 - 16)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby gives notice of serving the Company's responses to Staff's Third Set of Interrogatories (Nos. 12 - 16) to Lisa C. Bennett, Senior Attorney, on October 16, 2007, by FedEx overnight delivery.

Respectfully submitted the 16th day of October, 2007,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

070001-Hearing Exhibit 000026

12. Gulf lists "Gains/Loss on sales of natural gas and costs of contract dispute litigation" as a non-fuel generation expense. By month, since "costs of contract dispute litigation" was added to "Gains/Loss on sales of natural gas," please break out the two categories separately.

ANSWER:

The following table represents Gulf Power Company's gain/loss on sales of natural gas and contract dispute litigation fees for the period August 2006 through August 2007.

Year	Month	(Gain)/Loss on sale of natural gas $	Contract dispute litigation fees $
2006	Aug	(99,204.38)	30,439.40
	Sep	(55,379.63)	43,706.20
	Oct	(27,950.03)	8,348.42
	Nov	8,747.87	902.77
	Dec	21,748.55	9,255.99
2007	Jan	34,244.27	12,401.12
	Feb	(48,646.54)	5,855.94
	Mar	2,392.15	5,327.47
	Apr	(6,071.92)	5,322.56
	May	1,352.48	7,890.00
	Jun	31,515.58	10,585.87
	Jul	(49,683.86)	120.00
	Aug	(114,538.48)	8,870.94

13. Is "Gains/Loss on sales of natural gas" a physical hedging gain/loss?

ANSWER:

No, gains or losses on sales of natural gas result from the requirement by the natural gas pipeline to balance the flow of natural gas into and out of the natural gas pipeline system daily. Once natural gas is purchased and committed to flow into the pipeline system during a specified day, Gulf has the obligation to either burn the gas in its generating units, place the gas in storage, or sell the gas to third parties. If the generating unit nominated to receive the gas is unable to actually burn the quantity of gas nominated, due to either a lack of electrical demand or an unexpected maintenance outage, then Gulf will decide to either store the gas at its contracted storage facility for future use or sell the excess gas to third parties depending on current market conditions. This decision is made considering both operational and economic factors. If the decision is made to sell the excess gas to third parties, Gulf reflects the gain or loss on this sale as a reduction or increase to fuel expense.

14. Is "Gains/Loss on sales of natural gas" similar to hedging settlement costs?

ANSWER:

No. See answer to interrogatory no. 13.

15. Do the monthly dollar amounts labeled "hedging settlement costs" contain any dollars for non-natural hedging settlement costs (ex., light oil hedging settlement costs)? If hedging settlement costs do contain non-natural gas hedging settlement cost dollars, are the numbers of non-natural hedging settlement cost dollars great enough to affect the third digit of natural gas cost dollars (Schedule A-5) plus hedging settlement cost dollars (Schedule A-1) per MMBtu of natural gas purchased? If the number is great enough, please supply the Commission with monthly hedging settlement costs by fuel type, for 2002 to the present.

ANSWER:

The monthly dollar amounts for hedging settlement costs do not contain any dollars for non-natural gas hedging settlement costs.

16. Please supply the Commission with the 2002-through-2006 natural gas gains and losses resulting from Gulf's 2002-through-2006 physical and financial hedging activities, separated as follows: (1) natural gas – physical, (2) natural gas – financial, both for 2002 through 2006).

ANSWER:

The following table represents Gulf Power Company's natural gas gains and losses from hedging activities for the period 2002 through 2006. Gulf does not hedge gas prices physically.

YEAR	NATURAL GAS – PHYSICAL (GAIN) or LOSS	NATURAL GAS – FINANCIAL (GAIN) or LOSS
2002	**$ 0**	**$(238,750)**
2003	**$ 0**	**$ (4,862,077)**
2004	**$ 0**	**$ (6,652,155)**
2005	**$ 0**	**$ (22,571,977)**
2006	**$ 0**	**$ 18,714,562**

Gulf Power Company

Gulf Power Company Monthly Fuel Filings for January 2006 – December 2006 ("A" Schedules)

070001

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	39,090,984	41,601,548	(2,510,564)	(6.03)	1,412,826,000	1,422,060,000	(9,234,000)	(0.65)	2.7669	2.9254	(0.16)	(5.42)
2	Hedging Settlement Costs	52,040	0	52,040	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	5,750	2,757	2,993	108.56	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	14,495	0	14,495	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	39,163,269	41,604,305	(2,441,036)	(5.87)	1,412,826,000	1,422,060,000	(9,234,000)	(0.65)	2.7720	2.9256	(0.15)	(5.25)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	1,971,822	2,154,000	(182,178)	(8.46)	86,625,289	53,551,000	33,074,289	61.76	2.2763	4.0223	(1.75)	(43.41)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	108,228	0	108,228	5.02	1,843,000	0	1,843,000	#N/A	5.8724	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	2,080,050	2,154,000	(73,950)	(3.43)	88,468,289	53,551,000	34,917,289	65.20	2.3512	4.0223	(1.67)	(41.55)
14	Total Available MWH (Line 6 + Line 13)	41,243,319	43,758,305	(2,514,986)	(5.75)	1,501,294,289	1,475,611,000	25,683,289	1.74				
15	Fuel Cost of Economy Sales (A6)	(415,137)	(1,509,000)	1,093,863	(72.49)	(9,024,371)	(31,540,000)	22,515,629	71.39	(4.6002)	(4.7844)	0.18	3.85
16	Gain on Economy Sales (A6)	(73,864)	(285,000)	211,136	(74.08)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,713,001)	(2,769,000)	55,999	(2.02)	(133,346,625)	(129,342,000)	(4,004,625)	(3.10)	(2.0345)	(2.1408)	0.11	4.97
18	Fuel Cost of Other Power Sales (A6)	(19,114,683)	(11,040,000)	(8,074,683)	73.14	(472,990,480)	(324,757,000)	(148,233,480)	(45.64)	(4.0412)	(3.3995)	(0.64)	(18.88)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(22,316,685)	(15,603,000)	(6,713,685)	(43.03)	(615,361,476)	(485,639,000)	(129,722,476)	(26.71)	(3.6266)	(3.2129)	(0.41)	(12.88)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	18,926,634	28,155,305	(9,228,671)	(32.78)	885,932,813	989,972,000	(104,039,187)	(10.51)	2.1364	2.8441	(0.71)	(24.88)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	41,733	58,332	(16,599)	(28.46)	1,953,426	2,051,000	(97,574)	(4.76)	2.1364	2.8441	(0.71)	(24.88)
24	T & D Losses *	1,205,251	1,547,020	(341,769)	(22.09)	56,415,059	54,394,000	2,021,059	3.72	2.1364	2.8441	(0.71)	(24.88)
25	TERRITORIAL KWH SALES	18,926,634	28,155,305	(9,228,671)	(32.78)	827,564,328	933,527,000	(105,962,672)	(11.35)	2.2870	3.0160	(0.73)	(24.17)
26	Wholesale KWH Sales	693,434	1,005,849	(312,415)	(31.06)	30,320,646	33,350,000	(3,029,354)	(9.08)	2.2870	3.0160	(0.73)	(24.17)
27	Jurisdictional KWH Sales	18,233,200	27,149,456	(8,916,256)	(32.84)	797,243,682	900,177,000	(102,933,318)	(11.43)	2.2870	3.0160	(0.73)	(24.17)
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	18,245,963	27,168,461	(8,922,498)	(32.84)	797,243,682	900,177,000	(102,933,318)	(11.43)	2.2886	3.0181	(0.73)	(24.17)
29	TRUE-UP	955,051	955,051	0	0.00	797,243,682	900,177,000	(102,933,318)	(11.43)	0.1198	0.1061	0.01	12.91
30	TOTAL JURISDICTIONAL FUEL COST	19,201,014	28,123,512	(8,922,498)	(31.73)	797,243,682	900,177,000	(102,933,318)	(11.43)	2.4084	3.1242	(0.72)	(22.91)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									2.4101	3.1264	(0.72)	(22.91)
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	797,243,682	900,177,000	(102,933,318)	(11.43)	0.0046	0.0041	0.00	12.20
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.4147	3.1305	(0.72)	(22.87)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.415	3.131		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: JANUARY 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$39,090,984
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	14,495
4	Hedging Settlement Costs	Schedule A-2, Line A-6	52,040
5	Hedging Support Costs	Schedule A-2, Line A-5	5,750
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	1,971,822
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	108,228
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(22,316,685)
11	Total Fuel and Net Power Transactions		$ 18,926,634

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	39,090,984	41,601,548	(2,510,564)	(6.03)	1,412,826,000	1,422,060,000	(9,234,000)	(0.65)	2.7669	2.9254	(0.16)	(5.42)
2	Hedging Settlement Costs	52,040	0	52,040	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	5,750	2,757	2,993	108.56	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	14,495	0	14,495	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	39,163,269	41,604,305	(2,441,036)	(5.87)	1,412,826,000	1,422,060,000	(9,234,000)	(0.65)	2.7720	2.9256	(0.15)	(5.25)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	1,971,822	2,154,000	(182,178)	(8.46)	86,625,289	53,551,000	33,074,289	61.76	2.2763	4.0223	(1.75)	(43.41)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	108,228	0	108,228	#N/A	1,843,000	0	1,843,000	#N/A	5.8724	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	2,080,050	2,154,000	(73,950)	(3.43)	88,468,289	53,551,000	34,917,289	65.20	2.3512	4.0223	(1.67)	(41.55)
14	Total Available MWH (Line 6 + Line 13)	41,243,319	43,758,305	(2,514,986)	(5.75)	1,501,294,289	1,475,611,000	25,683,289	1.74				
15	Fuel Cost of Economy Sales (A6)	(415,137)	(1,509,000)	1,093,863	(72.49)	(9,024,371)	(31,540,000)	22,515,629	71.39	(4.6002)	(4.7844)	0.18	3.85
16	Gain on Economy Sales (A6)	(73,864)	(285,000)	211,136	(74.08)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,713,001)	(2,769,000)	55,999	(2.02)	(133,346,625)	(129,342,000)	(4,004,625)	(3.10)	(2.0345)	(2.1408)	0.11	4.97
18	Fuel Cost of Other Power Sales (A6)	(19,114,683)	(11,040,000)	(8,074,683)	73.14	(472,990,480)	(324,757,000)	(148,233,480)	(45.64)	(4.0412)	(3.3995)	(0.64)	(18.88)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(22,316,685)	(15,603,000)	(6,713,685)	(43.03)	(615,361,476)	(485,639,000)	(129,722,476)	(26.71)	(3.6266)	(3.2129)	(0.41)	(12.88)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	18,926,634	28,155,305	(9,228,671)	(32.78)	885,932,813	989,972,000	(104,039,187)	(10.51)	2.1364	2.8441	(0.71)	(24.88)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	41,733	58,332	(16,599)	(28.46)	1,953,426	2,051,000	(97,574)	4.76	2.1364	2.8441	(0.71)	(24.88)
24	T & D Losses *	1,205,251	1,547,020	(341,769)	(22.09)	56,415,059	54,394,000	2,021,059	(3.72)	2.1364	2.8441	(0.71)	(24.88)
25	TERRITORIAL KWH SALES	18,926,634	28,155,305	(9,228,671)	(32.78)	827,564,328	933,527,000	(105,962,672)	11.35	2.2870	3.0160	(0.73)	(24.17)
26	Wholesale KWH Sales	693,434	1,005,849	(312,415)	(31.06)	30,320,646	33,350,000	(3,029,354)	9.08	2.2870	3.0160	(0.73)	(24.17)
27	Jurisdictional KWH Sales	18,233,200	27,149,456	(8,916,256)	(32.84)	797,243,682	900,177,000	(102,933,318)	(11.43)	2.2870	3.0160	(0.73)	(24.17)
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	18,245,963	27,168,461	(8,922,498)	(32.84)	797,243,682	900,177,000	(102,933,318)	11.43	2.2886	3.0181	(0.73)	(24.17)
29	TRUE-UP	955,051	955,051	0	0.00	797,243,682	900,177,000	(102,933,318)	11.43	0.1198	0.1061	0.01	12.91
30	TOTAL JURISDICTIONAL FUEL COST	19,201,014	28,123,512	(8,922,498)	(31.73)	797,243,682	900,177,000	(102,933,318)	(11.43)	2.4084	3.1242	(0.72)	(22.91)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									2.4101	3.1264	(0.72)	(22.91)
33	GPIF Reward / (Penalty) **	36,832	36,832	0	0.00	797,243,682	900,177,000	(102,933,318)	(11.43)	0.0046	0.0041	0.00	12.20
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.4147	3.1305	(0.72)	(22.87)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.415	3.131		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	38,974,329.66	41,430,005	(2,455,675.34)	(5.93)	38,974,329.66	41,430,005	(2,455,675.34)	(5.93)
1a	Other Generation	116,654.62	171,543	(54,888.38)	(32.00)	116,654.62	171,543	(54,888.38)	(32.00)
2	Fuel Cost of Power Sold	(22,316,685.45)	(15,603,000)	(6,713,685.45)	43.03	(22,316,685.45)	(15,603,000)	(6,713,685.45)	43.03
3	Fuel Cost - Purchased Power	1,971,822.39	2,154,000	(182,177.61)	(8.46)	1,971,822.39	2,154,000	(182,177.61)	(8.46)
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	108,228.00	0	108,228.00	100.00	108,228.00	0	108,228.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	5,749.92	2,757	2,992.92	108.56	5,749.92	2,757	2,992.92	108.56
6	Hedging Settlement Cost	52,040.00	0	52,040.00	(100.00)	52,040.00	0	52,040.00	(100.00)
7	Total Fuel & Net Power Transactions	18,912,139.14	28,155,305	(9,243,166)	(32.83)	18,912,139.14	28,155,305	(9,243,166)	(32.83)
8	AdjustmentsTo Fuel Cost	14,494.66	0	14,494.66	#N/A	14,494.66	0	14,494.66	#N/A
9	Adj. Total Fuel & Net Power Transactions	18,926,633.80	28,155,305	(9,228,671.20)	(32.78)	18,926,633.80	28,155,305	(9,228,671.20)	(32.78)
B.	*KWH Sales*								
1	Jurisdictional Sales	797,243,682	900,177,000	(102,933,318)	(11.43)	797,243,682	900,177,000	(102,933,318)	(11.43)
2	Non-Jurisdictional Sales	30,320,646	33,350,000	(3,029,354)	(9.08)	30,320,646	33,350,000	(3,029,354)	(9.08)
3	Total Territorial Sales	827,564,328	933,527,000	(105,962,672)	(11.35)	827,564,328	933,527,000	(105,962,672)	(11.35)
4	Juris. Sales as % of Total Terr. Sales	96.3362	96.4275	(0.0913)	(0.09)	96.3362	96.4275	(0.0913)	(0.09)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	24,791,148.16	27,669,522	(2,878,373.84)	(10.40)	24,791,148.16	27,669,522	(2,878,373.84)	(10.40)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(955,051.42)	(955,051)	(0.42)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(36,805.83)	(36,806)	0.17	0.00
3	Juris. Fuel Revenue Applicable to Period	23,799,290.91	26,677,665	(2,878,374.09)	(10.79)	23,799,290.91	26,677,665	(2,878,374.09)	(10.79)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	18,926,633.80	28,155,305	(9,228,671.20)	(32.78)	18,926,633.80	28,155,305	(9,228,671.20)	(32.78)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.3362	96.4275	(0.0913)	(0.09)	96.3362	96.4275	(0.0913)	(0.09)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	18,245,963.03	27,168,461	(8,922,497.97)	(32.84)	18,245,963.03	27,168,461	(8,922,497.97)	(32.84)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	5,553,327.88	(490,796)	6,044,123.88	(1,231.49)	5,553,327.88	(490,796)	6,044,123.88	(1,231.49)
8	Interest Provision for the Month	(104,184.98)	(41,220)	(62,964.98)	152.75	(104,184.98)	(41,220)	(62,964.98)	152.75
9	Beginning True-Up & Interest Provision*	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	955,051.42	955,051	0.42	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(25,230,540.41)	(11,037,582)	(14,192,958.41)	128.59	(25,230,540.41)	(11,037,582)	(14,192,958.41)	128.59

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(25,126,355.43)	(10,996,362)	(14,129,993.43)	128.50
3	Total of Beginning & Ending True-Up Amts.	(56,761,090.16)	(22,456,979)	(34,304,111.16)	152.75
4	Average True-Up Amount	(28,380,545.08)	(11,228,490)	(17,152,055.08)	152.75
5	Interest Rate - 1st Day of Reporting Business Month	4.30	4.30	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	4.51	4.51	0.0000	
7	Total (D5+D6)	8.81	8.81	0.0000	
8	Annual Average Interest Rate	4.41	4.41	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.3671	0.3671	0.0000	
10	Interest Provision (D4*D9)	(104,184.98)	(41,220)	(62,964.98)	152.75
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

REVISED 6/19/06

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	39,435,645	37,604,916	1,830,729	4.87	1,352,455,000	1,254,950,000	97,505,000	7.77	2.9159	2.9965	(0.08)	(2.69)
2	Hedging Settlement Costs	894,967	0	894,967	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	6,743	2,757	3,986	144.58	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	16,135	0	16,135	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	40,353,490	37,607,673	2,745,817	7.30	1,352,455,000	1,254,950,000	97,505,000	7.77	2.9837	2.9967	(0.01)	(0.43)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	1,765,355	1,413,000	352,355	24.94	78,503,032	33,003,000	45,500,032	137.87	2.2488	4.2814	(2.03)	(47.48)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	57,627	0	57,627	4.08	1,204,194	0	1,204,194	#N/A	4.7855	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	1,822,982	1,413,000	409,982	29.02	79,707,226	33,003,000	46,704,226	141.52	2.2871	4.2814	(1.99)	(46.58)
14	Total Available MWH (Line 6 + Line 13)	42,176,472	39,020,673	3,155,799	8.09	1,432,162,226	1,287,953,000	144,209,226	11.20				
15	Fuel Cost of Economy Sales (A6)	(646,967)	(899,000)	252,033	(28.03)	(10,631,917)	(16,760,000)	6,128,083	36.56	(6.0851)	(5.3640)	(0.72)	(13.44)
16	Gain on Economy Sales (A6)	(116,342)	(239,000)	122,658	(51.32)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(3,071,702)	(3,128,000)	56,298	(1.80)	(140,186,977)	(135,872,000)	(4,314,977)	(3.18)	(2.1911)	(2.3022)	0.11	4.83
18	Fuel Cost of Other Power Sales (A6)	(16,728,477)	(9,854,000)	(6,874,477)	69.76	(443,074,639)	(280,206,000)	(162,868,639)	(58.12)	(3.7755)	(3.5167)	(0.26)	(7.36)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(20,563,488)	(14,120,000)	(6,443,488)	(45.63)	(593,893,533)	(432,838,000)	(161,055,533)	(37.21)	(3.4625)	(3.2622)	(0.20)	(6.14)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	21,612,984	24,900,673	(3,287,689)	(13.20)	838,268,693	855,115,000	(16,846,307)	(1.97)	2.5783	2.912	(0.33)	(11.46)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	45,805	57,046	(11,241)	(19.71)	1,776,544	1,959,000	(182,456)	(9.31)	2.5783	2.9120	(0.33)	(11.46)
24	T & D Losses *	444,185	1,174,876	(730,691)	(62.19)	17,227,834	40,346,000	(23,118,166)	(57.30)	2.5783	2.9120	(0.33)	(11.46)
25	TERRITORIAL KWH SALES	21,612,984	24,900,673	(3,287,689)	(13.20)	819,264,315	812,810,000	6,454,315	0.79	2.6381	3.0635	(0.43)	(13.89)
26	Wholesale KWH Sales	777,787	822,842	(45,055)	(5.48)	29,482,516	26,859,000	2,623,516	9.77	2.6381	3.0636	(0.43)	(13.89)
27	Jurisdictional KWH Sales	20,835,197	24,077,831	(3,242,634)	(13.47)	789,781,799	785,951,000	3,830,799	0.49	2.6381	3.0635	(0.43)	(13.89)
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	20,849,782	24,094,685	(3,244,903)	(13.47)	789,781,799	785,951,000	3,830,799	0.49	2.6399	3.0657	(0.43)	(13.89)
29	TRUE-UP	955,051	955,051	0	0.00	789,781,799	785,951,000	3,830,799	0.49	0.1209	0.1215	(0.00)	(0.49)
30	TOTAL JURISDICTIONAL FUEL COST	21,804,833	25,049,736	(3,244,903)	(12.95)	789,781,799	785,951,000	3,830,799	0.49	2.7608	3.1872	(0.43)	(13.38)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									2.7628	3.1895	(0.43)	(13.38)
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	789,781,799	785,951,000	3,830,799	0.49	0.0047	0.0047	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.7675	3.1942	(0.43)	(13.36)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.768	3.194		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: FEBRUARY 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$39,435,645
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	16,135
4	Hedging Settlement Costs	Schedule A-2, Line A-6	894,967
5	Hedging Support Costs	Schedule A-2, Line A-5	6,743
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	1,765,355
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	57,627
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(20,563,488)
11	Total Fuel and Net Power Transactions		$ 21,612,984

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FEBRUARY 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	78,526,629	79,206,464	(679,835)	(0.86)	2,765,261,000	2,677,010,000	88,271,000	3.30	2.8397	2.9588	(0.12)	(4.03)
2	Hedging Settlement Costs	947,007	0	947,007	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	12,493	5,514	6,979	126.57	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	30,630	0	30,630	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	79,516,759	79,211,978	304,781	0.38	2,765,261,000	2,677,010,000	88,271,000	3.30	2.8755	2.9590	(0.08)	(2.82)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	3,737,177	3,567,000	170,177	4.77	165,128,321	86,554,000	78,574,321	90.78	2.2632	4.1211	(1.86)	(45.08)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	165,855	0	165,855	#N/A	3,047,194	0	3,047,194	#N/A	5.4429	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	3,903,032	3,567,000	336,032	9.42	168,175,515	86,554,000	81,621,515	94.30	2.3208	4.1211	(1.80)	(43.68)
14	Total Available MWH (Line 6 + Line 13)	83,419,791	82,778,978	640,813	0.77	2,933,456,515	2,763,564,000	169,892,515	6.15				
15	Fuel Cost of Economy Sales (A6)	(1,062,104)	(2,408,000)	1,345,896	(55.89)	(19,656,288)	(48,300,000)	28,643,712	59.30	(5.4034)	(4.9855)	(0.42)	(8.38)
16	Gain on Economy Sales (A6)	(190,206)	(524,000)	333,794	(63.70)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(5,784,703)	(5,897,000)	112,297	(1.90)	(273,533,602)	(265,214,000)	(8,319,602)	(3.14)	(2.1148)	(2.2235)	0.11	4.89
18	Fuel Cost of Other Power Sales (A6)	(35,843,160)	(20,894,000)	(14,949,160)	71.55	(916,065,119)	(604,963,000)	(311,102,119)	(51.42)	(3.9127)	(3.4538)	(0.46)	(13.29)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(42,880,173)	(29,723,000)	(13,157,173)	(44.27)	(1,209,255,009)	(918,477,000)	(290,778,009)	(31.66)	(3.5460)	(3.2361)	(0.31)	(9.58)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	40,539,618	53,055,978	(12,516,360)	(23.59)	1,724,201,506	1,845,087,000	(120,885,494)	(6.55)	2.3512	2.8755	(0.52)	(18.23)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	87,699	115,308	(27,609)	(23.94)	3,729,970	4,010,000	(280,030)	6.98	2.3512	2.8755	(0.52)	(18.23)
24	T & D Losses *	1,731,492	2,724,249	(992,757)	(36.44)	73,642,893	94,740,000	(21,097,107)	22.27	2.3512	2.8755	(0.52)	(18.23)
25	TERRITORIAL KWH SALES	40,539,618	53,055,978	(12,516,360)	(23.59)	1,646,828,643	1,746,337,000	(99,508,357)	5.70	2.4617	3.0381	(0.58)	(18.97)
26	Wholesale KWH Sales	1,471,221	1,828,691	(357,470)	(19.55)	59,803,162	60,209,000	(405,838)	0.67	2.4601	3.0372	(0.58)	(19.00)
27	Jurisdictional KWH Sales	39,068,397	51,227,287	(12,158,890)	(23.74)	1,587,025,481	1,686,128,000	(99,102,519)	(5.88)	2.4617	3.0382	(0.58)	(18.98)
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	39,095,745	51,263,146	(12,167,401)	(23.74)	1,587,025,481	1,686,128,000	(99,102,519)	5.88	2.4635	3.0403	(0.58)	(18.97)
29	TRUE-UP	1,910,102	1,910,102	0	0.00	1,587,025,481	1,686,128,000	(99,102,519)	5.88	0.1204	0.1133	0.01	6.27
30	TOTAL JURISDICTIONAL FUEL COST	41,005,847	53,173,248	(12,167,401)	(22.88)	1,587,025,481	1,686,128,000	(99,102,519)	(5.88)	2.5839	3.1536	(0.57)	(18.07)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									2.5858	3.1559	(0.57)	(18.06)
33	GPIF Reward / (Penalty) **	73,664	73,665	0	0.00	1,587,025,481	1,686,128,000	(99,102,519)	(5.88)	0.0046	0.0044	0.00	4.55
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.5904	3.1603	(0.57)	(18.03)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.590	3.160		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	39,342,626.00	37,449,868	1,892,758.00	5.05	78,316,955.66	78,879,873	(562,917.34)	(0.71)
1a	Other Generation	93,019.02	155,048	(62,028.98)	(40.01)	209,673.64	326,591	(116,917.36)	(35.80)
2	Fuel Cost of Power Sold	(20,563,488.02)	(14,120,000)	(6,443,488.02)	45.63	(42,880,173.47)	(29,723,000)	(13,157,173.47)	44.27
3	Fuel Cost - Purchased Power	1,765,354.67	1,413,000	352,354.67	24.94	3,737,177.06	3,567,000	170,177.06	4.77
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	57,627.00	0	57,627.00	100.00	165,855.00	0	165,855.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	6,743.47	2,757	3,986.47	144.59	12,493.39	5,514	6,979.39	126.58
6	Hedging Settlement Cost	894,967.00	0	894,967.00	(100.00)	947,007.00	0	947,007.00	(100.00)
7	Total Fuel & Net Power Transactions	21,596,849.14	24,900,673	(3,303,824)	(13.27)	40,508,988.28	53,055,978	(12,546,990)	(23.65)
8	AdjustmentsTo Fuel Cost	16,135.10	0	16,135.10	#N/A	30,629.76	0	30,629.76	#N/A
9	Adj. Total Fuel & Net Power Transactions	21,612,984.24	24,900,673	(3,287,688.76)	(13.20)	40,539,618.04	53,055,978	(12,516,359.96)	(23.59)
B.	*KWH Sales*								
1	Jurisdictional Sales	789,781,799	785,951,000	3,830,799	0.49	1,587,025,481	1,686,128,000	(99,102,519)	(5.88)
2	Non-Jurisdictional Sales	29,482,516	26,859,000	2,623,516	9.77	59,803,162	60,209,000	(405,838)	(0.67)
3	Total Territorial Sales	819,264,315	812,810,000	6,454,315	0.79	1,646,828,643	1,746,337,000	(99,508,357)	(5.70)
4	Juris. Sales as % of Total Terr. Sales	96.4013	96.6955	(0.2942)	(0.30)	96.3686	96.5523	(0.1837)	(0.19)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	24,215,128.67	24,158,459	56,669.67	0.23	49,006,276.83	51,827,981	(2,821,704.17)	(5.44)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(1,910,102.84)	(1,910,102)	(0.84)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(73,611.66)	(73,612)	0.34	0.00
3	Juris. Fuel Revenue Applicable to Period	23,223,271.42	23,166,602	56,669.42	0.24	47,022,562.33	49,844,267	(2,821,704.67)	(5.66)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	21,612,984.24	24,900,673	(3,287,688.76)	(13.20)	40,539,618.04	53,055,978	(12,516,359.96)	(23.59)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.4013	96.6955	(0.2942)	(0.30)	96.3686	96.5523	(0.1837)	(0.19)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	20,849,782.41	24,094,685	(3,244,902.59)	(13.47)	39,095,745.44	51,263,146	(12,167,400.56)	(23.74)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	2,373,489.01	(928,083)	3,301,572.01	(355.74)	7,926,816.89	(1,418,879)	9,345,695.89	(658.67)
8	Interest Provision for the Month	(88,774.14)	(41,528)	(47,246.14)	113.77	(192,959.12)	(82,748)	(110,211.12)	133.19
9	Beginning True-Up & Interest Provision*	(25,230,540.41)	(11,037,582)	(14,192,958.41)	128.59	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	1,910,102.84	1,910,102	0.84	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(21,990,774.12)	(11,052,142)	(10,938,632.12)	98.97	(21,990,774.12)	(11,052,142)	(10,938,632.12)	98.97

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(25,230,540.41)	(11,037,582)	(14,192,958.41)	128.59
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(21,901,999.98)	(11,010,614)	(10,891,385.98)	98.92
3	Total of Beginning & Ending True-Up Amts.	(47,132,540.39)	(22,048,196)	(25,084,344.39)	113.77
4	Average True-Up Amount	(23,566,270.20)	(11,024,098)	(12,542,172.20)	113.77
5	Interest Rate - 1st Day of Reporting Business Month	4.51	4.51	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	4.53	4.53	0.0000	
7	Total (D5+D6)	9.04	9.04	0.0000	
8	Annual Average Interest Rate	4.52	4.52	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.3767	0.3767	0.0000	
10	Interest Provision (D4*D9)	(88,774.14)	(41,528)	(47,246.14)	113.77
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

REVISED 6/19/06

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	37,875,076	38,584,372	(709,296)	(1.84)	1,292,159,000	1,273,870,000	18,289,000	1.44	2.9311	3.0289	(0.10)	(3.23)
2	Hedging Settlement Costs	2,369,750	0	2,369,750	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	10,508	2,757	7,751	281.14	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	5,464	0	5,464	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	40,260,798	38,587,129	1,673,669	4.34	1,292,159,000	1,273,870,000	18,289,000	1.44	3.1158	3.0291	0.09	2.86
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	1,992,182	2,531,000	(538,818)	(21.29)	79,333,456	60,402,000	18,931,456	31.34	2.5111	4.1903	(1.68)	(40.07)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	14,293	0	14,293	0.56	316,569	0	316,569	#N/A	4.5150	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	2,006,475	2,531,000	(524,525)	(20.72)	79,650,025	60,402,000	19,248,025	31.87	2.5191	4.1903	(1.67)	(39.88)
14	Total Available MWH (Line 6 + Line 13)	42,267,273	41,118,129	1,149,144	2.79	1,371,809,025	1,334,272,000	37,537,025	2.81				
15	Fuel Cost of Economy Sales (A6)	(618,167)	(1,846,000)	1,227,833	(66.51)	(14,354,494)	(35,374,000)	21,019,506	59.42	(4.3064)	(5.2185)	0.91	17.48
16	Gain on Economy Sales (A6)	(126,527)	(202,000)	75,473	(37.36)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(3,383,974)	(3,602,000)	218,026	(6.05)	(151,143,653)	(159,074,000)	7,930,347	4.99	(2.2389)	(2.2644)	0.03	1.13
18	Fuel Cost of Other Power Sales (A6)	(11,355,656)	(9,688,000)	(1,667,656)	17.21	(343,976,954)	(273,375,000)	(70,601,954)	(25.83)	(3.3013)	(3.5439)	0.24	6.85
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(15,484,324)	(15,338,000)	(146,324)	(0.95)	(509,475,101)	(467,823,000)	(41,652,101)	(8.90)	(3.0393)	(3.2786)	0.24	7.30
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	26,782,949	25,780,129	1,002,820	3.89	862,333,924	866,449,000	(4,115,076)	(0.47)	3.1059	2.9754	0.13	4.39
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	53,321	63,703	(10,382)	(16.30)	1,716,767	2,141,000	(424,233)	(19.81)	3.1059	2.9754	0.13	4.39
24	T & D Losses *	2,294,565	1,243,747	1,050,818	84.49	73,877,619	41,801,000	32,076,619	76.74	3.1059	2.9754	0.13	4.39
25	TERRITORIAL KWH SALES	26,782,949	25,780,129	1,002,820	3.89	786,739,538	822,507,000	(35,767,462)	(4.35)	3.4043	3.1343	0.27	8.61
26	Wholesale KWH Sales	963,169	888,744	74,425	8.37	28,292,835	28,355,000	(62,165)	(0.22)	3.4043	3.1343	0.27	8.61
27	Jurisdictional KWH Sales	25,819,780	24,891,385	928,395	3.73	758,446,703	794,152,000	(35,705,297)	(4.50)	3.4043	3.1343	0.27	8.61
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	25,837,854	24,908,809	929,045	3.73	758,446,703	794,152,000	(35,705,297)	(4.50)	3.4067	3.1365	0.27	8.61
29	TRUE-UP	955,051	955,051	0	0.00	758,446,703	794,152,000	(35,705,297)	(4.50)	0.1259	0.1203	0.01	4.66
30	TOTAL JURISDICTIONAL FUEL COST	26,792,905	25,863,860	929,045	3.59	758,446,703	794,152,000	(35,705,297)	(4.50)	3.5326	3.2568	0.28	8.47
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5351	3.2591	0.28	8.47
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	758,446,703	794,152,000	(35,705,297)	(4.50)	0.0049	0.0046	0.00	6.52
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5400	3.2637	0.28	8.47
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.540	3.264		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: MARCH 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$37,875,076
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	5,464
4	Hedging Settlement Costs	Schedule A-2, Line A-6	2,369,750
5	Hedging Support Costs	Schedule A-2, Line A-5	10,508
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	1,992,182
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	14,293
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(15,484,324)
11	Total Fuel and Net Power Transactions		$ 26,782,949

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MARCH 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	116,401,705	117,790,836	(1,389,131)	(1.18)	4,057,440,000	3,950,880,000	106,560,000	2.70	2.8688	2.9814	(0.11)	(3.78)
2	Hedging Settlement Costs	3,316,757	0	3,316,757	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	23,001	8,271	14,730	178.09	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	36,094	0	36,094	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	119,777,557	117,799,107	1,978,450	1.68	4,057,440,000	3,950,880,000	106,560,000	2.70	2.9520	2.9816	(0.03)	(0.99)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	5,729,359	6,098,000	(368,641)	(6.05)	244,461,777	146,956,000	97,505,777	66.35	2.3437	4.1495	(1.81)	(43.52)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	180,148	0	180,148	#N/A	3,363,763	0	3,363,763	#N/A	5.3555	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	5,909,507	6,098,000	(188,493)	(3.09)	247,825,540	146,956,000	100,869,540	68.64	2.3845	4.1495	(1.77)	(42.54)
14	Total Available MWH (Line 6 + Line 13)	125,687,064	123,897,107	1,789,957	1.44	4,305,265,540	4,097,836,000	207,429,540	5.06				
15	Fuel Cost of Economy Sales (A6)	(1,680,271)	(4,254,000)	2,573,729	(60.50)	(34,010,782)	(83,674,000)	49,663,218	59.35	(4.9404)	(5.0840)	0.14	2.82
16	Gain on Economy Sales (A6)	(316,733)	(726,000)	409,267	(56.37)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(9,168,677)	(9,499,000)	330,323	(3.48)	(424,677,255)	(424,288,000)	(389,255)	(0.09)	(2.1590)	(2.2388)	0.08	3.56
18	Fuel Cost of Other Power Sales (A6)	(47,198,816)	(30,582,000)	(16,616,816)	54.34	(1,260,042,073)	(878,338,000)	(381,704,073)	(43.46)	(3.7458)	(3.4818)	(0.26)	(7.58)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(58,364,497)	(45,061,000)	(13,303,497)	(29.52)	(1,718,730,110)	(1,386,300,000)	(332,430,110)	(23.98)	(3.3958)	(3.2505)	(0.15)	(4.47)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	67,322,567	78,836,107	(11,513,540)	(14.60)	2,586,535,430	2,711,536,000	(125,000,570)	(4.61)	2.6028	2.9074	(0.30)	(10.48)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	141,768	178,834	(37,066)	(20.73)	5,446,737	6,151,000	(704,263)	11.45	2.6028	2.9074	(0.30)	(10.48)
24	T & D Losses *	3,839,664	3,969,793	(130,129)	(3.28)	147,520,512	136,541,000	10,979,512	(8.04)	2.6028	2.9074	(0.30)	(10.48)
25	TERRITORIAL KWH SALES	67,322,567	78,836,107	(11,513,540)	(14.60)	2,433,568,181	2,568,844,000	(135,275,819)	5.27	2.7664	3.0689	(0.30)	(9.86)
26	Wholesale KWH Sales	2,434,390	2,717,435	(283,045)	(10.42)	88,095,997	88,564,000	(468,003)	0.53	2.7633	3.0683	(0.31)	(9.94)
27	Jurisdictional KWH Sales	64,888,177	76,118,672	(11,230,495)	(14.75)	2,345,472,184	2,480,280,000	(134,807,816)	(5.44)	2.7665	3.0690	(0.30)	(9.86)
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	64,933,599	76,171,955	(11,238,356)	(14.75)	2,345,472,184	2,480,280,000	(134,807,816)	5.44	2.7685	3.0711	(0.30)	(9.85)
29	TRUE-UP	2,865,153	2,865,153	0	0.00	2,345,472,184	2,480,280,000	(134,807,816)	5.44	0.1222	0.1155	0.01	5.80
30	TOTAL JURISDICTIONAL FUEL COST	67,798,752	79,037,108	(11,238,356)	(14.22)	2,345,472,184	2,480,280,000	(134,807,816)	(5.44)	2.8907	3.1866	(0.30)	(9.29)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									2.8928	3.1889	(0.30)	(9.29)
33	GPIF Reward / (Penalty) **	110,496	110,497	0	0.00	2,345,472,184	2,480,280,000	(134,807,816)	(5.44)	0.0047	0.0045	0.00	4.44
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.8975	3.1934	(0.30)	(9.27)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.898	3.193		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	37,773,180.50	38,412,829	(639,648.50)	(1.67)	116,090,136.16	117,292,702	(1,202,565.84)	(1.03)
1a	Other Generation	101,895.64	171,543	(69,647.36)	(40.60)	311,569.28	498,134	(186,564.72)	(37.45)
2	Fuel Cost of Power Sold	(15,484,324.29)	(15,338,000)	(146,324.29)	0.95	(58,364,497.76)	(45,061,000)	(13,303,497.76)	29.52
3	Fuel Cost - Purchased Power	1,992,181.76	2,531,000	(538,818.24)	(21.29)	5,729,358.82	6,098,000	(368,641.18)	(6.05)
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	14,293.00	0	14,293.00	100.00	180,148.00	0	180,148.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	10,508.08	2,757	7,751.08	281.14	23,001.47	8,271	14,730.47	178.10
6	Hedging Settlement Cost	2,369,750.00	0	2,369,750.00	(100.00)	3,316,757.00	0	3,316,757.00	(100.00)
7	Total Fuel & Net Power Transactions	26,777,484.69	25,780,129	997,356	3.87	67,286,472.97	78,836,107	(11,549,634)	(14.65)
8	AdjustmentsTo Fuel Cost	5,464.21	0	5,464.21	#N/A	36,093.97	0	36,093.97	#N/A
9	Adj. Total Fuel & Net Power Transactions	26,782,948.90	25,780,129	1,002,819.90	3.89	67,322,566.94	78,836,107	(11,513,540.06)	(14.60)
B.	*KWH Sales*								
1	Jurisdictional Sales	758,446,703	794,152,000	(35,705,297)	(4.50)	2,345,472,184	2,480,280,000	(134,807,816)	(5.44)
2	Non-Jurisdictional Sales	28,292,835	28,355,000	(62,165)	(0.22)	88,095,997	88,564,000	(468,003)	(0.53)
3	Total Territorial Sales	786,739,538	822,507,000	(35,767,462)	(4.35)	2,433,568,181	2,568,844,000	(135,275,819)	(5.27)
4	Juris. Sales as % of Total Terr. Sales	96.4038	96.5526	(0.1488)	(0.15)	96.3800	96.5524	(0.1724)	(0.18)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2006

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	23,245,847.44	24,410,540	(1,164,692.56)	(4.77)	72,252,124.27	76,238,521	(3,986,396.73)	(5.23)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(2,865,154.26)	(2,865,153)	(1.26)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(110,417.49)	(110,418)	0.51	0.00
3	Juris. Fuel Revenue Applicable to Period	22,253,990.19	23,418,683	(1,164,692.81)	(4.97)	69,276,552.52	73,262,950	(3,986,397.48)	(5.44)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	26,782,948.90	25,780,129	1,002,819.90	3.89	67,322,566.94	78,836,107	(11,513,540.06)	(14.60)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.4038	96.5526	(0.1488)	(0.15)	96.3800	96.5524	(0.1724)	(0.18)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	25,837,854.34	24,908,809	929,045.34	3.73	64,933,599.78	76,171,955	(11,238,355.22)	(14.75)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(3,583,864.15)	(1,490,126)	(2,093,738.15)	140.51	4,342,952.74	(2,909,005)	7,251,957.74	(249.29)
8	Interest Provision for the Month	(90,400.80)	(43,909)	(46,491.80)	105.88	(283,359.92)	(126,657)	(156,702.92)	123.72
9	Beginning True-Up & Interest Provision*	(21,990,774.12)	(11,052,142)	(10,938,632.12)	98.97	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	2,865,154.26	2,865,153	1.26	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(24,709,987.65)	(11,631,126)	(13,078,861.65)	112.45	(24,709,987.65)	(11,631,126)	(13,078,861.65)	112.45

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(21,990,774.12)	(11,052,142)	(10,938,632.12)	98.97
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(24,619,586.85)	(11,587,217)	(13,032,369.85)	112.47
3	Total of Beginning & Ending True-Up Amts.	(46,610,360.97)	(22,639,359)	(23,971,001.97)	105.88
4	Average True-Up Amount	(23,305,180.49)	(11,319,680)	(11,985,500.49)	105.88
5	Interest Rate - 1st Day of Reporting Business Month	4.53	4.53	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	4.78	4.78	0.0000	
7	Total (D5+D6)	9.31	9.31	0.0000	
8	Annual Average Interest Rate	4.66	4.66	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.3879	0.3879	0.0000	
10	Interest Provision (D4*D9)	(90,400.80)	(43,909)	(46,491.80)	105.88
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

REVISED 6/19/06

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	30,610,272	28,905,375	1,704,897	5.90	994,666,000	1,089,450,000	(94,784,000)	(8.70)	3.0774	2.6532	0.42	15.99
2	Hedging Settlement Costs	976,400	0	976,400	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	6,647	2,757	3,890	141.10	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(23,307)	0	(23,307)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	31,570,012	28,908,132	2,661,880	9.21	994,666,000	1,089,450,000	(94,784,000)	(8.70)	3.1739	2.6535	0.52	19.61
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	5,741,932	3,165,000	2,576,932	81.42	164,132,495	74,861,000	89,271,495	119.25	3.4984	4.2278	(0.73)	(17.25)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	10,247	0	10,247	0.32	217,552	0	217,552	#N/A	4.7101	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	5,752,179	3,165,000	2,587,179	81.74	164,350,047	74,861,000	89,489,047	119.54	3.5000	4.2278	(0.73)	(17.21)
14	Total Available MWH (Line 6 + Line 13)	37,322,191	32,073,132	5,249,059	16.37	1,159,016,047	1,164,311,000	(5,294,953)	(0.45)				
15	Fuel Cost of Economy Sales (A6)	(387,105)	(873,000)	485,895	(55.66)	(8,490,019)	(19,306,000)	10,815,981	56.02	(4.5595)	(4.5219)	(0.04)	(0.83)
16	Gain on Economy Sales (A6)	(128,039)	(168,000)	39,961	(23.79)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,560,866)	(2,972,000)	411,134	(13.83)	(94,229,095)	(135,403,000)	41,173,905	30.41	(2.7177)	(2.1949)	(0.52)	(23.82)
18	Fuel Cost of Other Power Sales (A6)	(2,371,382)	(4,396,000)	2,024,618	(46.06)	(112,954,715)	(131,008,000)	18,053,285	13.78	(2.0994)	(3.3555)	1.26	37.43
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(5,447,392)	(8,409,000)	2,961,608	35.22	(215,673,829)	(285,717,000)	70,043,171	24.51	(2.5258)	(2.9431)	0.42	14.18
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	31,874,799	23,664,132	8,210,667	34.70	943,342,218	878,594,000	64,748,218	7.37	3.3789	2.6934	0.69	25.45
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	57,544	51,444	6,100	11.86	1,703,039	1,910,000	(206,961)	(10.84)	3.3789	2.6934	0.69	25.45
24	T & D Losses *	2,245,159	1,153,691	1,091,468	94.61	66,446,451	42,834,000	23,612,451	55.13	3.3789	2.6934	0.69	25.45
25	TERRITORIAL KWH SALES	31,874,799	23,664,132	8,210,667	34.70	875,192,728	833,850,000	41,342,728	4.96	3.6420	2.8379	0.80	28.33
26	Wholesale KWH Sales	1,084,125	766,623	317,502	41.42	29,767,311	27,013,000	2,754,311	10.20	3.6420	2.8380	0.80	28.33
27	Jurisdictional KWH Sales	30,790,674	22,897,509	7,893,165	34.47	845,425,417	806,837,000	38,588,417	4.78	3.6420	2.8379	0.80	28.33
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	30,812,227	22,913,537	7,898,690	34.47	845,425,417	806,837,000	38,588,417	4.78	3.6446	2.8399	0.80	28.34
29	TRUE-UP	955,051	955,051	0	0.00	845,425,417	806,837,000	38,588,417	4.78	0.1130	0.1184	(0.01)	(4.56)
30	TOTAL JURISDICTIONAL FUEL COST	31,767,278	23,868,588	7,898,690	33.09	845,425,417	806,837,000	38,588,417	4.78	3.7576	2.9583	0.80	27.02
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.7603	2.9604	0.80	27.02
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	845,425,417	806,837,000	38,588,417	4.78	0.0044	0.0046	(0.00)	(4.35)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.7647	2.9650	0.80	26.97
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.765	2.965		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: APRIL 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$30,610,272
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(23,307)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	976,400
5	Hedging Support Costs	Schedule A-2, Line A-5	6,647
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	5,741,932
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	10,247
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(5,447,392)
11	Total Fuel and Net Power Transactions		$ 31,874,799

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
APRIL 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	147,011,977	146,696,211	315,766	0.22	5,052,106,000	5,040,330,000	11,776,000	0.23	2.9099	2.9104	(0.00)	(0.02)
2	Hedging Settlement Costs	4,293,157	0	4,293,157	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	29,648	11,028	18,620	168.84	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	12,787	0	12,787	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	151,347,569	146,707,239	4,640,330	3.16	5,052,106,000	5,040,330,000	11,776,000	0.23	2.9957	2.9107	0.09	2.92
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	11,471,291	9,263,000	2,208,291	23.84	408,594,272	221,817,000	186,777,272	84.20	2.8075	4.1760	(1.37)	(32.77)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	190,395	0	190,395	#N/A	3,581,315	0	3,581,315	#N/A	5.3163	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	11,661,686	9,263,000	2,398,686	25.90	412,175,587	221,817,000	190,358,587	85.82	2.8293	4.1760	(1.35)	(32.25)
14	Total Available MWH (Line 6 + Line 13)	163,009,255	155,970,239	7,039,016	4.51	5,464,281,587	5,262,147,000	202,134,587	3.84				
15	Fuel Cost of Economy Sales (A6)	(2,067,376)	(5,127,000)	3,059,624	(59.68)	(42,500,801)	(102,980,000)	60,479,199	58.73	(4.8643)	(4.9786)	0.11	2.30
16	Gain on Economy Sales (A6)	(444,772)	(894,000)	449,228	(50.25)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(11,729,543)	(12,471,000)	741,457	(5.95)	(518,906,350)	(559,691,000)	40,784,650	7.29	(2.2604)	(2.2282)	(0.03)	(1.45)
18	Fuel Cost of Other Power Sales (A6)	(49,570,198)	(34,978,000)	(14,592,198)	41.72	(1,372,996,788)	(1,009,346,000)	(363,650,788)	(36.03)	(3.6104)	(3.4654)	(0.15)	(4.18)
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(63,811,889)	(53,470,000)	(10,341,889)	(19.34)	(1,934,403,939)	(1,672,017,000)	(262,386,939)	(15.69)	(3.2988)	(3.1979)	(0.10)	(3.16)
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	99,197,366	102,500,239	(3,302,873)	(3.22)	3,529,877,648	3,590,130,000	(60,252,352)	(1.68)	2.8102	2.8551	(0.04)	(1.57)
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	200,923	230,150	(29,227)	(12.70)	7,149,776	8,061,000	(911,224)	11.30	2.8102	2.8551	(0.04)	(1.57)
24	T & D Losses *	6,012,900	5,121,336	891,564	17.41	213,966,963	179,375,000	34,591,963	(19.28)	2.8102	2.8551	(0.04)	(1.57)
25	TERRITORIAL KWH SALES	99,197,366	102,500,239	(3,302,873)	(3.22)	3,308,760,909	3,402,694,000	(93,933,091)	2.76	2.9980	3.0123	(0.01)	(0.47)
26	Wholesale KWH Sales	3,518,515	3,484,058	34,457	0.99	117,863,308	115,577,000	2,286,308	(1.98)	2.9853	3.0145	(0.03)	(0.97)
27	Jurisdictional KWH Sales	95,678,851	99,016,181	(3,337,330)	(3.37)	3,190,897,601	3,287,117,000	(96,219,399)	(2.93)	2.9985	3.0122	(0.01)	(0.45)
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	95,745,826	99,085,492	(3,339,666)	(3.37)	3,190,897,601	3,287,117,000	(96,219,399)	2.93	3.0006	3.0144	(0.01)	(0.46)
29	TRUE-UP	3,820,204	3,820,204	0	0.00	3,190,897,601	3,287,117,000	(96,219,399)	2.93	0.1197	0.1162	0.00	3.01
30	TOTAL JURISDICTIONAL FUEL COST	99,566,030	102,905,696	(3,339,666)	(3.25)	3,190,897,601	3,287,117,000	(96,219,399)	(2.93)	3.1203	3.1306	(0.01)	(0.33)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.1225	3.1329	(0.01)	(0.33)
33	GPIF Reward / (Penalty) **	147,328	147,329	0	0.00	3,190,897,601	3,287,117,000	(96,219,399)	(2.93)	0.0046	0.0045	0.00	2.22
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.1271	3.1374	(0.01)	(0.33)
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.127	3.137		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	30,512,500.65	28,739,230	1,773,270.65	6.17	146,602,636.81	146,031,932	570,704.81	0.39
1a	Other Generation	97,770.93	166,145	(68,374.07)	(41.15)	409,340.21	664,279	(254,938.79)	(38.38)
2	Fuel Cost of Power Sold	(5,447,391.57)	(8,409,000)	2,961,608.43	(35.22)	(63,811,889.33)	(53,470,000)	(10,341,889.33)	19.34
3	Fuel Cost - Purchased Power	5,741,931.85	3,165,000	2,576,931.85	81.42	11,471,290.67	9,263,000	2,208,290.67	23.84
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	10,247.00	0	10,247.00	100.00	190,395.00	0	190,395.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	6,646.98	2,757	3,889.98	141.09	29,648.45	11,028	18,620.45	168.85
6	Hedging Settlement Cost	976,400.00	0	976,400.00	(100.00)	4,293,157.00	0	4,293,157.00	(100.00)
7	Total Fuel & Net Power Transactions	31,898,105.84	23,664,132	8,233,974	34.80	99,184,578.81	102,500,239	(3,315,660)	(3.23)
8	AdjustmentsTo Fuel Cost	(23,307.02)	0	(23,307.02)	#N/A	12,786.95	0	12,786.95	#N/A
9	Adj. Total Fuel & Net Power Transactions	31,874,798.82	23,664,132	8,210,666.82	34.70	99,197,365.76	102,500,239	(3,302,873.24)	(3.22)
B.	*KWH Sales*								
1	Jurisdictional Sales	845,425,417	806,837,000	38,588,417	4.78	3,190,897,601	3,287,117,000	(96,219,399)	(2.93)
2	Non-Jurisdictional Sales	29,767,311	27,013,000	2,754,311	10.20	117,863,308	115,577,000	2,286,308	1.98
3	Total Territorial Sales	875,192,728	833,850,000	41,342,728	4.96	3,308,760,909	3,402,694,000	(93,933,091)	(2.76)
4	Juris. Sales as % of Total Terr. Sales	96.5988	96.7604	(0.1616)	(0.17)	96.4378	96.6034	(0.1656)	(0.17)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	25,934,029.19	24,800,450	1,133,579.19	4.57	98,186,153.46	101,038,971	(2,852,817.54)	(2.82)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(3,820,205.68)	(3,820,204)	(1.68)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(147,223.32)	(147,224)	0.68	0.00
3	Juris. Fuel Revenue Applicable to Period	24,942,171.94	23,808,593	1,133,578.94	4.76	94,218,724.46	97,071,543	(2,852,818.54)	(2.94)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	31,874,798.82	23,664,132	8,210,666.82	34.70	99,197,365.76	102,500,239	(3,302,873.24)	(3.22)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.5988	96.7604	(0.1616)	(0.17)	96.4378	96.6034	(0.1656)	(0.17)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	30,812,226.63	22,913,537	7,898,689.63	34.47	95,745,826.41	99,085,492	(3,339,665.59)	(3.37)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(5,870,054.69)	895,056	(6,765,110.69)	(755.83)	(1,527,101.95)	(2,013,949)	486,847.05	(24.17)
8	Interest Provision for the Month	(110,245.67)	(43,445)	(66,800.67)	153.76	(393,605.59)	(170,102)	(223,503.59)	131.39
9	Beginning True-Up & Interest Provision*	(24,709,987.65)	(11,631,126)	(13,078,861.65)	112.45	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	3,820,205.68	3,820,204	1.68	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(29,735,236.59)	(9,824,464)	(19,910,772.59)	202.67	(29,735,236.59)	(9,824,464)	(19,910,772.59)	202.67

REVISED 6/19/06

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2006

		CURRENT MONTH			
		$			
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(24,709,987.65)	(11,631,126)	(13,078,861.65)	112.45
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(29,624,990.92)	(9,781,019)	(19,843,971.92)	202.88
3	Total of Beginning & Ending True-Up Amts.	(54,334,978.57)	(21,412,145)	(32,922,833.57)	153.76
4	Average True-Up Amount	(27,167,489.29)	(10,706,073)	(16,461,416.29)	153.76
5	Interest Rate - 1st Day of Reporting Business Month	4.78	4.78	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	4.96	4.96	0.0000	
7	Total (D5+D6)	9.74	9.74	0.0000	
8	Annual Average Interest Rate	4.87	4.87	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4058	0.4058	0.0000	
10	Interest Provision (D4*D9)	(110,245.67)	(43,445)	(66,800.67)	153.76
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

REVISED 6/19/06

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	39,128,248	42,372,989	(3,244,741)	(7.66)	1,294,606,000	1,582,980,000	(288,374,000)	(18.22)	3.0224	2.6768	0.35	12.91
2	Hedging Settlement Costs	1,348,845	0	1,348,845	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	6,478	2,757	3,721	134.97	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(72,461)	0	(72,461)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	40,411,110	42,375,746	(1,964,636)	(4.64)	1,294,606,000	1,582,980,000	(288,374,000)	(18.22)	3.1215	2.6770	0.44	16.60
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	3,776,812	997,000	2,779,812	278.82	153,195,097	21,988,000	131,207,097	596.72	2.4654	4.5343	(2.07)	(45.63)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	8,143	0	8,143	0.82	216,000	0	216,000	#N/A	3.7699	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	3,784,955	997,000	2,787,955	279.63	153,411,097	21,988,000	131,423,097	597.70	2.4672	4.5343	(2.07)	(45.59)
14	Total Available MWH (Line 6 + Line 13)	44,196,065	43,372,746	823,319	1.90	1,448,017,097	1,604,968,000	(156,950,903)	(9.78)				
15	Fuel Cost of Economy Sales (A6)	(678,071)	(1,022,000)	343,929	(33.65)	(16,213,352)	(20,526,000)	4,312,648	21.01	(4.1822)	(4.9791)	0.80	16.00
16	Gain on Economy Sales (A6)	(247,023)	(230,000)	(17,023)	7.40	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,844,947)	(2,728,000)	(116,947)	4.29	(126,343,855)	(132,096,000)	5,752,145	4.35	(2.2517)	(2.0652)	(0.19)	(9.03)
18	Fuel Cost of Other Power Sales (A6)	(4,960,337)	(11,460,000)	6,499,663	(56.72)	(201,376,234)	(323,145,000)	121,768,766	37.68	(2.4632)	(3.5464)	1.08	30.54
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(8,730,378)	(15,440,000)	6,709,622	43.46	(343,933,441)	(475,767,000)	131,833,559	27.71	(2.5384)	(3.2453)	0.71	21.78
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	35,465,687	27,932,746	7,532,941	26.97	1,104,083,656	1,129,201,000	(25,117,344)	(2.22)	3.2122	2.4737	0.74	29.85
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	57,640	53,951	3,689	6.84	1,794,409	2,181,000	(386,591)	(17.73)	3.2122	2.4737	0.74	29.85
24	T & D Losses *	1,492,718	1,736,142	(243,424)	(14.02)	46,470,263	70,184,000	(23,713,737)	(33.79)	3.2122	2.4737	0.74	29.85
25	TERRITORIAL KWH SALES	35,465,687	27,932,746	7,532,941	26.97	1,055,818,984	1,056,836,000	(1,017,016)	(0.10)	3.3591	2.6431	0.72	27.09
26	Wholesale KWH Sales	1,144,620	859,211	285,409	33.22	34,075,203	32,508,000	1,567,203	4.82	3.3591	2.6431	0.72	27.09
27	Jurisdictional KWH Sales	34,321,067	27,073,535	7,247,532	26.77	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	3.3591	2.6431	0.72	27.09
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	34,345,092	27,092,486	7,252,606	26.77	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	3.3614	2.6449	0.72	27.09
29	TRUE-UP	955,051	955,051	0	0.00	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	0.0935	0.0932	0.00	0.32
30	TOTAL JURISDICTIONAL FUEL COST	35,300,143	28,047,537	7,252,606	25.86	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	3.4549	2.7381	0.72	26.18
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.4574	2.7401	0.72	26.18
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	0.0036	0.0036	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4610	2.7437	0.72	26.14
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.461	2.744		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: MAY 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$39,128,248
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(72,461)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	1,348,845
5	Hedging Support Costs	Schedule A-2, Line A-5	6,478
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	3,776,812
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	8,143
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,730,378)
11	Total Fuel and Net Power Transactions		$ 35,465,687

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MAY 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	186,140,225	189,069,200	(2,928,975)	(1.55)	6,346,712,000	6,623,310,000	(276,598,000)	(4.18)	2.9329	2.8546	0.08	2.74
2	Hedging Settlement Costs	5,642,002	0	5,642,002	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	36,126	13,785	22,341	162.07	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(59,674)	0	(59,674)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	191,758,679	189,082,985	2,675,694	1.42	6,346,712,000	6,623,310,000	(276,598,000)	(4.18)	3.0214	2.8548	0.17	5.84
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	15,248,103	10,260,000	4,988,103	48.62	561,789,369	243,805,000	317,984,369	130.43	2.7142	4.2083	(1.49)	(35.50)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	198,538	0	198,538	#N/A	3,797,315	0	3,797,315	#N/A	5.2284	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	15,446,641	10,260,000	5,186,641	50.55	565,586,684	243,805,000	321,781,684	131.98	2.7311	4.2083	(1.48)	(35.10)
14	Total Available MWH (Line 6 + Line 13)	207,205,320	199,342,985	7,862,335	3.94	6,912,298,684	6,867,115,000	45,183,684	0.66				
15	Fuel Cost of Economy Sales (A6)	(2,745,447)	(6,149,000)	3,403,553	(55.35)	(58,714,153)	(123,506,000)	64,791,847	52.46	(4.6760)	(4.9787)	0.30	6.08
16	Gain on Economy Sales (A6)	(691,795)	(1,124,000)	432,205	(38.45)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(14,574,490)	(15,199,000)	624,510	(4.11)	(645,250,205)	(691,787,000)	46,536,795	6.73	(2.2587)	(2.1971)	(0.06)	(2.80)
18	Fuel Cost of Other Power Sales (A6)	(54,530,535)	(46,438,000)	(8,092,535)	17.43	(1,574,373,022)	(1,332,491,000)	(241,882,022)	(18.15)	(3.4636)	(3.4851)	0.02	0.62
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(72,542,267)	(68,910,000)	(3,632,267)	(5.27)	(2,278,337,380)	(2,147,784,000)	(130,553,380)	(6.08)	(3.1840)	(3.2084)	0.02	0.76
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	134,663,053	130,432,985	4,230,068	3.24	4,633,961,304	4,719,331,000	(85,369,696)	(1.81)	2.906	2.7638	0.14	5.15
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	259,918	283,068	(23,150)	(8.18)	8,944,185	10,242,000	(1,297,815)	12.67	2.9060	2.7638	0.14	5.15
24	T & D Losses *	7,568,306	6,897,312	670,994	9.73	260,437,226	249,559,000	10,878,226	(4.36)	2.9060	2.7638	0.14	5.15
25	TERRITORIAL KWH SALES	134,663,053	130,432,985	4,230,068	3.24	4,364,579,893	4,459,530,000	(94,950,107)	2.13	3.0854	2.9248	0.16	5.49
26	Wholesale KWH Sales	4,663,135	4,343,269	319,866	7.36	151,938,511	148,085,000	3,853,511	(2.60)	3.0691	2.9330	0.14	4.64
27	Jurisdictional KWH Sales	129,999,918	126,089,716	3,910,202	3.10	4,212,641,382	4,311,445,000	(98,803,618)	(2.29)	3.0859	2.9245	0.16	5.52
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	130,090,919	126,177,978	3,912,941	3.10	4,212,641,382	4,311,445,000	(98,803,618)	2.29	3.0881	2.9266	0.16	5.52
29	TRUE-UP	4,775,255	4,775,255	0	0.00	4,212,641,382	4,311,445,000	(98,803,618)	2.29	0.1134	0.1108	0.00	2.35
30	TOTAL JURISDICTIONAL FUEL COST	134,866,174	130,953,233	3,912,941	2.99	4,212,641,382	4,311,445,000	(98,803,618)	(2.29)	3.2015	3.0374	0.16	5.40
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.2038	3.0396	0.16	5.40
33	GPIF Reward / (Penalty) **	184,160	184,160	0	0.00	4,212,641,382	4,311,445,000	(98,803,618)	(2.29)	0.0044	0.0043	0.00	2.33
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.2082	3.0439	0.16	5.40
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.208	3.044		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	39,032,403.57	42,201,446	(3,169,042.43)	(7.51)	185,635,040.38	188,233,378	(2,598,337.62)	(1.38)
1a	Other Generation	95,844.90	171,543	(75,698.10)	(44.13)	505,185.11	835,822	(330,636.89)	(39.56)
2	Fuel Cost of Power Sold	(8,730,378.00)	(15,440,000)	6,709,622.00	(43.46)	(72,542,267.33)	(68,910,000)	(3,632,267.33)	5.27
3	Fuel Cost - Purchased Power	3,776,812.27	997,000	2,779,812.27	278.82	15,248,102.94	10,260,000	4,988,102.94	48.62
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	8,143.00	0	8,143.00	100.00	198,538.00	0	198,538.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	6,477.70	2,757	3,720.70	134.95	36,126.15	13,785	22,341.15	162.07
6	Hedging Settlement Cost	1,348,845.00	0	1,348,845.00	(100.00)	5,642,002.00	0	5,642,002.00	(100.00)
7	Total Fuel & Net Power Transactions	35,538,148.44	27,932,746	7,605,402	27.23	134,722,727.25	130,432,985	4,289,742	3.29
8	AdjustmentsTo Fuel Cost	(72,461.46)	0	(72,461.46)	#N/A	(59,674.51)	0	(59,674.51)	#N/A
9	Adj. Total Fuel & Net Power Transactions	35,465,686.98	27,932,746	7,532,940.98	26.97	134,663,052.74	130,432,985	4,230,067.74	3.24
B.	*KWH Sales*								
1	Jurisdictional Sales	1,021,743,781	1,024,328,000	(2,584,219)	(0.25)	4,212,641,382	4,311,445,000	(98,803,618)	(2.29)
2	Non-Jurisdictional Sales	34,075,203	32,508,000	1,567,203	4.82	151,938,511	148,085,000	3,853,511	2.60
3	Total Territorial Sales	1,055,818,984	1,056,836,000	(1,017,016)	(0.10)	4,364,579,893	4,459,530,000	(94,950,107)	(2.13)
4	Juris. Sales as % of Total Terr. Sales	96.7726	96.9240	(0.1514)	(0.16)	96.5188	96.6794	(0.1606)	(0.17)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	31,364,798.79	31,485,660	(120,861.21)	(0.38)	129,550,952.25	132,524,631	(2,973,678.75)	(2.24)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(4,775,257.10)	(4,775,255)	(2.10)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(184,029.15)	(184,030)	0.85	0.00
3	Juris. Fuel Revenue Applicable to Period	30,372,941.54	30,493,803	(120,861.46)	(0.40)	124,591,666.00	127,565,346	(2,973,680.00)	(2.33)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	35,465,686.98	27,932,746	7,532,940.98	26.97	134,663,052.74	130,432,985	4,230,067.74	3.24
5	Juris. Sales % of Total KWH Sales (Line B4)	96.7726	96.9240	(0.1514)	(0.16)	96.5188	96.6794	(0.1606)	(0.17)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	34,345,092.15	27,092,486	7,252,606.15	26.77	130,090,918.56	126,177,978	3,912,940.56	3.10
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(3,972,150.61)	3,401,317	(7,373,467.61)	(216.78)	(5,499,252.56)	1,387,368	(6,886,620.56)	(496.38)
8	Interest Provision for the Month	(129,786.69)	(31,763)	(98,023.69)	308.61	(523,392.28)	(201,865)	(321,527.28)	159.28
9	Beginning True-Up & Interest Provision*	(29,735,236.59)	(9,824,464)	(19,910,772.59)	202.67	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	4,775,257.10	4,775,255	2.10	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(32,882,122.47)	(5,499,859)	(27,382,263.47)	497.87	(32,882,122.47)	(5,499,859)	(27,382,263.47)	497.87

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2006

		CURRENT MONTH			
		$			
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(29,735,236.59)	(9,824,464)	(19,910,772.59)	202.67
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(32,752,335.78)	(5,468,096)	(27,284,239.78)	498.97
3	Total of Beginning & Ending True-Up Amts.	(62,487,572.37)	(15,292,560)	(47,195,012.37)	308.61
4	Average True-Up Amount	(31,243,786.19)	(7,646,280)	(23,597,506.19)	308.61
5	Interest Rate - 1st Day of Reporting Business Month	4.96	4.96	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.01	5.01	0.0000	
7	Total (D5+D6)	9.97	9.97	0.0000	
8	Annual Average Interest Rate	4.99	4.99	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4154	0.4154	0.0000	
10	Interest Provision (D4*D9)	(129,786.69)	(31,763)	(98,023.69)	308.61
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	45,346,391	49,826,246	(4,479,855)	(8.99)	1,498,754,000	1,710,530,000	(211,776,000)	(12.38)	3.0256	2.9129	0.11	3.87
2	Hedging Settlement Costs	1,879,290	0	1,879,290	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	12,229	2,757	9,472	343.56	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(275,537)	0	(275,537)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	46,962,373	49,829,003	(2,866,630)	(5.75)	1,498,754,000	1,710,530,000	(211,776,000)	(12.38)	3.1334	2.9131	0.22	7.56
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	3,074,968	1,580,000	1,494,968	94.62	121,143,482	30,351,000	90,792,482	299.14	2.5383	5.2058	(2.67)	(51.24)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	43,091	0	43,091	2.73	824,000	0	824,000	#N/A	5.2295	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	3,118,059	1,580,000	1,538,059	97.35	121,967,482	30,351,000	91,616,482	301.86	2.5565	5.2058	(2.65)	(50.89)
14	Total Available MWH (Line 6 + Line 13)	50,080,432	51,409,003	(1,328,571)	(2.58)	1,620,721,482	1,740,881,000	(120,159,518)	(6.90)				
15	Fuel Cost of Economy Sales (A6)	(810,061)	(1,949,000)	1,138,939	(58.44)	(16,158,996)	(36,357,000)	20,198,004	55.55	(5.0131)	(5.3607)	0.35	6.48
16	Gain on Economy Sales (A6)	(273,794)	(295,000)	21,206	(7.19)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,900,861)	(2,820,000)	(80,861)	2.87	(127,258,405)	(136,122,000)	8,863,595	6.51	(2.2795)	(2.0717)	(0.21)	(10.03)
18	Fuel Cost of Other Power Sales (A6)	(4,686,851)	(11,927,000)	7,240,149	(60.70)	(203,889,301)	(315,034,000)	111,144,699	35.28	(2.2987)	(3.7859)	1.49	39.28
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(8,671,567)	(16,991,000)	8,319,433	48.96	(347,306,702)	(487,513,000)	140,206,298	28.76	(2.4968)	(3.4852)	0.99	28.36
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	41,408,865	34,418,003	6,990,862	20.31	1,273,414,780	1,253,368,000	20,046,780	1.60	3.2518	2.746	0.51	18.42
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	61,432	54,783	6,649	12.14	1,889,181	1,995,000	(105,819)	(5.30)	3.2518	2.7460	0.51	18.42
24	T & D Losses *	1,626,993	2,372,379	(745,386)	(31.42)	50,033,599	86,394,000	(36,360,401)	(42.09)	3.2518	2.7460	0.51	18.42
25	TERRITORIAL KWH SALES	41,408,866	34,418,003	6,990,862	20.31	1,221,492,000	1,164,979,000	56,513,000	4.85	3.3900	2.9544	0.44	14.74
26	Wholesale KWH Sales	1,315,725	1,061,761	253,964	23.92	38,811,409	35,938,000	2,873,409	8.00	3.3900	2.9544	0.44	14.74
27	Jurisdictional KWH Sales	40,093,141	33,356,242	6,736,899	20.20	1,182,680,591	1,129,041,000	53,639,591	4.75	3.3900	2.9544	0.44	14.74
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	40,121,206	33,379,591	6,741,615	20.20	1,182,680,591	1,129,041,000	53,639,591	4.75	3.3924	2.9565	0.44	14.74
29	TRUE-UP	955,051	955,051	0	0.00	1,182,680,591	1,129,041,000	53,639,591	4.75	0.0808	0.0846	(0.00)	(4.49)
30	TOTAL JURISDICTIONAL FUEL COST	41,076,257	34,334,642	6,741,615	19.64	1,182,680,591	1,129,041,000	53,639,591	4.75	3.4732	3.0411	0.43	14.21
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.4757	3.0433	0.43	14.21
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	1,182,680,591	1,129,041,000	53,639,591	4.75	0.0031	0.0033	(0.00)	(6.06)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4788	3.0466	0.43	14.19
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.479	3.047		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: JUNE 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$45,346,391
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(275,537)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	1,879,290
5	Hedging Support Costs	Schedule A-2, Line A-5	12,229
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	3,074,968
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	43,091
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,671,567)
11	Total Fuel and Net Power Transactions		$ 41,408,865

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JUNE 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	231,486,616	238,895,446	(7,408,830)	(3.10)	7,845,466,000	8,333,840,000	(488,374,000)	(5.86)	2.9506	2.8666	0.08	2.93
2	Hedging Settlement Costs	7,521,292	0	7,521,292	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	48,355	16,542	31,813	192.32	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(335,211)	0	(335,211)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	238,721,052	238,911,988	(190,936)	(0.08)	7,845,466,000	8,333,840,000	(488,374,000)	(5.86)	3.0428	2.8668	0.18	6.14
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	18,323,071	11,840,000	6,483,071	54.76	682,932,851	274,156,000	408,776,851	149.10	2.6830	4.3187	(1.64)	(37.87)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	241,629	0	241,629	#N/A	4,621,315	0	4,621,315	#N/A	5.2286	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	18,564,700	11,840,000	6,724,700	56.80	687,554,166	274,156,000	413,398,166	150.79	2.7001	4.3187	(1.62)	(37.48)
14	Total Available MWH (Line 6 + Line 13)	257,285,752	250,751,988	6,533,764	2.61	8,533,020,166	8,607,996,000	(74,975,834)	(0.87)				
15	Fuel Cost of Economy Sales (A6)	(3,555,508)	(8,098,000)	4,542,492	(56.09)	(74,873,149)	(159,863,000)	84,989,851	53.16	(4.7487)	(5.0656)	0.32	6.26
16	Gain on Economy Sales (A6)	(965,589)	(1,419,000)	453,411	(31.95)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(17,475,351)	(18,019,000)	543,649	(3.02)	(772,508,610)	(827,909,000)	55,400,390	6.69	(2.2622)	(2.1764)	(0.09)	(3.94)
18	Fuel Cost of Other Power Sales (A6)	(59,217,386)	(58,365,000)	(852,386)	1.46	(1,778,262,323)	(1,647,525,000)	(130,737,323)	(7.94)	(3.3301)	(3.5426)	0.21	6.00
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(81,213,834)	(85,901,000)	4,687,166	5.46	(2,625,644,082)	(2,635,297,000)	9,652,918	0.37	(3.0931)	(3.2596)	0.17	5.11
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	176,071,918	164,850,988	11,220,930	6.81	5,907,376,084	5,972,699,000	(65,322,916)	(1.09)	2.9805	2.7601	0.22	7.99
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	322,888	337,753	(14,865)	(4.40)	10,833,366	12,237,000	(1,403,634)	11.47	2.9805	2.7601	0.22	7.99
24	T & D Losses *	9,253,583	9,272,639	(19,056)	(0.21)	310,470,825	335,953,000	(25,482,175)	7.59	2.9805	2.7601	0.22	7.99
25	TERRITORIAL KWH SALES	176,071,919	164,850,988	11,220,931	6.81	5,586,071,893	5,624,509,000	(38,437,107)	0.68	3.1520	2.9309	0.22	7.54
26	Wholesale KWH Sales	5,978,860	5,405,030	573,830	10.62	190,749,920	184,023,000	6,726,920	(3.66)	3.1344	2.9371	0.20	6.72
27	Jurisdictional KWH Sales	170,093,059	159,445,958	10,647,101	6.68	5,395,321,973	5,440,486,000	(45,164,027)	(0.83)	3.1526	2.9307	0.22	7.57
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	170,212,124	159,557,569	10,654,555	6.68	5,395,321,973	5,440,486,000	(45,164,027)	0.83	3.1548	2.9328	0.22	7.57
29	TRUE-UP	5,730,306	5,730,306	0	0.00	5,395,321,973	5,440,486,000	(45,164,027)	0.83	0.1062	0.1053	0.00	0.85
30	TOTAL JURISDICTIONAL FUEL COST	175,942,430	165,287,875	10,654,555	6.45	5,395,321,973	5,440,486,000	(45,164,027)	(0.83)	3.2610	3.0381	0.22	7.34
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.2633	3.0403	0.22	7.33
33	GPIF Reward / (Penalty) **	220,992	220,992	0	0.00	5,395,321,973	5,440,486,000	(45,164,027)	(0.83)	0.0041	0.0041	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.2674	3.0444	0.22	7.32
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.267	3.044		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

DN3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2006

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	45,221,761.79	49,660,101	(4,438,339.21)	(8.94)	230,856,802.17	237,893,479	(7,036,676.83)	(2.96)
1a	Other Generation	124,629.37	166,145	(41,515.63)	(24.99)	629,814.48	1,001,967	(372,152.52)	(37.14)
2	Fuel Cost of Power Sold	(8,671,566.43)	(16,991,000)	8,319,433.57	(48.96)	(81,213,833.76)	(85,901,000)	4,687,166.24	(5.46)
3	Fuel Cost - Purchased Power	3,074,967.99	1,580,000	1,494,967.99	94.62	18,323,070.93	11,840,000	6,483,070.93	54.76
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	43,091.00	0	43,091.00	100.00	241,629.00	0	241,629.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	12,228.69	2,757	9,471.69	343.55	48,354.84	16,542	31,812.84	192.32
6	Hedging Settlement Cost	1,879,290.00	0	1,879,290.00	(100.00)	7,521,292.00	0	7,521,292.00	(100.00)
7	Total Fuel & Net Power Transactions	41,684,402.41	34,418,003	7,266,399	21.11	176,407,129.66	164,850,988	11,556,142	7.01
8	AdjustmentsTo Fuel Cost	(275,536.70)	0	(275,536.70)	#N/A	(335,211.21)	0	(335,211.21)	#N/A
9	Adj. Total Fuel & Net Power Transactions	41,408,865.71	34,418,003	6,990,862.71	20.31	176,071,918.45	164,850,988	11,220,930.45	6.81
B.	*KWH Sales*								
1	Jurisdictional Sales	1,182,680,591	1,129,041,000	53,639,591	4.75	5,395,321,973	5,440,486,000	(45,164,027)	(0.83)
2	Non-Jurisdictional Sales	38,811,409	35,938,000	2,873,409	8.00	190,749,920	184,023,000	6,726,920	3.66
3	Total Territorial Sales	1,221,492,000	1,164,979,000	56,513,000	4.85	5,586,071,893	5,624,509,000	(38,437,107)	(0.68)
4	Juris. Sales as % of Total Terr. Sales	96.8226	96.9151	(0.0925)	(0.10)	96.5853	96.7282	(0.1429)	(0.15)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2006

C.		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
	True-up Calculation								
1	Jurisdictional Fuel Revenue	36,341,935.20	34,704,314	1,637,621.20	4.72	165,892,887.45	167,228,945	(1,336,057.55)	(0.80)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(5,730,308.52)	(5,730,306)	(2.52)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(220,834.98)	(220,836)	1.02	0.00
3	Juris. Fuel Revenue Applicable to Period	35,350,077.95	33,712,457	1,637,620.95	4.86	159,941,743.95	161,277,803	(1,336,059.05)	(0.83)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	41,408,865.71	34,418,003	6,990,862.71	20.31	176,071,918.45	164,850,988	11,220,930.45	6.81
5	Juris. Sales % of Total KWH Sales (Line B4)	96.8226	96.9151	(0.0925)	(0.10)	96.5853	96.7282	(0.1429)	(0.15)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	40,121,205.61	33,379,591	6,741,614.61	20.20	170,212,124.17	159,557,569	10,654,555.17	6.68
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(4,771,127.66)	332,866	(5,103,993.66)	(1,533.35)	(10,270,380.22)	1,720,234	(11,990,614.22)	(697.03)
8	Interest Provision for the Month	(149,319.37)	(20,842)	(128,477.37)	616.43	(672,711.65)	(222,707)	(450,004.65)	202.06
9	Beginning True-Up & Interest Provision*	(32,882,122.47)	(5,499,859)	(27,382,263.47)	497.87	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	5,730,308.52	5,730,306	2.52	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(36,847,518.08)	(4,232,784)	(32,614,734.08)	770.53	(36,847,518.08)	(4,232,784)	(32,614,734.08)	770.53

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(32,882,122.47)	(5,499,859)	(27,382,263.47)	497.87
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(36,698,198.71)	(4,211,942)	(32,486,256.71)	771.29
3	Total of Beginning & Ending True-Up Amts.	(69,580,321.18)	(9,711,801)	(59,868,520.18)	616.45
4	Average True-Up Amount	(34,790,160.59)	(4,855,901)	(29,934,259.59)	616.45
5	Interest Rate - 1st Day of Reporting Business Month	5.01	5.01	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.29	5.29	0.0000	
7	Total (D5+D6)	10.30	10.30	0.0000	
8	Annual Average Interest Rate	5.15	5.15	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4292	0.4292	0.0000	
10	Interest Provision (D4*D9)	(149,319.37)	(20,842)	(128,477.37)	616.43
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	50,347,113	52,269,027	(1,921,914)	(3.68)	1,594,594,000	1,704,510,000	(109,916,000)	(6.45)	3.1574	3.0665	0.09	2.96
2	Hedging Settlement Costs	3,020,757	0	3,020,757	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	6,746	8,059	(1,313)	(16.29)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(158,305)	0	(158,305)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	53,216,311	52,277,086	939,225	1.80	1,594,594,000	1,704,510,000	(109,916,000)	(6.45)	3.3373	3.0670	0.27	8.81
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	3,475,913	2,961,000	514,913	17.39	125,901,982	53,104,000	72,797,982	137.09	2.7608	5.5759	(2.82)	(50.49)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	39,684	0	39,684	1.34	630,905	0	630,905	#N/A	6.2900	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	3,515,597	2,961,000	554,597	18.73	126,532,887	53,104,000	73,428,887	138.27	2.7784	5.5759	(2.80)	(50.17)
14	Total Available MWH (Line 6 + Line 13)	56,731,908	55,238,086	1,493,822	2.70	1,721,126,887	1,757,614,000	(36,487,113)	(2.08)				
15	Fuel Cost of Economy Sales (A6)	(895,305)	(1,275,000)	379,695	(29.78)	(18,980,123)	(25,086,000)	6,105,877	24.34	(4.7171)	(5.0825)	0.37	7.19
16	Gain on Economy Sales (A6)	(328,234)	(411,000)	82,766	(20.14)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,994,945)	(3,172,000)	177,055	(5.58)	(139,145,676)	(134,506,000)	(4,639,676)	(3.45)	(2.1524)	(2.3583)	0.21	8.73
18	Fuel Cost of Other Power Sales (A6)	(3,493,355)	(10,819,000)	7,325,645	(67.71)	(187,222,768)	(285,246,000)	98,023,232	34.36	(1.8659)	(3.7929)	1.93	50.81
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(7,711,839)	(15,677,000)	7,965,161	50.81	(345,348,567)	(444,838,000)	99,489,433	22.37	(2.2331)	(3.5242)	1.29	36.64
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	49,020,069	39,561,086	9,458,983	23.91	1,375,778,320	1,312,776,000	63,002,320	4.80	3.5631	3.0135	0.55	18.24
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	77,144	57,950	19,194	33.12	2,165,068	1,923,000	242,068	12.59	3.5631	3.0135	0.55	18.24
24	T & D Losses *	4,232,929	2,842,273	1,390,656	48.93	118,799,059	94,318,000	24,481,059	25.96	3.5631	3.0135	0.55	18.24
25	TERRITORIAL KWH SALES	49,020,069	39,561,086	9,458,983	23.91	1,254,814,193	1,216,535,000	38,279,193	3.15	3.9066	3.2519	0.65	20.13
26	Wholesale KWH Sales	1,613,152	1,332,813	280,339	21.03	41,293,891	40,985,000	308,891	0.75	3.9065	3.2520	0.65	20.13
27	Jurisdictional KWH Sales	47,406,917	38,228,273	9,178,644	24.01	1,213,520,302	1,175,550,000	37,970,302	3.23	3.9066	3.2519	0.65	20.13
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	47,440,102	38,255,033	9,185,069	24.01	1,213,520,302	1,175,550,000	37,970,302	3.23	3.9093	3.2542	0.66	20.13
29	TRUE-UP	955,051	955,051	0	0.00	1,213,520,302	1,175,550,000	37,970,302	3.23	0.0787	0.0812	(0.00)	(3.08)
30	TOTAL JURISDICTIONAL FUEL COST	48,395,153	39,210,084	9,185,069	23.43	1,213,520,302	1,175,550,000	37,970,302	3.23	3.9880	3.3354	0.65	19.57
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.9909	3.3378	0.65	19.57
33	GPIF Reward / (Penalty) **	36,832	36,832	(0)	0.00	1,213,520,302	1,175,550,000	37,970,302	3.23	0.0030	0.0031	(0.00)	(3.23)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9939	3.3409	0.65	19.55
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.994	3.341		

001

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: JULY 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$50,347,113
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(158,305)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	3,020,757
5	Hedging Support Costs	Schedule A-2, Line A-5	6,746
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	3,475,913
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	39,684
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(7,711,839)
11	Total Fuel and Net Power Transactions		$ 49,020,069

070001-Hearing Exhibit 000070

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JULY 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	281,833,729	291,164,473	(9,330,744)	(3.20)	9,440,060,000	10,038,350,000	(598,290,000)	(5.96)	2.9855	2.9005	0.09	2.93
2	Hedging Settlement Costs	10,542,049	0	10,542,049	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	55,101	24,601	30,500	123.98	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) ***	(493,516)	0	(493,516)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	291,937,363	291,189,074	748,289	0.26	9,440,060,000	10,038,350,000	(598,290,000)	(5.96)	3.0925	2.9008	0.19	6.61
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	21,798,984	14,801,000	6,997,984	47.28	808,834,833	327,260,000	481,574,833	147.15	2.6951	4.5227	(1.83)	(40.41)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	281,313	0	281,313	#N/A	5,252,220	0	5,252,220	#N/A	5.3561	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	22,080,297	14,801,000	7,279,297	49.18	814,087,053	327,260,000	486,827,053	148.76	2.7123	4.5227	(1.81)	(40.03)
14	Total Available MWH (Line 6 + Line 13)	314,017,660	305,990,074	8,027,586	2.62	10,254,147,053	10,365,610,000	(111,462,947)	(1.08)				
15	Fuel Cost of Economy Sales (A6)	(4,450,813)	(9,373,000)	4,922,187	(52.51)	(93,853,272)	(184,949,000)	91,095,728	49.25	(4.7423)	(5.0679)	0.33	6.42
16	Gain on Economy Sales (A6)	(1,293,823)	(1,830,000)	536,177	(29.30)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(20,470,296)	(21,191,000)	720,704	(3.40)	(911,654,286)	(962,415,000)	50,760,714	5.27	(2.2454)	(2.2019)	(0.04)	(1.98)
18	Fuel Cost of Other Power Sales (A6)	(62,710,741)	(69,184,000)	6,473,259	(9.36)	(1,965,485,091)	(1,932,771,000)	(32,714,091)	(1.69)	(3.1906)	(3.5795)	0.39	10.86
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(88,925,673)	(101,578,000)	12,652,327	12.46	(2,970,992,649)	(3,080,135,000)	109,142,351	3.54	(2.9931)	(3.2978)	0.30	9.24
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	225,091,987	204,412,074	20,679,913	10.12	7,283,154,404	7,285,475,000	(2,320,596)	(0.03)	3.0906	2.8057	0.28	10.15
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	401,730	397,287	4,443	1.12	12,998,434	14,160,000	(1,161,566)	8.20	3.0906	2.8057	0.28	10.15
24	T & D Losses *	13,267,015	12,072,113	1,194,902	9.90	429,269,884	430,271,000	(1,001,116)	0.23	3.0906	2.8057	0.28	10.15
25	TERRITORIAL KWH SALES	225,091,988	204,412,074	20,679,914	10.12	6,840,886,086	6,841,044,000	(157,914)	0.00	3.2904	2.9880	0.30	10.12
26	Wholesale KWH Sales	7,592,012	6,737,843	854,169	12.68	232,043,811	225,008,000	7,035,811	(3.13)	3.2718	2.9945	0.28	9.26
27	Jurisdictional KWH Sales	217,499,976	197,674,231	19,825,745	10.03	6,608,842,275	6,616,036,000	(7,193,725)	(0.11)	3.2910	2.9878	0.30	10.15
27a	Jurisdictional Loss Multiplier***	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	217,652,226	197,812,602	19,839,624	10.03	6,608,842,275	6,616,036,000	(7,193,725)	0.11	3.2933	2.9899	0.30	10.15
29	TRUE-UP	6,685,357	6,685,357	0	0.00	6,608,842,275	6,616,036,000	(7,193,725)	0.11	0.1012	0.1010	0.00	0.20
30	TOTAL JURISDICTIONAL FUEL COST	224,337,583	204,497,959	19,839,624	9.70	6,608,842,275	6,616,036,000	(7,193,725)	(0.11)	3.3945	3.0909	0.30	9.82
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.3969	3.0931	0.30	9.82
33	GPIF Reward / (Penalty) **	257,824	257,824	0	0.00	6,608,842,275	6,616,036,000	(7,193,725)	(0.11)	0.0039	0.0039	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4008	3.0970	0.30	9.81
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.401	3.097		

* Include for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales.
***(Gain)/Loss on sales of natural gas

003

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	50,217,361.42	52,003,027	(1,785,665.58)	(3.43)	281,074,163.59	289,896,506	(8,822,342.41)	(3.04)
1a	Other Generation	129,752.07	266,000	(136,247.93)	(51.22)	759,566.55	1,267,967	(508,400.45)	(40.10)
2	Fuel Cost of Power Sold	(7,711,839.29)	(15,677,000)	7,965,160.71	(50.81)	(88,925,673.05)	(101,578,000)	12,652,326.95	(12.46)
3	Fuel Cost - Purchased Power	3,475,913.30	2,961,000	514,913.30	17.39	21,798,984.23	14,801,000	6,997,984.23	47.28
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	39,684.00	0	39,684.00	100.00	281,313.00	0	281,313.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	6,746.26	8,059	(1,312.74)	(16.29)	55,101.10	24,601	30,500.10	123.98
6	Hedging Settlement Cost	3,020,757.00	0	3,020,757.00	(100.00)	10,542,049.00	0	10,542,049.00	(100.00)
7	Total Fuel & Net Power Transactions	49,178,374.76	39,561,086	9,617,289	24.31	225,585,504.42	204,412,074	21,173,430	10.36
8	AdjustmentsTo Fuel Cost	(158,305.39)	0	(158,305.39)	#N/A	(493,516.60)	0	(493,516.60)	#N/A
9	Adj. Total Fuel & Net Power Transactions	49,020,069.37	39,561,086	9,458,983.37	23.91	225,091,987.82	204,412,074	20,679,913.82	10.12
B.	*KWH Sales*								
1	Jurisdictional Sales	1,213,520,302	1,175,550,000	37,970,302	3.23	6,608,842,275	6,616,036,000	(7,193,725)	(0.11)
2	Non-Jurisdictional Sales	41,293,891	40,985,000	308,891	0.75	232,043,811	225,008,000	7,035,811	3.13
3	Total Territorial Sales	1,254,814,193	1,216,535,000	38,279,193	3.15	6,840,886,086	6,841,044,000	(157,914)	0.00
4	Juris. Sales as % of Total Terr. Sales	96.7092	96.6310	0.0782	0.08	96.6080	96.7109	(0.1029)	(0.11)

Note: Line 8 - (Gain)/Loss on Sales of Natural Gas

004

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2006

C.	*True-up Calculation*	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE ACTUAL	PERIOD - TO - DATE ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	37,268,942.79	36,133,902	1,135,040.79	3.14	203,161,830.24	203,362,847	(201,016.76)	(0.10)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(6,685,359.94)	(6,685,357)	(2.94)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(257,640.81)	(257,642)	1.19	0.00
3	Juris. Fuel Revenue Applicable to Period	36,277,085.54	35,142,045	1,135,040.54	3.23	196,218,829.49	196,419,848	(201,018.51)	(0.10)
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	49,020,069.37	39,561,086	9,458,983.37	23.91	225,091,987.82	204,412,074	20,679,913.82	10.12
5	Juris. Sales % of Total KWH Sales (Line B4)	96.7092	96.6310	0.0782	0.08	96.6080	96.7109	(0.1029)	(0.11)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	47,440,101.77	38,255,033	9,185,068.77	24.01	217,652,225.94	197,812,602	19,839,623.94	10.03
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(11,163,016.23)	(3,112,988)	(8,050,028.23)	258.59	(21,433,396.45)	(1,392,754)	(20,040,642.45)	1,438.92
8	Interest Provision for the Month	(186,180.76)	(23,574)	(162,606.76)	689.77	(858,892.41)	(246,281)	(612,611.41)	248.74
9	Beginning True-Up & Interest Provision*	(36,847,518.08)	(4,232,784)	(32,614,734.08)	770.53	(31,634,734.73)	(11,460,617)	(20,174,117.73)	176.03
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	6,685,359.94	6,685,357	2.94	0.00
11	End of Period - Total Net True-Up, Before Adjustment (7+C8+C9+C10)	(47,241,663.65)	(6,414,295)	(40,827,368.65)	636.51	(47,241,663.65)	(6,414,295)	(40,827,368.65)	636.51

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(36,847,518.08)	(4,232,784)	(32,614,734.08)	770.53
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(47,055,482.89)	(6,390,721)	(40,664,761.89)	636.31
3	Total of Beginning & Ending True-Up Amts.	(83,903,000.97)	(10,623,505)	(73,279,495.97)	689.79
4	Average True-Up Amount	(41,951,500.49)	(5,311,753)	(36,639,747.49)	689.79
5	Interest Rate - 1st Day of Reporting Business Month	5.29	5.29	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.36	5.36	0.0000	
7	Total (D5+D6)	10.65	10.65	0.0000	
8	Annual Average Interest Rate	5.33	5.33	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4438	0.4438	0.0000	
10	Interest Provision (D4*D9)	(186,180.76)	(23,574)	(162,606.76)	689.77
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

900

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	57,475,259	52,177,415	5,297,844	10.15	1,641,890,000	1,711,520,000	(69,630,000)	(4.07)	3.5006	3.0486	0.45	14.83
2	Hedging Settlement Costs	1,960,976	0	1,960,976	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	11,726	8,059	3,667	45.50	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(68,765)	0	(68,765)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	59,379,196	52,185,474	7,193,722	13.78	1,641,890,000	1,711,520,000	(69,630,000)	(4.07)	3.6165	3.0491	0.57	18.61
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	5,851,296	2,517,000	3,334,296	132.47	157,390,355	48,706,000	108,684,355	223.14	3.7177	5.1677	(1.45)	(28.06)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	117,168	0	117,168	4.66	1,225,004	0	1,225,004	#N/A	9.5647	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	5,968,464	2,517,000	3,451,464	137.13	158,615,359	48,706,000	109,909,359	225.66	3.7629	5.1677	(1.40)	(27.18)
14	Total Available MWH (Line 6 + Line 13)	65,347,660	54,702,474	10,645,186	19.46	1,800,505,359	1,760,226,000	40,279,359	2.29				
15	Fuel Cost of Economy Sales (A6)	(1,044,011)	(1,276,000)	231,989	18.18	(21,400,389)	(25,290,000)	3,889,611	15.38	(4.8785)	(5.0455)	0.17	3.31
16	Gain on Economy Sales (A6)	(270,801)	(356,000)	85,199	23.93	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(2,907,332)	(3,175,000)	267,668	8.43	(141,858,206)	(135,478,000)	(6,380,206)	(4.71)	(2.0495)	(2.3436)	0.29	12.55
18	Fuel Cost of Other Power Sales (A6)	(6,527,655)	(10,280,000)	3,752,345	36.50	(260,626,039)	(261,547,000)	920,961	0.35	(2.5046)	(3.9305)	1.43	36.28
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(10,749,799)	(15,087,000)	4,337,201	28.75	(423,884,634)	(422,315,000)	(1,569,634)	(0.37)	(2.5360)	(3.5725)	1.04	29.01
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	54,597,861	39,615,474	14,982,387	37.82	1,376,620,725	1,337,911,000	38,709,725	2.89	3.9661	2.961	1.01	33.94
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	76,699	55,223	21,476	38.89	1,933,862	1,865,000	68,862	3.69	3.9661	2.9610	1.01	33.94
24	T & D Losses *	3,222,190	2,900,151	322,039	11.10	81,243,284	97,945,000	(16,701,716)	(17.05)	3.9661	2.9610	1.01	33.94
25	TERRITORIAL KWH SALES	54,597,861	39,615,474	14,982,387	37.82	1,293,443,579	1,238,101,000	55,342,579	4.47	4.2211	3.1997	1.02	31.92
26	Wholesale KWH Sales	1,819,583	1,324,583	495,000	37.37	43,106,267	41,397,000	1,709,267	4.13	4.2212	3.1997	1.02	31.92
27	Jurisdictional KWH Sales	52,778,278	38,290,891	14,487,387	37.84	1,250,337,312	1,196,704,000	53,633,312	4.48	4.2211	3.1997	1.02	31.92
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	52,815,223	38,317,695	14,497,528	37.84	1,250,337,312	1,196,704,000	53,633,312	4.48	4.2241	3.2019	1.02	31.92
29	TRUE-UP	955,051	955,051	0	0.00	1,250,337,312	1,196,704,000	53,633,312	4.48	0.0764	0.0798	(0.00)	(4.26)
30	TOTAL JURISDICTIONAL FUEL COST	53,770,274	39,272,746	14,497,528	36.91	1,250,337,312	1,196,704,000	53,633,312	4.48	4.3005	3.2817	1.02	31.04
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									4.3036	3.2841	1.02	31.04
33	GPIF Reward / (Penalty)	36,832	36,832	(0)	0.00	1,250,337,312	1,196,704,000	53,633,312	4.48	0.0029	0.0031	(0.00)	(6.45)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.3065	3.2872	1.02	31.01
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.307	3.287		

001

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: AUGUST 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$57,475,259
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(68,765)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	1,960,976
5	Hedging Support Costs	Schedule A-2, Line A-5	11,726
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	5,851,296
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	117,168
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,749,799)
11	Total Fuel and Net Power Transactions		$ 54,597,861

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
AUGUST 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	339,308,988	343,341,888	(4,032,900)	(1.17)	11,081,950,000	11,749,870,000	(667,920,000)	(5.68)	3.0618	2.9221	0.14	4.78
2	Hedging Settlement Costs	12,503,025	0	12,503,025	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	66,827	32,660	34,167	104.61	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(562,281)	0	(562,281)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	351,316,559	343,374,548	7,942,011	2.31	11,081,950,000	11,749,870,000	(667,920,000)	(5.68)	3.1702	2.9224	0.25	8.48
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	27,650,280	17,318,000	10,332,280	59.66	966,225,188	375,966,000	590,259,188	157.00	2.8617	4.6063	(1.74)	(37.87)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	398,481	0	398,481	#N/A	6,477,224	0	6,477,224	#N/A	6.1520	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	28,048,761	17,318,000	10,730,761	61.96	972,702,412	375,966,000	596,736,412	158.72	2.8836	4.6063	(1.72)	(37.40)
14	Total Available MWH (Line 6 + Line 13)	379,365,320	360,692,548	18,672,772	5.18	12,054,652,412	12,125,836,000	(71,183,588)	(0.59)				
15	Fuel Cost of Economy Sales (A6)	(5,494,824)	(10,649,000)	5,154,176	48.40	(115,253,661)	(210,239,000)	94,985,339	45.18	(4.7676)	(5.0652)	0.30	5.88
16	Gain on Economy Sales (A6)	(1,564,624)	(2,186,000)	621,376	28.43	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(23,377,628)	(24,366,000)	988,372	4.06	(1,053,512,492)	(1,097,893,000)	44,380,508	4.04	(2.2190)	(2.2193)	0.00	0.01
18	Fuel Cost of Other Power Sales (A6)	(69,238,396)	(79,464,000)	10,225,604	12.87	(2,226,111,130)	(2,194,318,000)	(31,793,130)	(1.45)	(3.1103)	(3.6214)	0.51	14.11
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(99,675,472)	(116,665,000)	16,989,528	14.56	(3,394,877,283)	(3,502,450,000)	107,572,717	3.07	(2.9361)	(3.3310)	0.39	11.86
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	279,689,848	244,027,548	35,662,300	14.61	8,659,775,129	8,623,386,000	36,389,129	0.42	3.2298	2.8298	0.40	14.14
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	482,283	453,475	28,808	6.35	14,932,296	16,025,000	(1,092,704)	(6.82)	3.2298	2.8298	0.40	14.14
24	T & D Losses *	16,488,554	14,947,456	1,541,098	10.31	510,513,168	528,216,000	(17,702,832)	(3.35)	3.2298	2.8298	0.40	14.14
25	TERRITORIAL KWH SALES	279,689,849	244,027,548	35,662,301	14.61	8,134,329,665	8,079,145,000	55,184,665	0.68	3.4384	3.0205	0.42	13.84
26	Wholesale KWH Sales	9,411,595	8,062,426	1,349,169	16.73	275,150,078	266,405,000	8,745,078	3.28	3.4205	3.0264	0.39	13.02
27	Jurisdictional KWH Sales	270,278,254	235,965,122	34,313,132	14.54	7,859,179,587	7,812,740,000	46,439,587	0.59	3.4390	3.0203	0.42	13.86
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	270,467,449	236,130,297	34,337,152	14.54	7,859,179,587	7,812,740,000	46,439,587	0.59	3.4414	3.0224	0.42	13.86
29	TRUE-UP	7,640,408	7,640,408	0	0.00	7,859,179,587	7,812,740,000	46,439,587	0.59	0.0972	0.0978	(0.00)	(0.61)
30	TOTAL JURISDICTIONAL FUEL COST	278,107,857	243,770,705	34,337,152	14.09	7,859,179,587	7,812,740,000	46,439,587	0.59	3.5386	3.1202	0.42	13.41
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5411	3.1224	0.42	13.41
33	GPIF Reward / (Penalty)	294,656	294,657	0	0.00	7,859,179,587	7,812,740,000	46,439,587	0.59	0.0037	0.0038	(0.00)	(2.63)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5448	3.1262	0.42	13.39
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.545	3.126		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

003

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	57,380,523.45	51,911,415	5,469,108.45	10.54	338,454,687.04	341,807,921	(3,353,233.96)	(0.98)
1a	Other Generation	94,735.93	266,000	(171,264.07)	(64.38)	854,302.48	1,533,967	(679,664.52)	(44.31)
2	Fuel Cost of Power Sold	(10,749,798.28)	(15,087,000)	4,337,201.72	28.75	(99,675,471.33)	(116,665,000)	16,989,528.67	14.56
3	Fuel Cost - Purchased Power	5,851,295.47	2,517,000	3,334,295.47	132.47	27,650,279.70	17,318,000	10,332,279.70	59.66
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	117,168.00	0	117,168.00	100.00	398,481.00	0	398,481.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	11,725.90	8,059	3,666.90	45.50	66,827.00	32,660	34,167.00	104.61
6	Hedging Settlement Cost	1,960,976.00	0	1,960,976.00	100.00	12,503,025.00	0	12,503,025.00	100.00
7	Total Fuel & Net Power Transactions	54,666,626.47	39,615,474	15,051,152	37.99	280,252,130.89	244,027,548	36,224,583	14.84
8	AdjustmentsTo Fuel Cost*	(68,764.98)	0	(68,764.98)	#N/A	(562,281.58)	0	(562,281.58)	#N/A
9	Adj. Total Fuel & Net Power Transactions	54,597,861.49	39,615,474	14,982,387.49	37.82	279,689,849.31	244,027,548	35,662,301.31	14.61
B.	*KWH Sales*								
1	Jurisdictional Sales	1,250,337,312	1,196,704,000	53,633,312	4.48	7,859,179,587	7,812,740,000	46,439,587	0.59
2	Non-Jurisdictional Sales	43,106,267	41,397,000	1,709,267	4.13	275,150,078	266,405,000	8,745,078	3.28
3	Total Territorial Sales	1,293,443,579	1,238,101,000	55,342,579	4.47	8,134,329,665	8,079,145,000	55,184,665	0.68
4	Juris. Sales as % of Total Terr. Sales	96.6673	96.6564	0.0109	0.01	96.6174	96.7026	(0.0852)	(0.09)

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

004

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	38,423,338.15	36,784,130	1,639,208.15	4.46	241,585,168.39	240,146,977	1,438,191.39	0.60
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(7,640,411.36)	(7,640,408)	(3.36)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(294,446.64)	(294,448)	1.36	0.00
3	Juris. Fuel Revenue Applicable to Period	37,431,480.90	35,792,273	1,639,207.90	4.58	233,650,310.39	232,212,121	1,438,189.39	0.62
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	54,597,861.49	39,615,474	14,982,387.49	37.82	279,689,849.31	244,027,548	35,662,301.31	14.61
5	Juris. Sales % of Total KWH Sales (Line B4)	96.6673	96.6564	0.0109	0.01	96.6174	96.7026	(0.0852)	(0.09)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	52,815,223.36	38,317,695	14,497,528.36	37.84	270,467,449.30	236,130,297	34,337,152.30	14.54
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(15,383,742.46)	(2,525,422)	(12,858,320.46)	(509.16)	(36,817,138.91)	(3,918,176)	(32,898,962.91)	(839.65)
8	Interest Provision for the Month	(241,185.66)	(31,887)	(209,298.66)	(656.38)	(1,100,078.07)	(278,168)	(821,910.07)	(295.47)
9	Beginning True-Up & Interest Provision	(47,241,663.65)	(6,414,295)	(40,827,368.65)	(636.51)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	(176.03)
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	7,640,411.36	7,640,408	3.36	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(61,911,540.35)	(8,016,553)	(53,894,987.35)	(672.30)	(61,911,540.35)	(8,016,553)	(53,894,987.35)	(672.30)

005

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(47,241,663.65)	(6,414,295)	(40,827,368.65)	636.51
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(61,670,354.69)	(7,984,666)	(53,685,688.69)	672.36
3	Total of Beginning & Ending True-Up Amts.	(108,912,018.34)	(14,398,961)	(94,513,057.34)	656.39
4	Average True-Up Amount	(54,456,009.17)	(7,199,481)	(47,256,528.17)	656.39
5	Interest Rate - 1st Day of Reporting Business Month	5.36	5.36	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.27	5.27	0.0000	
7	Total (D5+D6)	10.63	10.63	0.0000	
8	Annual Average Interest Rate	5.32	5.32	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4429	0.4429	0.0000	
10	Interest Provision (D4*D9)	(241,185.66)	(31,887)	(209,298.66)	656.38

900

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	45,968,822	45,537,045	431,777	0.95	1,439,414,000	1,542,660,000	(103,246,000)	(6.69)	3.1936	2.9519	0.24	8.19
2	Hedging Settlement Costs	2,816,400	0	2,816,400	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	10,244	8,059	2,185	27.11	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(11,673)	0	(11,673)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	48,783,793	45,545,104	3,238,689	7.11	1,439,414,000	1,542,660,000	(103,246,000)	(6.69)	3.3891	2.9524	0.44	14.79
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	587,577	1,624,000	(1,036,423)	(63.82)	72,356,785	33,517,000	38,839,785	115.88	0.8121	4.8453	(4.03)	(83.24)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	24,910	0	24,910	1.53	658,503	0	658,503	#N/A	3.7828	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	612,487	1,624,000	(1,011,513)	(62.29)	73,015,288	33,517,000	39,498,288	117.85	0.8388	4.8453	(4.01)	(82.69)
14	Total Available MWH (Line 6 + Line 13)	49,396,280	47,169,104	2,227,176	4.72	1,512,429,288	1,576,177,000	(63,747,712)	(4.04)				
15	Fuel Cost of Economy Sales (A6)	(352,698)	(669,000)	316,302	47.28	(9,396,148)	(15,572,000)	6,175,852	39.66	(3.7536)	(4.2962)	0.54	12.63
16	Gain on Economy Sales (A6)	(139,961)	(104,000)	(35,961)	(34.58)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(3,215,748)	(3,165,000)	(50,748)	(1.60)	(145,761,546)	(135,815,000)	(9,946,546)	(7.32)	(2.2062)	(2.3304)	0.12	5.33
18	Fuel Cost of Other Power Sales (A6)	(5,584,819)	(13,058,000)	7,473,181	57.23	(222,951,354)	(348,361,000)	125,409,646	36.00	(2.5049)	(3.7484)	1.24	33.17
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(9,293,226)	(16,996,000)	7,702,774	45.32	(378,109,048)	(499,748,000)	121,638,952	24.34	(2.4578)	(3.4009)	0.94	27.73
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	40,103,054	30,173,104	9,929,950	32.91	1,134,320,240	1,076,429,000	57,891,240	5.38	3.5354	2.8031	0.73	26.12
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	64,410	48,830	15,580	31.91	1,821,856	1,742,000	79,856	4.58	3.5354	2.8031	0.73	26.12
24	T & D Losses *	2,002,404	1,776,661	225,743	12.71	56,638,687	63,382,000	(6,743,313)	(10.64)	3.5354	2.8031	0.73	26.12
25	TERRITORIAL KWH SALES	40,103,054	30,173,104	9,929,950	32.91	1,075,859,697	1,011,305,000	64,554,697	6.38	3.7275	2.9836	0.74	24.93
26	Wholesale KWH Sales	1,284,300	1,063,149	221,151	20.80	34,454,403	35,633,000	(1,178,597)	(3.31)	3.7275	2.9836	0.74	24.93
27	Jurisdictional KWH Sales	38,818,754	29,109,955	9,708,799	33.35	1,041,405,294	975,672,000	65,733,294	6.74	3.7275	2.9836	0.74	24.93
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	38,845,927	29,130,332	9,715,595	33.35	1,041,405,294	975,672,000	65,733,294	6.74	3.7301	2.9857	0.74	24.93
29	TRUE-UP	955,051	955,051	0	0.00	1,041,405,294	975,672,000	65,733,294	6.74	0.0917	0.0979	(0.01)	(6.33)
30	TOTAL JURISDICTIONAL FUEL COST	39,800,978	30,085,383	9,715,595	32.29	1,041,405,294	975,672,000	65,733,294	6.74	3.8218	3.0836	0.74	23.94
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.8246	3.0858	0.74	23.94
33	GPIF Reward / (Penalty)	36,832	36,832	(0)	0.00	1,041,405,294	975,672,000	65,733,294	6.74	0.0035	0.0038	(0.00)	(7.89)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8281	3.0896	0.74	23.90
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.828	3.090		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: SEPTEMBER 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$45,968,822
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(11,673)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	2,816,400
5	Hedging Support Costs	Schedule A-2, Line A-5	10,244
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	587,577
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	24,910
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(9,293,226)
11	Total Fuel and Net Power Transactions		$ 40,103,054

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
SEPTEMBER 2006
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	385,277,810	388,878,933	(3,601,123)	(0.93)	12,521,364,000	13,292,530,000	(771,166,000)	(5.80)	3.0770	2.9255	0.15	5.18
2	Hedging Settlement Costs	15,319,425	0	15,319,425	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	77,071	40,719	36,352	89.28	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(573,954)	0	(573,954)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	400,100,352	388,919,652	11,180,700	2.87	12,521,364,000	13,292,530,000	(771,166,000)	(5.80)	3.1953	2.9259	0.27	9.21
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	28,237,857	18,942,000	9,295,857	49.08	1,038,581,973	409,483,000	629,098,973	153.63	2.7189	4.6258	(1.91)	(41.22)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	423,391	0	423,391	#N/A	7,135,727	0	7,135,727	#N/A	5.9334	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	28,661,248	18,942,000	9,719,248	51.31	1,045,717,700	409,483,000	636,234,700	155.38	2.7408	4.6258	(1.89)	(40.75)
14	Total Available MWH (Line 6 + Line 13)	428,761,600	407,861,652	20,899,948	5.12	13,567,081,700	13,702,013,000	(134,931,300)	(0.98)				
15	Fuel Cost of Economy Sales (A6)	(5,847,522)	(11,318,000)	5,470,478	48.33	(124,649,809)	(225,811,000)	101,161,191	44.80	(4.6912)	(5.0122)	0.32	6.40
16	Gain on Economy Sales (A6)	(1,704,585)	(2,290,000)	585,415	25.56	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(26,593,376)	(27,531,000)	937,624	3.41	(1,199,274,038)	(1,233,708,000)	34,433,962	2.79	(2.2175)	(2.2316)	0.01	0.63
18	Fuel Cost of Other Power Sales (A6)	(74,823,215)	(92,522,000)	17,698,785	19.13	(2,449,062,484)	(2,542,679,000)	93,616,516	3.68	(3.0552)	(3.6388)	0.58	16.04
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(108,968,698)	(133,661,000)	24,692,302	18.47	(3,772,986,331)	(4,002,198,000)	229,211,669	5.73	(2.8881)	(3.3397)	0.45	13.52
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	319,792,902	274,200,652	45,592,250	16.63	9,794,095,369	9,699,815,000	94,280,369	0.97	3.2652	2.8269	0.44	15.50
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	547,057	502,255	44,802	8.92	16,754,152	17,767,000	(1,012,848)	(5.70)	3.2652	2.8269	0.44	15.50
24	T & D Losses *	18,518,642	16,723,884	1,794,758	10.73	567,151,855	591,598,000	(24,446,145)	(4.13)	3.2652	2.8269	0.44	15.50
25	TERRITORIAL KWH SALES	319,792,903	274,200,652	45,592,251	16.63	9,210,189,362	9,090,450,000	119,739,362	1.32	3.4722	3.0164	0.46	15.11
26	Wholesale KWH Sales	10,695,895	9,125,575	1,570,320	17.21	309,604,481	302,038,000	7,566,481	2.51	3.4547	3.0213	0.43	14.34
27	Jurisdictional KWH Sales	309,097,008	265,075,077	44,021,931	16.61	8,900,584,881	8,788,412,000	112,172,881	1.28	3.4728	3.0162	0.46	15.14
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	309,313,376	265,260,629	44,052,747	16.61	8,900,584,881	8,788,412,000	112,172,881	1.28	3.4752	3.0183	0.46	15.14
29	TRUE-UP	8,595,459	8,595,459	0	0.00	8,900,584,881	8,788,412,000	112,172,881	1.28	0.0966	0.0978	(0.00)	(1.23)
30	TOTAL JURISDICTIONAL FUEL COST	317,908,835	273,856,088	44,052,747	16.09	8,900,584,881	8,788,412,000	112,172,881	1.28	3.5718	3.1161	0.46	14.62
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5744	3.1183	0.46	14.63
33	GPIF Reward / (Penalty)	331,488	331,489	0	0.00	8,900,584,881	8,788,412,000	112,172,881	1.28	0.0037	0.0038	(0.00)	(2.63)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5781	3.1221	0.46	14.61
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.578	3.122		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

03

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	45,876,845.68	45,279,045	597,800.68	1.32	384,331,532.72	387,086,966	(2,755,433.28)	(0.71)
1a	Other Generation	91,975.88	258,000	(166,024.12)	(64.35)	946,278.36	1,791,967	(845,688.64)	(47.19)
2	Fuel Cost of Power Sold	(9,293,225.73)	(16,996,000)	7,702,774.27	45.32	(108,968,697.06)	(133,661,000)	24,692,302.94	18.47
3	Fuel Cost - Purchased Power	587,577.21	1,624,000	(1,036,422.79)	(63.82)	28,237,856.91	18,942,000	9,295,856.91	49.08
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	24,910.00	0	24,910.00	100.00	423,391.00	0	423,391.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	10,244.23	8,059	2,185.23	27.12	77,071.23	40,719	36,352.23	89.28
6	Hedging Settlement Cost	2,816,400.00	0	2,816,400.00	100.00	15,319,425.00	0	15,319,425.00	100.00
7	Total Fuel & Net Power Transactions	40,114,727.27	30,173,104	9,941,623	32.95	320,366,858.16	274,200,652	46,166,206	16.84
8	AdjustmentsTo Fuel Cost*	(11,673.43)	0	(11,673.43)	#N/A	(573,955.01)	0	(573,955.01)	#N/A
9	Adj. Total Fuel & Net Power Transactions	40,103,053.84	30,173,104	9,929,949.84	32.91	319,792,903.15	274,200,652	45,592,251.15	16.63
B.	*KWH Sales*								
1	Jurisdictional Sales	1,041,405,294	975,672,000	65,733,294	6.74	8,900,584,881	8,788,412,000	112,172,881	1.28
2	Non-Jurisdictional Sales	34,454,403	35,633,000	(1,178,597)	(3.31)	309,604,481	302,038,000	7,566,481	2.51
3	Total Territorial Sales	1,075,859,697	1,011,305,000	64,554,697	6.38	9,210,189,362	9,090,450,000	119,739,362	1.32
4	Juris. Sales as % of Total Terr. Sales	96.7975	96.4765	0.3210	0.33	96.6385	96.6774	(0.0389)	(0.04)

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

FPU

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2006

C. *True-up Calculation*	CURRENT MONTH ACTUAL	$ DIFFERENCE ESTIMATED	AMOUNT ($)	%	PERIOD - TO - DATE ACTUAL	$ DIFFERENCE ESTIMATED	AMOUNT ($)	%
1 Jurisdictional Fuel Revenue	31,988,975.82	29,990,078	1,998,897.82	6.67	273,574,144.21	270,137,055	3,437,089.21	1.27
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(8,595,462.78)	(8,595,459)	(3.78)	0.00
2b Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(331,252.47)	(331,254)	1.53	0.00
3 Juris. Fuel Revenue Applicable to Period	30,997,118.57	28,998,221	1,998,897.57	6.89	264,647,428.96	261,210,342	3,437,086.96	1.32
4 Adjusted Total Fuel & Net Power Transactions (Line A9)	40,103,053.84	30,173,104	9,929,949.84	32.91	319,792,903.15	274,200,652	45,592,251.15	16.63
5 Juris. Sales % of Total KWH Sales (Line B4)	96.7975	96.4765	0.3210	0.33	96.6385	96.6774	(0.0389)	(0.04)
6 Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	38,845,926.67	29,130,332	9,715,594.67	33.35	309,313,375.97	265,260,629	44,052,746.97	16.61
7 True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(7,848,808.10)	(132,111)	(7,716,697.10)	(5,841.07)	(44,665,947.01)	(4,050,287)	(40,615,660.01)	(1,002.78)
8 Interest Provision for the Month	(286,792.74)	(33,371)	(253,421.74)	(759.41)	(1,386,870.81)	(311,539)	(1,075,331.81)	(345.17)
9 Beginning True-Up & Interest Provision	(61,911,540.35)	(8,016,553)	(53,894,987.35)	(672.30)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	(176.03)
10 True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	8,595,462.78	8,595,459	3.78	0.00
End of Period - Total Net True-Up, Before 11 Adjustment (C7+C8+C9+C10)	(69,092,089.77)	(7,226,984)	(61,865,105.77)	(856.03)	(69,092,089.77)	(7,226,984)	(61,865,105.77)	(856.03)

05

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2006

		CURRENT MONTH			
		$			
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(61,911,540.35)	(8,016,553)	(53,894,987.35)	672.30
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(68,805,297.03)	(7,193,613)	(61,611,684.03)	856.48
3	Total of Beginning & Ending True-Up Amts.	(130,716,837.38)	(15,210,166)	(115,506,671.38)	759.40
4	Average True-Up Amount	(65,358,418.69)	(7,605,083)	(57,753,335.69)	759.40
5	Interest Rate - 1st Day of Reporting Business Month	5.27	5.27	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.26	5.26	0.0000	
7	Total (D5+D6)	10.53	10.53	0.0000	
8	Annual Average Interest Rate	5.27	5.27	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4388	0.4388	0.0000	
10	Interest Provision (D4*D9)	(286,792.74)	(33,371)	(253,421.74)	759.41
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	41,620,128	37,885,723	3,734,405	9.86	1,306,615,000	1,234,630,000	71,985,000	5.83	3.1853	3.0686	0.12	3.80
2	Hedging Settlement Costs	1,515,633	0	1,515,633	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	7,399	8,059	(660)	(8.19)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(19,602)	0	(19,602)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	43,123,558	37,893,782	5,229,776	13.80	1,306,615,000	1,234,630,000	71,985,000	5.83	3.3004	3.0692	0.23	7.53
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	905,189	2,304,000	(1,398,811)	(60.71)	61,330,187	51,237,000	10,093,187	19.70	1.4759	4.4968	(3.02)	(67.18)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	13,918	0	13,918	0.60	374,000	0	374,000	#N/A	3.7214	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	919,107	2,304,000	(1,384,893)	(60.11)	61,704,187	51,237,000	10,467,187	20.43	1.4895	4.4968	(3.01)	(66.88)
14	Total Available MWH (Line 6 + Line 13)	44,042,665	40,197,782	3,844,883	9.56	1,368,319,187	1,285,867,000	82,452,187	6.41				
15	Fuel Cost of Economy Sales (A6)	(781,467)	(729,000)	(52,467)	(7.20)	(21,924,273)	(18,404,000)	(3,520,273)	(19.13)	(3.5644)	(3.9611)	0.40	10.01
16	Gain on Economy Sales (A6)	(239,967)	(122,000)	(117,967)	(96.69)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(1,073,683)	(969,000)	(104,683)	(10.80)	(39,077,479)	(30,214,000)	(8,863,479)	(29.34)	(2.7476)	(3.2071)	0.46	14.33
18	Fuel Cost of Other Power Sales (A6)	(9,186,103)	(10,365,000)	1,178,897	11.37	(327,978,999)	(298,164,000)	(29,814,999)	(10.00)	(2.8008)	(3.4763)	0.68	19.43
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(11,281,220)	(12,185,000)	903,780	7.42	(388,980,751)	(346,782,000)	(42,198,751)	(12.17)	(2.9002)	(3.5137)	0.61	17.46
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	32,761,445	28,012,782	4,748,663	16.95	979,338,436	939,085,000	40,253,436	4.29	3.3453	2.983	0.36	12.15
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	58,962	50,890	8,072	15.86	1,762,523	1,706,000	56,523	3.31	3.3453	2.9830	0.36	12.15
24	T & D Losses *	2,328,709	1,438,492	890,217	61.89	69,611,366	48,223,000	21,388,366	44.35	3.3453	2.9830	0.36	12.15
25	TERRITORIAL KWH SALES	32,761,445	28,012,782	4,748,663	16.95	907,964,547	889,156,000	18,808,547	2.12	3.6082	3.1505	0.46	14.53
26	Wholesale KWH Sales	1,112,218	999,664	112,554	11.26	30,824,549	31,730,000	(905,451)	(2.85)	3.6082	3.1505	0.46	14.53
27	Jurisdictional KWH Sales	31,649,227	27,013,118	4,636,109	17.16	877,139,998	857,426,000	19,713,998	2.30	3.6082	3.1505	0.46	14.53
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	31,671,381	27,032,027	4,639,354	17.16	877,139,998	857,426,000	19,713,998	2.30	3.6108	3.1527	0.46	14.53
29	TRUE-UP	955,051	955,051	0	0.00	877,139,998	857,426,000	19,713,998	2.30	0.1089	0.1114	(0.00)	(2.24)
30	TOTAL JURISDICTIONAL FUEL COST	32,626,432	27,987,078	4,639,354	16.58	877,139,998	857,426,000	19,713,998	2.30	3.7197	3.2641	0.46	13.96
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.7224	3.2665	0.46	13.96
33	GPIF Reward / (Penalty)	36,832	36,832	(0)	0.00	877,139,998	857,426,000	19,713,998	2.30	0.0042	0.0043	(0.00)	(2.33)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.7266	3.2708	0.46	13.94
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.727	3.271		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: OCTOBER 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$41,620,128
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	(19,602)
4	Hedging Settlement Costs	Schedule A-2, Line A-6	1,515,633
5	Hedging Support Costs	Schedule A-2, Line A-5	7,399
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	905,189
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	13,918
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(11,281,220)
11	Total Fuel and Net Power Transactions		$ 32,761,445

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
OCTOBER 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	426,897,938	426,764,656	133,282	0.03	13,827,979,000	14,527,160,000	(699,181,000)	(4.81)	3.0872	2.9377	0.15	5.09
2	Hedging Settlement Costs	16,835,058	0	16,835,058	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	84,470	48,778	35,692	73.17	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(593,556)	0	(593,556)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	443,223,910	426,813,434	16,410,476	3.84	13,827,979,000	14,527,160,000	(699,181,000)	(4.81)	3.2053	2.9380	0.27	9.10
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	29,143,046	21,246,000	7,897,046	37.17	1,099,912,160	460,720,000	639,192,160	138.74	2.6496	4.6115	(1.96)	(42.54)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	437,309	0	437,309	#N/A	7,509,727	0	7,509,727	#N/A	5.8232	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	29,580,355	21,246,000	8,334,355	39.23	1,107,421,887	460,720,000	646,701,887	140.37	2.6711	4.6115	(1.94)	(42.08)
14	Total Available MWH (Line 6 + Line 13)	472,804,265	448,059,434	24,744,831	5.52	14,935,400,887	14,987,880,000	(52,479,113)	(0.35)				
15	Fuel Cost of Economy Sales (A6)	(6,628,989)	(12,047,000)	5,418,011	44.97	(146,574,082)	(244,215,000)	97,640,918	39.98	(4.5226)	(4.9329)	0.41	8.32
16	Gain on Economy Sales (A6)	(1,944,552)	(2,412,000)	467,448	19.38	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(27,667,059)	(28,500,000)	832,941	2.92	(1,238,351,517)	(1,263,922,000)	25,570,483	2.02	(2.2342)	(2.2549)	0.02	0.92
18	Fuel Cost of Other Power Sales (A6)	(84,009,318)	(102,887,000)	18,877,682	18.35	(2,777,041,483)	(2,840,843,000)	63,801,517	2.25	(3.0251)	(3.6217)	0.60	16.47
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(120,249,918)	(145,846,000)	25,596,082	17.55	(4,161,967,082)	(4,348,980,000)	187,012,918	4.30	(2.8893)	(3.3536)	0.46	13.84
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	352,554,347	302,213,434	50,340,913	16.66	10,773,433,805	10,638,900,000	134,533,805	1.26	3.2724	2.8406	0.43	15.20
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	605,940	553,150	52,790	9.54	18,516,675	19,473,000	(956,325)	(4.91)	3.2724	2.8406	0.43	15.20
24	T & D Losses *	20,837,440	18,174,755	2,662,685	14.65	636,763,221	639,821,000	(3,057,779)	(0.48)	3.2724	2.8406	0.43	15.20
25	TERRITORIAL KWH SALES	352,554,348	302,213,434	50,340,914	16.66	10,118,153,909	9,979,606,000	138,547,909	1.39	3.4844	3.0283	0.46	15.06
26	Wholesale KWH Sales	11,808,113	10,125,239	1,682,874	16.62	340,429,030	333,768,000	6,661,030	2.00	3.4686	3.0336	0.44	14.34
27	Jurisdictional KWH Sales	340,746,235	292,088,195	48,658,040	16.66	9,777,724,879	9,645,838,000	131,886,879	1.37	3.4849	3.0281	0.46	15.09
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	340,984,757	292,292,656	48,692,101	16.66	9,777,724,879	9,645,838,000	131,886,879	1.37	3.4874	3.0302	0.46	15.09
29	TRUE-UP	9,550,510	9,550,510	0	0.00	9,777,724,879	9,645,838,000	131,886,879	1.37	0.0977	0.0990	(0.00)	(1.31)
30	TOTAL JURISDICTIONAL FUEL COST	350,535,267	301,843,166	48,692,101	16.13	9,777,724,879	9,645,838,000	131,886,879	1.37	3.5851	3.1292	0.46	14.57
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5877	3.1315	0.46	14.57
33	GPIF Reward / (Penalty)	368,320	368,320	(0)	0.00	9,777,724,879	9,645,838,000	131,886,879	1.37	0.0038	0.0038	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5915	3.1353	0.46	14.55
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.592	3.135		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	41,531,020.39	37,585,723	3,945,297.39	10.50	425,862,553.11	424,672,689	1,189,864.11	0.28
1a	Other Generation	89,107.62	300,000	(210,892.38)	(70.30)	1,035,385.98	2,091,967	(1,056,581.02)	(50.51)
2	Fuel Cost of Power Sold	(11,281,220.00)	(12,185,000)	903,780.00	7.42	(120,249,917.06)	(145,846,000)	25,596,082.94	17.55
3	Fuel Cost - Purchased Power	905,188.63	2,304,000	(1,398,811.37)	(60.71)	29,143,045.54	21,246,000	7,897,045.54	37.17
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	13,918.00	0	13,918.00	100.00	437,309.00	0	437,309.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	7,399.01	8,059	(659.99)	(8.19)	84,470.24	48,778	35,692.24	73.17
6	Hedging Settlement Cost	1,515,632.93	0	1,515,632.93	100.00	16,835,057.93	0	16,835,057.93	100.00
7	Total Fuel & Net Power Transactions	32,781,046.58	28,012,782	4,768,265	17.02	353,147,904.74	302,213,434	50,934,471	16.85
8	AdjustmentsTo Fuel Cost*	(19,601.61)	0	(19,601.61)	#N/A	(593,556.62)	0	(593,556.62)	#N/A
9	Adj. Total Fuel & Net Power Transactions	32,761,444.97	28,012,782	4,748,662.97	16.95	352,554,348.12	302,213,434	50,340,914.12	16.66
B.	*KWH Sales*								
1	Jurisdictional Sales	877,139,998	857,426,000	19,713,998	2.30	9,777,724,879	9,645,838,000	131,886,879	1.37
2	Non-Jurisdictional Sales	30,824,549	31,730,000	(905,451)	(2.85)	340,429,030	333,768,000	6,661,030	2.00
3	Total Territorial Sales	907,964,547	889,156,000	18,808,547	2.12	10,118,153,909	9,979,606,000	138,547,909	1.39
4	Juris. Sales as % of Total Terr. Sales	96.6051	96.4314	0.1737	0.18	96.6355	96.6555	(0.0200)	(0.02)

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	26,952,730.23	26,355,448	597,282.23	2.27	300,526,874.44	296,492,503	4,034,371.44	1.36
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(9,550,514.20)	(9,550,510)	(4.20)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(368,058.30)	(368,060)	1.70	0.00
3	Juris. Fuel Revenue Applicable to Period	25,960,872.98	25,363,591	597,281.98	2.35	290,608,301.94	286,573,933	4,034,368.94	1.41
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	32,761,444.97	28,012,782	4,748,662.97	16.95	352,554,348.12	302,213,434	50,340,914.12	16.66
5	Juris. Sales % of Total KWH Sales (Line B4)	96.6051	96.4314	0.1737	0.18	96.6355	96.6555	(0.0200)	(0.02)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	31,671,381.13	27,032,027	4,639,354.13	17.16	340,984,757.10	292,292,656	48,692,101.10	16.66
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(5,710,508.15)	(1,668,436)	(4,042,072.15)	(242.27)	(50,376,455.16)	(5,718,723)	(44,657,732.16)	(780.90)
8	Interest Provision for the Month	(313,609.56)	(33,277)	(280,332.56)	(842.42)	(1,700,480.37)	(344,816)	(1,355,664.37)	(393.16)
9	Beginning True-Up & Interest Provision	(69,092,089.77)	(7,226,984)	(61,865,105.77)	(856.03)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	(176.03)
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	9,550,514.20	9,550,510	4.20	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(74,161,156.06)	(7,973,646)	(66,187,510.06)	(830.08)	(74,161,156.06)	(7,973,646)	(66,187,510.06)	(830.08)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2006

		CURRENT MONTH			
		$			
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(69,092,089.77)	(7,226,984)	(61,865,105.77)	856.03
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(73,847,546.50)	(7,940,369)	(65,907,177.50)	830.03
3	Total of Beginning & Ending True-Up Amts.	(142,939,636.27)	(15,167,353)	(127,772,283.27)	842.42
4	Average True-Up Amount	(71,469,818.14)	(7,583,677)	(63,886,141.14)	842.42
5	Interest Rate - 1st Day of Reporting Business Month	5.26	5.26	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.27	5.27	0.0000	
7	Total (D5+D6)	10.53	10.53	0.0000	
8	Annual Average Interest Rate	5.27	5.27	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4388	0.4388	0.0000	
10	Interest Provision (D4*D9)	(313,609.56)	(33,277)	(280,332.56)	842.42
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	37,216,003	31,019,468	6,196,535	19.98	1,151,672,000	1,068,520,000	83,152,000	7.78	3.2315	2.9030	0.33	11.32
2	Hedging Settlement Costs	856,611	0	856,611	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	10,203	8,059	2,144	26.60	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	9,651	0	9,651	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	38,092,468	31,027,527	7,064,941	22.77	1,151,672,000	1,068,520,000	83,152,000	7.78	3.3076	2.9038	0.40	13.91
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	493,469	2,383,000	(1,889,531)	(79.29)	47,713,278	54,168,000	(6,454,722)	(11.92)	1.0342	4.3993	(3.37)	(76.49)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	24,035	0	24,035	1.01	666,401	0	666,401	#N/A	3.6067	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	517,504	2,383,000	(1,865,496)	(78.28)	48,379,679	54,168,000	(5,788,321)	(10.69)	1.0697	4.3993	(3.33)	(75.68)
14	Total Available MWH (Line 6 + Line 13)	38,609,972	33,410,527	5,199,445	15.56	1,200,051,679	1,122,688,000	77,363,679	6.89				
15	Fuel Cost of Economy Sales (A6)	(1,446,097)	(844,000)	(602,097)	(71.34)	(43,170,585)	(21,918,000)	(21,252,585)	(96.96)	(3.3497)	(3.8507)	0.50	13.01
16	Gain on Economy Sales (A6)	(671,535)	(325,000)	(346,535)	(106.63)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(1,280,517)	(1,435,000)	154,483	10.77	(68,032,005)	(55,317,000)	(12,715,005)	(22.99)	(1.8822)	(2.5941)	0.71	27.44
18	Fuel Cost of Other Power Sales (A6)	(5,902,783)	(6,287,000)	384,217	6.11	(226,961,477)	(182,632,000)	(44,329,477)	(24.27)	(2.6008)	(3.4424)	0.84	24.45
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(9,300,932)	(8,891,000)	(409,932)	(4.61)	(338,164,067)	(259,867,000)	(78,297,067)	(30.13)	(2.7504)	(3.4214)	0.67	19.61
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	29,309,040	24,519,527	4,789,513	19.53	861,887,612	862,821,000	(933,388)	(0.11)	3.4006	2.8418	0.56	19.66
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	55,641	53,795	1,846	3.43	1,636,215	1,893,000	(256,785)	(13.56)	3.4006	2.8418	0.56	19.66
24	T & D Losses *	754,650	1,158,403	(403,753)	(34.85)	22,191,662	40,763,000	(18,571,338)	(45.56)	3.4006	2.8418	0.56	19.66
25	TERRITORIAL KWH SALES	29,309,040	24,519,527	4,789,513	19.53	838,059,735	820,165,000	17,894,735	2.18	3.4972	2.9896	0.51	16.98
26	Wholesale KWH Sales	1,025,143	889,495	135,648	15.25	29,312,418	29,753,000	(440,582)	(1.48)	3.4973	2.9896	0.51	16.98
27	Jurisdictional KWH Sales	28,283,897	23,630,032	4,653,865	19.69	808,747,317	790,412,000	18,335,317	2.32	3.4972	2.9896	0.51	16.98
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	28,303,696	23,646,573	4,657,123	19.69	808,747,317	790,412,000	18,335,317	2.32	3.4997	2.9917	0.51	16.98
29	TRUE-UP	955,051	955,051	0	0.00	808,747,317	790,412,000	18,335,317	2.32	0.1181	0.1208	(0.00)	(2.24)
30	TOTAL JURISDICTIONAL FUEL COST	29,258,747	24,601,624	4,657,123	18.93	808,747,317	790,412,000	18,335,317	2.32	3.6178	3.1125	0.51	16.23
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.6204	3.1147	0.51	16.24
33	GPIF Reward / (Penalty)	36,832	36,832	(0)	0.00	808,747,317	790,412,000	18,335,317	2.32	0.0046	0.0047	(0.00)	(2.13)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6250	3.1194	0.51	16.21
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.625	3.119		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: NOVEMBER 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$37,216,003
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	9,651
4	Hedging Settlement Costs	Schedule A-2, Line A-6	856,611
5	Hedging Support Costs	Schedule A-2, Line A-5	10,203
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	493,469
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	24,035
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(9,300,932)
11	Total Fuel and Net Power Transactions		$ 29,309,040

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
NOVEMBER 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	464,113,941	457,784,124	6,329,817	1.38	14,979,651,000	15,595,680,000	(616,029,000)	(3.95)	3.0983	2.9353	0.16	5.55
2	Hedging Settlement Costs	17,691,669	0	17,691,669	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	94,673	56,837	37,836	66.57	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(583,905)	0	(583,905)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	481,316,378	457,840,961	23,475,417	5.13	14,979,651,000	15,595,680,000	(616,029,000)	(3.95)	3.2131	2.9357	0.28	9.45
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	29,636,515	23,629,000	6,007,515	25.42	1,147,625,438	514,888,000	632,737,438	122.89	2.5824	4.5892	(2.01)	(43.73)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	461,344	0	461,344	#N/A	8,176,128	0	8,176,128	#N/A	5.6426	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	30,097,859	23,629,000	6,468,859	27.38	1,155,801,566	514,888,000	640,913,566	124.48	2.6041	4.5892	(1.99)	(43.26)
14	Total Available MWH (Line 6 + Line 13)	511,414,237	481,469,961	29,944,276	6.22	16,135,452,566	16,110,568,000	24,884,566	0.15				
15	Fuel Cost of Economy Sales (A6)	(8,075,086)	(12,891,000)	4,815,914	37.36	(189,744,667)	(266,133,000)	76,388,333	28.70	(4.2558)	(4.8438)	0.59	12.14
16	Gain on Economy Sales (A6)	(2,616,087)	(2,737,000)	120,913	4.42	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(28,947,576)	(29,935,000)	987,424	3.30	(1,306,383,522)	(1,319,239,000)	12,855,478	0.97	(2.2159)	(2.2691)	0.05	2.34
18	Fuel Cost of Other Power Sales (A6)	(89,912,101)	(109,174,000)	19,261,899	17.64	(3,004,002,960)	(3,023,475,000)	19,472,040	0.64	(2.9931)	(3.6109)	0.62	17.11
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(129,550,850)	(154,737,000)	25,186,150	16.28	(4,500,131,149)	(4,608,847,000)	108,715,851	2.36	(2.8788)	(3.3574)	0.48	14.26
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	381,863,387	326,732,961	55,130,426	16.87	11,635,321,417	11,501,721,000	133,600,417	1.16	3.2819	2.8407	0.44	15.53
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	661,398	606,944	54,454	8.97	20,152,890	21,366,000	(1,213,110)	(5.68)	3.2819	2.8407	0.44	15.53
24	T & D Losses *	21,626,240	19,333,350	2,292,890	11.86	658,954,883	680,584,000	(21,629,117)	(3.18)	3.2819	2.8407	0.44	15.53
25	TERRITORIAL KWH SALES	381,863,388	326,732,961	55,130,427	16.87	10,956,213,644	10,799,771,000	156,442,644	1.45	3.4854	3.0254	0.46	15.20
26	Wholesale KWH Sales	12,833,256	11,014,734	1,818,522	16.51	369,741,448	363,521,000	6,220,448	1.71	3.4709	3.0300	0.44	14.55
27	Jurisdictional KWH Sales	369,030,132	315,718,227	53,311,905	16.89	10,586,472,196	10,436,250,000	150,222,196	1.44	3.4859	3.0252	0.46	15.23
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	369,288,453	315,939,229	53,349,224	16.89	10,586,472,196	10,436,250,000	150,222,196	1.44	3.4883	3.0273	0.46	15.23
29	TRUE-UP	10,505,561	10,505,561	0	0.00	10,586,472,196	10,436,250,000	150,222,196	1.44	0.0992	0.1007	(0.00)	(1.49)
30	TOTAL JURISDICTIONAL FUEL COST	379,794,014	326,444,790	53,349,224	16.34	10,586,472,196	10,436,250,000	150,222,196	1.44	3.5875	3.1280	0.46	14.69
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5901	3.1303	0.46	14.69
33	GPIF Reward / (Penalty)	405,152	405,152	(0)	0.00	10,586,472,196	10,436,250,000	150,222,196	1.44	0.0038	0.0039	(0.00)	(2.56)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5939	3.1342	0.46	14.67
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.594	3.134		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

03

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	37,112,695.95	30,729,468	6,383,227.95	20.77	462,975,249.06	455,402,157	7,573,092.06	1.66
1a	Other Generation	103,306.93	290,000	(186,693.07)	(64.38)	1,138,692.91	2,381,967	(1,243,274.09)	(52.20)
2	Fuel Cost of Power Sold	(9,300,931.86)	(8,891,000)	(409,931.86)	(4.61)	(129,550,848.92)	(154,737,000)	25,186,151.08	16.28
3	Fuel Cost - Purchased Power	493,468.96	2,383,000	(1,889,531.04)	(79.29)	29,636,514.50	23,629,000	6,007,514.50	25.42
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	24,035.00	0	24,035.00	100.00	461,344.00	0	461,344.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	10,203.39	8,059	2,144.39	26.61	94,673.63	56,837	37,836.63	66.57
6	Hedging Settlement Cost	856,610.89	0	856,610.89	100.00	17,691,668.82	0	17,691,668.82	100.00
7	Total Fuel & Net Power Transactions	29,299,389.26	24,519,527	4,779,862	19.49	382,447,294.00	326,732,961	55,714,333	17.05
8	AdjustmentsTo Fuel Cost*	9,650.64	0	9,650.64	#N/A	(583,905.98)	0	(583,905.98)	#N/A
9	Adj. Total Fuel & Net Power Transactions	29,309,039.90	24,519,527	4,789,512.90	19.53	381,863,388.02	326,732,961	55,130,427.02	16.87
B.	*KWH Sales*								
1	Jurisdictional Sales	808,747,317	790,412,000	18,335,317	2.32	10,586,472,196	10,436,250,000	150,222,196	1.44
2	Non-Jurisdictional Sales	29,312,418	29,753,000	(440,582)	(1.48)	369,741,448	363,521,000	6,220,448	1.71
3	Total Territorial Sales	838,059,735	820,165,000	17,894,735	2.18	10,956,213,644	10,799,771,000	156,442,644	1.45
4	Juris. Sales as % of Total Terr. Sales	96.5023	96.3723	0.1300	0.13	96.6253	96.6340	(0.0087)	(0.01)

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	24,804,612.54	24,295,580	509,032.54	2.10	325,331,486.98	320,788,083	4,543,403.98	1.42
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.42)	(955,051)	(0.42)	0.00	(10,505,565.62)	(10,505,561)	(4.62)	0.00
2b	Incentive Provision	(36,805.83)	(36,806)	0.17	0.00	(404,864.13)	(404,866)	1.87	0.00
3	Juris. Fuel Revenue Applicable to Period	23,812,755.29	23,303,723	509,032.29	2.18	314,421,057.23	309,877,656	4,543,401.23	1.47
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	29,309,039.90	24,519,527	4,789,512.90	19.53	381,863,388.02	326,732,961	55,130,427.02	16.87
5	Juris. Sales % of Total KWH Sales (Line B4)	96.5023	96.3723	0.1300	0.13	96.6253	96.6340	(0.0087)	(0.01)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	28,303,696.34	23,646,573	4,657,123.34	19.69	369,288,453.44	315,939,229	53,349,224.44	16.89
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(4,490,941.05)	(342,850)	(4,148,091.05)	(1,209.89)	(54,867,396.21)	(6,061,573)	(48,805,823.21)	(805.17)
8	Interest Provision for the Month	(332,797.25)	(33,607)	(299,190.25)	(890.26)	(2,033,277.62)	(378,423)	(1,654,854.62)	(437.30)
9	Beginning True-Up & Interest Provision	(74,161,156.06)	(7,973,646)	(66,187,510.06)	(830.08)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	(176.03)
10	True-Up Collected / (Refunded)	955,051.42	955,051	0.42	0.00	10,505,565.62	10,505,561	4.62	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(78,029,842.94)	(7,395,052)	(70,634,790.94)	(955.16)	(78,029,842.94)	(7,395,052)	(70,634,790.94)	(955.16)

050

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2006

		CURRENT MONTH			
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(74,161,156.06)	(7,973,646)	(66,187,510.06)	830.08
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(77,697,045.69)	(7,361,445)	(70,335,600.69)	955.46
3	Total of Beginning & Ending True-Up Amts.	(151,858,201.75)	(15,335,091)	(136,523,110.75)	890.27
4	Average True-Up Amount	(75,929,100.88)	(7,667,546)	(68,261,554.88)	890.27
5	Interest Rate - 1st Day of Reporting Business Month	5.27	5.27	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.25	5.25	0.0000	
7	Total (D5+D6)	10.52	10.52	0.0000	
8	Annual Average Interest Rate	5.26	5.26	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4383	0.4383	0.0000	
10	Interest Provision (D4*D9)	(332,797.25)	(33,607)	(299,190.25)	890.26
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2006
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	41,121,400	39,726,150	1,395,250	3.51	1,369,756,000	1,433,730,000	(63,974,000)	(4.46)	3.0021	2.7708	0.23	8.35
2	Hedging Settlement Costs	1,022,893	0	1,022,893	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	11,080	8,059	3,021	37.49	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	31,005	0	31,005	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	42,186,378	39,734,209	2,452,169	6.17	1,369,756,000	1,433,730,000	(63,974,000)	(4.46)	3.0798	2.7714	0.31	11.13
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	762,835	2,002,000	(1,239,165)	(61.90)	59,860,693	42,320,000	17,540,693	41.45	1.2744	4.7306	(3.46)	(73.06)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	41,915	0	41,915	2.09	1,156,845	0	1,156,845	#N/A	3.6232	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	804,750	2,002,000	(1,197,250)	(59.80)	61,017,538	42,320,000	18,697,538	44.18	1.3189	4.7306	(3.41)	(72.12)
14	Total Available MWH (Line 6 + Line 13)	42,991,128	41,736,209	1,254,919	3.01	1,430,773,538	1,476,050,000	(45,276,462)	(3.07)				
15	Fuel Cost of Economy Sales (A6)	(1,297,524)	(1,044,000)	(253,524)	(24.28)	(37,347,295)	(28,159,000)	(9,188,295)	(32.63)	(3.4742)	(3.7075)	0.23	6.29
16	Gain on Economy Sales (A6)	(805,878)	(311,000)	(494,878)	(159.12)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(3,088,800)	(2,994,000)	(94,800)	(3.17)	(129,593,542)	(128,562,000)	(1,031,542)	(0.80)	(2.3835)	(2.3288)	(0.05)	(2.35)
18	Fuel Cost of Other Power Sales (A6)	(9,058,898)	(11,998,000)	2,939,102	24.50	(325,907,361)	(354,087,000)	28,179,639	7.96	(2.7796)	(3.3884)	0.61	17.97
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(14,251,100)	(16,347,000)	2,095,900	12.82	(492,848,198)	(510,808,000)	17,959,802	3.52	(2.8916)	(3.2002)	0.31	9.64
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	28,740,028	25,389,209	3,350,819	13.20	937,925,340	965,242,000	(27,316,660)	(2.83)	3.0642	2.6303	0.43	16.50
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	56,148	55,105	1,043	1.89	1,832,398	2,095,000	(262,602)	(12.53)	3.0642	2.6303	0.43	16.50
24	T & D Losses *	1,897,477	1,345,188	552,289	41.06	61,924,063	51,142,000	10,782,063	21.08	3.0642	2.6303	0.43	16.50
25	TERRITORIAL KWH SALES	28,740,028	25,389,209	3,350,819	13.20	874,168,879	912,005,000	(37,836,121)	(4.15)	3.2877	2.7839	0.50	18.10
26	Wholesale KWH Sales	1,044,211	934,627	109,584	11.72	31,761,115	33,573,000	(1,811,885)	(5.40)	3.2877	2.7839	0.50	18.10
27	Jurisdictional KWH Sales	27,695,817	24,454,582	3,241,235	13.25	842,407,764	878,432,000	(36,024,236)	(4.10)	3.2877	2.7839	0.50	18.10
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	27,715,204	24,471,700	3,243,504	13.25	842,407,764	878,432,000	(36,024,236)	(4.10)	3.2900	2.7858	0.50	18.10
29	TRUE-UP	955,051	955,051	0	0.00	842,407,764	878,432,000	(36,024,236)	(4.10)	0.1134	0.1087	0.00	4.32
30	TOTAL JURISDICTIONAL FUEL COST	28,670,255	25,426,751	3,243,504	12.76	842,407,764	878,432,000	(36,024,236)	(4.10)	3.4034	2.8945	0.51	17.58
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.4059	2.8966	0.51	17.58
33	GPIF Reward / (Penalty)	36,836	36,836	(0)	0.00	842,407,764	878,432,000	(36,024,236)	(4.10)	0.0044	0.0042	0.00	4.76
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4103	2.9008	0.51	17.56
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.410	2.901		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

070001-Hearing Exhibit 000099

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1
FOR THE MONTH OF: DECEMBER 2006

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$41,121,400
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-8	31,005
4	Hedging Settlement Costs	Schedule A-2, Line A-6	1,022,893
5	Hedging Support Costs	Schedule A-2, Line A-5	11,080
6	Fuel Cost of Purchased Power	Schedule A-7	0
7	Energy Cost of Economy Purchases	Sch. A-9, Col. 5, Line 11	762,835
8	Demand & Non Fuel Cost of Purchased Power	Schedule A-9 Footnote	0
9	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 8	41,915
10	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(14,251,100)
11	Total Fuel and Net Power Transactions		$ 28,740,028

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
DECEMBER 2006
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	505,235,341	497,510,274	7,725,067	1.55	16,349,407,000	17,029,410,000	(680,003,000)	(3.99)	3.0902	2.9215	0.17	5.77
2	Hedging Settlement Costs	18,714,562	0	18,714,562	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Hedging Support Costs	105,754	64,896	40,858	62.96	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
5	Adjustments to Fuel Cost (A2, Page 1) **	(552,900)	0	(552,900)	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
6	TOTAL COST OF GENERATED POWER	523,502,757	497,575,170	25,927,587	5.21	16,349,407,000	17,029,410,000	(680,003,000)	(3.99)	3.2020	2.9219	0.28	9.59
7	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	30,399,350	25,631,000	4,768,350	18.60	1,207,486,131	557,208,000	650,278,131	116.70	2.5176	4.5999	(2.08)	(45.27)
10	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities (A8)	503,259	0	503,259	#N/A	9,332,973	0	9,332,973	#N/A	5.3923	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	30,902,609	25,631,000	5,271,609	20.57	1,216,819,104	557,208,000	659,611,104	118.38	2.5396	4.5999	(2.06)	(44.79)
14	Total Available MWH (Line 6 + Line 13)	554,405,366	523,206,170	31,199,196	5.96	17,566,226,104	17,586,618,000	(20,391,896)	(0.12)				
15	Fuel Cost of Economy Sales (A6)	(9,372,610)	(13,935,000)	4,562,390	32.74	(227,091,962)	(294,292,000)	67,200,038	22.83	(4.1272)	(4.7351)	0.61	12.84
16	Gain on Economy Sales (A6)	(3,421,965)	(3,048,000)	(373,965)	(12.27)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales (A6)	(32,036,376)	(32,929,000)	892,624	2.71	(1,435,977,064)	(1,447,801,000)	11,823,936	0.82	(2.2310)	(2.2744)	0.04	1.91
18	Fuel Cost of Other Power Sales (A6)	(98,970,999)	(121,172,000)	22,201,001	18.32	(3,329,910,321)	(3,377,562,000)	47,651,679	1.41	(2.9722)	(3.5876)	0.62	17.15
19	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 15 + 16 + 17 + 18)	(143,801,950)	(171,084,000)	27,282,050	15.95	(4,992,979,347)	(5,119,655,000)	126,675,653	2.47	(2.8801)	(3.3417)	0.46	13.81
20	Net Inadvertant Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
21	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 6 + 13 + 19)	410,603,416	352,122,170	58,481,246	16.61	12,573,246,757	12,466,963,000	106,283,757	0.85	3.2657	2.8244	0.44	15.62
22	Net Unbilled Sales *	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
23	Company Use *	717,974	662,632	55,342	8.35	21,985,288	23,461,000	(1,475,712)	(6.29)	3.2657	2.8244	0.44	15.62
24	T & D Losses *	23,541,744	20,666,869	2,874,875	13.91	720,878,946	731,726,000	(10,847,054)	(1.48)	3.2657	2.8244	0.44	15.62
25	TERRITORIAL KWH SALES	410,603,416	352,122,170	58,481,246	16.61	11,830,382,523	11,711,776,000	118,606,523	1.01	3.4708	3.0066	0.46	15.44
26	Wholesale KWH Sales	13,877,467	11,949,361	1,928,106	16.14	401,502,563	397,094,000	4,408,563	1.11	3.4564	3.0092	0.45	14.86
27	Jurisdictional KWH Sales	396,725,949	340,172,809	56,553,140	16.62	11,428,879,960	11,314,682,000	114,197,960	1.01	3.4713	3.0065	0.46	15.46
27a	Jurisdictional Loss Multiplier	1.00070	1.00070							1.00070	1.00070		
28	Jurisdictional KWH Sales Adj. for Line Losses	397,003,657	340,410,929	56,592,728	16.62	11,428,879,960	11,314,682,000	114,197,960	1.01	3.4737	3.0086	0.47	15.46
29	TRUE-UP	11,460,612	11,460,612	0	0.00	11,428,879,960	11,314,682,000	114,197,960	1.01	0.1003	0.1013	(0.00)	(0.99)
30	TOTAL JURISDICTIONAL FUEL COST	408,464,269	351,871,541	56,592,728	16.08	11,428,879,960	11,314,682,000	114,197,960	1.01	3.5740	3.1099	0.46	14.92
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									3.5766	3.1121	0.46	14.93
33	GPIF Reward / (Penalty)	441,988	441,988	0	0.00	11,428,879,960	11,314,682,000	114,197,960	1.01	0.0039	0.0039	0.00	0.00
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5805	3.1160	0.46	14.91
35	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.581	3.116		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

03

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	41,018,460.70	39,393,150	1,625,310.70	4.13	503,993,709.76	494,795,307	9,198,402.76	1.86
1a	Other Generation	102,939.56	333,000	(230,060.44)	(69.09)	1,241,632.47	2,714,967	(1,473,334.53)	(54.27)
2	Fuel Cost of Power Sold	(14,251,099.79)	(16,347,000)	2,095,900.21	12.82	(143,801,948.71)	(171,084,000)	27,282,051.29	15.95
3	Fuel Cost - Purchased Power	762,835.37	2,002,000	(1,239,164.63)	(61.90)	30,399,349.87	25,631,000	4,768,349.87	18.60
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	41,915.00	0	41,915.00	100.00	503,259.00	0	503,259.00	#N/A
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0	0.00	#N/A
5	Hedging Support Cost	11,079.88	8,059	3,020.88	37.48	105,753.51	64,896	40,857.51	62.96
6	Hedging Settlement Cost	1,022,893.10	0	1,022,893.10	100.00	18,714,561.92	0	18,714,561.92	100.00
7	Total Fuel & Net Power Transactions	28,709,023.82	25,389,209	3,319,815	13.08	411,156,317.82	352,122,170	59,034,148	16.77
8	AdjustmentsTo Fuel Cost*	31,004.54	0	31,004.54	#N/A	(552,901.44)	0	(552,901.44)	#N/A
9	Adj. Total Fuel & Net Power Transactions	28,740,028.36	25,389,209	3,350,819.36	13.20	410,603,416.38	352,122,170	58,481,246.38	16.61
B.	*KWH Sales*								
1	Jurisdictional Sales	842,407,764	878,432,000	(36,024,236)	(4.10)	11,428,879,960	11,314,682,000	114,197,960	1.01
2	Non-Jurisdictional Sales	31,761,115	33,573,000	(1,811,885)	(5.40)	401,502,563	397,094,000	4,408,563	1.11
3	Total Territorial Sales	874,168,879	912,005,000	(37,836,121)	(4.15)	11,830,382,523	11,711,776,000	118,606,523	1.01
4	Juris. Sales as % of Total Terr. Sales	96.3667	96.3188	0.0479	0.05	96.6062	96.6094	(0.0032)	0.00

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

04

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2006

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	28,641,594.20	27,001,128	1,640,466.20	6.08	353,973,081.18	347,789,211	6,183,870.18	1.78
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(955,051.38)	(955,056)	4.62	0.00	(11,460,617.00)	(11,460,617)	0.00	0.00
2b	Incentive Provision	(36,805.87)	(36,806)	0.13	0.00	(441,670.00)	(441,672)	2.00	0.00
3	Juris. Fuel Revenue Applicable to Period	27,649,736.95	26,009,266	1,640,470.95	6.31	342,070,794.18	335,886,922	6,183,872.18	1.84
4	Adjusted Total Fuel & Net Power Transactions (Line A9)	28,740,028.36	25,389,209	3,350,819.36	13.20	410,603,416.38	352,122,170	58,481,246.38	16.61
5	Juris. Sales % of Total KWH Sales (Line B4)	96.3667	96.3188	0.0479	0.05	96.6062	96.6094	(0.0032)	0.00
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	27,715,203.98	24,471,700	3,243,503.98	13.25	397,003,657.42	340,410,929	56,592,728.42	16.62
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(65,467.03)	1,537,566	(1,603,033.03)	104.26	(54,932,863.24)	(4,524,007)	(50,408,856.24)	(1,114.25)
8	Interest Provision for the Month	(340,055.28)	(26,950)	(313,105.28)	(1,161.80)	(2,373,332.90)	(405,373)	(1,967,959.90)	(485.47)
9	Beginning True-Up & Interest Provision	(78,029,842.94)	(7,395,052)	(70,634,790.94)	(955.16)	(31,634,734.73)	(11,460,617)	(20,174,117.73)	(176.03)
10	True-Up Collected / (Refunded)	955,051.38	955,056	(4.62)	0.00	11,460,617.00	11,460,617	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(77,480,313.87)	(4,929,380)	(72,550,933.87)	(1,471.81)	(77,480,313.87)	(4,929,380)	(72,550,933.87)	(1,471.81)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2006

		CURRENT MONTH			
		$			
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(78,029,842.94)	(7,395,052)	(70,634,790.94)	955.16
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(77,140,258.59)	(4,902,430)	(72,237,828.59)	1,473.51
3	Total of Beginning & Ending True-Up Amts.	(155,170,101.53)	(12,297,482)	(142,872,619.53)	1,161.80
4	Average True-Up Amount	(77,585,050.77)	(6,148,741)	(71,436,309.77)	1,161.80
5	Interest Rate - 1st Day of Reporting Business Month	5.25	5.25	0.0000	
6	Interest Rate - 1st Day of Subsequent Business Month	5.27	5.27	0.0000	
7	Total (D5+D6)	10.52	10.52	0.0000	
8	Annual Average Interest Rate	5.26	5.26	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.4383	0.4383	0.0000	
10	Interest Provision (D4*D9)	(340,055.28)	(26,950)	(313,105.28)	1,161.80
	Jurisdictional Loss Multiplier (From A-1)	1.0007	1.0007		

Tampa Electric Company's Responses to

STAFF'S 2nd ROGS Nos. 11 - 32

070001

11. For each month of 2006, please provide the commodity cost, transportation cost, hedging gain or loss, and total cost for natural gas.

A. The requested information is provided in the table below.

Month	Commodity	Transportation	Hedging (Gains) Losses	Other [1]	Total Costs
Jan-06	38,055,077	2,982,312	(5,724,270)	(6,162,043)	29,151,075
Feb-06	40,089,122	2,793,451	580,900	(5,914,344)	37,549,130
Mar-06	26,294,857	2,952,657	1,362,660	(4,449,399)	26,160,775
Apr-06	48,283,848	4,278,962	3,219,540	(9,990,036)	45,792,314
May-06	47,554,875	5,302,555	5,156,780	(4,215,845)	53,798,365
Jun-06	38,697,395	5,156,572	9,499,350	(2,374,169)	50,979,148
Jul-06	39,797,502	5,329,683	9,859,660	(3,919,194)	51,067,652
Aug-06	58,704,239	5,328,366	5,082,530	(11,567,770)	57,547,365
Sep-06	39,094,618	5,098,565	5,361,780	(4,527,751)	45,027,212
Oct-06	38,115,337	4,587,304	14,380,850	(4,776,646)	52,306,845
Nov-06	35,484,626	3,031,265	3,577,320	(4,186,055)	37,907,155
Dec-06	21,827,829	3,076,589	2,125,020	(917,873)	26,111,564
Total	$471,999,326	$49,918,280	$54,482,120	($63,001,125)	$513,398,601

1) Other represents off-system sales of natural gas as well as natural gas storage costs.

12. Is TECO planning to upgrade its Big Bend Unit 3? If so, when will the upgrade commence and when is it expected to be completed?

A. Tampa Electric Company will be performing planned maintenance on its Big Bend Unit 3 beginning on November 23, 2007. This planned maintenance outage will be completed on March 31, 2008.

13. What are the expected equivalent availability factors and capacity factors for Big Bend Unit 3 for the two years following the proposed upgrades discussed above?

A. The expected equivalent availability factor and capacity factor for the balance of 2008 and for 2009 for Big Bend Unit 3 after the planned maintenance outage is completed in 2008 are as follows:

Year	Expected EAF	Expected Capacity Factor
2008	56.5%	50.9%
2009	73.2%	66.1%

14. What is the expected improvement in heat rate that is anticipated as a result of the proposed upgrades to Big Bend Unit 3?

A. Once the planned maintenance outage is completed in 2008, the expected heat rate for Big Bend Unit 3 is expected to be 10,670.

15. What are the projected capital costs, and operation and maintenance costs for the proposed upgrades to Big Bend Unit 3?

A. The projected capital costs for the planned maintenance outage on Big Bend Unit 3 are approximately $189.3 million dollars. The projected operation and maintenance costs for the planned maintenance outage are approximately $6.8 million dollars.

16. Will Big Bend Unit 3 experience planned outages because of the proposed upgrade? If so, what is the timing and duration for each planned outage?

A. Other than the planned maintenance outage anticipated to be completed by March 31, 2008, there are no additional planned maintenance outages scheduled in 2008 for Big Bend Unit 3.

17. Is TECO planning to sell TECO Transport?

A. Yes. In the first quarter of 2007, TECO Energy announced that it was reviewing options for TECO Transport, including its sale.

18. If TECO is planning to sell TECO transport, describe how TECO will market and sell TECO Transport?

A. TECO Energy retained the services of Morgan Stanley to assist in the sale of TECO Transport. Morgan Stanley is handling the marketing material as well as assisting in the screening and evaluation of all potential bidders.

19. If TECO is selling TECO Transport, what is the status of the proposed sale?

A. The negotiations for the sale of TECO Transport are still ongoing. TECO Energy is now negotiating with a short list of bidders toward reaching a final agreement. The recent turmoil in the high-yield debt market and the leveraged buyout market has slowed the process somewhat and this could be a factor in the timing for the completion of the sale transaction.

20. According to the 2006 Monthly Outage Listing for Big Bend Unit 1, there were forced outages for Exciter Trip in July, and August, 2006. What were the causes of these outages?

A. The causes of the forced outages on Big Bend Unit 1 during the months of July and August 2006 were related to an electrical short in the exciter windings. As a result of the electrical short occurrences, the station installed a temporary resistor bank to help mitigate the issue until rewind maintenance could take place.

21. According to the 2006 Monthly Outage Listing, there were several forced outages due to opacity. Please explain in detail, the cause for each 2006 opacity outage.

A. The specific causes for opacity restrictions and or derations on the Big Bend Units are not individually identified. However, opacity restrictions and or derations on the Big Bend Units are caused by the following issues: (i) equipment malfunction and mechanical degradation of the ash collection systems, (ii) fuel type and its preparation, (iii) instrumentation malfunction, (iv) inclement weather or (v) Compliance Assurance Monitoring. The causes that result in opacity restrictions may be independent of each other or may be in any combination.

22. What were the causes of the July 2006 outages at Big Bend Unit 1 labeled in the 2006 Monthly Outage List as Dirty Condenser?

A. The causes for the July 2006 dirty condenser restrictions on Big Bend Unit 1 were related to the condenser heat exchanging tubes being fouled by marine growth and mud.

23. What were the causes of the forced outages reported as Tube Leak that occurred at Big Bend 1 in August, 2006; and at Big Bend 2 in September, 2006; and at Big Bend 3 in July, August, October, and December, 2006?

A. The cause for the tube leak on Big Bend Unit 1 in August 2006 was soot blower erosion.

The cause for the tube leak on Big Bend Unit 2 in September 2006 was stress corrosion cracking.

The cause for the tube leak on Big Bend Unit 3 in July 2006 was a defect in the tube.

The cause for the tube leak on Big Bend Unit 3 in August 2006 was short term over heating.

The cause for the tube leak on Big Bend Unit 3 in October 2006 was short term over heating.

The cause for the tube leak on Big Bend Unit 3 in December 2006 was a defect in the tube's weld overlay.

24. What were the causes of the December 2006 outages at Big Bend Unit 1 reported in the 2006 Monthly Outage List as MDC, Reliability?

A. The de-rations in generation experienced by Big Bend Unit 1 identified as MDC, Reliability in December 2006 are the result of an operating guidance that balances generation capacity and generation availability. It is a prudent guidance that provides the operator a tool that helps mitigate equipment wear and tear to achieve long term, dependable and beneficial performance. The peak capacity remains available and can be used when needed to meet customer peak demand.

25. What were the causes of the December 2006 outages at Big Bend Units 1 and 4 which were labeled 6th PT HTR Heat Shield Failure on the 2006 Monthly Outage Listing?

A. The cause for the heat shield failure on Big Bend Unit 1 on December of 2006 was pipe stress in which the heat shield failed and punctured a heat exchanger tube.

26. What were the causes of the outages labeled HP Fouling that were reported on the 2006 Monthly Outage Listing at Big Bend 3 for July, August, October, and December 2006?

A. The suspected high pressure fouling on Big Bend Unit 3 for July, August, October, and December 2006 was caused by multiple boiler chemistry excursions. Since the turbine is the recipient of the steam that the boiler generates, any upsets or excursions in the chemistry of that steam directly affect the main turbine and all down stream systems.

27. What were the causes of the outages at Big Bend Unit 3 reported on the 2006 Monthly Outage List as 3A Force Draft Fan for October, 2006, and 3B PA Fan Wheel Failure for December, 2006.

A. The generation deration experienced on Big Bend Unit 3 for October 2006 was caused by an oil leak on the outboard fan bearing of the 3A force draft fan.

The generation deration experienced on Big Bend Unit 3 for December 2006 was caused by a linear crack that developed on the structural member of the 3B PA fan wheel.

28. What were the causes of the July and December 2006 outages at Big Bend Unit 4 labeled on the 2006 Monthly Outage list as 3rd PT HTR?

A. The generation derations and associated outages on Big Bend Unit 4 for the months of July and December 2006 listed as 3rd PT HTR were caused by tube leaks within the 3rd point feedwater heater. Over time heat exchanger tubes become fouled, corroded and in some cases broken. Short term maintenance or plugging the tube effectively removes the tube from service and impacts the overall efficiency of the heat exchanger to handle heat transfer it was designed to manage.

29. What was the cause of the September 2006 outage at Big Bend Unit 2 labeled on the 2006 Monthly Outage list as High Reheat Temps?

A. The generation derations experienced on Big Bend Unit 2 in September 2006 listed as High Reheat Temps were caused by excess flyash accumulation in the bypass section of the boiler furnace backpass.

30. What was the cause of the July 2006 outage at Big Bend Unit 4 labeled on the Monthly Outage List as Low Reheat Temps?

A. The generation derations experienced by Big Bend Unit 4 identified as Low Reheat Temps in July are the result of an operating guidance that balances generation capacity and generation availability. It is a prudent guidance that provides the operator a tool that helps mitigate equipment wear and tear to achieve long term, dependable and beneficial performance. The peak capacity remains available and can be used when needed to meet customer peak demand.

31. What were the causes of the September 2006 outages at Big Bend Unit 2 labeled on the 2006 Monthly Outage List as Green Muscles?

A. The generation derations and associated outage experienced on Big Bend Unit 2 for the month of September 2006 listed as Green Mussels were caused by a large amount of green lip mussel marine growth in the circulating water system.

32. Describe all preventative or follow-up actions taken to reduce future outages of the types discussed in interrogatories 20-31 above?

A. Interrogatory 20 – The Big Bend Unit 1 exciter was inspected / rewound during the December 2006 major outage.

Interrogatory 21 – The opacity restrictions will be reduced as equipment and systems receive planned and unplanned maintenance. Planned maintenance events that will include the replacement of degraded boiler gas duct work and other equipment rebuilds will occur on each of the units over the next three years, beginning in the fall of 2007 with the outage of Big Bend Unit 3.

Interrogatory 22 – The condenser on Big Bend Unit 1 was replaced during the December 2006 major outage as was the debris filtering system. In addition, a condenser tube cleaning system was installed during the same outage.

Interrogatory 23 – The tube assembly that failed on Big Bend Unit 1 is scheduled for replacement during the major outage in 2009. The area of the failure on Big Bend Unit 2 will be inspected during the major outage in 2008. The areas of failure on Big Bend Unit 3 will either be replaced or inspected during the major outage starting at the end of 2007.

Interrogatory 24 - Recognizing that over time equipment and operating systems will wear out and require maintenance. Equipment and operating systems are constantly being reviewed, tested and evaluated for wear and tear, operating adjustments and performance enhancements. Each outage, whether planned or forced, is used as an opportunity to perform maintenance on the equipment to keep the equipment and operating systems in operating condition.

Interrogatory 25 – The area of the failure was inspected and repaired during the forced outage on Big Bend Unit 1.

Interrogatory 26 – The high pressure turbine will be inspected and repaired during the fall 2007 major outage.

Tampa Electric Company's

Late Filed Deposition Exhibit No. 5 of Witness Joann T. Wehle

070001

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
WITNESS: JOANN T. WEHLE
LATE-FILED DEPOSITION EXHIBIT
EXHIBIT NO. 5
BATES STAMPED PAGE: 526
FILED: OCTOBER 30, 2007

Annual and Cumulative Natural Gas Hedging Results

5. Provide Tampa Electric's annual and cumulative natural gas financial hedging results for the period beginning January 1, 2003 through the most current information available.

A. The requested information is shown in the table below.

Natural Gas Hedging Results

2003 - 2007

2007 through September	$ (45,985,730)
2006	$ (54,482,120)
2005	$ 53,231,770
2004	$ 8,413,170
2003	$ (2,758,028)
Cumulative Gains / (Losses)	$ (41,580,938)

CONFIDENTIAL
Staff Composite Exhibit – 3

Progress Energy Florida

1. PEF's Response to Staff's Third Set of Interrogatories (No. 26) (DN 09607-07).

Florida Power & Light Company

2. FPL's Response to Staff's Second Set of Interrogatories (No. 12) (DN 09053-07).

3. FPL's Response to Staff's Third Set of Interrogatories (No. 16) (DN 09657-07).

4. FPL's Response to Staff's Second Request for Production of Documents (Nos. 9 & 13) (DN 09819-07).

5. Late Filed Panel Deposition Exhibit No. 3 to FPL witnesses Dubin/Yupp/Jones taken 10/30/07.

Gulf Power Company

6. Gulf's Risk Management Plan (DN 02925-07).

Tampa Electric Company

7. Confidential portions of TECO's Risk Management Report (DN 07996-07).

8. TECO's Risk Management Plan (DN 02854-07).

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 3
COMPANY FPSC Staff
WITNESS Conf. Staff Composite Exhibit 3
DATE 11-06-07

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
WILL GARRETT

FINAL TRUE-UP AMOUNT
JANUARY THROUGH DECEMBER 2006

FUEL COST RECOVERY (WG-1T)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 4
COMPANY Progress Energy Fl, Inc.
WITNESS Will Garrett (WG-1T)
DATE 11-06-07

Progress Energy Florida
Fuel Adjustment Clause
Summary of Final True-Up Amount
January through December 2006

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional Kwh sales - difference	(716,404,233)
2	Non-Jurisdictional Kwh sales - difference	(156,779,889)
3	Total System Kwh sales - difference Schedule A2, pg 1 of 2, line B3	(873,184,122)
	System:	
4	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C4	$ (150,892,114)
	Jurisdictional:	
5	Fuel Revenues - difference Schedule A2, page 2 of 2, line C3	$ (54,393,939)
6	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C6	(136,993,347)
7	True Up amount for the period	82,599,409
8	True Up for the prior period - difference Schedule A2, page 2 of 2, lines C9 + C10	(385,055)
9	Interest Provision Schedule A2, page 2 of 2, line C8	(6,869,481)
10	Actual True Up ending balance for the period January 2006 through December 2006 Schedule A2, page 2 of 2, line C13	75,344,873
11	Estimated True Up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2006, Docket No. 060001-EI.	46,480,257
12	Final True Up for the period January 2006 through December 2006	$ 28,864,616

Progress Energy Florida
Fuel Adjustment Clause
Calculation of Actual True-Up
2006

DESCRIPTION	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	TOTAL PERIOD
REVENUE													
1 Jurisdictional MWH Sales	3,020,207	2,807,302	2,760,124	2,794,806	3,207,226	3,658,724	3,673,280	4,197,478	3,950,808	3,361,153	3,084,405	2,916,326	39,431,838
2 Jurisdictional Fuel Factor (Pre-Tax)	5.235	5.217	5.196	5.216	5.282	5.313	5.338	5.358	5.341	5.302	5.242	5.182	
3 Total Jurisdictional Fuel Revenue	158,112,614	146,448,587	143,416,835	145,767,263	169,393,283	194,376,345	196,081,785	224,908,844	211,014,151	178,223,003	161,682,606	151,126,016	2,080,551,333
4 Less: True-Up Provision	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(315,692,056)
5 Less: GPIF Provision	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(532,353)
6 Less: Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	131,760,580	120,096,553	117,064,801	119,415,229	143,041,249	168,024,311	169,729,751	198,556,810	184,662,117	151,870,969	135,330,572	124,773,982	1,764,326,924
FUEL EXPENSE													
8 Total Cost of Generated Power	99,869,005	86,580,220	99,891,767	118,284,058	124,969,331	161,963,045	167,349,849	171,758,275	146,637,085	108,989,354	94,128,063	95,104,888	1,475,524,940
9 Total Cost of Purchased Power	29,538,467	28,694,188	26,530,713	26,111,073	28,061,807	36,491,314	35,366,491	73,304,210	36,659,118	27,854,991	20,114,100	29,260,774	397,987,246
10 Total Cost of Power Sales	(7,877,861)	(8,953,044)	(9,347,555)	(9,866,876)	(10,951,808)	(8,697,917)	(11,649,613)	(16,873,427)	(18,079,235)	(17,325,006)	(12,961,419)	(8,728,756)	(141,312,517)
11 Total Fuel and Net Power	121,529,611	105,321,364	117,074,925	134,528,255	142,079,330	189,756,442	191,066,727	228,189,057	165,216,968	119,519,339	101,280,744	115,636,906	1,732,199,669
12 Jurisdictional Percentage	96.28%	96.59%	96.80%	96.84%	97.08%	97.12%	96.61%	96.98%	96.55%	96.20%	96.56%	96.70%	96.72%
13 Jurisdictional Loss Multiplier	1.00207	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382
14 Jurisdictional Fuel Cost	117,250,918	103,088,104	113,761,443	130,774,821	138,457,509	184,995,450	185,294,697	222,143,105	160,126,337	115,416,819	98,170,270	112,248,044	1,681,727,515
COST RECOVERY													
15 Net Fuel Revenue Less Expense	14,509,663	17,008,449	3,303,359	(11,359,592)	4,583,741	(16,971,139)	(15,564,946)	(23,586,295)	24,535,779	36,454,150	37,160,302	12,525,938	82,599,409
16 Interest Provision	(1,085,103)	(960,169)	(850,432)	(802,882)	(728,895)	(670,323)	(652,161)	(623,758)	(503,289)	(256,135)	19,770	243,897	(6,869,481)
17 Current Cycle Balance	13,424,560	29,472,839	31,925,766	19,763,292	23,618,137	5,976,676	(10,240,431)	(34,450,485)	(10,417,995)	25,780,020	62,960,092	75,729,927	
18 Plus: Prior Period Balance	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	
19 Plus: Cumulative True-Up Provision	26,307,671	52,615,343	78,923,014	105,230,685	131,538,357	157,846,028	184,153,699	210,461,371	236,769,042	263,076,713	289,384,385	315,692,056	
20 Total Retail Balance	(276,344,880)	(233,988,929)	(205,228,331)	(191,083,133)	(160,920,617)	(152,254,407)	(142,163,843)	(140,066,225)	(89,726,063)	(27,220,378)	36,267,366	75,344,872	

Progress Energy Florida
Fuel Adjustment Clause
Calculation of Estimated True-Up
2006 Reprojection (Filed 10/25/06)

DESCRIPTION	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Estimated Oct-06	Estimated Nov-06	Estimated Dec-06	TOTAL PERIOD
REVENUE													
1 Jurisdictional MWH Sales	3,020,207	2,607,302	2,760,124	2,794,806	3,267,226	3,658,724	3,673,280	4,197,478	3,950,808	3,499,387	3,089,034	3,025,370	39,683,745
2 Jurisdictional Fuel Factor (Pre-Tax)	5.235	5.217	5.196	5.216	5.282	5.313	5.338	5.358	5.341	5.321	5.321	5.321	
3 Total Jurisdictional Fuel Revenue	158,112,614	146,448,587	143,416,835	145,767,263	169,393,283	194,376,345	196,081,785	224,908,844	211,014,151	186,202,382	164,367,499	160,979,938	2,101,069,527
4 Less: True-Up Provision	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(26,307,671)	(315,692,056)
5 Less: GPIF Provision	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(44,363)	(532,353)
6 Less: Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	131,760,580	120,096,553	117,064,801	119,415,229	143,041,249	168,024,311	169,729,751	198,556,810	184,662,117	159,850,348	138,015,465	134,627,904	1,784,845,117
FUEL EXPENSE													
8 Total Cost of Generated Power	99,869,005	86,580,220	99,891,767	118,284,058	124,969,331	161,963,045	167,349,849	171,758,275	146,637,085	136,187,467	98,316,172	106,096,559	1,517,902,834
9 Total Cost of Purchased Power	29,538,467	28,694,188	26,530,713	26,111,073	28,061,807	36,491,314	35,366,491	73,304,210	36,659,118	22,921,586	29,477,357	29,030,781	402,187,105
10 Total Cost of Power Sales	(7,877,861)	(8,953,044)	(9,347,555)	(9,866,876)	(10,951,808)	(8,697,917)	(11,649,613)	(16,873,427)	(18,079,235)	(13,791,017)	(11,005,647)	(10,008,221)	(137,102,221)
11 Total Fuel and Net Power	121,529,611	106,321,364	117,074,925	134,528,255	142,079,330	189,756,442	191,066,727	228,189,057	165,216,968	145,318,036	116,787,882	125,119,119	1,782,987,717
12 Jurisdictional Percentage	96.28%	96.59%	96.80%	96.84%	97.08%	97.12%	96.61%	96.98%	96.55%	96.28%	96.32%	96.80%	
13 Jurisdictional Loss Multiplier	1.00207	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	1.00382	
14 Jurisdictional Fuel Cost	117,250,918	103,088,104	113,761,443	130,774,821	138,457,509	184,995,450	185,294,697	222,143,105	160,126,337	140,451,380	112,924,116	121,576,771	1,730,844,650
COST RECOVERY													
15 Net Fuel Revenue Less Expense	14,509,663	17,008,449	3,303,359	(11,359,592)	4,583,741	(16,971,139)	(15,564,946)	(23,586,295)	24,535,779	19,398,968	25,091,349	13,051,133	54,000,468
16 Interest Provision	(1,085,103)	(960,169)	(850,432)	(802,882)	(728,895)	(670,323)	(652,161)	(623,758)	(503,289)	(293,571)	(81,713)	117,142	(7,135,156)
17 Current Cycle Balance	13,424,560	29,472,839	31,925,766	19,763,292	23,618,137	5,976,676	(10,240,431)	(34,450,485)	(10,417,995)	8,687,402	33,697,037	46,865,312	
18 Plus: Prior Period Balance	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	(316,077,111)	
19 Plus: Cumulative True-Up Provision	26,307,671	52,615,343	78,923,014	105,230,685	131,538,357	157,846,028	184,153,699	210,461,371	236,769,042	263,076,713	289,384,385	315,692,056	
20 Total Retail Balance	(276,344,880)	(233,988,929)	(205,228,331)	(191,083,133)	(160,920,617)	(152,254,407)	(142,163,843)	(140,066,225)	(89,726,063)	(44,312,995)	7,004,311	46,480,257	

Progress Energy Florida
Fuel and Net Power Cost Variance Analysis
January through December 2006

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	($62,120,064)	($11,975,617)	($44,000,297)	($118,095,978)
2	Light Oil	6,872,935	(2,697,028)	(8,733,181)	(4,557,274)
3	Coal	6,696,257	4,249,323	17,390,032	28,335,612
4	Gas	(39,649,573)	20,429,274	(149,647,680)	(168,867,979)
5	Nuclear	(906,193)	8,833	574,026	(323,334)
6	Other Fuel	0	0	(9,352,481)	(9,352,481)
7	Total Generation	(89,106,638)	10,014,785	(193,769,581)	(272,861,434)
8	Firm Purchases	(41,280)	0	27,186,596	27,145,316
9	Economy Purchases	21,345,513	0	14,948,839	36,294,352
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(8,384,377)	0	27,863,968	19,479,591
12	Total Purchases	12,919,856	0	69,999,403	82,919,259
13	Economy Sales	0	0	0	0
14	Other Power Sales	30,265,186	0	2,108,684	32,373,870
15	Supplemental Sales	(13,189,990)	0	20,348,233	7,158,243
16	Total Sales	17,075,196	0	22,456,917	39,532,113
17	Nuclear Fuel Disposal Cost	0	0	(218,515)	(218,515)
18	Nuclear Decom & Decon	0	0	257,708	257,708
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 2 Line 6b	0	0	(521,247)	(521,247)
20	Total Fuel and Net Power Cost Variance	($59,111,586)	$10,014,785	($101,795,314)	($150,892,114)

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
WILL GARRETT

FINAL TRUE-UP AMOUNT
JANUARY THROUGH DECEMBER 2006

CAPACITY COST RECOVERY (WG-2T)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 5
COMPANY Progress Energy FL, Inc.
WITNESS Will Garrett (WG-2T)
DATE 11-06-07

Progress Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2006

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 41	$ 334,295,200	$ 341,008,652	$ (6,713,452)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 38	341,826,643	341,008,652	817,991
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 43	(649,820)	(399,911)	(249,909)
4	Sub Total Current Period Over/(Under) Recovery	$ (8,181,263)	$ (399,911)	$ (7,781,352)
5	Prior Period True-up - January through December 2005 - Over/(Under) Recovery Sheet 2 of 3, Line 45	(12,197,739)	(11,616,464)	(581,275)
6	Prior Period True-up - January through December 2005 - (Refunded)/Collected Sheet 2 of 3, Line 46	11,616,464	11,616,464	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2006 Sheet 2 of 3, Line 47	$ (8,762,537)	$ (399,911)	$ (8,362,626)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2006 Docket No. 060001-EI. (Sheet 3 of 3, Line 46)	(5,380,565)		
9	Final Over/(Under) Recovery for the period January through December 2006 (Line 7 - Line 8)	$ (3,381,972)		

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January Through December 2006

		ACTUAL JAN	ACTUAL FEB	ACTUAL MAR	ACTUAL APR	ACTUAL MAY	ACTUAL JUN	ACTUAL JUL	ACTUAL AUG	ACTUAL SEP	ACTUAL OCT	ACTUAL NOV	ACTUAL DEC	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	6,430,080
2	Auburndale Power Partners, L.P. (AUBSET)	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	30,591,051
3	Bay County (BAYCOUNT)	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	3,165,360
4	Cargill Fertilizer, Inc. (CARGILLF)	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	6,339,600
5	Lake County (LAKCOUNT)	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	6,029,730
6	Lake Cogen Limited (LAKORDER)	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	31,975,807
7	Metro-Dade County (METRDADE)	604,154	738,558	749,425	798,056	899,574	908,572	964,602	984,123	1,217,818	989,860	989,860	1,015,118	10,859,750
8	Orange Cogen (ORANGECO)	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	27,318,197
9	Orlando Cogen Limited (ORLACOGL)	2,220,699	1,963,398	1,963,806	1,912,636	1,989,708	2,032,631	2,032,631	2,032,631	2,102,525	2,032,631	2,032,631	2,032,631	24,348,755
10	Pasco Cogen Limited (PASCOGEN)	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	37,996,612
11	Pasco County Resource Recovery (PASCOUNT)	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	10,877,160
12	Pinellas County Resource Recovery (PINCOUNT)	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	25,892,370
13	Polk Power Partners, L.P. (MULBERRY)	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	33,307,512
14	Polk Power Partners, L.P. (ROYSTER)	1,057,309	1,057,309	1,057,309	1,957,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	12,687,711
15	U S Agri-Chemicals (AGRICHEM)	(43,838)	0	0	0	0	0	0	0	0	0	0	0	(43,838)
16	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	731,466	772,240	763,595	766,949	773,281	791,864	800,587	800,946	835,327	1,066,052	725,113	612,032	9,439,452
17	Cargill Power Market	0	0	0	0	0	0	0	0	0	0	0	500,000	500,000
18	Central Power & Lime Capacity Purchase (133 MW)	1,182,713	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	16,119,943
19	UPS Purchase (414 total mw) - Southern	4,667,122	4,951,688	4,662,176	4,011,325	4,386,326	4,581,817	4,724,663	3,988,157	4,550,957	4,608,617	4,609,659	6,004,790	56,347,347
20	Incremental Security	26,639	39,115	(38,843)	6,029	458,313	43,299	341,573	50,571	23,561	551,304	32,343	648,270	2,182,164
21	Subtotal - Base Level Capacity Charges	28,773,211	29,797,195	28,842,385	28,837,440	29,349,399	29,100,378	29,606,251	28,598,623	29,472,384	29,990,659	29,131,801	31,555,036	352,364,762
22	Base Production Jurisdictional Responsibility	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	
23	Base Level Jurisdictional Capacity Charges	26,975,748	27,382,622	27,040,601	27,035,986	27,422,149	27,282,477	27,756,749	26,812,067	27,631,244	28,117,142	27,311,937	29,583,793	330,352,636
	Intermediate Production Level Capacity Charges:													
24	TECO Power Purchase (70 mw)	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
25	Schedule H Capacity Sales	(14,797)	(14,377)	(14,797)	(14,657)	(16,089)	(4,453)	(4,601)	(4,601)	(4,453)	(4,601)	(4,453)	(4,601)	(106,479)
26	Subtotal - Intermediate Level Capacity Charges	644,970	645,390	644,970	645,110	643,678	655,314	655,166	655,166	655,314	655,166	655,314	655,166	7,810,725
27	Intermediate Production Jurisdict. Responsibility	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	
28	Intermediate Level Jurisdict. Capacity Charges	509,923	510,155	509,873	509,934	508,802	518,000	517,882	517,882	518,000	517,882	518,000	517,882	6,174,066
	Peaking Production Level Capacity Charges:													
29	Chattahoochee Capacity Purchase	12,500	11,636	13,364	11,814	12,787	12,834	13,366	20,000	15,135	14,769	14,500	12,500	165,200
30	The Energy Authority Capacity Purchase	0	0	0	0	0	200,000	200,000	200,000	200,000	0	0	416,750	1,216,750
31	Osceola Capacity Purchase	0	0	0	0	0	606,720	606,720	479,325	530,047	606,720	606,720	606,720	4,042,971
32	Peakers Purchases - Summer Peak	0	0	0	0	0	27,416	0	27,416	0	0	0	0	54,832
33	Peaking Purchases - Winter Peak	0	0	0	0	0	0	0	0	0	0	0	862,500	862,500
34	Subtotal - Peaking Level Capacity Charges	12,500	11,636	13,364	11,814	12,787	846,970	820,086	726,741	745,181	621,489	621,220	1,900,470	6,344,253
35	Peaking Production Jurisdictional Responsibility	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	
36	Peaking Level Jurisdictional Capacity Charges	11,122	10,354	11,891	10,512	11,373	753,675	729,704	646,647	663,055	552,995	552,755	1,691,019	5,645,053
	Other Capacity Charges:													
37	Retail Wheeling	(12,967)	(69,785)	(60,381)	(26,376)	(45,018)	(11,582)	(16,482)	(4,229)	(3,222)	(23,353)	(47,329)	(24,290)	(345,012)
38	Total Jurisdictional Capacity Charges	27,483,727	27,833,346	27,501,934	27,529,036	27,927,346	28,542,521	28,987,853	27,972,368	28,809,077	29,164,666	28,335,364	31,768,405	341,826,843
39	Capacity Cost Recovery Revenues (net of tax)	26,493,798	24,540,339	23,908,440	24,159,906	27,928,251	32,147,769	32,489,271	37,348,165	34,902,158	29,576,470	26,806,417	25,619,679	345,911,664
40	Prior Period True-Up Provision	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(11,616,464)
41	Current Period Revenues (net of tax) (line 39 + 40)	25,525,759	23,572,300	22,940,401	23,192,867	26,960,212	31,179,730	31,521,232	36,380,126	33,934,119	28,608,431	25,838,378	24,651,640	334,295,200
	True-Up Provision													
42	True-Up Provision - Over/(Under) Recov (line 41 - 38)	(1,957,968)	(4,261,046)	(4,561,532)	(4,347,168)	(937,134)	2,637,209	2,533,379	8,407,758	5,125,043	(556,234)	(2,496,985)	(7,116,764)	(7,531,442)
43	Interest Provision for the Month	(46,595)	(56,100)	(71,315)	(89,067)	(98,359)	(94,299)	(82,238)	(53,895)	(19,690)	(5,499)	(7,957)	(24,806)	(649,820)
44	Current Cycle Balance - Over/(Under) (line 42 + 43)	(2,004,563)	(6,321,709)	(10,954,556)	(15,390,792)	(16,426,284)	(13,883,375)	(11,432,234)	(3,078,371)	2,026,982	1,465,250	(1,039,692)	(8,181,262)	(8,181,262)
45	Plus: Prior Period Balance	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)
46	Plus: Cumulative True-up Provision	968,039	1,936,077	2,904,116	3,872,155	4,840,193	5,808,232	6,776,271	7,744,309	8,712,348	9,680,387	10,648,425	11,616,464	11,616,464
47	Net True-up Over/(Under) (lines 44 through 46)	(13,234,263)	(16,583,371)	(20,248,179)	(23,716,376)	(23,783,830)	(20,272,882)	(16,853,703)	(7,531,801)	(1,458,409)	(1,052,103)	(2,589,006)	(8,762,537)	(8,762,537)

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Estimated/Actual True-Up
Jananuary- December 2006 (Filed 10/25/06)

		ACTUAL JAN	ACTUAL FEB	ACTUAL MAR	ACTUAL APR	ACTUAL MAY	ACTUAL JUN	ACTUAL JUL	ACTUAL AUG	ACTUAL SEP	ESTIMATED OCT	ESTIMATED NOV	ESTIMATED DEC	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	6,430,080
2	Auburndale Power Partners, L.P. (AUBSET)	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	30,591,050
3	Bay County (BAYCOUNT)	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	3,165,360
4	Cargill Fertilizer, Inc. (CARGILLF)	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	6,339,600
5	Jefferson Power L.C. (JEFFPOWR)	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Lake County (LAKCOUNT)	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	6,029,732
7	Lake Cogen Limited (LAKORDER)	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	31,975,808
8	Metro-Dade County (METRODAE)	694,154	736,558	749,455	798,056	899,574	938,572	964,602	984,123	1,217,818	989,860	989,860	989,860	10,834,492
9	Orange Cogen (ORANGECO)	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	27,318,196
10	Orlando Cogen Limited (ORLACOGL)	2,220,699	1,963,398	1,963,806	1,912,636	1,989,708	2,032,631	2,032,631	2,032,631	2,102,525	2,032,631	2,032,631	2,032,631	24,348,757
11	Orlando Cogen Limited (ORLCOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Pasco Cogen Limited (PASCCOGL)	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	37,996,611
13	Pasco County Resource Recovery (PASCOUNT)	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	10,877,160
14	Pinellas County Resource Recovery (PINCOUNT)	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	25,892,372
15	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	3,832,935	45,995,223
16	U S Agri-Chemicals (AGRICHEM)	(43,838)	0	0	0	0	0	0	0	0	0	0	0	(43,838)
17	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	731,466	772,240	763,595	766,949	773,283	791,854	800,587	800,946	835,327	800,946	800,946	800,946	9,439,093
18	Central Power & Lime (133 MW)	1,182,713	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	16,119,943
19	UPS Purchase (414 total mw) - Southern	4,667,122	4,951,688	4,662,176	4,611,375	4,386,326	4,581,817	4,724,663	3,988,157	4,550,957	4,529,000	4,529,000	4,529,000	54,711,281
20	Incremental Security (5060001, 5240001 & 5490001)	26,630	39,115	(38,843)	6,029	456,313	43,299	341,573	50,571	23,561	871,087	99,688	871,087	2,792,109
21	Subtotal - Base Level Capacity Charges	28,773,211	29,207,195	28,842,385	26,837,440	29,249,399	29,100,378	29,606,251	28,598,623	29,472,384	29,965,720	29,194,321	29,965,720	350,813,027
22	Base Production Jurisdictional Responsibility	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	
23	Base Level Jurisdictional Capacity Charges	26,975,748	27,382,621	27,040,600	27,035,965	27,422,188	27,282,477	27,756,749	26,812,067	27,631,244	28,093,761	27,370,551	28,093,761	328,897,734
	Intermediate Production Level Capacity Charges:													
24	TECO Power Purchase (70 mw)	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
25	Schedule H Capacity Sales	(14,797)	(14,377)	(14,797)	(14,657)	(16,089)	(4,453)	(4,601)	(4,601)	(4,453)	(4,453)	(4,453)	(4,453)	(106,182)
26	Subtotal - Intermediate Level Capacity Charges	644,970	645,390	644,970	645,110	643,678	655,314	655,166	655,166	655,314	655,314	655,314	655,314	7,811,022
27	Intermediate Production Jurisdict. Responsibility	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	
28	Intermediate Level Jurisdict. Capacity Charges	509,823	510,155	509,825	509,934	508,803	518,000	517,882	517,882	518,000	518,000	518,000	518,000	6,174,301
	Peaking Production Level Capacity Charges:													
29	Chattahoochee	12,500	11,636	13,364	11,814	12,782	12,834	13,366	20,000	15,135	15,135	15,135	15,135	168,835
30	Osceola	0	0	0	0	0	606,720	606,720	479,325	530,047	606,720	606,720	606,720	4,042,971
31	TEA	0	0	0	0	0	200,000	200,000	200,000	200,000	0	0	418,750	1,218,750
32	Peaking Purchases - Summer Peak	0	0	0	0	0	27,416	0	27,416	0	0	0	0	54,832
33	Peaking Purchases - Winter Peak	0	0	0	0	0	0	0	0	0	0	0	1,437,500	1,437,500
34	Subtotal -Peaking Level Capacity Charges	12,500	11,636	13,364	11,814	12,782	846,970	820,086	726,741	745,181	621,855	621,855	2,478,105	6,922,888
35	Peaking Production Jurisdictional Responsibility	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	
36	Peaking Level Jurisdictional Capacity Charges	11,122	10,354	11,891	10,512	11,373	753,626	729,704	646,647	663,055	553,320	553,320	2,204,983	6,159,917
	Other Capacity Charges:													
37	Retail Wheeling	(12,967)	(69,785)	(60,381)	(26,376)	(45,018)	(11,582)	(16,482)	(4,229)	(3,222)	(27,437)	(22,531)	(32,324)	(332,333)
38	Total Jurisdictional Capacity Payments	27,483,727	27,833,346	27,501,934	27,530,036	27,897,345	28,542,521	28,987,853	27,972,368	28,809,077	29,137,644	28,419,340	30,784,430	340,899,621
39	Capacity Cost Recovery Revenues (net of tax)	26,493,798	24,540,339	23,908,440	24,150,906	27,928,251	32,147,769	32,469,271	37,346,165	34,902,158	30,735,396	27,131,233	26,572,067	348,347,792
40	Prior Period True-Up Provision	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(968,039)	(1,549,315)	(12,197,740)
41	Current Period Revenues (net of tax) (line 40 + 41)	25,525,759	23,572,300	22,940,402	23,182,868	26,960,213	31,179,730	31,501,232	36,380,126	33,934,119	29,767,357	26,163,194	25,022,752	336,150,052
	True-Up Provision													
42	True-Up Provision - Over/(Under) Recov (line 42 - 39)	(1,957,968)	(4,261,046)	(4,561,532)	(4,347,169)	(937,133)	2,637,209	2,533,379	8,407,758	5,125,043	629,713	(2,256,146)	(5,761,679)	(4,749,571)
43	Interest Provision for the Month	(46,595)	(56,100)	(71,315)	(89,067)	(98,359)	(94,299)	(82,238)	(53,895)	(19,690)	(2,895)	(2,228)	(14,312)	(630,994)
44	Current Cycle Balance - Over/(Under) (line 43 + 44)	(2,004,563)	(6,321,709)	(10,954,556)	(15,390,793)	(16,426,284)	(13,883,375)	(11,432,234)	(3,078,371)	2,026,962	2,653,800	395,425	(5,380,565)	(5,380,565)
45	Plus: Prior Period Balance	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)	(12,197,739)
46	Plus Cumulative True up Provision	968,039	1,936,077	2,904,116	3,872,155	4,840,193	5,808,232	6,776,271	7,744,309	8,712,348	9,680,387	10,648,425	12,197,740	12,197,740
47	Net True-up Over/(Under) (lines 45 through 47)	(13,234,263)	(16,583,371)	(20,248,179)	(23,716,377)	(23,783,830)	(20,272,882)	(16,853,703)	(7,531,801)	(1,458,409)	136,447	(1,153,889)	(5,380,565)	(5,380,565)

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
WILL GARRETT

FINAL TRUE-UP AMOUNT
JANUARY THROUGH DECEMBER 2006

SCHEDULES A1 through A3, A6, AND A12 (WG-3T)
(Year-to-Date)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 6
COMPANY Progress Energy FL, Inc.
WITNESS Will Garrett (WG-3T)
DATE 11-06-07

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2006

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,430,384,794	1,693,893,744	(263,508,950)	(15.6)	35,918,673	37,240,450	(1,321,777)	(3.6)	3.9823	4.5485	(0.5662)	(12.5)
2	SPENT NUCLEAR FUEL DISPOSAL COST	6,010,389	6,228,904	(218,515)	(3.5)	6,382,175	6,636,378	(254,203)	(3.8)	0.0942	0.0939	0.0003	0.3
3	COAL CAR INVESTMENT	1,057,675	10,413,156	(9,355,481)	(89.8)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	2,004,539	0	2,004,539	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	36,067,543	38,332,621	(2,265,079)	(5.9)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	1,475,524,940	1,748,868,426	(273,343,486)	(15.6)	35,918,673	37,240,450	(1,321,777)	(3.6)	4.1080	4.6962	(0.5882)	(12.5)
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	141,270,912	114,125,596	27,145,316	23.8	4,913,747	4,915,525	(1,778)	(0.0)	2.8750	2.3217	0.5533	23.8
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	91,935,463	55,641,111	36,294,352	65.2	1,075,355	777,200	298,155	38.4	8.5493	7.1592	1.3901	19.4
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	164,780,871	145,301,280	19,479,591	13.4	4,393,925	4,663,000	(269,076)	(5.8)	3.7502	3.1160	0.6342	20.4
12	TOTAL COST OF PURCHASED POWER	397,987,246	315,067,987	82,919,259	26.3	10,383,026	10,355,725	27,301	0.3	3.8331	3.0425	0.7906	26.0
13	TOTAL AVAILABLE MWH					46,301,699	47,596,175	(1,294,476)	(2.7)				
14	FUEL COST OF ECONOMY SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(17,107,129)	(45,615,405)	28,508,276	(62.5)	(312,762)	(759,138)	446,375	(58.8)	5.4697	6.0088	(0.5391)	(9.0)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(1,990,442)	(5,856,036)	3,865,594	(66.0)	(312,762)	(759,138)	446,375	(58.8)	0.6364	0.7714	(0.1350)	(17.5)
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF STRATIFIED SALES	(122,214,946)	(129,373,189)	7,158,243	(5.5)	(2,750,965)	(2,496,445)	(254,520)	10.2	4.4426	5.1823	(0.7397)	(14.3)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(141,312,517)	(180,844,630)	39,532,113	(21.9)	(3,063,727)	(3,255,583)	191,855	(5.9)	4.6124	5.5549	(0.9425)	(17.0)
19	NET INADVERTENT AND WHEELED INTERCHANGE					29,236	0	29,236					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	1,732,199,669	1,883,091,783	(150,892,114)	(8.0)	43,267,208	44,340,592	(1,073,385)	(2.4)	4.0035	4.2469	(0.2434)	(5.7)
21	NET UNBILLED	(4,555,615)	(8,498)	(4,547,117)	53,508.1	113,791	1,582	112,209	7,091.0	(0.0112)	0.0000	(0.0112)	0.0
22	COMPANY USE	6,596,882	5,072,250	1,524,632	30.1	(164,778)	(120,000)	(44,778)	37.3	0.0162	0.0122	0.0040	32.8
23	T & D LOSSES	98,385,602	109,172,312	(10,786,710)	(9.9)	(2,457,494)	(2,570,699)	113,205	(4.4)	0.2414	0.2621	(0.0207)	(7.9)
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,732,199,669	1,883,091,783	(150,892,114)	(8.0)	40,758,727	41,651,476	(892,749)	(2.1)	4.2499	4.5211	(0.2712)	(6.0)
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(56,667,920)	(68,127,896)	11,459,976	(16.8)	(1,346,454)	(1,503,234)	156,780	(10.4)	4.2087	4.5321	(0.3234)	(7.1)
26	JURISDICTIONAL KWH SALES	1,675,531,749	1,814,963,887	(139,432,138)	(7.7)	39,412,273	40,148,242	(735,969)	(1.8)	4.2513	4.5207	(0.2694)	(6.0)
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00382	1,681,727,515	1,818,720,862	(136,993,347)	(7.5)	39,412,273	40,148,242	(735,969)	(1.8)	4.2670	4.5300	(0.2630)	(5.8)
28	PRIOR PERIOD TRUE-UP	315,692,056	315,692,056	(0)	0.0	39,412,273	40,148,242	(735,969)	(1.8)	0.8010	0.7863	0.0147	1.9
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	39,412,273	40,148,242	(735,969)	(1.8)	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	39,412,273	40,148,242	(735,969)	(1.8)	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	1,997,419,571	2,134,412,918	(136,993,347)	(6.4)	39,412,273	40,148,242	(735,969)	(1.8)	5.0680	5.3163	(0.2483)	(4.7)
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									5.0716	5.3201	(0.2485)	(4.7)
32	GPIF	532,353	532,353			39,412,273	40,148,242			0.0014	0.0013	0.0001	92.9
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.073	5.321	(0.248)	(4.7)

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2006

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A	FUEL COSTS AND NET POWER TRANSACTIONS								
1	FUEL COST OF SYSTEM NET GENERATION	$91,123,652	118,766,003	($27,642,351)	(23.3)	$1,430,384,794	$1,693,893,744	($263,508,950)	(15.6)
1a.	NUCLEAR FUEL DISPOSAL COST	554,762	534,681	20,081	3.8	6,010,389	6,228,904	(218,515)	(3.5)
1b	NUCLEAR DECOM & DECON	6,733	0	6,733	100.0	2,004,539	0	2,004,539	100.0
1c.	COAL CAR INVESTMENT	79,833	874,598	(794,765)	(90.9)	1,057,675	10,413,156	(9,355,481)	(89.8)
2	FUEL COST OF POWER SOLD	(1,332,012)	(5,530,660)	4,198,648	(75.9)	(17,107,129)	(45,615,405)	28,508,276	(62.5)
2a	GAIN ON POWER SALES	(218,616)	(700,687)	482,071	(68.8)	(1,990,442)	(5,856,036)	3,865,594	(66.0)
3	FUEL COST OF PURCHASED POWER	10,293,640	10,332,367	(38,727)	(0.4)	141,270,912	114,125,596	27,145,316	23.8
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	16,184,676	12,495,946	3,688,730	29.5	164,780,871	145,301,280	19,479,591	13.4
3b.	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	0.0	0	0	0	0.0
4	ENERGY COST OF ECONOMY PURCHASES	2,782,458	2,145,225	637,233	29.7	91,935,463	55,641,111	36,294,352	65.2
5	TOTAL FUEL & NET POWER TRANSACTIONS	119,475,125	138,917,473	(19,442,347)	(14.0)	1,818,347,072	1,974,132,351	(155,785,279)	(7.9)
6	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(7,178,128)	(9,152,488)	1,974,360	(21.6)	(122,214,946)	(129,373,189)	7,158,243	(5.5)
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	3,339,909	3,016,619	323,290	10.7	36,067,543	38,332,621	(2,265,079)	(5.9)
6c	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7	ADJUSTED TOTAL FUEL & NET PWR TRNS	$115,636,906	$132,781,604	($17,144,698)	(12.9)	$1,732,199,669	$1,883,091,783	($150,892,114)	(8.0)

FOOTNOTE: DETAIL OF LINE 6b ABOVE

INSPECTION & FUEL ANALYSIS REPORTS (Wholesale Portion)	$3,626	$0	$3,626	$56,050	$0	$56,050
INEFFICIENT USE OF HINES 3	0	0	0	0	0	0
UNIV OF FL STEAM REVENUE ALLOCATION (Wholesale Portion)	3,300	0	3,300	39,690	0	39,690
ADDL ADJUSTMENT FOR 518.13 CLEANUP	(6,733)	0	(6,733)	(134,008)	1,743,831	(1,877,840)
GAS CONVERSION PROJECTS (DEPRECIATION & RETURN)	0	0	0	0	0	0
EMISSIONS	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT (Grossed up)	0	0	0	(45,811)	0	(45,811)
FPSC FUEL AUDIT ADJUSTMENT	0	0	0	0	0	0
COGEN ADJUSTMENT INTEREST (GROSSED UP)	0	0	0	64,754	0	64,754
RETURN ON COAL INVENTORY IN TRANSIT (GROSSED UP)	323,084	0	323,084	3,359,530	0	3,359,530
DOE CRUDE OIL REFUND DISTRIBUTION	0	0	0	(3,861,594)	0	(3,861,594)
HINES 2 (DEPREC & RETURN)	3,016,631	3,016,619	12	36,588,932	36,588,790	142
SUBTOTAL LINE 6b SHOWN ABOVE	$3,339,909	$3,016,619	$323,290	$36,067,543	$38,332,621	($2,265,079)

Note: Return on Coal Inventory in Transit based on: Avg Investment $31,106,713 Avg tons: 458,630

B.	KWH SALES								
1	JURISDICTIONAL SALES	2,916,326,024	3,001,370,000	(85,043,976)	(2.8)	39,431,837,767	40,148,242,000	(716,404,233)	(1.8)
2	NON JURISDICTIONAL (WHOLESALE) SALES	99,623,387	106,606,000	(6,982,613)	(6.6)	1,346,454,111	1,503,234,000	(156,779,889)	(10.4)
3	TOTAL SALES	3,015,949,411	3,107,976,000	(92,026,589)	(3.0)	40,778,291,878	41,651,476,000	(873,184,122)	(2.1)
4	JURISDICTIONAL SALES % OF TOTAL SALES	96.70	96.57	0.13	0.1	96.70	96.39	0.31	0.3

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2006

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C	TRUE UP CALCULATION								
1	JURISDICTIONAL FUEL REVENUE	$151,126,016	$159,602,522	($8,476,506)	(5.3)	$2,080,551,333	$2,134,945,272	($54,393,939)	(2.6)
2.	ADJUSTMENTS: PRIOR PERIOD ADJ	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(26,307,671)	(26,307,675)	4	0.0	(315,692,056)	(315,692,056)	0	0.0
2b	INCENTIVE PROVISION	(44,363)	(44,360)	(3)	0.0	(532,353)	(532,353)	0	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3	TOTAL JURISDICTIONAL FUEL REVENUE	124,773,982	133,250,487	(8,476,505)	(6.4)	1,764,326,924	1,818,720,862	(54,393,939)	(3.0)
4	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	115,636,906	132,781,604	(17,144,698)	(12.9)	1,732,199,669	1,883,091,783	(150,892,114)	(8.0)
5	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	96.70	96.57	0.13	0.1	96.70	96.39	0.31	0.3
6	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00382 LOSS MULTIPLIER)	112,248,044	128,492,522	(16,244,478)	(12.6)	1,681,727,515	1,818,720,862	(136,993,347)	(7.5)
7	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	12,525,938	4,757,965	7,767,973	163.3	82,599,409	0	82,599,409	100.0
8	INTEREST PROVISION FOR THE MONTH (LINE D10)	243,897	(56,153)	300,050	(534.3)	(6,869,481)	(5,793,513)	(1,075,968)	18.6
9	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	36,267,366	(36,803,000)	73,070,367	(198.5)	(316,077,111)	(315,692,056)	(385,055)	0.1
10	TRUE UP COLLECTED (REFUNDED)	26,307,671	26,307,675	(4)	0.0	315,692,056	315,692,056	(0)	0.0
11	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	75,344,873	(5,793,513)	81,138,385	(1,400.5)	75,344,873	(5,793,513)	81,138,385	(1,400.5)
12	OTHER:								
13	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	$75,344,873	(5,793,513)	81,138,385	(1,400.5)	$75,344,873	(5,793,513)	81,138,385	(1,400.5)
D.	INTEREST PROVISION								
1.	BEGINNING TRUE UP (LINE C9)	$36,267,366	N/A	--	--				
2.	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	75,100,976	N/A	--	--				
3	TOTAL OF BEGINNING & ENDING TRUE UP	111,368,342	N/A	--	--		NOT		
4	AVERAGE TRUE UP (50% OF LINE D3)	55,684,171	N/A	--	--				
5	INTEREST RATE - FIRST DAY OF REPORTING MONTH	5.250	N/A	--	--				
6	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	5.270	N/A	--	--				
7	TOTAL (LINE D5 + LINE D6)	10.520	N/A	--	--		APPLICABLE		
8	AVERAGE INTEREST RATE (50% OF LINE D7)	5.260	N/A	--	--				
9.	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.438	N/A	--	--				
10	INTEREST PROVISION (LINE D4 * LINE D9)	$243,897	N/A	--	--				

© Wall Data Incorporated 2006 FactSet Research Systems Inc. All rights reserved

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)					
1	HEAVY OIL	307,869,797	425,965,775	-118,095,978	-27.7%
2	LIGHT OIL	59,201,312	63,758,586	-4,557,274	-7.1%
3	COAL	460,168,336	431,832,724	28,335,612	6.6%
4	GAS	579,811,305	748,679,284	-168,867,979	-22.6%
5	NUCLEAR	23,334,044	23,657,378	-323,334	-1.4%
6					
7					
8	TOTAL ($)	1,430,384,794	1,693,893,747	-263,508,953	-15.6%
SYSTEM NET GENERATION (MWH)					
9	HEAVY OIL	4,603,832	5,389,913	-786,081	-14.6%
10	LIGHT OIL	307,625	277,691	29,934	10.8%
11	COAL	14,968,731	14,740,143	228,588	1.6%
12	GAS	9,656,309	10,196,325	-540,016	-5.3%
13	NUCLEAR	6,382,175	6,636,378	-254,203	-3.8%
14					
15					
16	TOTAL (MWH)	35,918,672	37,240,450	-1,321,778	-3.5%
UNITS OF FUEL BURNED					
17	HEAVY OIL (BBL)	7,353,386	9,018,949	-1,665,563	-18.5%
18	LIGHT OIL (BBL)	710,104	664,524	45,580	6.9%
19	COAL (TON)	5,977,187	5,718,999	258,188	4.5%
20	GAS (MCF)	76,629,028	80,330,843	-3,701,815	-4.6%
21	NUCLEAR (MMBTU)	65,780,814	68,373,920	-2,593,106	-3.8%
22					
23					

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
BTUS BURNED (MILLION BTU)					
24	HEAVY OIL	48,422,567	58,623,171	-10,200,604	-17.4%
25	LIGHT OIL	4,106,716	3,854,233	252,483	6.6%
26	COAL	146,597,286	142,974,941	3,622,345	2.5%
27	GAS	78,269,038	80,330,843	-2,061,805	-2.6%
28	NUCLEAR	65,780,814	68,373,920	-2,593,106	-3.8%
29					
30					
31	TOTAL (MILLION BTU)	343,176,421	354,157,108	-10,980,687	-3.1%
GENERATION MIX (% MWH)					
32	HEAVY OIL	12.8	14.47	-1.7	-11.4%
33	LIGHT OIL	0.9	0.75	0.1	14.9%
34	COAL	41.7	39.58	2.1	5.3%
35	GAS	26.9	27.38	-0.5	-1.8%
36	NUCLEAR	17.8	17.82	-0.1	-0.3%
37					
38					
39	TOTAL (% MWH)	100.0	100.0	0.0	0.0%

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
FUEL COST PER UNIT ($)					
40	HEAVY OIL ($/BBL)	41.87	47.23	-5.36	-11.4%
41	LIGHT OIL ($/BBL)	83.37	95.95	-12.58	-13.1%
42	COAL ($/TON)	76.99	75.51	1.48	2.0%
43	GAS ($/MCF)	7.57	9.32	-1.75	-18.8%
44	NUCLEAR ($/MBTU)	0.35	0.35	0.01	2.5%
45					
46					
FUEL COST PER MILLION BTU ($/MILLION BTU)					
47	HEAVY OIL	6.36	7.27	-0.91	-12.5%
48	LIGHT OIL	14.42	16.54	-2.13	-12.9%
49	COAL	3.14	3.02	0.12	3.9%
50	GAS	7.41	9.32	-1.91	-20.5%
51	NUCLEAR	0.35	0.35	0.01	2.5%
52					
53					
54	SYSTEM ($/MBTU)	4.17	4.78	-0.61	-12.9%
BTU BURNED PER KWH (BTU/KWH)					
55	HEAVY OIL	10,518	10,876	-359	-3.3%
56	LIGHT OIL	13,350	13,880	-530	-3.82%
57	COAL	9,794	9,700	94	1.0%
58	GAS	8,105	7,878	227	2.9%
59	NUCLEAR	10,307	10,303	4	0.0%
60					
61					
62	SYSTEM (BTU/KWH)	9,554	9,510	44	0.5%

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

01-2006 Thru 12-2006
FINAL

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)					
63	HEAVY OIL	6.69	7.90	-1.22	-15.4%
64	LIGHT OIL	19.24	22.96	-3.72	-16.2%
65	COAL	3.07	2.93	0.14	4.9%
66	GAS	6.00	7.34	-1.34	-18.2%
67	NUCLEAR	0.37	0.36	0.01	2.6%
68					
69					
70	SYSTEM (CENTS/KWH)	3.98	4.55	-0.57	-12.4%

Progress Energy Florida, Inc.
Schedule A6
Power Sold for the Month of
December 2006

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)
Sold To	Type & Schedule	Total KWH Sold (000)	KWH Wheeled from Other Systems (000)	KWH from Own Generation (000)	Fuel Cost C/KWH	Total Cost C/KWH	Fuel Adj Total $	Total Cost $	Gain on Sales $
ESTIMATED		94,000		94,000	5.884	6.629	5,530,660.00	6,231,347.00	700,687.00
ACTUAL									
City of New Smyrna Beach, FL	Schedule H	0		0	0.000	0.000	0.00	0.00	0.00
City of New Smyrna Beach, FL	Schedule I	0		0	0.000	0.000	8,615.52	8,615.52	0.00
City of New Smyrna Beach, FL	Schedule OS	110		110	4.095	5.580	4,504.50	6,138.00	1,633.50
Cobb Electric Membership Corp.	EEI	3,757		3,757	4.208	5.282	158,100.63	198,436.69	40,336.06
ConocoPhillips Company	EEI	208		208	9.195	9.441	19,125.60	19,637.28	511.68
Florida Municipal Power Agency	CR-1	325		325	4.256	4.859	13,832.00	15,792.25	1,960.25
Florida Power & Light Company	CR-1	2,212		2,212	4.479	4.684	99,073.35	103,602.36	4,529.01
Oglethorpe Power Corp.	EEI	410		410	5.665	8.417	23,226.50	34,509.70	11,283.20
Reedy Creek Improvement District	Schedule OS	1,740		1,740	3.153	3.872	54,867.96	67,377.16	12,509.20
Seminole Electric Cooperative, Inc	CR-1	2,430		2,430	3.313	4.803	80,495.70	116,711.05	36,215.35
Seminole Electric Cooperative, Inc.	Load Following	9,752		9,752	4.864	4.864	474,308.41	474,308.41	0.00
Tampa Electric Company	CR-1	6,447		6,447	4.358	5.712	280,976.51	368,228.27	87,251.76
Tampa Electric Company	EEI	50		50	5.966	6.721	2,983.00	3,360.50	377.50
Tennessee Valley Authority	MR1	1,815		1,815	4.479	6.379	81,296.79	115,771.19	34,474.40
The Energy Authority, Inc.	Contract	760		760	4.027	5.218	30,605.54	39,657.22	9,051.68
Pennsylvania-New Jersey-Maryland Int.	MR1	(100)		(100)	0.000	21.518	0.00	(21,517.61)	(21,517.61)
Subtotal - Gain on Other Power Sales		29,916		29,916	4.453	5.183	1,332,012.01	1,550,627.99	218,615.98
CURRENT MONTH TOTAL		29,916		29,916	4.453	5.183	1,332,012.01	1,550,627.99	218,615.98
DIFFERENCE		(64,084)		(64,084)	(1.431)	(1.446)	(4,198,647.99)	(4,680,719.01)	(482,071.02)
DIFFERENCE %		(68.17)		(68.17)	(24.33)	(21.81)	(75.92)	(75.12)	(68.80)
CUMULATIVE ACTUAL		312,762		312,762	5.470	6.106	17,107,128.56	19,097,570.73	1,990,442.17
CUMULATIVE ESTIMATED		759,137		759,137	6.009	6.780	45,615,405.00	51,471,441.00	5,856,036.00
DIFFERENCE		(446,375)		(446,375)	(0.539)	(0.674)	(28,508,276.44)	(32,373,870.27)	(3,865,593.83)
DIFFERENCE %		(58.80)		(58.80)	(8.97)	(9.94)	(62.50)	(62.90)	(66.01)

PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A12 - CAPACITY COSTS
FOR THE PERIOD JAN - DEC 2006

	Counterparty	Type	MW	Start Date - End Date	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YTD
1	Auburndale Power Partners, L P (AUBRDLFC)	QF	17 00	1/1/95 - 12/31/13	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	535,840	6,430,080
2	Auburndale Power Partners, L P (AUBSET)	QF	114 18	8/1/94 - 12/31/13	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	2,549,254	30,591,051
3	Bay County (BAYCOUNT)	QF	11 00	1/1/95 - 12/31/56	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	263,780	3,165,360
4	Cargill Fertilizer, Inc (CARGILLF)	QF	15 00	9/1/92 - 12/31/07	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	528,300	6,339,600
5	Jefferson Power L C (JEFFPOWR)	QF	2 05	7/1/02 - 7/31/05	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Lake County (LAKCOUNT)	QF	12 75	1/1/95 - 6/30/14	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	502,478	6,029,730
7	Lake Cogen Limited (LAKORDER)	QF	110 00	7/1/93 - 7/31/13	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	2,664,651	31,975,807
8	Metro-Dade County (METRDADE)	QF	43 00	11/1/91 - 11/30/13	604,154	738,558	749,455	798,056	899,574	908,572	964,602	984,123	1,217,818	989,860	989,860	1,015,118	10,859,750
9	Orange Cogen (ORANGECO)	QF	74 00	7/1/95 - 12/31/24	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	2,276,516	27,318,197
10	Orlando Cogen Limited (ORLACOGL)	QF	79 20	9/1/93 - 12/31/23	2,220,699	1,963,398	1,963,806	1,912,836	1,989,708	2,032,631	2,032,631	2,032,631	2,102,525	2,032,631	2,032,631	2,032,631	24,348,755
11	Pasco Cogen Limited (PASCCOGL)	QF	109 00	7/1/93 - 12/31/08	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	3,166,384	37,996,612
12	Pasco County Resource Recovery (PASCOUNT)	QF	23 00	1/1/95 - 12/31/24	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	906,430	10,877,160
13	Pinellas County Resource Recovery (PINCOUNT)	QF	54 75	1/1/95 - 12/31/24	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	2,157,698	25,892,370
14	Polk Power Partners, L P (MULBERRY)	QF	79 20	8/1/94 - 8/8/24	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	2,775,626	33,307,512
15	Polk Power Partners, L P. (ROYSTER)	QF	30 80	8/1/94 - 8/9/09	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	1,057,309	12,687,711
16	U S Agri-Chemicals (AGRICHEM)	QF	5 61	1/1/97 - 11/23/05	(43,838)	0	0	0	0	0	0	0	0	0	0	0	(43,838)
17	Wheelabrator Ridge Energy Inc (RIDGEGEN)	QF	39 60	8/1/94 - 12/31/23	731,466	772,240	763,595	766,949	773,283	791,864	800,587	800,946	835,327	1,066,052	725,113	612,032	9,439,452
18	UPS Purchase (414 total mw) - Southern	Other	414	7/19/88 - 5/31/10	4,667,122	4,951,688	4,662,176	4,611,375	4,386,326	4,581,817	4,724,663	3,988,157	4,550,957	4,608,617	4,609,659	6,004,790	56,347,347
19	Incremental Security				26,630	39,115	(38,843)	6,029	458,313	43,299	341,573	50,571	23,561	551,304	32,343	648,270	2,182,164
20	TECO Power Purchase (70 mw)	Other	70	3/30/93 - 2/28/11	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
21	Retail Wheeling				(12,967)	(69,785)	(60,381)	(26,376)	(45,018)	(11,582)	(16,482)	(4,229)	(3,222)	(23,353)	(47,329)	(24,290)	(345,012)
	SUBTOTAL				28,237,298	28,439,247	28,083,840	28,112,902	28,506,218	28,390,633	28,891,606	27,896,232	29,770,999	29,269,143	28,386,309	30,332,583	343,317,011
	Confidential Capacity Contracts (Aggregated):																
	Purchases/Sales (Net)	Other	MW	Contracts													
	Total		777.25 to 935.25	9	1,180,417	1,355,188	1,356,498	1,355,088	1,354,623	2,200,448	2,173,414	2,090,070	2,098,658	1,974,818	1,974,697	3,753,799	22,857,717
	TOTAL				29,417,715	29,794,436	29,440,338	29,467,989	29,860,841	30,591,080	31,065,021	29,976,301	30,869,658	31,243,961	30,361,006	34,086,382	366,174,728

D:\Fuel Closing\2006\Dec\[Monthly Fuel x/s]CCR - Sch A12
2/27/07 7 48 AM

Docket No. 070001-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No __ (LC-1R)

EXHIBITS TO THE TESTIMONY OF LORI CROSS

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2007

SCHEDULES E1-B - E9 AND PART A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 7
COMPANY Progress Energy FL, Inc
WITNESS Lori Cross (LC-1R)
DATE 11-06-07

EXHIBIT TO THE SUPPLEMENTAL DIRECT TESTIMONY OF LORI CROSS

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2007

SCHEDULES E1-B - E9

Schedule E1-B - Calculation of Estimated True-up
Schedule E2 - Fuel Cost Recovery Clause Calculation by Month
Schedule E3 - Generating System Comparative Data
Schedule E4 - System Net Generation & Fuel Cost by Month
Schedule E5 - Inventory Analysis
Schedule E6 - Fuel Cost of Power Sold
Schedule E7 - Purchased Power
Schedule E8 - Energy Payments to Qualifying Facilities
Schedule E9 - Economy Energy Purchases

Progress Energy Florida
Calculation of Estimated True-Up
Actual/Estimated for the Period of January Through December 2007

DESCRIPTION	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	TOTAL PERIOD
REVENUE													
1 Jurisdictional MWH Sales	2,762,442	2,884,939	2,774,080	2,821,984	3,019,929	3,356,677	3,920,937	4,019,656	4,037,088	3,535,821	3,096,056	3,093,900	39,323,508
2 Jurisdictional Fuel Factor (Pre-Tax)	4.979	5.011	4.997	5.010	5.063	5.091	5.128	5.128	5.128	5.128	5.128	5.128	
3 Total Jurisdictional Fuel Revenue	137,534,227	144,566,416	138,611,197	141,372,027	152,903,793	170,895,864	201,067,694	206,130,055	207,023,978	181,318,744	158,767,366	158,656,805	1,998,848,165
4 True-Up Provision	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,354	46,480,257
5 GPIF Provision	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,919	1,547,048
6 Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	141,536,502	148,568,692	142,613,472	145,374,302	156,906,068	174,698,140	205,069,970	210,132,331	211,026,254	185,321,020	162,769,642	162,659,078	2,046,875,471
FUEL EXPENSE													
8 Total Cost of Generated Power	96,621,011	113,662,628	111,865,762	116,524,802	138,090,209	171,271,216	207,379,567	199,774,623	170,747,073	162,410,686	140,579,887	129,533,498	1,758,460,962
9 Total Cost of Purchased Power	27,651,795	23,971,853	23,987,275	34,023,359	39,471,227	38,928,003	42,480,859	46,604,387	39,471,730	46,409,403	30,713,059	31,552,763	425,324,714
10 Total Cost of Power Sales	(9,943,088)	(14,748,006)	(13,621,475)	(19,122,799)	(16,501,133)	(17,668,309)	(17,394,139)	(20,703,340)	(20,443,924)	(20,673,006)	(18,104,028)	(12,456,525)	(201,379,774)
11 Total Fuel and Net Power	114,329,718	122,886,475	122,231,562	131,425,362	161,060,303	192,530,909	232,466,287	225,735,670	189,774,879	188,146,081	153,188,919	148,629,737	1,982,405,902
12 Jurisdictional Percentage	96.82%	96.80%	96.83%	96.76%	97.00%	96.25%	96.28%	96.14%	95.88%	95.75%	96.00%	96.67%	
13 Jurisdictional Loss Multiplier	1.00382	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	
14 Jurisdictional Fuel Cost	111,116,884	119,137,297	118,539,091	127,363,018	156,469,086	185,596,379	224,152,954	217,353,488	182,244,080	180,423,758	147,290,774	143,695,602	1,913,582,413
COST RECOVERY													
15 Net Fuel Revenue Less Expense	30,419,618	29,431,394	24,074,381	18,011,284	436,982	(10,698,240)	(19,082,984)	(7,221,157)	28,782,174	4,897,262	15,478,867	18,763,475	133,293,058
16 Interest Provision	389,033	503,959	606,379	684,237	710,671	675,885	596,479	524,356	556,980	616,348	646,775	707,772	7,218,873
17 Current Cycle Balance	30,808,651	60,744,004	85,424,765	104,120,286	105,267,939	95,245,585	76,759,079	70,062,278	99,401,432	104,915,042	121,040,684	140,511,931	
18 Plus: Prior Period Balance	75,344,873	75,344,873	75,344,873	75,344,874	75,344,875	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	
19 Plus: Cumulative True-Up Provision	(3,873,355)	(7,746,710)	(11,620,064)	(15,493,419)	(19,366,774)	(23,240,129)	(27,113,484)	(30,986,839)	(34,860,194)	(38,733,549)	(42,606,904)	(46,480,257)	
20 Total Retail Balance	102,280,169	128,342,168	149,149,573	163,971,741	161,246,040	147,350,329	124,990,469	114,420,313	139,886,112	141,526,366	153,778,653	169,376,547	

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Calculation of Variance -- Actual/Estimate versus Original Projection
For the Period of: January Through December 2007

		DOLLARS			
		Actual / Estimate	Original Estimate	Variance Amount	Variance %
1.	Fuel Cost of System Net Generation	1,715,054,010	1,865,445,051	(150,391,041)	(8.1)
2.	Spent Nuclear Fuel Disposal Cost	5,681,653	5,591,566	90,088	1.6
3.	Coal Car Investment	822,631	2,781,762	(1,959,131)	(70.4)
4.	Adjustment to Fuel Cost	36,902,668	39,912,398	(3,009,730)	(7.5)
5.	TOTAL COST OF GENERATED POWER	1,758,460,962	1,913,730,776	(155,269,814)	(8.1)
6.	Energy Cost of P. P. (Excl. Econ & Cogens)	229,548,681	261,990,517	(32,441,836)	(12.4)
7.	Energy Cost Econ Purch (Broker)	0	0	0	0.0
8.	Energy Cost of Econ Purch (Non-Broker)	44,001,409	56,994,410	(12,993,001)	--
9.	Energy Cost of Schedule E Economy Purch	0	0	0	0.0
10.	Capacity Cost of Economy Purchases	0	0	0	0.0
11.	Payments to Qualifying Facilities	151,774,623	159,230,743	(7,456,120)	(4.7)
12.	TOTAL COST OF PURCHASED POWER	425,324,714	478,215,670	(52,890,956)	(11.1)
13.	TOTAL AVAILABLE KWH				
14.	Fuel Cost of Economy Sales	0	0	0	0.0
14a.	Gain on Economy Sales - 80%	0	0	0	0.0
15.	Fuel Cost of Other Power Sales	(22,740,689)	(19,584,223)	(3,156,466)	16.1
15a.	Gain on Other Power Sales	(3,529,481)	(2,176,024)	(1,353,457)	62.2
16.	Fuel Cost of Unit Power Sales	0	0	0	0.0
16a.	Gain on Unit Power Sales	0	0	0	0.0
17.	Fuel Cost of Stratified Sales	(175,109,604)	(164,945,256)	(10,164,348)	6.2
18.	TOTAL FUEL COST & GAINS ON POWER SALES	(201,379,774)	(186,705,503)	(14,674,271)	7.9
19.	Net Inadvertent Interchange				
20.	TOTAL FUEL & NET POWER TRANSACTIONS	1,982,405,902	2,205,240,943	(222,835,041)	(10.1)
21.	Net Unbilled	6,964,444 *	4,791,007 *	2,173,437	N/A
22.	Company Use	5,976,742 *	7,033,647 *	(1,056,905)	(15.0)
23.	T & D Losses	115,347,898 *	132,073,504 *	(16,725,606)	(12.7)
24.	Adjusted System KWH Sales	1,982,405,902	2,205,240,943	(222,835,041)	(10.1)
25.	Wholesale KWH Sales (Excl Suppl. Sales)	(72,017,869)	(71,569,089)	(448,781)	0.6
26.	Jurisdictional KWH Sales	1,910,388,033	2,133,671,855	(223,283,822)	(10.5)
27.	Jurisd KWH Sales Adj for Line Losses	1,913,582,413	2,141,822,481	(228,240,068)	(10.7)
28.	Prior Period True-Up **	(75,344,873)	(46,480,257)	(28,864,616)	62.1
29.	Other	0	0	0	0.0
30.	Total Jurisdictional Fuel Cost	1,838,237,540	2,095,342,224	(257,104,684)	(12.3)
31.	GPIF **	(1,547,048)	(1,547,048)	(0)	0.0

* For Informational Purposes Only
** Based on Jurisdictional Sales

SCHEDULE E-2

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Actual/Estimated for the Period of January Through December 2007

			Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	TOTAL
1	Fuel Cost of System Net Generation		$92,918,766	$109,666,861	$107,850,618	$112,495,909	$124,795,349	$167,954,401	$208,462,450	$195,878,619	$166,868,965	$153,570,080	$137,216,204	$128,517,478	$1,715,054,610
1a	Nuclear Fuel Disposal Cost		564,672	490,518	559,682	537,568	913,291	630,932	542,703	542,703	525,197	521,105	35,600	373,797	5,681,553
1b	Adjustments to Fuel Cost		3,787,613	3,765,224	3,461,962	3,491,286	3,460,610	2,946,883	3,376,409	3,383,401	3,353,614	3,639,461	3,326,064	342,224	37,725,299
2	Fuel Cost of Power Sold		(1,068,695)	(3,677,670)	(1,078,396)	(1,442,170)	(1,215,554)	(1,330,947)	(2,187,041)	(2,484,305)	(1,997,381)	(1,864,537)	(2,840,953)	(3,257,025)	(32,740,689)
2a	Gains on Power Sales		(245,220)	(882,282)	(259,072)	(202,766)	(167,866)	(229,852)	(270,510)	(324,260)	(173,603)	(164,390)	(291,325)	(293,083)	(3,529,481)
2b	Fuel Cost of Stratified Sales		(9,629,178)	(9,968,204)	(10,059,807)	(17,477,843)	(16,927,894)	(16,102,510)	(14,990,570)	(17,884,776)	(16,932,683)	(19,244,051)	(15,571,742)	(8,905,417)	(175,139,604)
3	Fuel Cost of Purchased Power (Exc. Economy)		11,410,594	10,162,496	10,993,412	19,740,338	20,728,681	21,737,639	28,385,368	28,918,883	23,058,265	27,094,153	13,934,620	14,488,282	229,548,681
3a	Energy Payments to Qualifying Facilities		12,967,053	13,936,701	11,362,764	11,783,196	13,456,860	12,870,930	13,239,622	13,058,645	12,563,734	12,193,801	12,871,074	13,892,314	161,774,623
4	Energy Cost of Economy Purchases		3,284,179	2,853,652	2,841,118	3,499,885	2,887,686	4,312,434	2,852,954	4,456,879	3,871,731	6,620,349	3,901,359	3,172,187	44,001,409
5	Total System Fuel & Net Power Transactions		$114,329,716	$120,686,476	$122,231,562	$131,426,362	$147,000,916	$192,330,909	$232,466,097	$225,735,670	$189,774,879	$183,140,251	$153,189,919	$148,629,737	$1,982,405,902
6	Jurisdictional MWH Sold		2,762,442	2,864,939	2,774,380	2,921,864	3,319,924	3,356,677	3,920,937	4,019,656	4,037,086	3,635,821	3,096,056	3,093,900	39,323,506
7	Jurisdictional % of Total Sales		96.82%	96.80%	96.83%	96.76%	97.00%	96.25%	96.25%	96.14%	95.88%	95.79%	96.00%	96.67%	96.37%
8	Jurisdictional Fuel & Net Power Transactions		110,694,053	116,864,105	118,356,821	127,167,181	156,224,484	185,311,000	223,828,289	217,019,279	181,963,855	180,146,333	147,064,295	143,674,344	1,910,388,033
9	Jurisdictional Loss Multiplier		1.00362	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00167	1.00167
10	Jurisdictional Fuel & Net Power Transactions		111,116,884	116,137,297	118,539,091	127,363,018	156,469,086	185,596,379	224,152,954	217,353,468	182,244,080	180,423,768	147,290,774	143,895,602	1,913,582,413
11	Adjusted System Sales	MWH	2,853,243	2,960,281	2,864,775	2,916,511	3,119,407	3,487,417	4,070,616	4,181,102	4,210,385	3,692,836	3,224,994	3,209,610	40,798,179
12	System Cost per KWH Sold	¢/kwh	4.0070	4.1233	4.2667	4.5063	5.1731	5.5207	5.7090	5.3990	4.5073	5.0949	4.7531	4.6438	4.8591
13	Jurisdictional Loss Multiplier	x	1.00362	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00167	1.00167
14	Jurisdictional Cost per KWH Sold	¢/kwh	4.0214	4.1296	4.2721	4.5132	5.1612	5.5292	5.7165	5.4073	4.5142	5.1027	4.7574	4.6559	4.8663
15	Prior Period True-Up	+	-0.1402	-0.1343	-0.1396	-0.1378	-0.1253	-0.1154	-0.0968	-0.0964	-0.0959	-0.1096	-0.1251	-0.1252	-0.2142
16	Total Jurisdictional Fuel Expense	¢/kwh	3.8822	3.9954	4.1336	4.3760	5.0360	5.4138	5.6180	5.3109	4.4183	4.9932	4.6323	4.5258	4.6521
17	Revenue Tax Multiplier	x	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
18	Recovery Factor Adjusted for Taxes	¢/kwh	3.8850	3.9982	4.1364	4.3791	5.0396	5.4177	5.6221	5.3147	4.4215	4.9968	4.6356	4.5290	4.6554
19	GPIF	+	-0.0047	-0.0045	-0.0046	-0.0046	-0.0043	-0.0038	-0.0033	-0.0032	-0.0032	-0.0036	-0.0042	-0.0042	-0.0039
20	Total Recovery Factor (rounded .001)	¢/kwh	3.880	3.994	4.132	4.378	5.052	5.414	5.619	5.312	4.418	4.993	4.631	4.525	4.652

Progress Energy Florida

Generating System Comparative Data by Fuel Type

Actual/Estimated for the Period of : January Through December 2007

			Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		41,276,418	50,305,876	48,058,452	39,411,638	32,568,775	25,385,098	237,006,257
2	LIGHT OIL		24,798,458	10,040,877	3,588,724	17,583,371	2,541,244	3,389,995	61,942,669
3	COAL		45,703,146	45,571,213	45,698,285	36,035,854	44,713,955	45,024,417	263,746,870
4	GAS		89,469,359	87,747,478	67,381,217	63,495,692	57,249,427	52,534,749	417,877,920
5	NUCLEAR		2,213,075	2,213,075	2,141,685	2,043,525	142,803	1,483,219	10,237,382
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	203,460,456	195,878,519	166,868,363	158,570,080	137,216,204	128,817,478	990,811,098
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		475,309	572,486	557,990	457,102	375,140	294,799	2,732,826
9	LIGHT OIL		90,459	37,371	11,867	69,387	5,961	8,566	223,611
10	COAL		1,451,320	1,450,214	1,438,547	1,117,857	1,411,057	1,450,300	8,319,095
11	GAS		1,274,083	1,264,997	939,407	774,501	776,203	705,613	5,734,804
12	NUCLEAR		577,344	577,344	558,720	533,112	37,872	397,656	2,682,048
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,868,515	3,902,412	3,506,531	2,951,759	2,606,233	2,856,934	19,692,384
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	774,894	924,520	892,785	733,484	596,863	471,939	4,394,485
16	LIGHT OIL	BBL	258,478	110,576	39,917	179,528	25,703	33,996	648,198
17	COAL	TON	574,560	575,433	570,753	445,810	556,207	572,380	3,295,143
18	GAS	MCF	10,126,900	9,836,561	7,481,495	7,000,023	5,749,794	5,183,092	45,377,865
19	NUCLEAR	MMBTU	5,981,281	5,981,281	5,788,337	5,523,038	385,954	4,052,512	27,712,403
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		5,044,555	6,018,624	5,812,030	4,774,977	3,885,580	3,072,321	28,608,087
22	LIGHT OIL		1,498,143	640,874	231,357	1,040,529	148,964	197,033	3,756,900
23	COAL		14,147,940	14,132,040	13,996,073	10,942,227	13,625,546	14,019,569	80,863,395
24	GAS		10,126,900	9,836,561	7,481,495	7,000,023	5,749,794	5,183,092	45,377,865
25	NUCLEAR		5,981,281	5,981,281	5,788,337	5,523,038	385,954	4,052,512	27,712,403
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	36,798,819	36,609,380	33,309,292	29,280,794	23,795,838	26,524,527	186,318,650
	GENERATION MIX (% MWH)								
28	HEAVY OIL		12.29%	14.67%	15.91%	15.49%	14.39%	10.32%	13.88%
29	LIGHT OIL		2.34%	0.96%	0.34%	2.35%	0.23%	0.30%	1.14%
30	COAL		37.52%	37.16%	41.03%	37.86%	54.14%	50.76%	42.25%
31	GAS		32.94%	32.42%	26.79%	26.24%	29.78%	24.70%	29.12%
32	NUCLEAR		14.92%	14.80%	15.93%	18.06%	1.45%	13.92%	13.62%
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	53.27	54.41	53.83	53.73	54.57	53.79	53.93
36	LIGHT OIL	$/BBL	95.94	90.81	89.90	97.94	98.87	99.72	95.56
37	COAL	$/TON	79.54	79.19	80.07	80.83	80.39	80.41	80.04
38	GAS	$/MCF	8.83	8.92	9.01	9.07	9.96	10.14	9.21
39	NUCLEAR	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		8.18	8.36	8.27	8.25	8.38	8.26	8.29
42	LIGHT OIL		16.55	15.67	15.51	16.90	17.06	17.21	16.49
43	COAL		3.23	3.23	3.27	3.29	3.28	3.28	3.26
44	GAS		8.84	8.92	9.01	9.07	9.96	10.14	9.21
45	NUCLEAR		0.37	0.37	0.37	0.37	0.37	0.37	0.37
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	5.53	5.35	5.01	5.42	5.77	4.86	5.32
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,613	10,513	10,416	10,446	10,358	10,422	10,468
49	LIGHT OIL		16,562	17,149	19,496	14,996	24,990	23,002	16,801
50	COAL		9,748	9,745	9,729	9,790	9,656	9,667	9,720
51	GAS		7,948	7,776	7,964	9,038	7,408	7,346	7,913
52	NUCLEAR		10,360	10,360	10,360	10,360	10,191	10,191	10,333
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,512	9,381	9,499	9,920	9,130	9,284	9,461
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		8.68	8.79	8.61	8.62	8.68	8.61	8.67
56	LIGHT OIL		27.41	26.87	30.24	25.34	42.63	39.58	27.70
57	COAL		3.15	3.14	3.18	3.22	3.17	3.17	3.17
58	GAS		7.02	6.94	7.17	8.20	7.38	7.45	7.29
59	NUCLEAR		0.38	0.38	0.38	0.38	0.38	0.37	0.38
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	5.26	5.02	4.76	5.37	5.26	4.51	5.03

SCHEDULE E4

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of Jul-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV UNIT	3	769	577,143	100.9	100.00	10,362	NUCLEAR	5,981,281 MMBTU	1.00	5,981,281	2,213,075	0.38
2 ANCLOTE	1	498	166,833	45.0	99.87	10,116	HEAVY OIL	282,346 BBLS	6.51	1,707,873	13,597,616	8.05
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	486	181,088	35.9	99.97	10,413	HEAVY OIL	209,691 BBLS	6.51	1,365,031	10,871,825	6.29
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	38,916	42.6	96.12	11,192	HEAVY OIL	65,875 BBLS	6.51	428,947	3,396,587	9.66
7 BARTOW	2	119	35,351	34.5	95.26	11,610	HEAVY OIL	55,093 BBLS	6.51	358,455	2,836,259	9.39
8 BARTOW	3	304	66,268	43.7	92.22	10,681	HEAVY OIL	108,724 BBLS	6.51	707,790	5,604,242	8.46
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	205,562	72.8	94.38	10,284	COAL	84,915 TONS	24.82	2,107,936	6,550,206	3.19
11 CRYSTAL RIVER	2	486	270,567	74.6	91.15	10,022	COAL	109,011 TONS	24.82	2,706,081	8,394,717	3.10
12 CRYSTAL RIVER	4	720	486,153	90.8	93.65	9,567	COAL	189,669 TONS	24.52	4,651,089	15,333,192	3.15
13 CRYSTAL RIVER	5	717	489,236	91.7	94.71	9,572	COAL	190,985 TONS	24.52	4,682,654	15,435,031	3.15
14 SUWANNEE	1	32	9,203	72.7	92.90	12,296	HEAVY OIL	17,382 BBLS	6.51	113,156	1,178,991	12.82
15 SUWANNEE	1		8,094			13,068	GAS	105,732 MCF	1.00	105,732	876,797	10.83
16 SUWANNEE	2	31	9,609	41.7	96.45	12,629	HEAVY OIL	18,494 BBLS	6.51	120,393	1,255,468	13.07
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	21,631	48.8	85.04	11,231	HEAVY OIL	37,319 BBLS	6.51	242,946	2,533,441	11.71
19 SUWANNEE	3		7,443			13,106	GAS	97,548 MCF	1.00	97,548	810,766	10.89
20 AVON PARK	1-2	52	411	1.1	96.61	15.3	LIGHT OIL	1,954 BBLS	5.79	11,323	182,846	44.49
21 AVON PARK	1-2		464			23,009	GAS	10,676 MCF	1.00	10,676	119,408	25.73
22 BARTOW	1-4	157	10,405	11.8	97.82	37.3	LIGHT OIL	34,684 BBLS	5.80	201,030	3,278,438	31.51
23 BARTOW	1-4		6,034			15,788	GAS	101,298 MCF	1.00	101,298	903,284	14.97
24 BAYBORO	1-4	184	23,453	17.1	98.87	66.0	LIGHT OIL	59,741 BBLS	5.80	346,256	5,646,814	24.08
25 DEBARY	1-10	667	19,510	10.9	98.68	80.5	LIGHT OIL	53,696 BBLS	5.80	310,637	5,103,324	27.15
26 DEBARY	1-10		35,039			13,572	GAS	475,526 MCF	1.00	475,526	4,320,414	12.33
27 HIGGINS	1-4	122	0	0.0	87.34	80.6	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		7,158			16,629	GAS	119,032 MCF	1.00	119,032	1,050,678	14.69
29 HINES	1-3	1,490	935,395	84.3	73.36	6,911	GAS	6,464,699 MCF	1.00	6,464,699	57,088,140	6.17
30 HINES	1-3		0			0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	655	22,595	10.4	92.14	64.6	LIGHT OIL	97,171 BBLS	5.80	563,569	9,603,269	24.97
32 INT CITY	1-14		128,672			12,618	GAS	1,600,906 MCF	1.00	1,600,906	13,858,015	10.91
33 RIO PINAR	1	15	381	3.3	99.68	81.4	LIGHT OIL	1,964 BBLS	5.80	7,909	128,649	33.77
34 SUWANNEE	1-3	164	6,034	5.4	99.46	22.7	LIGHT OIL	16,710 BBLS	5.80	96,852	1,710,364	28.18
35 SUWANNEE	1-3		0			0	GAS	0 MCF		0	0	0.00
36 TIGER BAY	*	227	115,293	74.9	93.87	8,415	GAS	954,899 MCF	1.00	954,899	7,534,906	6.54
37 TURNER	1-4	164	7,410	6.5	96.55	15.7	LIGHT OIL	25,735 BBLS	5.80	149,160	2,432,582	32.83
38 UNIV OF FLA	*	35	32,292	124.0	96.45	128.5	GAS	298,584 MCF	1.00	298,584	2,304,961	7.14
39 OTHER - START UP		-	0	-		-	LIGHT OIL	7,524 BBLS	5.80	43,609	712,152	0.00
40 OTHER												
41 TOTAL	8,533	4,859,575				9,612				36,795,819	233,460,456	6.26

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Aug-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	769	577,344	100.9	100.62	10.309	NUCLEAR	5,951,281 MMBTU	1.00	5,951,281	2,213,075	0.38
2 ANCLOTE	1	488	196,459	53.9	56.73	10,031	HEAVY OIL	301,766 BBLS	6.51	1,964,512	16,013,225	8.15
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	495	197,766	45.6	56.45	46.3	10,260	HEAVY OIL	264,919 BBLS	6.51	1,724,521	14,059,857	9.38
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	101	45,357	60.4	96.11	51.1	10,089	HEAVY OIL	76,569 BBLS	6.51	498,464	4,028,800	8.88
7 BARTOW	2	115	36,457	41.2	97.59	41.3	11,545	HEAVY OIL	64,670 BBLS	6.51	421,000	3,402,703	9.33
8 BARTOW	3	204	77,739	51.2	92.93	52.9	10,647	HEAVY OIL	125,943 BBLS	6.51	819,692	6,626,719	8.52
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	199,455	70.7	91.67	73.8	10,264	COAL	82,671 TONS	24.76	2,047,277	6,399,786	3.21
11 CRYSTAL RIVER	2	486	271,437	75.1	91.64	79.4	10,003	COAL	109,637 TONS	24.76	2,715,060	8,467,242	3.12
12 CRYSTAL RIVER	4	720	493,488	92.1	94.64	93.9	9,565	COAL	193,001 TONS	24.46	4,720,025	15,464,296	3.13
13 CRYSTAL RIVER	5	717	486,534	91.1	93.54	94.1	9,571	COAL	190,124 TONS	24.46	4,649,678	15,239,689	3.14
14 SUWANNEE	1	33	13,458	76.9	94.52	81.4	12,264	HEAVY OIL	25,415 BBLS	6.51	165,452	1,731,124	12.86
15 SUWANNEE	1		4,844			12,961	GAS	62,882 MCF	1.00	62,882	527,060	10.89
16 SUWANNEE	2	31	14,031	53.8	59.71	51.7	12,529	HEAVY OIL	27,003 BBLS	6.51	175,789	1,839,270	13.11
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	22,206	44.6	85.59	51.9	11,208	HEAVY OIL	38,233 BBLS	6.51	248,894	2,604,178	11.73
19 SUWANNEE	3		4,470			13,018	GAS	58,191 MCF	1.00	58,191	487,741	10.91
20 AVON PARK	1-2	58	125	0.3	98.48	6.5	28,904	LIGHT OIL	623 BBLS	5.80	3,613	55,757	44.61
21 AVON PARK	1-2		914			18,156	GAS	16,595 MCF	1.00	16,595	169,770	18.57
22 BARTOW	1-4	187	855	4.8	97.02	69.4	17,659	LIGHT OIL	2,620 BBLS	5.80	15,198	236,818	27.38
23 BARTOW	1-4		5,556			14,525	GAS	80,699 MCF	1.00	80,699	737,748	13.28
24 BAYBORO	1-4	164	5,270	3.6	97.98	69.4	14,780	LIGHT OIL	13,439 BBLS	5.80	77,859	1,214,477	23.05
25 DEBARY	1-10	667	17,681	8.9	99.03	50.7	15,648	LIGHT OIL	48,347 BBLS	5.80	280,216	4,369,179	24.71
26 DEBARY	1-10		26,474			19,306	GAS	362,271 MCF	1.00	362,271	3,320,741	12.54
27 HIGGINS	1-4	122	0	0.0	96.77	79.9	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		5,924			16,817	GAS	99,663 MCF	1.00	99,663	936,664	15.14
29 HINES	1-3	1,490	946,819	84.9	73.11	28.7	6,896	GAS	6,529,881 MCF	1.00	6,529,881	58,688,782	6.20
30 HINES	1-3		0			0	LIGHT OIL	0 BBLS		0	0	0	0.00
31 INT CITY	1-14	598	7,819	1.8	92.10	76.1	14,649	LIGHT OIL	19,520 BBLS	5.80	113,772	1,897,128	23.11
32 INT CITY	1-14		114,270			12,476	GAS	1,425,819 MCF	1.00	1,425,819	12,802,985	10.94
33 RIO PINAR	1	13	173	1.6	98.39	78.3	21,109	LIGHT OIL	631 BBLS	5.80	3,657	56,675	32.85
34 SUWANNEE	1-3	164	1,870	0.9	99.57	9.3	14,645	LIGHT OIL	2,704 BBLS	5.80	15,679	260,782	24.37
35 SUWANNEE	1-3		0			0	GAS	0 MCF		0	0	0	0.00
36 TIGER BAY	1	207	125,116	79.9	94.19	85.0	7,408	GAS	912,011 MCF	1.00	912,011	8,073,681	6.56
37 TURNER	1-4	154	4,016	3.6	97.96	13.1	21,313	LIGHT OIL	16,070 BBLS	5.80	93,137	1,452,231	33.25
38 UNIV OF FLA	1	35	32,509	124.8	97.10	128.0	9,193	GAS	298,529 MCF	1.00	298,529	2,342,106	7.20
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	6,522 BBLS	5.79	37,792	587,631	0.00
40 OTHER													
41 TOTAL	6,633	3,903,412				9,881				36,659,360	195,878,519	5.02

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of Sep-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	709	318,720	97.7	100.00	10,830	NUCLEAR	3,789,337 MMBTU	1.00	3,789,337	2,141,685	0.38
2 ANCLOTE	1	499	267,722	54.4	96.25	10,016	HEAVY OIL	310,353 BBLS	6.51	2,013,396	16,517,175	6.19
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	499	170,401	46.3	95.13	10,253	HEAVY OIL	268,431 BBLS	6.51	1,747,289	14,286,726	8.39
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	43,935	48.8	96.63	10,963	HEAVY OIL	74,157 BBLS	6.51	482,764	3,964,256	9.02
7 BARTOW	2	119	34,965	39.5	96.58	11,548	HEAVY OIL	62,024 BBLS	6.51	403,773	3,265,459	9.34
8 BARTOW	3	304	76,877	50.7	94.80	10,537	HEAVY OIL	124,427 BBLS	6.51	810,023	6,550,950	8.52
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	370	200,967	71.3	90.79	10,237	COAL	83,221 TONS	24.72	2,057,394	6,592,277	3.28
11 CRYSTAL RIVER	2	486	272,036	75.2	89.73	9,977	COAL	109,787 TONS	24.72	2,714,160	8,536,133	3.17
12 CRYSTAL RIVER	4	723	481,976	90.0	93.48	9,552	COAL	188,480 TONS	24.42	4,602,678	15,204,401	3.16
13 CRYSTAL RIVER	5	717	483,666	90.7	93.79	9,556	COAL	189,265 TONS	24.42	4,621,841	15,265,474	3.16
14 SUWANNEE	1	32	7,182	48.8	94.67	12,296	HEAVY OIL	13,528 BBLS	6.51	88,068	894,839	12.49
15 SUWANNEE	1		3,970			13,252	GAS	52,611 MCF	1.00	52,611	436,564	11.00
16 SUWANNEE	2	31	2,194	9.5	96.67	12,531	HEAVY OIL	4,223 BBLS	6.51	27,493	279,356	12.73
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	20,714	49.7	82.61	11,211	HEAVY OIL	35,672 BBLS	6.51	232,227	2,359,659	11.39
19 SUWANNEE	3		3,539			13,320	GAS	46,741 MCF	1.00	46,741	387,855	11.05
20 AVON PARK	1-2	52	141	0.4	94.67	9.4	28,617 LIGHT OIL	696 BBLS	5.80	4,035	61,976	43.95
21 AVON PARK	1-2		609			18,103	GAS	11,037 MCF	1.00	11,037	122,260	20.08
22 BARTOW	1-4	197	293	0.1	91.47	84.1	19,918 LIGHT OIL	1,007 BBLS	5.80	5,836	90,572	30.91
23 BARTOW	1-4		3,991			14,969	GAS	59,740 MCF	1.00	59,740	557,070	13.96
24 BAYBORO	1-4	184	1,340	1.0	98.53	84.7	15,449 LIGHT OIL	3,571 BBLS	5.80	20,701	321,271	23.98
25 DEBARY	1-10	867	5,258	0.8	98.57	75.0	14,806 LIGHT OIL	13,326 BBLS	5.80	77,237	1,191,969	22.54
26 DEBARY	1-10		23,432			13,363	GAS	313,118 MCF	1.00	313,118	2,966,341	12.66
27 HIGGINS	1-4	122	0	0.0	97.08	81.7	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		4,610			16,652	GAS	76,766 MCF	1.00	76,766	696,349	15.15
29 HINES	1-3	1,469	665,853	59.7	52.77	6.998	GAS	4,659,716 MCF	1.00	4,659,716	42,623,213	6.40
30 HINES	1-3		0			0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	899	3,285	14.4	91.98	74.6	14,610 LIGHT OIL	8,280 BBLS	5.80	47,995	746,636	22.80
32 INT CITY	1-14		92,964			12,589	GAS	1,170,368 MCF	1.00	1,170,368	10,263,621	11.04
33 RIO PINAR	1	13	182	1.7	100.00	77.9	20,914 LIGHT OIL	585 BBLS	5.79	3,388	52,446	32.37
34 SUWANNEE	1-3	164	337	0.3	99.56	3.7	15,273 LIGHT OIL	689 BBLS	5.80	5,147	84,166	24.98
35 SUWANNEE	1-3		0			0	GAS	0 MCF		0	0	0.00
36 TIGER BAY	1	207	109,109	70.8	95.33	9.267	GAS	903,754 MCF	1.00	903,754	7,036,909	6.51
37 TURNER	1-4	154	1,021	0.9	89.75	20.3	19,913 LIGHT OIL	3,232 BBLS	5.80	18,810	299,683	29.35
38 UNIV OF FLA	1	35	21,320	100.3	96.67	129.6	9,184 GAS	287,644 MCF	1.00	287,644	2,226,775	7.11
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	8,232 BBLS	5.80	47,708	737,866	0.00
40 OTHER												
41 TOTAL	8,919	3,506,551				9,499				33,309,292	166,868,381	4.76

SCHEDULE E4

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of Oct-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	A.H.R. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	766	533,112	93.2	90.32	10,360	NUCLEAR	5,523,036 MMBTU	1.00	5,523,036	2,043,525	0.38
2 ANCLOTE	1	466	61,767	16.7	28.06	9,994	HEAVY OIL	94,812 BBLS	6.51	617,229	5,016,562	8.12
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	466	206,519	56.1	98.91	10,162	HEAVY OIL	322,995 BBLS	6.51	2,102,703	17,049,095	8.26
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	53,764	56.4	97.37	10,871	HEAVY OIL	84,770 BBLS	6.51	551,850	4,575,123	8.51
7 BARTOW	2	119	37,280	42.1	96.38	11,447	HEAVY OIL	65,551 BBLS	6.51	426,738	3,537,879	9.49
8 BARTOW	3	304	85,586	56.4	94.02	10,476	HEAVY OIL	137,726 BBLS	6.51	896,594	7,433,229	8.69
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	222,896	79.0	93.73	10,212	COAL	92,182 TONS	24.69	2,276,169	7,298,142	3.27
11 CRYSTAL RIVER	2	486	294,838	81.5	90.20	9,956	COAL	116,877 TONS	24.69	2,885,318	9,356,665	3.17
12 CRYSTAL RIVER	4	720	360,850	67.4	65.90	9,551	COAL	141,180 TONS	24.41	3,446,481	11,647,173	3.20
13 CRYSTAL RIVER	5	717	239,071	44.8	40.76	9,556	COAL	93,571 TONS	24.41	2,284,259	7,833,874	3.28
14 SUWANNEE	1	32	3,624	53.4	93.57	209.0	12,295	HEAVY OIL	6,845 BBLS	6.51	44,556	445,714
15 SUWANNEE	1		9,093			12,959	GAS	117,708 MCF	1.00	117,708	978,581	10.77
16 SUWANNEE	2	31	4,381	19.0	98.57	61.4	12,528	HEAVY OIL	8,431 BBLS	6.51	54,867	549,036	12.53
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	60	7,191	26.4	86.67	96.5	11,183	HEAVY OIL	12,353 BBLS	6.51	80,418	804,421	11.19
19 SUWANNEE	3		8,519			12,961	GAS	110,582 MCF	1.00	110,582	919,338	10.79
20 AVON PARK	1-2	62	374	1.0	93.87	8.6	21,521	LIGHT OIL	1,369 BBLS	5.79	8,049	132,800	35.51
21 AVON PARK	1-2		2,283			17,493	GAS	39,937 MCF	1.00	39,937	352,697	15.89
22 BARTOW	1-4	187	3,681	10.9	71.53	56.9	17,929	LIGHT OIL	12,006 BBLS	5.80	69,584	1,159,193	29.87
23 BARTOW	1-4		11,231			14,647	GAS	164,506 MCF	1.00	164,506	1,428,992	12.72
24 BAYBORO	1-4	184	6,695	4.9	98.87	74.6	14,345	LIGHT OIL	16,570 BBLS	5.80	96,042	1,599,954	23.90
25 DEBARY	1-10	667	24,964	13.8	98.74	71.2	14,066	LIGHT OIL	60,584 BBLS	5.80	351,141	5,973,612	23.53
26 DEBARY	1-10		43,709			13,159	GAS	576,469 MCF	1.00	576,469	5,160,652	11.81
27 HIGGINS	1-4	102	0	0.0	97.10	85.2	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		14,440			16,279	GAS	235,062 MCF	1.00	235,062	2,015,567	13.96
29 HINES	1-3	1,469	409,043	56.7	30.03	27.2	7,163	GAS	2,929,929 MCF	1.00	2,929,929	28,315,429	6.92
30 HINES	1-3		0			0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	899	24,750	29.8	95.76	71.9	13,368	LIGHT OIL	57,040 BBLS	5.80	330,832	5,662,963	22.88
32 INT CITY	1-14		147,662			12,676	GAS	1,961,492 MCF	1.00	1,961,492	16,027,917	10.85
33 RIO PINAR	1	19	427	4.4	99.35	82.1	20,962	LIGHT OIL	1,515 BBLS	5.80	8,786	145,914	34.17
34 SUWANNEE	1-3	161	4,461	3.7	99.89	17.5	13,879	LIGHT OIL	10,682 BBLS	5.80	61,914	1,106,976	24.81
35 SUWANNEE	1-3		0			0	GAS	0 MCF		0	0	0.00
36 TIGER BAY	1	207	117,939	76.5	87.02	92.3	7,349	GAS	866,998 MCF	1.00	866,998	7,629,040	6.47
37 TURNER	1-4	154	3,635	3.3	72.98	93.1	16,909	LIGHT OIL	10,653 BBLS	5.80	61,740	1,028,521	28.82
38 UNIV OF FLA	1	33	10,642	41.1	31.26	126.4	9,196	GAS	98,349 MCF	1.00	98,349	657,479	6.15
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	9,089 BBLS	5.80	52,677	873,436	0.00
40 OTHER													
41 TOTAL	6,835	2,951,759				9,920				29,280,794	156,570,080	5.37

SCHEDULE E4

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Nov-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	A.O. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS R V NUC	3	788	37.872	6.5	6.67	10,191	NUCLEAR	385,954 MMBTU	1.00	385,954	142,603	0.38
2 ANCLOTE	1	522	153,044	39.4	95.45	10,045	HEAVY OIL	236,147 BBLS	6.51	1,537,319	12,974,466	8.48
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	522	126,966	32.7	95.62	10,367	HEAVY OIL	201,987 BBLS	6.51	1,314,934	11,100,036	8.74
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	123	25,979	28.4	95.97	10,940	HEAVY OIL	43,656 BBLS	6.51	284,200	2,336,207	8.99
7 BARTOW	2	121	19,265	21.4	96.12	11,507	HEAVY OIL	34,318 BBLS	6.51	223,409	1,836,488	9.53
8 BARTOW	3	208	49,586	32.2	94.28	10,639	HEAVY OIL	80,755 BBLS	6.51	525,716	4,321,566	8.66
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	383	196,251	68.9	92.60	10,231	COAL	81,397 TONS	24.87	2,038,225	6,473,412	3.30
11 CRYSTAL RIVER	2	491	264,978	72.5	91.43	9,934	COAL	105,689 TONS	24.87	2,632,243	8,426,966	3.18
12 CRYSTAL RIVER	4	735	484,657	85.6	96.14	9,446	COAL	187,555 TONS	24.41	4,577,831	15,180,146	3.13
13 CRYSTAL RIVER	5	732	465,143	85.4	92.59	9,475	COAL	180,556 TONS	24.41	4,407,244	14,634,440	3.15
14 SUWANNEE	1	33	0	0.0	100.00	0.0	HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		1,393			14,053	GAS	19,576 MCF	1.00	19,576	176,869	12.70
16 SUWANNEE	2	32	0	0.0	100.00	0.0	HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	81	0	0.0	100.00	0.0	HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		1,100			14,521	GAS	15,973 MCF	1.00	15,973	144,316	13.12
20 AVON PARK	1-2	64	41	0.1	95.17	53,659	LIGHT OIL	380 BBLS	5.79	2,200	36,847	89.87
21 AVON PARK	1-2		101			31,971	GAS	3,219 MCF	1.00	3,219	59,759	59.17
22 BARTOW	1-4	219	318	0.5	97.16	20,579	LIGHT OIL	1,129 BBLS	5.80	6,544	110,851	34.80
23 BARTOW	1-4		547			20,459	GAS	11,190 MCF	1.00	11,190	162,361	29.68
24 BAYBORO	1-4	232	1,026	0.6	98.76	18,197	LIGHT OIL	3,221 BBLS	5.79	18,660	315,518	30.75
25 DEBARY	1-10	762	1,358	1.0	98.77	14,945	LIGHT OIL	4,436 BBLS	5.80	25,727	435,955	32.10
26 DEBARY	1-10		4,476			15,084	GAS	67,514 MCF	1.00	67,514	978,089	21.85
27 HIGGINS	1-4	134	0	0.0	97.00	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		656			24,419	GAS	16,019 MCF	1.00	16,019	206,080	31.41
29 HINES	1-3	1,687	648,470	51.7	92.00	7,009	GAS	4,545,409 MCF	1.00	4,545,409	45,024,920	6.94
30 HINES	1-3		0			0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,220	1,872	0.2	92.29	44.4	16,300	LIGHT OIL	5,265 BBLS	5.80	30,514	527,586	28.18
32 INT CITY	1-14		21,115			13,476	GAS	284,546 MCF	1.00	284,546	3,123,026	14.79
33 RIO PINAR	1	16	126	1.1	98.67	69.6	14,360	LIGHT OIL	527 BBLS	5.80	3,057	51,568	40.93
34 SUWANNEE	1-3	251	727	0.5	99.22	19.3	17,171	LIGHT OIL	2,302 BBLS	5.80	13,342	240,889	33.08
35 SUWANNEE	1-3		0			0	GAS	0 MCF		0	0	0.00
36 TIGER BAY	1	223	64,248	38.7	52.78	97.0	7,419	GAS	476,631 MCF	1.00	476,631	4,735,809	7.37
37 TURNER	1-4	184	443	0.3	73.08	29.5	18,296	LIGHT OIL	1,398 BBLS	5.80	8,105	137,045	30.94
38 UNIV OF FLA	1	47	34,099	111.5	98.67	117.1	9,083	GAS	309,727 MCF	1.00	309,727	2,638,298	7.74
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	7,043 BBLS	5.80	40,815	685,495	0.00
40 OTHER												
41 TOTAL	9,750	2,606,235				9,130				23,795,836	187,216,204	5.26

SCHEDULE E4

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of Dec-07

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	788	337,656	57.8	57.74	100.1	10,197	NUCLEAR	4,658,512 MMBTU	1.00	4,658,512	1,483,219	0.37
2 ANCLOTE	1	522	131,382	33.8	95.08	36.5	10,114	HEAVY OIL	204,114 BBLS	6.51	1,328,782	11,086,016	8.44
3 ANCLOTE	1		0				0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	522	67,147	27.6	95.17	27.6	10,516	HEAVY OIL	173,084 BBLS	6.51	1,126,760	9,403,249	8.78
5 ANCLOTE	2		0				0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	123	11,964	13.0	95.74	39.5	11,060	HEAVY OIL	20,157 BBLS	6.51	131,220	1,041,624	8.78
7 BARTOW	2	121	12,636	14.3	97.16	32.9	11,636	HEAVY OIL	23,584 BBLS	6.51	147,019	1,167,037	9.24
8 BARTOW	3	208	31,770	20.5	94.06	39.3	10,655	HEAVY OIL	52,000 BBLS	6.51	338,520	2,687,172	8.46
9 BARTOW	3		0				0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	383	205,991	72.3	89.56	76.5	10,209	COAL	85,292 TONS	24.66	2,102,950	6,784,518	3.29
11 CRYSTAL RIVER	2	491	285,771	78.2	93.30	81.1	9,925	COAL	115,035 TONS	24.66	2,836,301	9,084,307	3.18
12 CRYSTAL RIVER	4	736	486,410	88.9	94.09	91.0	9,469	COAL	165,521 TONS	24.41	4,601,035	15,272,782	3.14
13 CRYSTAL RIVER	5	732	472,128	86.7	91.55	91.1	9,487	COAL	163,522 TONS	24.41	4,479,283	14,882,610	3.15
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		873				14,796	GAS	12,917 MCF	1.00	12,917	117,716	13.48
16 SUWANNEE	2	32	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	81	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		733				15,067	GAS	11,037 MCF	1.00	11,037	100,583	13.72
20 AVON PARK	1-2	64	36	0.1	95.81	6.3	44,856	LIGHT OIL	277 BBLS	5.79	1,604	27,072	75.20
21 AVON PARK	1-2		76				47,643	GAS	3,335 MCF	1.00	3,335	61,068	87.24
22 BARTOW	1-4	219	309	0.5	97.98	29.5	20,683	LIGHT OIL	1,103 BBLS	5.79	6,391	108,689	35.24
23 BARTOW	1-4		546				20,410	GAS	11,144 MCF	1.00	11,144	162,907	29.84
24 BAYBORO	1-4	232	1,598	0.9	99.11	52.7	15,122	LIGHT OIL	4,965 BBLS	5.80	28,777	490,300	30.68
25 DEBARY	1-10	762	1,585	0.6	99.03	33.3	19,673	LIGHT OIL	5,107 BBLS	5.80	29,599	505,665	31.92
26 DEBARY	1-10		1,745				18,410	GAS	32,125 MCF	1.00	32,125	660,863	37.87
27 HIGGINS	1-4	134	0	0.0	97.25	27.8	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		587				29,518	GAS	17,386 MCF	1.00	17,386	219,791	37.44
29 HINES	1-4	1,687	587,140	46.6	99.69	23.6	7,022	GAS	4,123,015 MCF	1.00	4,123,015	41,531,034	7.07
30 HINES	1-4		0				0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,206	3,307	1.9	96.62	30.2	16,109	LIGHT OIL	9,191 BBLS	5.80	53,274	930,685	28.15
32 INT CITY	1-14		8,057				16,500	GAS	127,792 MCF	1.00	127,792	1,716,751	21.30
33 RIO PINAR	1	18	41	0.3	99.03	64.1	24,749	LIGHT OIL	170 BBLS	5.80	986	16,760	40.86
34 SUWANNEE	1-3	201	711	0.5	99.69	16.1	17,048	LIGHT OIL	2,091 BBLS	5.80	12,121	220,897	31.07
35 SUWANNEE	1-3		0				0	GAS	0 MCF		0	0	0.00
36 TIGER BAY	1	223	70,461	42.7	91.94	69.0	7,426	GAS	526,207 MCF	1.00	526,207	5,224,693	7.37
37 TURNER	1-4	154	969	0.7	91.26	42.8	16,591	LIGHT OIL	2,821 BBLS	5.80	16,349	278,552	28.77
38 UNIV OF FLA	1	41	35,021	114.8	98.05	117.0	9,084	GAS	318,134 MCF	1.00	318,134	2,736,143	7.82
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	8,271 BBLS	5.80	47,935	610,765	0.00
40 OTHER													
41 TOTAL	9,750	2,868,934				9,284					26,624,827	128,617,478	4.51

Progress Energy Florida
Inventory Analysis
Estimated for the Period of : July Through December 2007

	HEAVY OIL		Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
1	PURCHASES								
2	UNITS	BBL	774,894	924,520	892,785	733,484	596,863	471,939	4,394,485
3	UNIT COST	$/BBL	53.27	54.41	53.83	53.73	54.57	53.79	53.93
4	AMOUNT	$	41,276,418	50,305,876	48,058,452	39,411,638	32,568,775	25,385,098	237,006,257
5	BURNED								
6	UNITS	BBL	774,894	924,520	892,785	733,484	596,863	471,939	4,394,485
7	UNIT COST	$/BBL	53.27	54.41	53.83	53.73	54.57	53.79	53.93
8	AMOUNT	$	41,276,418	50,305,876	48,058,452	39,411,638	32,568,775	25,385,098	237,006,257
9	ENDING INVENTORY								
10	UNITS	BBL	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	
11	UNIT COST	$/BBL	53.27	54.41	53.83	53.73	54.57	53.79	
12	AMOUNT	$	58,593,920	59,854,300	59,212,780	59,105,310	60,023,260	59,167,790	
	LIGHT OIL								
13	PURCHASES								
14	UNITS	BBL	258,478	110,576	39,917	179,528	25,703	33,996	648,198
15	UNIT COST	$/BBL	95.94	90.81	89.90	97.94	98.87	99.72	95.56
16	AMOUNT	$	24,798,458	10,040,877	3,588,724	17,583,371	2,541,244	3,389,995	61,942,669
17	BURNED								
18	UNITS	BBL	258,478	110,576	39,917	179,528	25,703	33,996	648,198
19	UNIT COST	$/BBL	95.94	90.81	89.90	97.94	98.87	99.72	95.56
20	AMOUNT	$	24,798,458	10,040,877	3,588,724	17,583,371	2,541,244	3,389,995	61,942,669
21	ENDING INVENTORY								
22	UNITS	BBL	883,900	883,900	883,900	883,900	883,900	883,900	
23	UNIT COST	$/BBL	95.94	90.81	89.90	97.94	98.87	99.72	
24	AMOUNT	$	84,801,360	80,265,959	79,462,619	86,569,166	87,391,193	88,142,508	
	COAL								
25	PURCHASES								
26	UNITS	TON	574,560	575,433	570,753	445,810	556,207	572,380	3,295,143
27	UNIT COST	$/TON	79.54	79.19	80.07	80.83	80.39	80.41	80.04
28	AMOUNT	$	45,703,145	45,571,186	45,698,309	36,035,848	44,713,991	46,024,389	263,746,859
29	BURNED								
30	UNITS	TON	574,560	575,433	570,753	445,810	556,207	572,380	3,295,143
31	UNIT COST	$/TON	79.54	79.19	80.07	80.83	80.39	80.41	80.04
32	AMOUNT	$	45,703,146	45,571,213	45,698,285	36,035,854	44,713,955	46,024,417	263,746,870
33	ENDING INVENTORY								
34	UNITS	TON	768,000	768,000	768,000	768,000	768,000	768,000	
35	UNIT COST	$/TON	79.54	79.19	80.07	80.83	80.39	80.41	
36	AMOUNT	$	61,090,253	60,821,453	61,491,226	62,079,206	61,740,211	61,753,956	
	GAS								
37	BURNED								
38	UNITS	MCF	10,126,900	9,836,561	7,481,495	7,000,023	5,749,794	5,183,092	45,377,865
39	UNIT COST	$/MCF	8.83	8.92	9.01	9.07	9.96	10.14	9.21
40	AMOUNT	$	89,469,359	87,747,478	67,381,217	63,495,692	57,249,427	52,534,749	417,877,920
	NUCLEAR								
41	BURNED								
42	UNITS	MMBTU	5,981,281	5,981,281	5,788,337	5,523,038	385,954	4,052,512	27,712,403
43	UNIT COST	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
44	AMOUNT	$	2,213,075	2,213,075	2,141,685	2,043,525	142,803	1,483,219	10,237,382

Progress Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : July Through December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jul-07	ECONSALE	--	40,947		40,947	5.195	5.870	2,127,047	2,403,563	276,516
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	293,452		293,452	5.108	5.108	14,990,576	14,990,576	0
	TOTAL		334,399		334,399	5.119	5.202	17,117,623	17,394,139	276,516
Aug-07	ECONSALE	--	45,624		45,624	5.467	6.178	2,494,305	2,818,565	324,260
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	319,719		319,719	5.594	5.594	17,884,775	17,884,775	0
	TOTAL		365,343		365,343	5.578	5.667	20,379,080	20,703,340	324,260
Sep-07	ECONSALE	--	28,603		28,603	4.676	5.284	1,337,381	1,511,241	173,860
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	326,566		326,566	5.798	5.798	18,932,683	18,932,683	0
	TOTAL		355,169		355,169	5.707	5.756	20,270,064	20,443,924	173,860
Oct-07	ECONSALE	--	22,158		22,158	5.707	6.449	1,264,537	1,428,927	164,390
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	330,816		330,816	5.817	5.817	19,244,081	19,244,081	0
	TOTAL		352,974		352,974	5.810	5.857	20,508,618	20,673,008	164,390
Nov-07	ECONSALE	--	32,730		32,730	6.847	7.737	2,240,963	2,532,288	291,325
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	274,630		274,630	5.670	5.670	15,571,740	15,571,740	0
	TOTAL		307,360		307,360	5.795	5.890	17,812,703	18,104,028	291,325
Dec-07	ECONSALE	--	41,882		41,882	7.777	8.788	3,257,025	3,680,439	423,414
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	(130,331)	(130,331)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	196,468		196,468	4.533	4.533	8,906,417	8,906,417	0
	TOTAL		238,350		238,350	5.103	5.226	12,163,442	12,456,525	293,083
Jul-07	ECONSALE	--	211,944		211,944	6.002	6.782	12,721,258	14,375,023	1,653,765
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-07	EXCESS GAIN*20%	--	0		0	0.000	0.000	0	(130,331)	(130,331)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,741,651		1,741,651	5.485	5.485	95,530,272	95,530,272	0
	TOTAL		1,953,595		1,953,595	5.541	5.619	108,251,530	109,774,964	1,523,434

Progress Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : July Through December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jul-07	C P & LIME	--	95,122			95,122	3.232	3.232	3,074,331
	TECO	--	30,878			30,878	5.793	5.793	1,788,818
	SOUTHERN	UPS	296,856			296,856	2.340	2.340	6,946,490
	SHADY HILLS	--	98,158			98,158	10.225	10.225	10,037,130
	RELIANT	--	44,647			44,647	10.149	10.149	4,531,249
	TEA	--	60			60	12.375	12.375	7,425
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		565,721	0	0	565,721	4.664	4.664	26,385,383
Aug-07	C P & LIME	--	92,249			92,249	3.232	3.232	2,981,482
	TECO	--	31,276			31,276	5.791	5.791	1,811,038
	SOUTHERN	UPS	296,856			296,856	2.344	2.344	6,958,305
	SHADY HILLS	--	119,457			119,457	10.184	10.184	12,165,329
	RELIANT	--	49,615			49,615	10.068	10.068	4,995,128
	TEA	--	60			60	12.635	12.635	7,581
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		589,513	0	0	589,513	4.906	4.906	28,918,863
Sep-07	C P & LIME	--	90,972			90,972	3.232	3.232	2,940,216
	TECO	--	29,798			29,798	5.801	5.801	1,728,544
	SOUTHERN	UPS	287,280			287,280	2.362	2.362	6,785,552
	SHADY HILLS	--	78,023			78,023	10.276	10.276	8,017,746
	RELIANT	--	35,160			35,160	10.094	10.094	3,549,168
	TEA	--	120			120	12.533	12.533	15,039
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		521,353	0	0	521,353	4.419	4.419	23,036,265
Oct-07	C P & LIME	--	41,815			41,815	3.232	3.232	1,351,467
	TECO	--	31,022			31,022	5.792	5.792	1,796,820
	SOUTHERN	UPS	296,856			296,856	2.390	2.390	7,094,858
	SHADY HILLS	--	156,494			156,494	9.555	9.555	14,952,711
	RELIANT	--	23,516			23,516	10.199	10.199	2,398,297
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		549,703	0	0	549,703	5.020	5.020	27,594,153
Nov-07	C P & LIME	--	51,391			51,391	3.232	3.232	1,660,964
	TECO	--	29,507			29,507	5.803	5.803	1,712,329
	SOUTHERN	UPS	287,280			287,280	2.411	2.411	6,926,321
	SHADY HILLS	--	23,178			23,178	13.276	13.276	3,077,111
	RELIANT	--	3,476			3,476	16.059	16.059	557,901
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		394,832	0	0	394,832	3.529	3.529	13,934,626
Dec-07	C P & LIME	--	95,441			95,441	3.232	3.232	3,084,648
	TECO	--	31,259			31,259	5.791	5.791	1,810,089
	SOUTHERN	UPS	296,856			296,856	2.458	2.458	7,296,721
	SHADY HILLS	--	9,821			9,821	18.451	18.451	1,812,045
	RELIANT	--	2,447			2,447	19.810	19.810	484,759
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		435,824	0	0	435,824	3.324	3.324	14,488,262
Jul-07	C P & LIME	--	466,990			466,990	3.232	3.232	15,093,108
thru	TECO	--	183,740			183,740	5.795	5.795	10,647,638
Dec-07	SOUTHERN	UPS	1,761,984			1,761,984	2.384	2.384	42,008,187
	SHADY HILLS	--	485,131			485,131	10.319	10.319	50,062,072
	RELIANT	--	158,861			158,861	10.397	10.397	16,516,502
	TEA	--	240			240	12.519	12.519	30,045
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		3,056,946	0	0	3,056,946	4.395	4.395	134,357,552

SCHEDULE E-8

Progress Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : July Through December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jul-07	QUAL. FACILITIES	COGEN	383,228			383,228	3.453	11.816	13,232,522
Aug-07	QUAL. FACILITIES	COGEN	382,598			382,598	3.465	11.829	13,258,645
Sep-07	QUAL. FACILITIES	COGEN	364,497			364,497	3.447	11.810	12,563,734
Oct-07	QUAL. FACILITIES	COGEN	354,964			354,964	3.435	11.799	12,193,901
Nov-07	QUAL. FACILITIES	COGEN	376,565			376,565	3.420	11.783	12,877,074
Dec-07	QUAL. FACILITIES	COGEN	404,574			404,574	3.434	11.797	13,892,314
TOTAL	QUAL. FACILITIES	COGEN	2,266,426			2,266,426	3.442	11.806	78,018,190

Progress Energy Florida
Economy Energy Purchases
Estimated for the Period of : July Through December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (B)-(7)
Jul-07	ECONPURCH	--	32,875	7.403	7.403	2,433,614	11.733	3,857,089	1,423,475
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,427	4.554	4.554	429,340	4.554	429,340	0
	TOTAL		42,302	6.768	6.768	2,862,954	10.133	4,286,429	1,423,475
Aug-07	ECONPURCH	--	48,735	8.326	8.326	4,057,539	12.517	6,099,974	2,042,435
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,427	4.554	4.554	429,340	4.554	429,340	0
	TOTAL		58,162	7.714	7.714	4,486,879	11.226	6,529,314	2,042,435
Sep-07	ECONPURCH	--	48,162	7.176	7.176	3,456,241	9.946	4,790,355	1,334,114
	OTHER		0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,123	4.554	4.554	415,490	4.554	415,490	0
	TOTAL		57,285	6.759	6.759	3,871,731	9.088	5,205,845	1,334,114
Oct-07	ECONPURCH	--	79,447	7.793	7.793	6,191,009	12.895	10,245,053	4,054,044
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,427	4.554	4.554	429,340	4.554	429,340	0
	TOTAL		88,874	7.449	7.449	6,620,349	12.011	10,674,393	4,054,044
Nov-07	ECONPURCH	--	49,140	7.094	7.094	3,485,869	12.882	6,330,200	2,844,331
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,123	4.554	4.554	415,490	4.554	415,490	0
	TOTAL		58,263	6.696	6.696	3,901,359	11.578	6,745,690	2,844,331
Dec-07	ECONPURCH		42,381	6.472	6.472	2,742,847	9.596	4,066,773	1,323,926
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	9,427	4.554	4.554	429,340	4.554	429,340	0
	TOTAL		51,808	6.123	6.123	3,172,187	8.678	4,496,113	1,323,926
Jul-07	ECONPURCH	--	300,740	7.437	7.437	22,367,119	11.767	35,389,444	13,022,325
THRU	OTHER	--	0	0.000	0.000	0	0.000	0	0
Dec-07	OTHER	--	55,954	4554.348	4554.348	2,548,340	4554.348	2,548,340	0
	TOTAL		356,694	6.985	6.985	24,915,459	10.636	37,937,784	13,022,325

EXHIBITS TO THE TESTIMONY OF LORI CROSS

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2007

PART A - CAPACITY COST RECOVERY CALCULATIONS

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Estimated/Actual True-up
For the Year 2007

Docket 070001
Witness: L. Cross
Part A
Page 1 of 2

		ACTUAL Jan-07	ACTUAL Feb-07	ACTUAL Mar-07	ACTUAL Apr-07	ACTUAL May-07	ACTUAL Jun-07	ESTIMATED Jul-07	ESTIMATED Aug-07	ESTIMATED Sep-07	ESTIMATED Oct-07	ESTIMATED Nov-07	ESTIMATED Dec-07	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	535,840	603,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	6,838,080
2	Auburndale Power Partners, L.P. (AUBSET)	2,549,254	2,810,603	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	32,159,137
3	Bay County (BAYCOUNT)	263,780	(263,780)	0	0	0	0	0	0	0	0	0	0	-
4	Cargill Fertilizer, Inc. (CARGILLF)	528,300	582,000	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	6,661,800
5	Jefferson Power L.C. (JEFFPOWR)	0	0	0	0	0	0	0	0	0	0	0	0	-
6	Lake County (LAKCOUNT)	502,476	568,228	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	6,412,236
7	Lake Cogen Limited (LAKORDER)	2,064,851	2,934,217	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	33,593,208
8	Metro-Dade County (METRDADE)	988,860	1,091,340	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	12,487,200
9	Orange Cogen (ORANGECO)	2,276,516	2,592,986	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	28,677,024
10	Orlando Cogen Limited (ORLACOGL)	2,032,631	2,241,015	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	25,641,876
11	Orlando Cogen Limited (ORLCOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	-
12	Pasco Cogen Limited (PASCOGSL)	3,166,384	3,485,505	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	39,911,339
13	Pasco County Resource Recovery (PASCOUNT)	906,430	1,021,430	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	11,567,160
14	Pinellas County Resource Recovery (PINCOUNT)	2,157,698	2,431,446	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	27,534,876
15	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	3,832,935	4,224,590	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	48,345,155
16	U S Agri-Chemicals (AGRICHEM)	0	0	0	0	0	0	0	0	0	0	0	0	-
17	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,352
18	Cargill Power Market	0	0	0	0	0	600,000	(600,000)	0	0	0	0	0	
19	Central Power & Lime (133 MW)	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	16,295,160
20	UPS Purchase (414 total mw) - Southern	4,889,449	4,989,915	3,202,476	4,684,602	3,720,148	3,659,218	4,618,000	4,735,000	4,628,000	4,667,000	4,607,000	4,727,000	53,147,808
21	Incremental Security	13,977	72,049	42,116	302,628	109,301	63,713	341,573	50,571	23,561	871,087	89,658	871,087	2,861,351
22	Subtotal - Base Level Capacity Charges	29,469,089	31,452,265	28,722,580	30,465,198	29,307,417	29,800,888	29,837,540	30,263,538	30,129,528	31,036,054	30,164,655	31,076,054	361,744,762
23	Base Production Jurisdictional Responsibility	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	
24	Base Level Jurisdictional Capacity Charges	27,628,127	29,487,441	26,928,261	28,562,036	27,476,582	27,939,236	27,973,589	28,372,975	28,247,336	29,097,232	28,299,019	29,134,733	339,146,567
	Intermediate Production Level Capacity Charges:													
25	TECO Power Purchase (70 mw)	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
26	Schedule H Capacity Sales	(4,601)	(4,156)	(4,601)	(4,453)	(138,817)	(4,350)	(4,601)	(4,601)	(4,453)	(4,453)	(4,453)	(4,453)	(187,691)
27	Subtotal - Intermediate Level Capacity Charges	655,166	655,611	655,166	655,314	520,950	655,417	655,166	655,166	655,314	655,314	655,314	655,314	7,729,513
28	Intermediate Production Jurisdict. Responsibility	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	
29	Intermediate Level Jurisdict. Capacity Charges	517,883	518,234	517,883	518,000	411,791	518,318	517,882	517,882	518,000	518,000	518,000	518,000	6,109,872
	Peaking Production Level Capacity Charges:													
30	Chattahoochee	12,500	11,636	13,364	12,231	12,368	12,630	12,630	12,630	12,630	12,630	12,630	12,630	150,507
31	Osceola	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	606,720	606,720	606,720	12,741,120
32	TEA	200,000	200,000	0	0	0	262,500	725,000	725,000	725,000	0	0	0	2,837,500
33	Shady Hills	0	0	0	2,300,650	965,756	3,873,623	4,187,700	4,187,700	1,954,260	1,395,900	1,395,900	1,954,260	22,215,749
34	Cargill	0	0	0	0	0	0	1,200,000	800,000	600,000	0	0	0	2,400,000
35	Summer Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Other Capacity Purchases	862,500	862,500	0	0	0	250,000	0	0	0	0	0	0	1,975,000
37	Subtotal - Peaking Level Capacity Charges	2,288,440	2,287,576	1,226,804	3,526,321	2,191,562	5,612,193	7,338,770	6,738,770	4,505,330	2,015,250	2,015,250	2,573,610	42,319,876
38	Peaking Production Jurisdictional Responsibility	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	
39	Peaking Level Jurisdictional Capacity Charges	2,036,231	2,035,462	1,091,598	3,137,685	1,950,030	4,993,873	6,529,964	5,996,090	4,008,798	1,793,149	1,793,149	2,289,972	37,655,802
	Other Capacity Charges:													
40	Retail Wheeling	(51,197)	(201,993)	(58,718)	(52,917)	(30,001)	(35,237)	(34,486)	(36,426)	(24,090)	(23,996)	(35,445)	(45,356)	(631,863)
41	Total Jurisdictional Capacity Payments	39,131,043	31,839,145	28,479,925	32,164,805	29,868,401	33,415,960	34,980,949	34,848,522	32,750,043	31,384,385	30,574,723	31,897,349	382,280,380
42	Capacity Cost Recovery Revenues (net of tax)	26,198,026	27,708,712	26,486,291	26,720,510	28,782,502	32,302,594	37,759,785	38,710,476	38,878,353	34,051,004	29,615,936	29,795,174	377,211,364
43	Prior Period True-Up Provision	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(5,380,565)
44	Current Period Revenues (net of tax) (line 42 + 43)	25,749,646	27,260,332	26,039,911	26,272,130	28,334,122	31,854,214	37,311,405	38,262,098	38,429,973	33,602,624	29,367,556	29,346,794	371,830,799
	True-Up Provision													
45	True-Up Provision - Over/(Under) Recov (line 44 - 41)	(4,381,398)	(4,578,814)	(2,439,114)	(5,892,675)	(1,474,279)	(1,561,777)	2,324,456	3,413,575	5,679,929	2,218,239	(1,207,167)	(2,550,556)	(10,449,581)
46	Interest Provision for the Month	(47,079)	(64,858)	(76,548)	(95,175)	(109,761)	(115,189)	(112,053)	(97,981)	(76,483)	(57,513)	(53,578)	(60,093)	(968,311)
47	Current Cycle Balance - Over/(Under) (line 45 + 46)	(4,428,477)	(9,072,148)	(11,589,811)	(17,577,661)	(19,161,690)	(20,838,656)	(18,626,253)	(15,310,659)	(9,707,212)	(7,546,487)	(8,807,232)	(11,417,881)	(11,417,892)
48	Plus: Prior Period Balance	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)
49	Plus: Cumulative True-up Provision	448,380	896,761	1,345,141	1,793,522	2,241,902	2,690,282	3,138,663	3,587,043	4,035,423	4,483,804	4,932,184	5,380,565	5,380,565
50	Net True-up Over/(Under) (lines 47 through 49)	(12,742,633)	(16,937,924)	(19,007,206)	(24,546,676)	(25,680,335)	(26,910,910)	(24,250,127)	(20,486,152)	(14,434,325)	(11,825,220)	(12,637,584)	(14,799,853)	(14,799,865)

Contract Data:

Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
Auburndale Power Partners, L.P. (AUBRDLFC)	Jan-95	Dec-13	QF	Purch	17.00
Auburndale Power Partners, L.P. (AUBSET)	Aug-94	Dec-13	QF	Purch	114.18
Bay County (BAYCOUNT)	Jan-95	Dec-06	QF	Purch	11.00
Cargill Fertilizer, Inc. (CARGILLF)	Sep-92	Dec-07	QF	Purch	15.00
Jefferson Power L.C. (JEFFPOWER)	Jul-02	Sep-06	QF	Purch	2.00
Lake County (LAKCOUNT)	Jan-95	Jun-14	QF	Purch	12.75
Lake Cogen Limited (LAKORDER)	Jul-93	Jul-13	QF	Purch	110.00
Metro-Dade County (METRDADE)	Nov-91	Nov-13	QF	Purch	43.00
Orange Cogen (ORANGECO)	Jul-95	Dec-24	QF	Purch	74.00
Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	79.20
Pasco Cogen Limited (PASCOGL)	Jul-93	Dec-08	QF	Purch	109.00
Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
Polk Power Partners, L.P. (MULBERY)	Aug-94	Aug-24	QF	Purch	79.20
Polk Power Partners, L.P. (ROYSTER)	Aug-94	Aug-09	QF	Purch	30.80
U.S. Agri-Chemicals (AGRICHEM)	Jan-97	Dec-06	QF	Purch	5.61
Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
UPS Purchase - Southern	Jul-88	May-10	Other	Purch	414.00
TECO Power Purchase	Mar-93	Feb-11	Other	Purch	70.00
Schedule H Capacity - New Smyrna Beach	Nov-85	(1)	Other	Sale	[redacted]
OUC	Dec-06	Feb-07	Other	Purch	
Osceola	Jun-06	Feb-09	Other	Purch	
Osceola	Jan-07	Sep-07	Other	Purch	
The Energy Authority	Jun-06	Sep-06	Other	Purch	
The Energy Authority	Dec-06	Feb-07	Other	Purch	
Chattahoochee	Oct-02	Dec-17	Other	Purch	
Central Power & Lime	Dec-05	Dec-10	Other	Purch	

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Progress Energy Florida or NSB upon 1 year's written notice.

Docket No. 070001-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No. __ (LC-1P)
Filed: September 4, 2007

EXHIBIT TO THE DIRECT TESTIMONY OF LORI CROSS

FUEL AND CAPACITY COST RECOVERY FACTOR JANUARY THROUGH DECEMBER 2008

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 8
COMPANY Progress Energy FL, Inc.
WITNESS Lori Cross (LC-1P)
DATE 11-06-07

EXHIBIT TO THE DIRECT TESTIMONY
OF LORI CROSS

FUEL AND CAPACITY COST RECOVERY FACTOR
JANUARY THROUGH DECEMBER 2008

SECTION A - FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

Docket 070001-EI
Exhibit__LC-1P

PROJECTED MARKET PRICE BY FUEL TYPE

	Heavy Oil 1% SO_2		Heavy Oil 1.5% SO_2		Light Oil		Coal Crystal River 1 & 2		Coal Crystal River 4 & 5		Natural Gas
Month	$/barrel	$/mmbtu	$/barrel	$/mmbtu	$/barrel	$/mmbtu	$/ton	$/mmbtu	$/ton	$/mmbtu	$/mmbtu
Jan 2008	63.06	9.69	61.98	9.52	98.62	16.99	76.45	3.11	75.15	3.07	11.28
Feb 2008	62.80	9.65	61.80	9.49	98.86	17.04	75.92	3.09	74.71	3.05	11.27
Mar 2008	62.39	9.58	61.49	9.45	97.84	16.87	75.56	3.08	74.32	3.04	11.04
Apr 2008	61.89	9.51	61.09	9.38	96.11	16.56	75.14	3.07	74.07	3.03	9.80
May 2008	62.14	9.55	61.32	9.42	94.33	16.26	74.38	3.04	73.96	3.03	9.71
Jun 2008	62.45	9.59	61.61	9.46	94.12	16.11	74.19	3.04	73.88	3.04	9.80
Jul 2008	62.80	9.65	61.92	9.51	94.10	16.18	73.91	3.02	73.46	3.03	9.90
Aug 2008	63.06	9.69	62.16	9.55	94.99	16.30	73.67	3.01	73.18	3.02	9.97
Sep 2008	63.21	9.71	62.31	9.57	96.20	16.46	73.46	3.01	73.02	3.02	10.01
Oct 2008	63.37	9.73	62.46	9.59	96.46	16.63	73.15	2.99	72.93	3.02	10.13
Nov 2008	63.51	9.76	62.60	9.62	97.47	16.81	73.25	3.00	73.60	3.02	10.60
Dec 2008	63.82	9.80	62.88	9.66	98.46	16.97	73.16	2.99	73.59	3.02	11.08

Heavy and Light Oil: The base market oil price forecasts are developed by using the NYMEX forwards and applying a methodology to convert these forward prices to spot forecast prices. Oil projected prices are based on expected contract structures and specifications and incorporate current hedge positions. This table includes oil market commodity prices only; however, the fuel forecast incorporates hedges and transportation costs.

Coal: Coal price projections are based on current coal supply, transportation agreements, and forecasted deliveries. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and, 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5. This table includes transportation costs.

Natural Gas: The base market natural gas price forecast is developed by using the NYMEX forwards and applying a methodology to convert these forward prices to spot forecast prices. This table includes natural gas market commodity prices only; however, the fuel forecast incorporates hedges and transportation costs. Forecast prices are based on expected contract specifications and incorporate current hedge positions. Firm transportation costs for Florida Gas Transmission and Gulfstream pipeline are based on expected tariff rates and/or negotiated rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

Nuclear: The Nuclear Fuel Forecast uses known values of remaining balances of current fuel batches, projected costs of future batches, and projected batch energy production to determine a cost rate that is reported on a cost per unit of energy production basis (e.g., cents per million BTU). The projection of costs of future batches uses projections for each of the several components of nuclear fuel, and each component's projection is based on the contract portfolio and market projections in effect for that component for 2007 and 2008. The contract portfolio/market mix is determined by the procurement strategy in effect for each fuel component. Fuel requirements and individual batch energy forecasts are derived from core physics models that incorporate energy projection forecasts and operating/refueling outage strategies for 2007 through 2008. Nuclear Fuel Management & Safety Analysis is responsible for all aspects of the forecast.

EXHIBIT TO THE DIRECT TESTIMONY
OF LORI CROSS

FUEL AND CAPACITY COST RECOVERY FACTOR
JANUARY THROUGH DECEMBER 2008

SECTION B - 2008 FUEL COST RECOVERY SCHEDULES

Schedule E1 - Fuel Cost Recovery Clause Calculation
Schedule E1-A - Calculation of Total True-up
Schedule E1-B - Calculation of Prior Year Estimated True-up
Schedule E1-C - Calculation of GPIF & True-up Factors
Schedule E1-D - Calculation of Levelized Fuel Adjustment Factors
Schedule E1-E - Calculation of Factors for Metering Voltage and Time of Use
Schedule E1-F - Calculation of Jurisdictional Delivery Loss Multipliers
Schedule E2 - Fuel Cost Recovery Clause Calculation by Month
Schedule E3 - Generating System Comparative Data
Schedule E4 - System Net Generation & Fuel Cost by Month
Schedule E5 - Inventory Analysis
Schedule E6 - Fuel Cost of Power Sold
Schedule E7 - Purchased Power
Schedule E8 - Energy Payments to Qualifying Facilities
Schedule E9 - Economy Energy Purchases
Schedule E10 - Residential Bill Comparison
Calculation of Inverted Residential Fuel Rate
Schedule H1 - Generating System Comparative Data

SCHEDULE E1

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January Through December 2008

			DOLLARS	MWH		CENTS/KWH
1.	Fuel Cost of System Net Generation		1,921,245,832	38,766,785		4.95591
2.	Spent Nuclear Fuel Disposal Cost		6,235,810	6,633,840	*	0.09400
3.	Coal Car Investment		636,943	0		0.00000
4.	Adjustment to Fuel Cost		(11,103,378)	0		0.00000
5.	TOTAL COST OF GENERATED POWER		1,917,015,206	38,766,785		4.94499
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		245,062,379	5,692,323		4.30514
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0		0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		48,955,777	677,976		7.22087
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0		0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0	*	0.00000
11.	Payments to Qualifying Facilities (E8)		149,188,340	4,317,642		3.45532
12.	TOTAL COST OF PURCHASED POWER		443,206,496	10,687,941		4.14679
13.	TOTAL AVAILABLE KWH			49,454,726		
14	Fuel Cost of Economy Sales	(E6)	0	0		0.00000
14a.	Gain on Economy Sales - 80%	(E6)	0	0	*	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(32,008,721)	(487,122)		6.57099
15a.	Gain on Other Power Sales	(E6)	(3,819,149)	(487,122)	*	0.78402
16.	Fuel Cost of Unit Power Sales	(E6)	0	0		0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0		0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(168,606,955)	(3,022,884)		5.57769
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(204,434,825)	(3,510,006)		5.82434
19.	Net Inadvertent Interchange			0		
20	TOTAL FUEL AND NET POWER TRANSACTIONS		2,155,786,877	45,944,720		4.69213
21.	Net Unbilled		3,234,152	(68,927)		0.00750
22.	Company Use		6,756,670	(144,000)		0.01567
23.	T & D Losses		122,061,771	(2,601,414)		0.28301
24.	Adjusted System KWH Sales		2,155,786,877	43,130,379		4.99830
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(76,664,718)	(1,539,311)		4.98046
26.	Jurisdictional KWH Sales		2,079,122,160	41,591,068		4.99896
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.00154	2,082,324,008	41,591,068		5.00666
28.	Prior Period True-Up (Sch E1-A)		(169,376,547)	41,591,068		(0.40724)
29.	Total Jurisdictional Fuel Cost		1,912,947,461	41,591,068		4.59942
30.	Revenue Tax Factor					1.00072
31.	Fuel Cost Adjusted for Taxes		1,914,324,783	41,591,068		4.60273
32.	GPIF **		607,201	41,591,068		0.00146
33.	Fuel Factor Adjusted for taxes including GPIF		1,914,931,984	41,591,068		4.60419
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)					4.604

* For Informational Purposes Only

** Based on Jurisdictional Sales

SCHEDULE E1-A

Progress Energy Florida
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January Through December 2008

1.	ACTUAL OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2006 (Schedule E1-B, Line 18 - Dec '07)	$	75,344,873
2.	PROJECTED DECEMBER 2006 OVER RECOVERY COLLECTED THROUGH DECEMBER 2007 (Schedule E1-B, Line 19 - Dec '07)	$	(46,480,257)
3.	ESTIMATED OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2007 (Schedule E1-B, Line 17 - Dec '07)	$	140,511,931
4.	TOTAL OVER/(UNDER) RECOVERY TO BE INCLUDED IN THE JANUARY - DECEMBER 2008 PROJECTED PERIOD (Lines 1 through 3)	$	169,376,547
5.	JURISDICTIONAL MWH SALES (Projected Period)	Mwh	41,591,068
6.	TRUE-UP FACTOR (Line 5 / Line 6)	Cents/kwh	(0.407)

SCHEDULE E1-B

Progress Energy Florida
Calculation of Estimated True-Up
Actual/Estimated for the Period of : January Through December 2007

DESCRIPTION	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	TOTAL PERIOD
REVENUE													
1 Jurisdictional MWH Sales	2,762,442	2,884,939	2,774,080	2,821,984	3,019,929	3,356,677	3,920,937	4,019,656	4,037,088	3,535,821	3,096,056	3,093,900	39,323,508
2 Jurisdictional Fuel Factor (Pre-Tax)	4.979	5.011	4.997	5.010	5.063	5.091	5.128	5.128	5.128	5.128	5.128	5.128	
3 Total Jurisdictional Fuel Revenue	137,534,227	144,566,416	138,611,197	141,372,027	152,903,793	170,895,864	201,067,694	206,130,055	207,023,978	181,318,744	158,767,366	158,656,805	1,998,848,165
4 True-Up Provision	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,355	3,873,354	46,480,257
5 GPIF Provision	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,921	128,919	1,547,048
6 Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	141,536,502	148,568,692	142,613,472	145,374,302	156,906,068	174,898,140	205,069,970	210,132,331	211,026,254	185,321,020	162,769,642	162,659,078	2,046,875,471
FUEL EXPENSE													
8 Total Cost of Generated Power	96,621,011	113,662,628	111,865,762	116,524,802	138,090,209	171,271,216	207,379,567	199,774,623	170,747,073	162,410,686	140,579,887	129,533,498	1,758,460,962
9 Total Cost of Purchased Power	27,651,795	23,971,853	23,987,275	34,023,359	39,471,227	38,928,003	42,480,859	46,664,387	39,471,730	46,408,403	30,713,059	31,552,763	425,324,714
10 Total Cost of Power Sales	(9,943,088)	(14,748,006)	(13,621,475)	(19,122,799)	(16,501,133)	(17,668,309)	(17,394,139)	(20,703,340)	(20,443,924)	(20,673,008)	(18,104,028)	(12,456,525)	(201,379,774)
11 Total Fuel and Net Power	114,329,718	122,886,475	122,231,562	131,425,362	161,060,303	192,530,909	232,466,287	225,735,670	189,774,879	188,146,081	153,188,919	148,629,737	1,982,405,902
12 Jurisdictional Percentage	96.82%	96.80%	96.83%	96.76%	97.00%	96.25%	96.28%	96.14%	95.88%	95.75%	96.00%	96.67%	
13 Jurisdictional Loss Multiplier	1.00382	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	
14 Jurisdictional Fuel Cost	111,116,884	119,137,297	118,539,091	127,363,018	156,469,086	185,596,379	224,152,954	217,353,488	182,244,080	180,423,758	147,290,774	143,895,602	1,913,582,413
COST RECOVERY													
15 Net Fuel Revenue Less Expense	30,419,618	29,431,394	24,074,381	18,011,284	436,982	(10,698,240)	(19,082,984)	(7,221,157)	28,782,174	4,897,262	15,478,867	18,763,475	133,293,056
16 Interest Provision	389,033	503,959	606,379	684,237	710,671	675,885	596,479	524,356	556,980	616,348	646,775	707,772	7,218,873
17 Current Cycle Balance	30,808,651	60,744,004	85,424,765	104,120,286	105,267,939	95,245,585	76,759,079	70,062,278	99,401,432	104,915,042	121,040,684	140,511,931	
18 Plus: Prior Period Balance	75,344,873	75,344,873	75,344,873	75,344,874	75,344,875	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	75,344,873	
19 Plus: Cumulative True-Up Provision	(3,873,355)	(7,746,710)	(11,620,064)	(15,493,419)	(19,366,774)	(23,240,129)	(27,113,484)	(30,986,839)	(34,860,194)	(38,733,549)	(42,606,904)	(46,480,257)	
20 Total Retail Balance	102,280,169	128,342,168	149,149,573	163,971,741	161,246,040	147,350,329	124,990,469	114,420,313	139,886,112	141,526,366	153,778,653	169,376,547	

SCHEDULE E1-C

Progress Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period: January Through December 2008

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	607,201
	B. True-Up (Over) / Under Recovery	$	(169,376,547)
2.	JURISDICTIONAL MWH SALES	Mwh	41,591,068
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kwh	0.001
	B. True-Up Factor	Cents/kwh	(0.407)

SCHEDULE E1-D

Progress Energy Florida
Calculation of Levelized Fuel Adjustment Factors
(Projected Period)
Estimated for the Period of : January Through December 2008

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$	2,082,324,008
2.	Prior Period True-Up (E1, line 28)	$	(169,376,547)
3.	Other Adjustments	$	0
4.	Regulatory Assessment Fee (E1, line 30)	$	1,377,322
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	$	607,201
6.	Total Jurisdictional Fuel Cost (E1, line 33)	$	1,914,931,984
7.	Jurisdictional Sales (E1, line 26)	Mwh	41,591,068
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line 7 / 10)	Cents/kwh	4.604
9.	Effective Jurisdictional Sales (See Below)	Mwh	41,533,666

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	Cents/kwh	4.611
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	Cents/kwh	4.565
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	Cents/kwh	4.519

TIERED FUEL FACTORS:

13.	Fuel Factor - First Tier (0-1000 kWh)	Cents/kwh	4.278
14.	Fuel Factor - Second Tier (Over 1000 kWh)	Cents/kwh	5.278

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	36,335,967	36,335,967
Distribution Primary	4,770,050	4,722,350
Transmission	485,051	475,350
Total	41,591,068	41,533,666

Progress Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January Through December 2008

Line:	Metering Voltage	First Tier Factor Cents/Kwh	Second Tier Factor Cents/Kwh	Levelized Factors Cents/Kwh	---------Time of Use--------- On-Peak Multiplier 1.379	Off-Peak Multiplier 0.624
1.	Distribution Secondary	4.278	5.278	4.611	6.359	3.799
2.	Distribution Primary	--	--	4.565	6.295	3.762
3.	Transmission	--	--	4.519	6.232	3.724
4.	Lighting Service	--	--	4.278	--	--

Line 4 calculated at secondary rate of 4.611 * (18.7% * On-Peak Multiplier 1.379 + 81.3% * Off-Peak Multiplier 0.824).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-08	1,107,009	112,501,294	10.163	2,755,243	178,837,854	6.491	3,862,252	291,339,148	7.543
Feb-08	964,726	96,706,719	10.024	2,370,427	139,683,607	5.893	3,335,153	236,390,326	7.088
Mar-08	946,590	97,114,444	10.259	2,645,766	177,447,897	6.707	3,592,356	274,562,341	7.643
Apr-08	1,216,233	108,845,789	8.949	2,341,212	134,577,172	5.748	3,557,445	243,422,961	6.843
May-08	1,530,265	169,189,962	11.056	2,764,885	175,823,290	6.359	4,295,150	345,013,252	8.033
Jun-08	1,530,199	180,460,982	11.793	3,035,178	192,973,188	6.358	4,565,377	373,434,170	8.180
Jul-08	1,747,844	198,202,049	11.340	3,192,058	206,799,350	6.479	4,939,902	405,001,399	8.199
Aug-08	1,636,873	219,899,599	13.434	3,364,590	234,580,609	6.972	5,001,463	454,480,208	9.087
Sep-08	1,541,497	203,160,120	13.179	2,966,141	212,188,522	7.154	4,507,638	415,348,642	9.214
Oct-08	1,418,382	147,187,488	10.377	2,605,743	166,925,692	6.406	4,024,125	314,113,180	7.806
Nov-08	838,610	78,384,405	9.347	2,603,303	185,796,806	7.137	3,441,913	264,181,211	7.675
Dec-08	1,046,386	112,874,682	10.787	2,800,467	215,110,121	7.681	3,846,853	327,984,803	8.526
TOTAL	15,524,614	1,724,527,531	11.108	33,445,013	2,220,744,109	6.640	48,969,627	3,945,271,640	8.057

MARGINAL FUEL COST	ON-PEAK	OFF-PEAK	AVERAGE
WEIGHTING MULTIPLIER	1.379	0.824	1.000

SCHEDULE E1-F

Progress Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2006
Estimated for the Period of: January Through December 2008

		Energy Delivered @ Billing Level							
		Billed MWH	Unbilled MWH	Total MWH	% of Total	Delivery Efficiency	Energy Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
Retail									
Transmission		495,586	(1,686)	493,900		0.9768000	505,631		
Distribution Primary		4,708,320	(16,017)	4,692,303		0.9668000	4,853,437		
Distribution Secondary		34,227,932	(116,444)	34,111,488		0.9384178	36,350,000		
Total Retail		39,431,838	(134,147)	39,297,691	96.06%	0.9421858	41,709,067	96.21%	1.00154
						5.78%			
Wholesale									
Generation Level		287,482	(291)	287,191		1.0000000	287,191		
Transmission		1,264,273	(10,092)	1,254,181		0.9768000	1,283,969		
Distribution Primary		70,495	(115)	70,380		0.9668000	72,797		
Distribution Secondary		-	-	-			-		
Total Wholesale		1,622,250	(10,498)	1,611,752	3.94%	0.9804101	1,643,957	3.79%	0.96249
						1.96%			
Subtotal Class		41,054,088	(144,645)	40,909,443	100.00%	0.9436353	43,353,024	100.00%	1.00000
						5.64%			
Non-Class									
Sepa	Transmission	35,521	-	35,521		0.9768000	36,365		
Homestead - Base	Generation	131,400	(6,506)	124,894		1.0000000	124,894		
MM, FP&L - Base/Int	Generation	407,165	(20,160)	387,005		1.0000000	387,005		
TECO - Intermediate	Transmission	0	-	0		0.9768000	-		
Reedy Crk - Fuel Collar - Base	Generation	553,640	(27,412)	526,228		1.0000000	526,228		
Seminole Elect. Coop	Generation	1,370,352	(29,783)	1,340,569		1.0000000	1,340,569		
Tallahassee - Base	Transmission	99,851	(4,944)	94,907		0.9768000	97,161		
Interchange	Generation	312,762	-	312,762		1.0000000	312,762		
Company Use	Secondary	164,778	-	164,778		0.9384178	175,591		
Total Non-Class		3,075,469	(88,805)	2,986,664			3,000,575		
Total System		44,129,557	-233,450	43,896,107		0.946984	46,353,599		

SCHEDULE E-2

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January Through December 2008

			Estimated Jan-08	Estimated Feb-08	Estimated Mar-08	Estimated Apr-08	Estimated May-08	Estimated Jun-08	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	TOTAL
1	Fuel Cost of System Net Generation		$147,477,555	$120,409,951	$132,631,233	$124,770,245	$168,307,028	$181,259,343	$225,187,587	$218,289,539	$185,076,482	$155,106,187	$127,697,758	$134,832,911	$1,921,245,852
1a	Nuclear Fuel Disposal Cost		551,795	516,195	551,795	484,092	455,171	525,197	542,703	542,703	437,664	542,703	533,995	551,795	6,235,810
1b	Adjustments to Fuel Cost		(14,303,274)	358,272	357,812	350,281	349,345	350,241	350,261	346,589	344,492	341,367	341,050	347,129	(10,466,435)
2	Fuel Cost of Power Sold		(5,761,119)	(4,730,579)	(2,959,986)	(2,259,934)	(2,062,021)	(1,861,893)	(2,208,605)	(2,288,670)	(1,533,002)	(1,627,177)	(1,929,115)	(2,766,620)	(32,009,721)
2a	Gains on Power Sales		(751,545)	(614,975)	(384,798)	(293,791)	(268,063)	(242,046)	(287,119)	(297,527)	(199,290)	(211,534)	(250,785)	(17,676)	(3,819,149)
2b	Fuel Cost of Stratified Sales		(10,521,569)	(10,270,543)	(10,135,614)	(12,070,103)	(13,435,850)	(14,719,511)	(15,441,674)	(18,707,353)	(20,442,107)	(18,913,594)	(15,262,620)	(8,685,419)	(168,605,955)
3	Fuel Cost of Purchased Power (Excl Economy)		19,462,265	18,181,132	21,660,537	16,344,272	21,746,379	23,092,598	25,359,916	30,002,391	23,024,745	17,932,393	12,818,662	15,437,089	245,062,379
3a	Energy Payments to Qualifying Facilities		13,200,614	12,217,928	9,775,404	12,408,124	12,928,410	12,493,131	12,859,334	12,994,979	12,273,870	11,773,889	12,594,058	13,658,599	149,189,340
4	Energy Cost of Economy Purchases		3,707,839	3,431,292	4,189,110	3,710,379	4,038,508	3,992,649	2,856,244	4,391,426	4,995,991	4,746,686	4,401,110	4,498,843	48,960,777
5	Total System Fuel & Net Power Transactions		$153,042,562	$139,498,683	$155,684,493	$143,443,266	$192,058,907	$204,889,709	$249,220,648	$245,274,078	$203,978,845	$169,684,921	$141,144,134	$157,866,632	$2,155,785,877
6	Jurisdictional MWH Sold		3,287,927	3,118,594	2,920,867	2,989,598	3,197,696	3,750,064	4,024,824	4,154,278	4,136,532	3,642,503	3,202,716	3,165,449	41,591,068
7	Jurisdictional % of Total Sales		96.81%	96.49%	96.54%	96.52%	96.64%	96.46%	96.66%	96.47%	96.15%	95.96%	96.09%	96.64%	96.44%
8	Jurisdictional Fuel & Net Power Transactions		148,157,884	134,606,591	149,991,886	138,447,153	185,599,792	197,643,827	240,902,476	236,616,950	196,132,925	162,826,500	135,624,412	152,569,766	2,079,122,160
9	Jurisdictional Loss Multiplier		1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154
10	Jurisdictional Fuel & Net Power Transactions		148,386,047	134,815,888	150,222,873	138,660,361	185,885,615	197,948,199	241,273,465	236,981,340	196,434,969	163,077,252	135,833,274	152,804,723	2,082,324,008
11	Adjusted System Sales	MWH	3,396,328	3,231,887	3,031,722	3,097,483	3,308,980	3,887,567	4,163,798	4,306,271	4,302,006	3,795,929	3,333,062	3,275,346	43,130,379
12	System Cost per KWH Sold	c/kwh	4.5061	4.3163	5.1352	4.6310	5.8042	5.2703	5.9854	5.6957	4.7415	4.4702	4.2347	4.8198	4.9983
13	Jurisdictional Loss Multiplier	x	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154	1.00154
14	Jurisdictional Cost per KWH Sold	c/kwh	4.5131	4.3230	5.1431	4.6381	5.8131	5.2785	5.9946	5.7045	4.7488	4.4771	4.2412	4.8273	5.0067
15	Prior Period True-Up	+	-0.4293	-0.4526	-0.4832	-0.4721	-0.4414	-0.3764	-0.3507	-0.3398	-0.3412	-0.3875	-0.4407	-0.4459	-0.4072
16	Total Jurisdictional Fuel Expense	c/kwh	4.0838	3.8704	4.6599	4.1660	5.3717	4.9021	5.6439	5.3648	4.4076	4.0896	3.8035	4.3814	4.5994
17	Revenue Tax Multiplier	x	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
18	Recovery Factor Adjusted for Taxes	c/kwh	4.0867	3.8732	4.6632	4.1690	5.3756	4.9056	5.6480	5.3686	4.4107	4.0925	3.8032	4.3845	4.6027
19	GPIF	+	0.0015	0.0016	0.0017	0.0017	0.0016	0.0013	0.0013	0.0012	0.0012	0.0014	0.0016	0.0016	0.0015
20	Total Recovery Factor (rounded .001)	c/kwh	4.088	3.875	4.665	4.171	5.377	4.907	5.649	5.370	4.412	4.094	3.805	4.386	4.604

Progress Energy Florida
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January Through December 2008

			Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		30,035,402	25,104,514	20,305,531	21,647,278	37,587,302	44,096,163	178,776,190
2	LIGHT OIL		6,508,418	7,286,215	6,029,449	11,197,301	4,652,590	3,408,422	41,082,395
3	COAL		41,644,609	36,086,162	38,618,562	38,235,261	40,934,370	41,410,696	236,929,657
4	GAS		65,099,613	49,884,816	65,488,178	51,759,534	83,296,706	90,225,531	405,764,376
5	NUCLEAR		2,189,514	2,048,255	2,189,514	1,920,872	1,836,061	2,118,532	12,302,748
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	147,477,555	120,409,961	132,631,233	124,770,245	168,307,028	181,259,343	874,855,365
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		324,400	273,411	227,137	239,261	404,573	463,947	1,932,729
9	LIGHT OIL		26,669	20,696	16,632	32,967	14,896	10,322	122,182
10	COAL		1,375,149	1,191,267	1,279,764	1,272,328	1,355,439	1,378,286	7,852,233
11	GAS		717,988	530,101	716,328	683,428	1,145,910	1,262,703	5,056,458
12	NUCLEAR		587,016	549,144	587,016	514,992	484,224	558,720	3,281,112
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,031,222	2,564,619	2,826,877	2,742,976	3,405,042	3,673,978	18,244,714
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	522,910	443,079	364,973	385,439	649,214	749,980	3,115,595
16	LIGHT OIL	BBL	80,184	68,586	57,638	109,734	46,832	34,683	397,657
17	COAL	TON	543,024	472,438	508,678	505,633	544,289	551,587	3,125,649
18	GAS	MCF	5,693,173	4,326,079	5,748,011	5,285,658	8,802,652	9,489,883	39,345,456
19	NUCLEAR	MMBTU	5,982,282	5,596,328	5,982,282	5,248,283	5,016,559	5,788,337	33,614,071
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		3,404,140	2,884,445	2,375,977	2,509,209	4,226,388	4,882,369	20,282,528
22	LIGHT OIL		464,748	397,536	334,062	636,013	271,453	201,018	2,304,830
23	COAL		13,312,537	11,569,276	12,439,397	12,354,207	13,281,845	13,445,018	76,402,280
24	GAS		5,693,173	4,326,079	5,748,011	5,285,658	8,802,652	9,489,883	39,345,456
25	NUCLEAR		5,982,282	5,596,328	5,982,282	5,248,283	5,016,559	5,788,337	33,614,071
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	28,856,880	24,773,664	26,879,729	26,033,370	31,598,897	33,806,625	171,949,165
	GENERATION MIX (% MWH)								
28	HEAVY OIL		10.70%	10.66%	8.04%	8.72%	11.88%	12.63%	10.59%
29	LIGHT OIL		0.88%	0.81%	0.59%	1.20%	0.44%	0.28%	0.67%
30	COAL		45.37%	46.45%	45.27%	46.39%	39.81%	37.52%	43.04%
31	GAS		23.69%	20.67%	25.34%	24.92%	33.65%	34.37%	27.72%
32	NUCLEAR		19.37%	21.41%	20.77%	18.78%	14.22%	15.21%	17.98%
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	57.44	56.66	55.64	56.16	57.90	58.80	57.38
36	LIGHT OIL	$/BBL	106.11	106.23	104.61	102.04	99.35	98.27	103.31
37	COAL	$/TON	76.69	76.38	75.92	75.62	75.21	75.08	75.80
38	GAS	$/MCF	11.43	11.53	11.39	9.79	9.46	9.51	10.31
39	NUCLEAR	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		8.82	8.70	8.55	8.63	8.89	9.03	8.81
42	LIGHT OIL		18.31	18.33	18.05	17.61	17.14	16.96	17.82
43	COAL		3.13	3.12	3.11	3.10	3.08	3.08	3.10
44	GAS		11.44	11.53	11.39	9.79	9.46	9.51	10.31
45	NUCLEAR		0.37	0.37	0.37	0.37	0.37	0.37	0.37
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	5.11	4.86	4.93	4.79	5.33	5.36	5.09
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,494	10,550	10,461	10,487	10,447	10,524	10,494
49	LIGHT OIL		17,427	19,208	20,085	19,292	18,223	19,475	18,864
50	COAL		9,681	9,712	9,720	9,710	9,799	9,755	9,730
51	GAS		7,929	8,161	8,024	7,734	7,682	7,516	7,781
52	NUCLEAR		10,191	10,191	10,191	10,191	10,360	10,360	10,245
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,520	9,660	9,509	9,491	9,280	9,202	9,425
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		9.26	9.18	8.94	9.05	9.29	9.50	9.25
56	LIGHT OIL		31.90	35.21	36.25	33.97	31.23	33.02	33.62
57	COAL		3.03	3.03	3.02	3.01	3.02	3.00	3.02
58	GAS		9.07	9.41	9.14	7.57	7.27	7.15	8.02
59	NUCLEAR		0.37	0.37	0.37	0.37	0.38	0.38	0.37
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.87	4.70	4.69	4.55	4.94	4.93	4.80

Progress Energy Florida
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January Through December 2008

			Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		49,097,514	53,481,221	48,893,074	34,722,130	28,166,340	25,503,086	418,639,555
2	LIGHT OIL		24,244,775	13,241,430	5,829,106	8,807,866	3,269,467	3,157,829	99,432,868
3	COAL		41,685,981	41,843,275	42,033,333	36,629,596	26,825,678	37,857,110	463,804,628
4	GAS		107,970,168	107,534,464	86,555,526	72,957,446	67,517,389	66,125,373	914,424,740
5	NUCLEAR		2,189,150	2,189,150	1,765,444	2,189,150	2,118,885	2,189,514	24,944,041
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	225,187,587	218,289,539	185,076,482	155,106,187	127,897,758	134,832,911	1,921,245,832
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		509,815	550,426	511,256	362,347	302,867	275,079	4,444,519
9	LIGHT OIL		86,069	46,232	17,898	27,193	7,784	7,320	314,678
10	COAL		1,401,053	1,411,279	1,423,606	1,240,901	902,530	1,289,187	15,520,789
11	GAS		1,454,990	1,450,064	1,188,867	997,504	883,924	821,152	11,852,959
12	NUCLEAR		577,344	577,344	465,600	577,344	568,080	587,016	6,633,840
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	4,029,271	4,035,345	3,607,227	3,205,289	2,665,185	2,979,754	38,766,785
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	827,193	892,196	823,118	586,323	483,172	440,398	7,169,995
16	LIGHT OIL	BBL	245,324	136,135	58,479	82,730	31,126	29,925	981,376
17	COAL	TON	563,110	567,302	571,235	498,678	362,185	512,484	6,200,643
18	GAS	MCF	11,162,153	11,007,837	8,971,976	7,571,627	6,503,977	6,003,081	90,566,107
19	NUCLEAR	MMBTU	5,981,281	5,981,281	4,823,614	5,981,281	5,789,305	5,982,282	68,153,115
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		5,385,028	5,808,185	5,358,500	3,829,981	3,145,451	2,866,994	46,676,668
22	LIGHT OIL		1,421,910	789,059	338,936	479,478	180,409	173,462	5,688,084
23	COAL		13,698,817	13,781,297	13,867,784	12,092,764	8,840,503	12,500,176	151,183,621
24	GAS		11,162,153	11,007,837	8,971,976	7,571,627	6,503,977	6,003,081	90,566,107
25	NUCLEAR		5,981,281	5,981,281	4,823,614	5,981,281	5,789,305	5,982,282	68,153,115
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	37,649,189	37,367,660	33,360,810	29,955,131	24,459,645	27,525,995	362,267,595
	GENERATION MIX (% MWH)								
28	HEAVY OIL		12.65%	13.64%	14.17%	11.31%	11.36%	9.23%	11.47%
29	LIGHT OIL		2.14%	1.15%	0.50%	0.85%	0.29%	0.25%	0.81%
30	COAL		34.77%	34.97%	39.47%	38.71%	33.86%	43.27%	40.04%
31	GAS		36.11%	35.93%	32.96%	31.12%	33.17%	27.56%	30.58%
32	NUCLEAR		14.33%	14.31%	12.91%	18.01%	21.32%	19.70%	17.11%
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	59.35	59.94	59.40	59.02	58.29	57.91	58.39
36	LIGHT OIL	$/BBL	98.83	97.27	99.68	104.05	105.04	105.52	101.32
37	COAL	$/TON	74.03	73.76	73.58	73.45	74.07	73.87	74.80
38	GAS	$/MCF	9.67	9.77	9.65	9.64	10.38	11.02	10.10
39	NUCLEAR	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		9.12	9.21	9.12	9.07	8.96	8.90	8.97
42	LIGHT OIL		17.05	16.78	17.20	17.95	18.12	18.21	17.48
43	COAL		3.04	3.04	3.03	3.03	3.03	3.03	3.07
44	GAS		9.67	9.77	9.65	9.64	10.38	11.02	10.10
45	NUCLEAR		0.37	0.37	0.37	0.37	0.37	0.37	0.37
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	5.98	5.84	5.55	5.18	5.23	4.90	5.30
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,563	10,552	10,481	10,570	10,386	10,422	10,502
49	LIGHT OIL		16,521	17,067	18,937	17,632	23,177	23,697	18,076
50	COAL		9,778	9,765	9,741	9,745	9,795	9,696	9,741
51	GAS		7,672	7,591	7,547	7,591	7,358	7,311	7,641
52	NUCLEAR		10,360	10,360	10,360	10,360	10,191	10,191	10,274
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,344	9,260	9,248	9,346	9,177	9,238	9,345
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		9.63	9.72	9.56	9.58	9.30	9.27	9.42
56	LIGHT OIL		28.17	28.64	32.57	31.65	42.00	43.14	31.60
57	COAL		2.98	2.96	2.95	2.95	2.97	2.94	2.99
58	GAS		7.42	7.42	7.28	7.31	7.64	8.05	7.71
59	NUCLEAR		0.38	0.38	0.38	0.38	0.37	0.37	0.38
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	5.59	5.41	5.13	4.84	4.80	4.52	4.96

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-08 through Dec-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	779	6,633,840	95.4	96.5	99.7	10,274 NUCLEAR	68,153,115 MMBTU	1.00	68,153,115	24,944,041	0.38
2 ANCLOTE	1	510	1,653,622	36.3	91.6	40.3	10,135 HEAVY OIL	2,574,943 BBLS	6.50	16,762,873	149,146,174	9.02
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	517	1,351,108	29.3	84.3	34.9	10,432 HEAVY OIL	2,158,845 BBLS	6.50	14,054,082	125,654,768	9.30
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	325,136	25.6	91.7	44.7	11,059 HEAVY OIL	552,341 BBLS	6.50	3,595,741	31,846,651	9.79
7 BARTOW	2	122	276,465	25.5	93.1	37.1	11,606 HEAVY OIL	492,887 BBLS	6.50	3,208,694	28,358,714	10.26
8 BARTOW	3	210	688,952	36.8	88.7	43.5	10,609 HEAVY OIL	1,122,771 BBLS	6.50	7,309,242	64,516,355	9.36
9 BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	2,306,055	67.5	93.6	70.1	10,268 COAL	967,639 TONS	24.77	23,678,946	71,900,760	3.12
11 CRYSTAL RIVER	2	494	2,938,103	66.7	87.7	75.1	9,982 COAL	1,198,403 TONS	24.77	29,326,759	89,104,338	3.03
12 CRYSTAL RIVER	4	728	4,837,216	74.4	83.1	88.0	9,550 COAL	1,898,554 TONS	24.71	46,196,595	142,663,012	2.95
13 CRYSTAL RIVER	5	728	5,439,405	83.7	93.6	88.0	9,556 COAL	2,136,047 TONS	24.71	51,981,321	160,136,499	2.94
14 SUWANNEE	1	32	31,691	11.3	97.5	69.7	12,295 HEAVY OIL	59,852 BBLS	6.50	389,635	4,270,617	13.48
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	29,763	10.8	87.4	61.7	12,529 HEAVY OIL	57,279 BBLS	6.50	372,886	4,085,437	13.73
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	87,582	12.1	81.9	41.3	11,230 HEAVY OIL	151,077 BBLS	6.50	983,515	10,760,639	12.29
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	60	1,645	0.3	94.9	9.7	33,883 LIGHT OIL	9,617 BBLS	5.80	55,738	962,251	58.50
21 AVON PARK	1-2	0	3,679	0.0	0.0	0.0	24,115 GAS	88,696 MCF	5.80	88,696	1,297,617	35.28
22 BARTOW	1-4	201	21,372	2.6	96.8	37.0	19,491 LIGHT OIL	71,871 BBLS	5.80	416,562	7,177,155	33.59
23 BARTOW	1-4		25,542				17,242 GAS	440,403 MCF	1.00	440,403	5,025,982	19.68
24 BAYBORO	1-4	205	60,857	3.3	98.4	59.5	15,825 LIGHT OIL	166,163 BBLS	5.80	963,092	16,636,313	27.34
25 DEBARY	1-10	711	77,377	3.9	98.8	50.4	16,564 LIGHT OIL	221,132 BBLS	5.80	1,281,692	22,112,325	28.58
26 DEBARY	1-10		165,152				13,945 GAS	2,358,776 MCF	1.00	2,358,776	24,566,257	14.52
27 HIGGINS	1-4	122	0	0.0	84.1	60.8	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
28 HIGGINS	1-4		25,205				19,003 GAS	478,961 MCF	1.00	478,961	5,389,958	21.38
29 HINES	1-4	2,177	9,632,343	49.6	87.2	18.4	7,031 GAS	67,726,738 MCF	1.00	67,726,738	697,617,474	7.14
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 INT CITY	1-14	1,088	102,475	7.5	88.6	63.5	15,032 LIGHT OIL	265,766 BBLS	5.80	1,540,391	27,428,650	26.77
32 INT CITY	1-14		628,310				13,174 GAS	8,277,633 MCF	1.00	8,277,633	81,880,939	13.03
33 RIO PINAR	1	15	2,317	1.8	98.9	70.1	22,498 LIGHT OIL	8,992 BBLS	5.80	52,129	905,402	39.08
34 SUWANNEE	1-3	178	18,413	5.2	86.9	67.2	15,286 LIGHT OIL	48,558 BBLS	5.80	281,453	5,198,284	28.23
35 SUWANNEE	1-3		63,459				13,801 GAS	875,773 MCF	1.00	875,773	8,127,599	12.81
36 TIGER BAY	1	214	957,287	50.1	74.7	85.4	7,457 GAS	7,138,331 MCF	1.00	7,138,331	72,285,560	7.55
37 TURNER	1-4	176	30,222	1.9	98.6	17.3	19,569 LIGHT OIL	102,043 BBLS	5.80	591,429	10,225,895	33.84
38 UNIV OF FLA.	1	46	347,983	84.7	85.4	100.6	9,141 GAS	3,180,796 MCF	1.00	3,180,796	28,233,264	8.11
39 OTHER - START UP		-	0	-	-	-	0 LIGHT OIL	87,234 BBLS	5.80	505,598	8,786,593	0.00
40 OTHER		-	0	-	-	-	-	- -	-	-	0	-
41 TOTAL	9,925	38,766,785				9,345				362,267,595	1,921,245,832	4.96

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Jan-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	788	557,016	100.1	100.00	10,191	NUCLEAR	5,982,262 MMBTU	1.00	5,982,282	2,169,514	0.37
2 ANCLOTE	1	522	123,526	31.8	97.48	32.1	10,211 HEAVY OIL	193,760 BBLS	6.51	1,261,377	11,139,169	9.02
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	526	96,281	25.1	94.84	25.4	10,514 HEAVY OIL	158,726 BBLS	6.51	1,033,304	9,126,335	9.29
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	125	21,359	23.0	95.83	44.2	10,914 HEAVY OIL	35,808 BBLS	6.51	233,109	2,052,771	9.61
7 BARTOW	2	124	19,858	21.5	98.08	38.1	11,458 HEAVY OIL	34,950 BBLS	6.51	227,526	2,003,607	10.09
8 BARTOW	3	215	61,376	38.4	95.68	39.1	10,571 HEAVY OIL	99,666 BBLS	6.51	648,824	5,713,550	9.31
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	386	193,295	67.3	93.94	67.9	10,257 COAL	80,629 TONS	24.59	1,982,657	6,164,644	3.19
11 CRYSTAL RIVER	2	496	250,911	68.0	90.41	73.2	9,943 COAL	101,451 TONS	24.59	2,494,684	7,756,536	3.09
12 CRYSTAL RIVER	4	734	469,804	86.0	95.14	87.7	9,479 COAL	181,938 TONS	24.48	4,453,481	13,971,875	2.97
13 CRYSTAL RIVER	5	734	461,139	84.4	93.57	87.5	9,502 COAL	179,006 TONS	24.48	4,381,715	13,751,553	2.96
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	80.55	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	82	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	70	165	0.3	94.84	11.5	27,533 LIGHT OIL	784 BBLS	5.79	4,543	81,197	49.21
21 AVON PARK	1-2		562				19,084 GAS	10,725 MCF	1.00	10,725	146,966	26.51
22 BARTOW	1-4	226	472	1.8	97.50	43.6	18,110 LIGHT OIL	1,475 BBLS	5.80	8,548	154,231	32.68
23 BARTOW	1-4		2,511				16,401 GAS	41,183 MCF	1.00	41,183	509,522	19.93
24 BAYBORO	1-4	232	2,944	1.7	98.55	58.3	16,919 LIGHT OIL	8,594 BBLS	5.80	49,810	898,722	30.53
25 DEBARY	1-10	779	5,777	3.2	98.65	57.5	14,803 LIGHT OIL	14,754 BBLS	5.80	85,516	1,549,037	26.81
26 DEBARY	1-10		12,681				13,917 GAS	175,367 MCF	1.00	175,367	2,033,564	16.14
27 HIGGINS	1-4	133	0	0.0	96.85	56.6	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		2,852				18,987 GAS	54,150 MCF	1.00	54,150	633,652	22.22
29 HINES	1-4	2,177	534,931	33.0	97.94	17.2	7,149 GAS	3,824,170 MCF	1.00	3,824,170	44,662,321	8.35
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,184	13,590	6.6	98.82	43.4	15,310 LIGHT OIL	35,898 BBLS	5.80	208,063	3,859,569	28.40
32 INT CITY	1-14		44,131				13,309 GAS	587,331 MCF	1.00	587,331	6,496,173	14.72
33 RIO PINAR	1	16	152	1.3	99.35	67.9	22,855 LIGHT OIL	599 BBLS	5.80	3,474	62,542	41.15
34 SUWANNEE	1-3	199	921	4.6	99.57	68.6	15,699 LIGHT OIL	2,495 BBLS	5.80	14,459	279,492	30.35
35 SUWANNEE	1-3		5,954				13,440 GAS	80,024 MCF	1.00	80,024	821,573	13.80
36 TIGER BAY	1	225	79,916	47.7	94.19	76.6	7,585 GAS	606,198 MCF	1.00	606,198	6,689,869	8.37
37 TURNER	1-4	201	2,648	1.8	98.63	20.8	18,827 LIGHT OIL	8,601 BBLS	5.80	49,854	899,516	33.97
38 UNIV OF FLA	1	47	34,560	98.8	96.77	102.1	9,086 GAS	314,025 MCF	1.00	314,025	3,112,973	9.01
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	6,984 BBLS	5.80	40,481	724,112	0.00
40 OTHER												
41 TOTAL	10,285	3,031,222				9,520				28,856,880	147,477,555	4.87

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Feb-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	768	549,144	93.7	100.00	100.1	10,191 NUCLEAR	5,596,328 MMBTU	1.00	5,596,328	2,048,255	0.37
2 ANCLOTE	1	522	105,039	27.0	95.79	29.4	10,272 HEAVY OIL	165,691 BBLS	6.51	1,078,648	9,421,774	8.97
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	526	85,304	21.8	96.46	25.7	10,598 HEAVY OIL	138,877 BBLS	6.51	904,087	7,898,199	9.26
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	125	15,463	16.6	95.68	39.6	11,048 HEAVY OIL	26,241 BBLS	6.51	170,830	1,474,790	9.54
7 BARTOW	2	124	14,102	15.3	98.21	34.3	11,565 HEAVY OIL	25,051 BBLS	6.51	163,085	1,407,927	9.98
8 BARTOW	3	215	53,533	33.5	95.18	37.4	10,606 HEAVY OIL	87,219 BBLS	6.51	567,795	4,901,824	9.16
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	386	159,344	55.5	93.43	60.5	10,315 COAL	66,983 TONS	24.54	1,643,627	5,095,945	3.19
11 CRYSTAL RIVER	2	496	218,692	59.3	93.19	65.8	9,985 COAL	88,989 TONS	24.54	2,183,613	6,756,662	3.09
12 CRYSTAL RIVER	4	734	406,697	74.5	93.58	82.5	9,512 COAL	158,131 TONS	24.46	3,868,517	12,114,139	2.98
13 CRYSTAL RIVER	5	734	406,534	74.4	93.42	82.7	9,528 COAL	158,335 TONS	24.46	3,873,519	12,129,415	2.98
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	0.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	82	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	70	80	0.2	95.52	5.6	48,125 LIGHT OIL	664 BBLS	5.80	3,850	68,992	86.24
21 AVON PARK	1-2		273				30,949 GAS	8,449 MCF	1.00	8,449	123,296	45.16
22 BARTOW	1-4	226	564	1.5	96.98	33.4	20,773 LIGHT OIL	2,021 BBLS	5.80	11,716	211,943	37.58
23 BARTOW	1-4		2,018				18,337 GAS	37,005 MCF	1.00	37,005	447,540	22.18
24 BAYBORO	1-4	232	3,790	2.2	99.31	51.5	18,204 LIGHT OIL	11,904 BBLS	5.80	68,994	1,248,102	32.93
25 DEBARY	1-10	779	3,796	2.5	98.79	44.4	18,222 LIGHT OIL	11,940 BBLS	5.80	69,209	1,256,974	33.10
26 DEBARY	1-10		10,908				14,881 GAS	162,323 MCF	1.00	162,323	1,855,394	17.01
27 HIGGINS	1-4	133	0	0.0	97.07	43.5	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		2,341				21,653 GAS	50,689 MCF	1.00	50,689	584,300	24.96
29 HINES	1-4	2,177	402,646	24.9	91.60	16.8	7,221 GAS	2,907,628 MCF	1.00	2,907,628	34,459,865	8.56
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,184	8,718	5.9	98.92	38.8	15,975 LIGHT OIL	24,028 BBLS	5.80	139,269	2,590,263	29.71
32 INT CITY	1-14		35,154				14,113 GAS	496,145 MCF	1.00	496,145	5,424,739	15.43
33 RIO PINAR	1	16	220	1.8	98.62	62.5	24,114 LIGHT OIL	915 BBLS	5.80	5,305	95,755	43.53
34 SUWANNEE	1-3	199	1,152	4.1	91.57	57.1	17,476 LIGHT OIL	3,473 BBLS	5.80	20,132	390,138	33.87
35 SUWANNEE	1-3		4,982				14,364 GAS	71,562 MCF	1.00	71,562	715,187	14.36
36 TIGER BAY	1	225	39,753	23.7	93.79	78.9	7,578 GAS	301,248 MCF	1.00	301,248	3,476,948	8.75
37 TURNER	1-4	201	2,374	1.6	98.97	41.7	16,586 LIGHT OIL	6,834 BBLS	5.80	39,613	716,599	30.19
38 UNIV OF FLA	1	47	32,026	91.6	95.86	102.2	9,087 GAS	291,030 MCF	1.00	291,030	2,797,549	8.74
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	6,807 BBLS	5.80	39,448	707,449	0.00
40 OTHER												
41 TOTAL	10,285	2,564,619				9,660				24,773,664	120,409,961	4.70

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Mar-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	788	567,016	100.1	100.00	100.1	10,191 NUCLEAR	5,982,282 MMBTU	1.00	5,982,282	2,189,514	0.37
2 ANCLOTE	1	522	129,939	33.5	96.67	33.9	10,173 HEAVY OIL	203,062 BBLS	6.51	1,321,934	11,308,599	8.70
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	526	26,407	6.7	18.64	31.4	10,422 HEAVY OIL	42,276 BBLS	6.51	275,216	2,360,150	8.94
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	125	28,324	30.5	95.99	43.8	10,919 HEAVY OIL	47,507 BBLS	6.51	309,271	2,635,463	9.30
7 BARTOW	2	124	27,135	29.4	97.36	36.0	11,381 HEAVY OIL	47,437 BBLS	6.51	308,816	2,631,585	9.70
8 BARTOW	3	215	15,332	9.6	26.78	44.0	10,484 HEAVY OIL	24,691 BBLS	6.51	160,738	1,369,734	8.93
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	386	178,035	62.0	91.94	64.1	10,287 COAL	74,746 TONS	24.50	1,831,429	5,648,690	3.17
11 CRYSTAL RIVER	2	495	239,801	65.0	91.67	69.0	9,978 COAL	97,653 TONS	24.50	2,392,686	7,379,607	3.08
12 CRYSTAL RIVER	4	734	430,261	78.8	93.36	82.2	9,520 COAL	167,674 TONS	24.43	4,096,264	12,760,523	2.97
13 CRYSTAL RIVER	5	734	431,667	79.0	93.17	81.9	9,542 COAL	168,605 TONS	24.43	4,119,018	12,829,741	2.97
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	77.42	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	82	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	70	202	0.4	95.16	8.7	42,797 LIGHT OIL	1,492 BBLS	5.79	8,645	153,501	75.99
21 AVON PARK	1-2		522				23,667 GAS	12,354 MCF	1.00	12,354	165,315	31.67
22 BARTOW	1-4	226	643	1.9	97.74	35.1	20,092 LIGHT OIL	2,229 BBLS	5.80	12,919	231,566	36.02
23 BARTOW	1-4		2,491				17,679 GAS	44,038 MCF	1.00	44,038	528,498	21.22
24 BAYBORO	1-4	232	3,124	1.8	98.63	51.8	18,070 LIGHT OIL	9,740 BBLS	5.80	56,450	1,011,922	32.39
25 DEBARY	1-10	779	4,539	3.4	93.44	51.5	17,293 LIGHT OIL	13,542 BBLS	5.80	78,492	1,412,385	31.12
26 DEBARY	1-10		15,032				14,001 GAS	210,468 MCF	1.00	210,468	2,387,544	15.88
27 HIGGINS	1-4	133	0	0.0	46.55	36.1	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		1,296				21,522 GAS	27,892 MCF	1.00	27,892	363,225	28.03
29 HINES	1-4	2,177	548,601	33.9	73.89	16.7	7,153 GAS	3,923,912 MCF	1.00	3,923,912	45,567,254	8.31
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,184	5,562	7.2	77.39	47.4	15,506 LIGHT OIL	14,880 BBLS	5.80	86,243	1,589,113	28.57
32 INT CITY	1-14		58,099				13,298 GAS	772,615 MCF	1.00	772,615	8,374,956	14.42
33 RIO PINAR	1	16	248	2.1	99.03	64.6	24,222 LIGHT OIL	1,036 BBLS	5.80	6,007	107,441	43.32
34 SUWANNEE	1-3	199	0	0.0	66.45	67.9	0 LIGHT OIL	0 BBLS		0	0	0.00
35 SUWANNEE	1-3		6,215				13,620 GAS	84,650 MCF	1.00	84,650	866,497	13.94
36 TIGER BAY	1	225	60,457	36.1	61.08	79.3	7,568 GAS	457,514 MCF	1.00	457,514	5,149,309	8.52
37 TURNER	1-4	201	2,314	1.5	99.71	40.2	16,309 LIGHT OIL	6,512 BBLS	5.80	37,739	676,509	29.24
38 UNIV OF FLA	1	47	23,616	67.5	65.36	102.1	9,086 GAS	214,568 MCF	1.00	214,568	2,085,378	8.83
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	8,207 BBLS	5.80	47,567	846,992	0.00
40 OTHER												
41 TOTAL	10,285	2,826,677				9,509				26,879,729	132,631,233	4.69

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Apr-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	514,992	87.8	90.67	10,191	NUCLEAR	5,248,283 MMBTU	1.00	5,248,283	1,920,672	0.37
2 ANCLOTE	1	522	114,197	29.4	95.29	10,228	HEAVY OIL	179,270 BBLS	6.51	1,167,045	10,007,359	8.77
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	526	41,022	10.5	35.82	10,388	HEAVY OIL	65,459 BBLS	6.51	426,141	3,656,778	8.92
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	125	12,828	13.8	43.80	10,980	HEAVY OIL	21,636 BBLS	6.51	140,853	1,227,228	9.57
7 BARTOW	2	124	16,503	17.9	80.33	11,679	HEAVY OIL	29,607 BBLS	6.51	192,742	1,679,327	10.18
8 BARTOW	3	215	54,801	34.3	94.15	10,628	HEAVY OIL	89,467 BBLS	6.51	582,428	5,074,593	9.26
9 BARTOW	3		0	0.0		0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	386	185,211	64.5	95.69	67.6	10,262	COAL	77,661 TONS	24.47	1,900,668	5,835,614	3.15
11 CRYSTAL RIVER	2	496	233,027	63.1	89.95	70.1	9,974	COAL	94,964 TONS	24.47	2,324,152	7,135,710	3.06
12 CRYSTAL RIVER	4	734	426,530	78.1	93.56	83.7	9,507	COAL	166,115 TONS	24.41	4,055,203	12,603,174	2.95
13 CRYSTAL RIVER	5	734	427,560	78.3	93.15	83.7	9,529	COAL	166,893 TONS	24.41	4,074,184	12,660,762	2.96
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0	GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	82	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0	GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	70	59	0.1	93.50	4.6	53,576	LIGHT OIL	545 BBLS	5.80	3,161	54,704	92.72
21 AVON PARK	1-2		289				28,343	GAS	8,191 MCF	1.00	8,191	108,777	37.64
22 BARTOW	1-4	226	2,803	2.3	96.92	28.3	19,542	LIGHT OIL	9,451 BBLS	5.80	54,775	957,234	34.15
23 BARTOW	1-4		1,111				19,573	GAS	21,746 MCF	1.00	21,746	283,342	25.50
24 BAYBORO	1-4	232	7,628	4.4	99.42	52.2	17,420	LIGHT OIL	22,925 BBLS	5.80	132,878	2,322,142	30.44
25 DEBARY	1-10	779	6,795	2.7	94.92	39.3	17,442	LIGHT OIL	20,448 BBLS	5.80	118,515	2,076,316	30.56
26 DEBARY	1-10		8,765				14,140	GAS	123,939 MCF	1.00	123,939	1,291,110	14.73
27 HIGGINS	1-4	133	0	0.0	49.08	25.3	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		555				26,285	GAS	14,588 MCF	1.00	14,588	202,242	36.44
29 HINES	1-4	2,177	606,441	37.4	64.78	16.8	7,167	GAS	4,346,467 MCF	1.00	4,346,467	42,503,497	7.01
30 HINES	1-4		0				0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,184	12,270	5.1	66.66	38.2	15,912	LIGHT OIL	33,686 BBLS	5.80	195,241	3,497,546	28.50
32 INT CITY	1-14		32,443				13,638	GAS	442,466 MCF	1.00	442,466	4,243,261	13.08
33 RIO PINAR	1	16	228	1.9	98.67	62.0	24,535	LIGHT OIL	965 BBLS	5.80	5,594	97,536	42.78
34 SUWANNEE	1-3	199	0	0.0	66.56	62.3	0	LIGHT OIL	0 BBLS		0	0	0.00
35 SUWANNEE	1-3		4,216				14,026	GAS	59,162 MCF	1.00	59,162	505,918	11.97
36 TIGER BAY	1	225	0	0.0	0.00	0.0	0	GAS	0 MCF		0	466,289	0.00
37 TURNER	1-4	201	3,184	2.1	99.00	9.3	25,239	LIGHT OIL	13,866 BBLS	5.80	80,360	1,404,351	44.11
38 UNIV OF FLA	1	47	29,606	84.7	85.51	102.1	9,089	GAS	269,099 MCF	1.00	269,099	2,186,088	7.38
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	7,848 BBLS	5.80	45,489	787,472	0.00
40 OTHER													
41 TOTAL	10,285	2,742,976				9,491				26,033,370	124,770,245	4.55

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: May-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	484,224	84.6	83.87	100.9	10,360 NUCLEAR	5,016,559 MMBTU	1.00	5,016,559	1,836,061	0.38
2 ANCLOTE	4	498	163,483	44.1	96.01	45.0	10,133 HEAVY OIL	254,464 BBLS	6.51	1,656,562	14,824,095	9.07
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	507	133,535	35.4	96.85	35.6	10,415 HEAVY OIL	213,636 BBLS	6.51	1,390,773	12,446,797	9.32
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	19,794	22.0	95.25	46.5	11,096 HEAVY OIL	33,738 BBLS	6.51	219,637	1,921,767	9.71
7 BARTOW	2	119	21,266	24.0	62.21	37.2	11,723 HEAVY OIL	38,297 BBLS	6.51	249,311	2,181,407	10.26
8 BARTOW	3	204	66,494	43.8	93.16	45.0	10,679 HEAVY OIL	109,079 BBLS	6.51	710,105	6,213,255	9.34
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	193,717	68.7	93.48	70.3	10,294 COAL	81,555 TONS	24.45	1,994,189	6,066,886	3.13
11 CRYSTAL RIVER	2	491	259,316	71.0	92.69	74.6	10,024 COAL	106,311 TONS	24.45	2,599,511	7,908,275	3.05
12 CRYSTAL RIVER	4	722	455,510	84.8	94.11	86.2	9,626 COAL	179,878 TONS	24.38	4,384,695	13,602,953	2.99
13 CRYSTAL RIVER	5	721	446,696	83.3	93.66	86.3	9,630 COAL	176,545 TONS	24.38	4,303,450	13,356,355	2.99
14 SUWANNEE	1	30	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	50	72	0.2	95.81	5.4	32,125 LIGHT OIL	399 BBLS	5.80	2,313	38,971	54.13
21 AVON PARK	1-2		474				21,814 GAS	10,340 MCF	1.00	10,340	126,690	27.19
22 BARTOW	1-4	176	476	2.6	97.02	53.8	19,639 LIGHT OIL	1,612 BBLS	5.80	9,348	159,089	33.42
23 BARTOW	1-4		3,144				16,335 GAS	51,356 MCF	1.00	51,356	524,881	16.69
24 BAYBORO	1-4	177	2,308	1.8	98.79	68.6	15,503 LIGHT OIL	6,173 BBLS	5.80	35,780	606,922	26.30
25 DEBARY	1-10	643	4,621	4.9	98.77	67.8	15,948 LIGHT OIL	12,714 BBLS	5.80	73,695	1,255,124	27.16
26 DEBARY	1-10		18,622				13,669 GAS	257,277 MCF	1.00	257,277	2,473,310	13.14
27 HIGGINS	1-4	110	0	0.0	48.63	99.1	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		2,696				16,737 GAS	45,156 MCF	1.00	45,156	470,899	17.45
29 HINES	1-4	1,917	963,947	67.5	90.93	20.1	7,042 GAS	6,782,077 MCF	1.00	6,782,077	64,454,120	6.69
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	992	4,991	10.4	62.50	63.3	14,264 LIGHT OIL	12,283 BBLS	5.80	71,194	1,237,360	24.79
32 INT CITY	1-14		71,524				12,835 GAS	918,042 MCF	1.00	918,042	8,459,872	11.83
33 RIO PINAR	1	13	196	2.0	99.03	76.2	21,455 LIGHT OIL	733 BBLS	5.80	4,248	72,125	36.43
34 SUWANNEE	1-3	157	720	6.3	67.63	85.0	14,775 LIGHT OIL	1,835 BBLS	5.80	10,638	193,187	26.83
35 SUWANNEE	1-3		5,666				13,456 GAS	89,697 MCF	1.00	89,697	781,910	11.72
36 TIGER BAY	1	203	46,811	31.0	35.01	88.4	7,439 GAS	348,234 MCF	1.00	348,234	3,498,434	7.47
37 TURNER	1-4	150	1,510	1.4	99.19	48.7	16,452 LIGHT OIL	4,286 BBLS	5.80	24,842	422,774	28.00
38 UNIV OF FLA	1	45	32,724	97.7	97.74	100.0	9,182 GAS	300,473 MCF	1.00	300,473	2,505,290	7.66
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	6,797 BBLS	5.80	39,395	665,038	0.00
40 OTHER												
41 TOTAL	9,305	3,405,042				9,280				31,598,897	168,307,928	4.94

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Jul-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (¢/KWH)
1 CRYS RIV NUC	3	769	577,344	100.9	100.90	100.9	10,369 NUCLEAR	5,981,261 MMBTU	1.00	5,981,281	2,189,150	0.38
2 ANCLOTE	1	498	172,987	46.7	95.93	48.2	10,099 HEAVY OIL	268,359 BBLS	6.51	1,747,082	15,630,209	9.04
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	507	147,892	39.2	95.14	39.5	10,356 HEAVY OIL	235,272 BBLS	6.51	1,531,620	13,703,485	9.27
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	41,048	45.6	95.25	46.3	11,108 HEAVY OIL	70,041 BBLS	6.51	455,969	4,077,127	9.93
7 BARTOW	2	119	34,096	38.5	96.52	38.6	11,644 HEAVY OIL	60,990 BBLS	6.51	397,042	3,550,221	10.41
8 BARTOW	3	204	74,055	48.8	95.59	49.6	10,600 HEAVY OIL	120,585 BBLS	6.51	785,011	7,019,314	9.48
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	199,145	70.6	94.27	72.0	10,280 COAL	83,763 TONS	24.44	2,047,163	6,191,184	3.11
11 CRYSTAL RIVER	2	491	267,235	73.2	93.61	75.8	10,020 COAL	109,564 TONS	24.44	2,677,750	8,098,079	3.03
12 CRYSTAL RIVER	4	722	470,021	87.5	95.27	89.2	9,599 COAL	185,910 TONS	24.27	4,511,663	13,773,159	2.93
13 CRYSTAL RIVER	5	721	464,652	86.6	94.70	89.5	9,603 COAL	183,873 TONS	24.27	4,462,241	13,623,558	2.93
14 SUWANNEE	1	30	9,136	40.9	93.55	63.6	12,296 HEAVY OIL	17,256 BBLS	6.51	112,335	1,227,485	13.44
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	9,496	41.2	98.71	61.5	12,530 HEAVY OIL	18,277 BBLS	6.51	118,985	1,300,149	13.69
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	21,103	35.5	83.05	41.6	11,230 HEAVY OIL	36,403 BBLS	6.51	236,984	2,589,524	12.27
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	50	268	0.7	94.03	18.2	24,045 LIGHT OIL	1,112 BBLS	5.79	6,444	107,902	40.26
21 AVON PARK	1-2		269				24,312 GAS	6,540 MCF	1.00	6,540	98,221	36.51
22 BARTOW	1-4	176	10,535	10.9	97.18	37.3	19,311 LIGHT OIL	35,101 BBLS	5.80	203,444	3,441,178	32.65
23 BARTOW	1-4		3,733				17,612 GAS	65,744 MCF	1.00	65,744	674,479	18.07
24 BAYBORO	1-4	177	22,993	17.5	99.19	68.5	14,764 LIGHT OIL	58,569 BBLS	5.80	339,466	5,741,573	24.97
25 DEBARY	1-10	643	17,649	9.9	98.65	50.4	16,290 LIGHT OIL	49,602 BBLS	5.80	287,496	4,859,791	27.54
26 DEBARY	1-10		29,505				13,939 GAS	411,308 MCF	1.00	411,308	3,966,628	13.44
27 HIGGINS	1-4	110	0	0.0	97.34	82.1	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		3,315				17,443 GAS	57,894 MCF	1.00	57,894	602,226	18.17
29 HINES	1-4	1,917	1,170,676	82.1	97.38	21.6	6,955 GAS	8,154,244 MCF	1.00	8,154,244	79,418,056	6.78
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	992	22,395	14.8	91.91	47.4	14,403 LIGHT OIL	55,649 BBLS	5.80	322,545	5,553,369	24.80
32 INT CITY	1-14		56,708				13,287 GAS	1,152,118 MCF	1.00	1,152,118	10,924,180	19.26
33 RIO PINAR	1	13	167	1.7	98.39	80.3	20,551 LIGHT OIL	592 BBLS	5.80	3,432	57,914	34.68
34 SUWANNEE	1-3	157	6,354	13.6	99.35	68.6	14,770 LIGHT OIL	16,192 BBLS	5.80	93,851	1,689,069	26.58
35 SUWANNEE	1-3		9,478				14,033 GAS	133,003 MCF	1.00	133,003	1,207,281	12.74
36 TIGER BAY	1	203	118,653	78.6	94.52	89.0	7,430 GAS	881,782 MCF	1.00	881,782	8,470,312	7.14
37 TURNER	1-4	150	5,738	5.1	98.63	12.2	22,328 LIGHT OIL	21,989 BBLS	5.80	127,449	2,155,752	37.77
38 UNIV OF FLA	1	45	32,616	97.4	97.42	100.0	9,183 GAS	299,520 MCF	1.00	299,520	2,607,763	8.00
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	6,518 BBLS	5.80	37,781	637,917	0.00
40 OTHER												
41 TOTAL	9,305	4,029,271				9,344				37,649,189	225,187,587	5.59

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Aug-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	577,344	100.9	100.00	10,360	NUCLEAR	5,981,281 MMBTU	1.00	5,981,281	2,159,150	0.36
2 ANCLOTE	1	496	180,135	48.6	95.22	49.4	10,089 HEAVY OIL	279,169 BBLS	6.51	1,817,387	16,384,671	9.10
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	507	182,452	43.1	95.89	43.2	10,307 HEAVY OIL	257,205 BBLS	6.51	1,674,406	15,095,646	8.29
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	44,639	49.6	95.61	50.4	11,009 HEAVY OIL	75,491 BBLS	6.51	491,444	4,426,322	9.92
7 BARTOW	2	119	37,508	42.4	96.94	43.1	11,508 HEAVY OIL	66,306 BBLS	6.51	431,650	3,887,771	10.37
8 BARTOW	3	204	76,813	50.6	93.30	51.4	10,575 HEAVY OIL	124,779 BBLS	6.51	812,311	7,316,297	9.52
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	197,847	70.2	92.07	72.3	10,277 COAL	83,189 TONS	24.44	2,033,311	6,128,962	3.10
11 CRYSTAL RIVER	2	491	257,016	73.1	91.69	78.1	10,006 COAL	109,305 TONS	24.44	2,671,642	8,052,892	3.02
12 CRYSTAL RIVER	4	722	477,164	88.8	95.98	91.2	9,586 COAL	188,889 TONS	24.22	4,574,125	13,939,360	2.92
13 CRYSTAL RIVER	5	721	469,252	87.5	93.54	90.6	9,594 COAL	185,919 TONS	24.22	4,502,219	13,722,060	2.92
14 SUWANNEE	1	30	13,443	60.2	94.19	63.9	12,294 HEAVY OIL	25,387 BBLS	6.51	165,267	1,812,316	13.48
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	13,981	60.6	98.06	61.8	12,527 HEAVY OIL	26,904 BBLS	6.51	175,143	1,920,618	13.74
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	21,455	36.0	83.19	42.5	11,213 HEAVY OIL	36,955 BBLS	6.51	240,578	2,638,178	12.30
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	50	182	0.5	93.87	11.7	25,571 LIGHT OIL	803 BBLS	5.80	4,654	77,115	42.37
21 AVON PARK	1-2		440				22,396 GAS	9,855 MCF	1.00	9,855	129,176	29.36
22 BARTOW	1-4	176	844	3.8	57.82	54.5	19,712 LIGHT OIL	2,870 BBLS	5.80	16,637	278,495	33.00
23 BARTOW	1-4		4,190				16,075 GAS	67,356 MCF	1.00	67,356	695,016	16.59
24 BAYBORO	1-4	177	7,252	5.5	98.63	69.6	14,981 LIGHT OIL	18,770 BBLS	5.80	108,794	1,821,160	25.08
25 DEBARY	1-10	643	18,024	6.3	98.65	49.3	16,220 LIGHT OIL	50,438 BBLS	5.80	292,342	4,876,022	27.05
26 DEBARY	1-10		21,451				13,730 GAS	294,513 MCF	1.00	294,513	2,932,288	13.67
27 HIGGINS	1-4	110	0	0.0	96.94	78.5	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		4,445				17,834 GAS	79,271 MCF	1.00	79,271	804,216	18.09
29 HINES	1-4	1,917	1,178,245	82.6	96.67	21.7	6,963 GAS	8,203,555 MCF	1.00	8,203,555	80,584,849	6.84
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	992	12,072	12.8	91.77	55.9	14,598 LIGHT OIL	30,404 BBLS	5.80	176,230	2,981,447	24.70
32 INT CITY	1-14		82,250				12,940 GAS	1,064,353 MCF	1.00	1,064,353	10,220,839	12.43
33 RIO PINAR	1	13	318	3.3	99.35	78.9	21,242 LIGHT OIL	1,165 BBLS	5.80	6,755	112,805	35.47
34 SUWANNEE	1-3	157	1,576	9.4	99.78	80.9	14,704 LIGHT OIL	3,998 BBLS	5.80	23,174	410,132	26.02
35 SUWANNEE	1-3		8,252				13,621 GAS	112,401 MCF	1.00	112,401	1,030,129	12.48
36 TIGER BAY	1	203	117,851	78.0	94.64	89.7	7,417 GAS	874,115 MCF	1.00	874,115	8,477,350	7.19
37 TURNER	1-4	150	5,954	5.3	97.82	16.3	20,020 LIGHT OIL	20,566 BBLS	5.80	119,200	1,995,351	33.51
38 UNIV OF FLA	1	45	32,940	98.4	98.39	100.0	9,181 GAS	302,418 MCF	1.00	302,418	2,665,601	8.09
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	7,121 BBLS	5.80	41,273	688,903	0.00
40 OTHER												
41 TOTAL	9,305	4,035,345				9,260				37,367,660	219,269,539	5.41

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Sep-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (CK/WH)
1 CRYS RIV NUC	3	769	455,600	81.4	83.33	10,350	NUCLEAR	4,823,614 MMBTU	1.00	4,823,614	1,765,444	0.38
2 ANCLOTE	1	498	182,316	49.2	94.67	10,057	HEAVY OIL	281,651 BBLS	6.51	1,833,550	16,522,789	9.06
3 ANCLOTE	1		0			0	GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	507	153,159	40.6	95.58	42.5	10,308	HEAVY OIL	242,505 BBLS	6.51	1,578,705	14,227,301	9.29
5 ANCLOTE	2		0			0	GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	40,347	44.8	95.27	47.1	11,081	HEAVY OIL	68,676 BBLS	6.51	447,078	4,003,509	9.92
7 BARTOW	2	119	33,622	38.0	96.42	39.6	11,604	HEAVY OIL	58,928 BBLS	6.51	390,133	3,493,576	10.39
8 BARTOW	3	204	71,524	47.1	93.76	49.5	10,594	HEAVY OIL	116,389 BBLS	6.51	757,694	6,785,024	9.49
9 BARTOW	3		0			0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	205,952	73.0	94.56	76.8	10,242	COAL	86,284 TONS	24.45	2,109,292	6,338,985	3.08
11 CRYSTAL RIVER	2	491	270,609	74.1	91.00	82.3	9,981	COAL	110,486 TONS	24.45	2,700,931	8,116,861	3.00
12 CRYSTAL RIVER	4	722	464,399	86.5	92.32	93.4	9,568	COAL	183,709 TONS	24.19	4,443,554	13,531,444	2.91
13 CRYSTAL R VER	5	721	482,647	90.0	95.03	95.5	9,560	COAL	190,756 TONS	24.19	4,614,007	14,046,042	2.91
14 SUWANNEE	1	30	6,639	29.7	93.33	63.8	12,295	HEAVY OIL	12,539 BBLS	6.51	81,629	897,021	13.51
15 SUWANNEE	1		0			0	GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	2,983	12.9	97.33	61.7	12,526	HEAVY OIL	5,740 BBLS	6.51	37,366	410,615	13.77
17 SUWANNEE	2		0			0	GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	20,675	34.7	84.62	41.4	11,238	HEAVY OIL	35,690 BBLS	6.51	232,345	2,553,239	12.35
19 SUWANNEE	3		0			0	GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	50	436	1.2	94.59	15.3	32,583	LIGHT OIL	2,451 BBLS	5.80	14,206	240,996	55.27
21 AVON PARK	1-2		243				28,514	GAS	6,929 MCF	1.00	6,929	100,567	41.39
22 BARTOW	1-4	176	750	2.0	97.67	41.9	20,272	LIGHT OIL	2,624 BBLS	5.79	15,204	260,516	34.73
23 BARTOW	1-4		1,849				18,056	GAS	33,386 MCF	1.00	33,386	375,053	20.28
24 BAYBORO	1-4	177	3,376	2.6	98.92	67.5	15,282	LIGHT OIL	8,901 BBLS	5.80	51,593	884,013	26.19
25 DEBARY	1-10	643	4,143	3.9	98.77	58.6	17,423	LIGHT OIL	12,454 BBLS	5.80	72,185	1,233,716	29.75
26 DEBARY	1-10		14,674				13,872	GAS	203,565 MCF	1.00	203,565	2,046,115	13.94
27 HIGGINS	1-4	110	0	0.0	96.42	67.3	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		2,832				19,027	GAS	53,884 MCF	1.00	53,884	557,612	19.69
29 HINES	1-4	1,917	955,619	67.0	68.34	21.6	6,944	GAS	6,635,529 MCF	1.00	6,635,529	64,497,871	6.75
30 HINES	1-4		0				0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	992	5,301	9.7	91.83	57.8	14,690	LIGHT OIL	13,435 BBLS	5.80	77,871	1,351,557	25.50
32 INT CITY	1-14		86,602				12,954	GAS	862,747 MCF	1.00	862,747	8,150,003	12.24
33 RIO P NAR	1	13	395	4.1	99.00	77.9	21,408	LIGHT OIL	1,459 BBLS	5.80	8,456	144,556	36.59
34 SUWANNEE	1-3	157	837	4.7	99.67	73.2	15,260	LIGHT OIL	2,204 BBLS	5.80	12,773	231,656	27.66
35 SUWANNEE	1-3		4,679				14,095	GAS	65,950 MCF	1.00	65,950	567,357	12.55
36 TIGER BAY	1	203	110,617	73.2	95.33	90.8	7,399	GAS	818,453 MCF	1.00	818,453	7,755,515	7.01
37 TURNER	1-4	150	2,660	2.4	98.42	42.9	16,202	LIGHT OIL	7,436 BBLS	5.80	43,098	738,457	27.76
38 UN V OF FLA	1	45	31,752	94.5	98.00	99.9	9,182	GAS	291,533 MCF	1.00	291,533	2,485,433	7.83
39 OTHER - START UP		-	0	-		-	0	LIGHT OIL	7,515 BBLS	5.80	43,550	743,651	0.00
40 OTHER												
41 TOTAL	9,305	3,607,227				9,248				33,360,810	185,076,482	5.13

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Oct-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	577,344	100.9	100.56	100.9	10,360 NUCLEAR	5,981,281 MMBTU	1.00	5,981,281	2,189,150	0.38
2 ANCLOTE	1	498	82,746	22.3	53.01	45.6	10,128 HEAVY OIL	128,728 BBLS	6.51	838,020	7,515,657	9.05
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	597	144,354	38.3	96.65	35.6	10,365 HEAVY OIL	229,829 BBLS	6.51	1,496,185	13,412,585	9.29
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	121	38,939	43.3	96.71	43.5	11,181 HEAVY OIL	66,880 BBLS	6.51	435,386	3,965,894	10.18
7 BARTOW	2	119	21,356	24.1	98.45	36.7	11,799 HEAVY OIL	38,707 BBLS	6.51	251,984	2,295,301	10.75
8 BARTOW	3	204	67,496	44.5	93.14	45.6	10,662 HEAVY OIL	110,546 BBLS	6.51	719,654	6,555,267	9.71
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	379	190,377	57.5	92.55	69.8	10,299 COAL	80,200 TONS	24.45	1,960,727	5,867,058	3.08
11 CRYSTAL RIVER	2	491	120,295	32.9	39.45	72.9	10,031 COAL	49,355 TONS	24.45	1,206,625	3,610,785	3.00
12 CRYSTAL RIVER	4	722	467,112	87.0	94.01	88.9	9,588 COAL	185,216 TONS	24.18	4,478,532	13,623,607	2.92
13 CRYSTAL RIVER	5	721	463,117	86.3	93.94	89.0	9,602 COAL	183,907 TONS	24.18	4,446,880	13,528,145	2.92
14 SUWANNEE	1	30	1,869	8.4	93.57	63.6	12,296 HEAVY OIL	3,530 BBLS	6.51	22,982	253,101	13.54
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	2,287	9.9	97.66	61.5	12,531 HEAVY OIL	4,402 BBLS	6.51	28,659	315,622	13.80
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	80	3,298	5.5	61.58	40.8	11,253 HEAVY OIL	5,701 BBLS	6.51	37,111	408,703	12.39
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	50	44	0.1	95.15	6.3	34,705 LIGHT OIL	263 BBLS	5.81	1,527	26,750	60.80
21 AVON PARK	1-2		146				27,651 GAS	4,037 MCF	1.00	4,037	74,210	50.83
22 BARTOW	1-4	176	2,995	2.2	90.89	37.1	19,426 LIGHT OIL	10,005 BBLS	5.80	57,986	1,025,656	34.36
23 BARTOW	1-4		1,174				18,230 GAS	21,402 MCF	1.00	21,402	265,139	22.58
24 BAYBORO	1-4	177	3,504	2.7	93.24	68.3	15,033 LIGHT OIL	9,089 BBLS	5.80	52,676	931,732	26.59
25 DEBARY	1-10	643	6,945	4.6	99.16	53.9	16,572 LIGHT OIL	19,859 BBLS	5.80	115,092	2,042,998	29.42
26 DEBARY	1-10		15,089				13,754 GAS	207,678 MCF	1.00	207,678	2,051,851	13.59
27 HIGGINS	1-4	110	0	0.0	97.26	75.2	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		1,819				18,239 GAS	33,176 MCF	1.00	33,176	368,249	20.24
29 HINES	1-4	1,917	828,559	58.1	80.24	20.5	6,977 GAS	5,781,109 MCF	1.00	5,781,109	56,026,264	6.76
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	992	9,256	8.9	87.56	53.4	14,479 LIGHT OIL	23,125 BBLS	5.80	134,021	2,435,831	26.32
32 INT CITY	1-14		56,465				13,047 GAS	736,685 MCF	1.00	736,685	6,917,685	12.25
33 R O PINAR	1	13	92	1.0	98.06	78.5	21,565 LIGHT OIL	342 BBLS	5.80	1,984	35,014	38.06
34 SUWANNEE	1-3	157	3,173	6.5	76.69	70.4	14,841 LIGHT OIL	8,124 BBLS	5.80	47,089	892,572	28.12
35 SUWANNEE	1-3		4,457				13,759 GAS	61,326 MCF	1.00	61,326	537,052	12.05
36 TIGER BAY	1	203	57,299	37.9	47.78	86.6	7,465 GAS	427,704 MCF	1.00	427,704	4,211,835	7.35
37 TURNER	1-4	153	1,194	1.1	98.23	17.2	20,113 LIGHT OIL	4,143 BBLS	5.80	24,015	424,777	35.58
38 UNIV OF FLA	1	45	32,508	97.1	97.10	100.1	9,183 GAS	298,510 MCF	1.00	298,510	2,593,161	7.79
39 OTHER - START UP		-	0	-		-	0 LIGHT OIL	7,780 BBLS	5.80	45,088	792,536	0.00
40 OTHER												
41 TOTAL	9,305	3,205,289				9,346				29,955,131	155,106,187	4.84

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Nov-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQU V AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS R V NUC	3	788	568,050	96.9	100.00	10,191	NUCLEAR	5,789,305 MMBTU	1.00	5,789,305	2,118,885	0.37
2 ANCLOTE	1	522	111,843	28.8	88.17	40.6	10,059 HEAVY OIL	172,824 BBLS	6.51	1,125,084	10,180,052	9.10
3 ANCLOTE	1		0				0 GAS	0 MCF		0	0	0.00
4 ANCLOTE	2	528	118,700	30.3	94.93	31.9	10,409 HEAVY OIL	189,787 BBLS	6.51	1,235,513	11,178,537	9.42
5 ANCLOTE	2		0				0 GAS	0 MCF		0	0	0.00
6 BARTOW	1	125	13,923	15.3	97.90	39.9	11,028 HEAVY OIL	23,586 BBLS	6.51	153,545	1,331,833	9.57
7 BARTOW	2	124	13,128	14.2	95.96	31.4	11,687 HEAVY OIL	23,568 BBLS	6.51	153,427	1,330,810	10.14
8 BARTOW	3	215	45,273	28.3	95.09	39.4	10,556 HEAVY OIL	73,407 BBLS	6.51	477,882	4,145,098	9.16
9 BARTOW	3		0				0 GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER	1	386	200,936	70.0	95.88	73.3	10,225 COAL	84,035 TONS	24.45	2,054,665	6,156,339	3.06
11 CRYSTAL RIVER	2	496	257,190	69.7	91.37	76.9	9,946 COAL	104,624 TONS	24.45	2,558,049	7,664,478	2.98
12 CRYSTAL RIVER	4	734	0	0.0	0.00	0.0	0 COAL	0 TONS		0	116,355	0.00
13 CRYSTAL RIVER	5	734	444,402	81.4	93.97	85.7	9,513 COAL	173,526 TONS	24.36	4,227,789	12,888,505	2.90
14 SUWANNEE	1	33	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE	1		0				0 GAS	0 MCF		0	0	0.00
16 SUWANNEE	2	31	0	0.0	100.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE	2		0				0 GAS	0 MCF		0	0	0.00
18 SUWANNEE	3	82	0	0.0	0.00	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE	3		0				0 GAS	0 MCF		0	0	0.00
20 AVON PARK	1-2	70	30	0.1	95.33	6.1	52,700 LIGHT OIL	273 BBLS	5.79	1,581	27,966	93.22
21 AVON PARK	1-2		87				30,529 GAS	2,656 MCF	1.00	2,656	63,713	73.23
22 BARTOW	1-4	226	709	0.7	98.25	27.7	19,824 LIGHT OIL	2,425 BBLS	5.80	14,065	251,008	35.40
23 BARTOW	1-4		463				20,179 GAS	9,343 MCF	1.00	9,343	165,150	35.67
24 BAYBORO	1-4	232	1,128	0.7	99.00	51.2	17,755 LIGHT OIL	3,455 BBLS	5.80	20,028	357,680	31.71
25 DEBARY	1-10	779	1,123	1.2	98.50	52.5	18,963 LIGHT OIL	3,674 BBLS	5.80	21,295	381,713	33.99
26 DEBARY	1-10		5,664				13,956 GAS	79,047 MCF	1.00	79,047	972,903	17.18
27 HIGGINS	1-4	133	0	0.0	96.00	36.3	0 LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS	1-4		591				24,413 GAS	14,428 MCF	1.00	14,428	212,749	36.00
29 HINES	1-4	2,177	735,565	45.4	75.69	19.5	7,079 GAS	5,206,508 MCF	1.00	5,206,508	54,126,058	7.36
30 HINES	1-4		0				0 LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY	1-14	1,184	2,455	2.7	87.72	45.6	16,017 LIGHT OIL	6,784 BBLS	5.80	39,322	721,757	29.40
32 INT CITY	1-14		21,622				13,266 GAS	286,839 MCF	1.00	286,839	3,150,662	14.57
33 RIO PINAR	1	16	110	0.9	99.33	62.5	24,200 LIGHT OIL	459 BBLS	5.80	2,662	47,434	43.12
34 SUWANNEE	1-3	199	1,557	2.3	76.33	56.3	17,204 LIGHT OIL	4,621 BBLS	5.80	26,786	512,550	32.92
35 SUWANNEE	1-3		1,878				13,703 GAS	25,735 MCF	1.00	25,735	240,840	12.82
36 TIGER BAY	*	225	115,054	70.5	92.33	84.6	7,449 GAS	879,421 MCF	1.00	879,421	8,696,313	7.57
37 TURNER	1-4	201	672	0.4	98.50	22.3	19,077 LIGHT OIL	2,213 BBLS	5.79	12,820	228,953	34.07
38 UNIV OF FLA	1	47	0	0.0	0.00	0.0	0 GAS	0 MCF		0	-110,990	0.00
39 OTHER - START UP	-	-	0	-		-	0 LIGHT OIL	7,222 BBLS	5.80	41,860	746,406	0.00
40 OTHER												
41 TOTAL	10,285	2,665,185				9,177				24,459,645	127,897,758	4.80

Progress Energy Florida
System Net Generation and Fuel Cost
Estimated for the Month of: Dec-08

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC 3	788	587,016	100.1	100.00	100.1	10,191	NUCLEAR	5,982,282 MMBTU	1.00	5,982,282	2,189,514	0.37
2 ANCLOTE 1	522	122,615	31.6	95.19	34.1	10,155	HEAVY OIL	191,577 BBLS	6.51	1,247,165	11,301,661	9.20
3 ANCLOTE 1		0				0	GAS	0 MCF		0	0	0.00
4 ANCLOTE 2	526	101,890	26.0	94.34	26.5	10,552	HEAVY OIL	165,152 BBLS	6.51	1,075,141	9,743,805	9.56
5 ANCLOTE 2		0				0	GAS	0 MCF		0	0	0.00
6 BARTOW 1	125	9,199	9.9	95.47	48.0	11,023	HEAVY OIL	15,575 BBLS	6.51	101,403	829,862	9.02
7 BARTOW 2	124	6,317	5.8	97.74	32.2	11,672	HEAVY OIL	11,326 BBLS	6.51	73,734	603,425	9.55
8 BARTOW 3	215	34,856	21.6	95.26	37.1	10,602	HEAVY OIL	56,767 BBLS	6.51	369,551	3,024,333	8.68
9 BARTOW 3		0				0	GAS	0 MCF		0	0	0.00
10 CRYSTAL RIVER 1	386	215,263	75.0	92.73	76.2	10,206	COAL	89,854 TONS	24.45	2,197,118	6,574,340	3.05
11 CRYSTAL RIVER 2	496	290,202	78.6	93.68	82.4	9,918	COAL	117,707 TONS	24.45	2,878,176	8,612,066	2.97
12 CRYSTAL RIVER 4	734	337,434	56.3	57.33	93.3	9,451	COAL	119,330 TONS	24.35	2,905,695	8,897,365	2.89
13 CRYSTAL RIVER 5	734	476,266	87.2	93.11	91.0	9,489	COAL	185,593 TONS	24.35	4,519,187	13,773,338	2.89
14 SUWANNEE 1	33	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
15 SUWANNEE 1		0				0	GAS	0 MCF		0	0	0.00
16 SUWANNEE 2	31	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
17 SUWANNEE 2		0				0	GAS	0 MCF		0	0	0.00
18 SUWANNEE 3	82	0	0.0	83.87	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
19 SUWANNEE 3		0				0	GAS	0 MCF		0	0	0.00
20 AVON PARK 1-2	70	66	0.1	94.84	9.0	51,424	LIGHT OIL	586 BBLS	5.79	3,394	60,566	91.77
21 AVON PARK 1-2		89				29,169	GAS	2,596 MCF	1.00	2,596	64,577	72.56
22 BARTOW 1-4	226	244	0.4	96.77	26.4	19,959	LIGHT OIL	840 BBLS	5.80	4,870	87,733	35.96
23 BARTOW 1-4		413				21,080	GAS	8,706 MCF	1.00	8,706	163,966	39.70
24 BAYBORO 1-4	232	1,227	0.7	98.95	51.6	18,185	LIGHT OIL	3,849 BBLS	5.80	22,313	401,970	32.76
25 DEBARY 1-10	779	1,216	0.5	99.97	32.8	18,762	LIGHT OIL	3,935 BBLS	5.80	22,814	412,592	33.93
26 DEBARY 1-10		1,824				17,293	GAS	31,542 MCF	1.00	31,542	545,646	29.91
27 HIGGINS 1-4	133	0	0.0	97.58	32.3	0	LIGHT OIL	0 BBLS		0	0	0.00
28 HIGGINS 1-4		451				26,009	GAS	11,730 MCF	1.00	11,730	193,930	43.00
29 HINES 1-4	2,177	668,074	41.2	91.99	19.3	7,031	GAS	4,697,533 MCF	1.00	4,697,533	51,941,710	7.77
30 HINES 1-4		0				0	LIGHT OIL	0 BBLS		0	0	0.00
31 INT CITY 1-14	1,184	2,847	1.3	99.03	31.4	16,096	LIGHT OIL	7,905 BBLS	5.80	45,825	848,679	29.81
32 INT CITY 1-14		8,539				15,580	GAS	133,118 MCF	1.00	133,118	1,785,150	20.91
33 R O P NAR 1	16	59	0.5	96.71	61.5	24,254	LIGHT OIL	247 BBLS	5.79	1,431	25,722	43.60
34 SUWANNEE 1-3	199	746	1.4	99.57	53.9	16,471	LIGHT OIL	2,120 BBLS	5.80	12,287	237,139	31.79
35 SUWANNEE 1-3		1,400				14,994	GAS	20,992 MCF	1.00	20,992	207,977	14.86
36 TIGER BAY 1	225	106,263	63.5	94.52	86.7	7,404	GAS	786,814 MCF	1.00	786,814	8,261,603	7.77
37 TURNER 1-4	201	915	0.6	98.87	42.7	16,342	LIGHT OIL	2,590 BBLS	5.80	14,953	269,378	29.44
38 UNIV OF FLA. 1	47	34,099	97.5	95.45	102.2	9,093	GAS	310,050 MCF	1.00	310,050	2,960,812	8.68
39 OTHER - START UP	-	0	-		-	0	LIGHT OIL	7,863 BBLS	5.80	45,575	814,050	0.00
40 OTHER												
41 TOTAL	10,285	2,979,754				9,238				27,525,995	134,832,911	4.52

Progress Energy Florida
Inventory Analysis
Estimated for the Period of : January Through December 2008

	HEAVY OIL		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Subtotal
1	PURCHASES:								
2	UNITS	BBL	522,910	443,079	364,973	385,439	649,214	749,980	3,115,595
3	UNIT COST	$/BBL	57.44	56.66	55.64	56.16	57.90	58.80	57.38
4	AMOUNT	$	30,035,402	25,104,514	20,305,531	21,647,278	37,587,302	44,096,163	178,776,190
5	BURNED:								
6	UNITS	BBL	522,910	443,079	364,973	385,439	649,214	749,980	3,115,595
7	UNIT COST	$/BBL	57.44	56.66	55.64	56.16	57.90	58.80	57.38
8	AMOUNT	$	30,035,402	25,104,514	20,305,531	21,647,278	37,587,302	44,096,163	178,776,190
9	ENDING INVENTORY:								
10	UNITS	BBL	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	
11	UNIT COST	$/BBL	57.44	56.66	55.64	56.16	57.90	58.80	
12	AMOUNT	$	63,182,900	62,325,120	61,199,270	61,778,970	63,686,260	64,676,150	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	80,184	68,586	57,638	109,734	46,832	34,683	397,657
15	UNIT COST	$/BBL	106.11	106.23	104.61	102.04	99.35	98.27	103.31
16	AMOUNT	$	8,508,418	7,286,215	6,029,449	11,197,301	4,652,590	3,408,422	41,082,395
17	BURNED:								
18	UNITS	BBL	80,184	68,586	57,638	109,734	46,832	34,683	397,657
19	UNIT COST	$/BBL	106.11	106.23	104.61	102.04	99.35	98.27	103.31
20	AMOUNT	$	8,508,418	7,286,215	6,029,449	11,197,301	4,652,590	3,408,422	41,082,395
21	ENDING INVENTORY:								
22	UNITS	BBL	883,900	883,900	883,900	883,900	883,900	883,900	
23	UNIT COST	$/BBL	106.11	106.23	104.61	102.04	99.35	98.27	
24	AMOUNT	$	93,790,629	93,896,697	92,464,779	90,193,156	87,815,465	86,860,853	
	COAL								
25	PURCHASES:								
26	UNITS	TON	543,024	472,438	508,678	505,633	544,289	551,587	3,125,649
27	UNIT COST	$/TON	76.69	76.38	75.92	75.62	75.21	75.08	75.80
28	AMOUNT	$	41,644,619	36,086,185	38,618,579	38,235,260	40,934,343	41,410,670	236,929,655
29	BURNED:								
30	UNITS	TON	543,024	472,438	508,678	505,633	544,289	551,587	3,125,649
31	UNIT COST	$/TON	76.69	76.38	75.92	75.62	75.21	75.08	75.80
32	AMOUNT	$	41,644,609	36,086,162	38,618,562	38,235,261	40,934,370	41,410,696	236,929,657
33	ENDING INVENTORY:								
34	UNITS	TON	768,000	768,000	768,000	768,000	768,000	768,000	
35	UNIT COST	$/TON	76.69	76.38	75.92	75.62	75.21	75.08	
36	AMOUNT	$	58,898,074	58,662,067	58,306,176	58,075,085	57,758,976	57,657,984	
	GAS								
37	BURNED:								
38	UNITS	MCF	5,693,173	4,326,079	5,748,011	5,285,658	8,802,652	9,489,883	39,345,456
39	UNIT COST	$/MCF	11.43	11.53	11.39	9.79	9.46	9.51	10.31
40	AMOUNT	$	65,099,613	49,884,816	65,488,178	51,769,534	83,296,706	90,225,531	405,764,376
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	5,982,282	5,596,328	5,982,282	5,248,283	5,016,559	5,788,337	33,614,071
43	UNIT COST	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
44	AMOUNT	$	2,189,514	2,048,255	2,189,514	1,920,872	1,836,061	2,118,532	12,302,748

Progress Energy Florida
Inventory Analysis
Estimated for the Period of : January Through December 2008

	HEAVY OIL		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
1	PURCHASES:								
2	UNITS	BBL	827,193	892,196	823,118	568,323	483,172	440,398	7,169,995
3	UNIT COST	$/BBL	59.35	59.94	59.40	59.02	58.29	57.91	58.39
4	AMOUNT	$	49,097,514	53,481,221	48,893,074	34,722,130	28,166,340	25,503,086	418,639,555
5	BURNED:								
6	UNITS	BBL	827,193	892,196	823,118	568,323	483,172	440,398	7,169,995
7	UNIT COST	$/BBL	59.35	59.94	59.40	59.02	58.29	57.91	58.39
8	AMOUNT	$	49,097,514	53,481,221	48,893,074	34,722,130	28,166,340	25,503,086	418,639,555
9	ENDING INVENTORY:								
10	UNITS	BBL	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	
11	UNIT COST	$/BBL	59.35	59.94	59.40	59.02	58.29	57.91	
12	AMOUNT	$	65,289,840	65,937,740	65,339,780	64,920,680	64,124,060	63,700,120	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	245,324	136,135	58,479	82,730	31,126	29,925	981,376
15	UNIT COST	$/BBL	98.83	97.27	99.68	104.05	105.04	105.52	101.32
16	AMOUNT	$	24,244,775	13,241,430	5,829,106	8,607,866	3,269,467	3,157,829	99,432,868
17	BURNED:								
18	UNITS	BBL	245,324	136,135	58,479	82,730	31,126	29,925	981,376
19	UNIT COST	$/BBL	98.83	97.27	99.68	104.05	105.04	105.52	101.32
20	AMOUNT	$	24,244,775	13,241,430	5,829,106	8,607,866	3,269,467	3,157,829	99,432,868
21	ENDING INVENTORY:								
22	UNITS	BBL	883,900	883,900	883,900	883,900	883,900	883,900	
23	UNIT COST	$/BBL	98.83	97.27	99.68	104.05	105.04	105.52	
24	AMOUNT	$	87,355,837	85,976,953	88,107,152	91,969,795	92,844,856	93,269,128	
	COAL								
25	PURCHASES:								
26	UNITS	TON	563,110	567,302	571,235	498,678	362,185	512,484	6,200,643
27	UNIT COST	$/TON	74.03	73.76	73.58	73.45	74.07	73.87	74.80
28	AMOUNT	$	41,685,963	41,843,288	42,033,356	36,629,595	26,825,667	37,857,091	463,804,615
29	BURNED:								
30	UNITS	TON	563,110	567,302	571,235	498,678	362,185	512,484	6,200,643
31	UNIT COST	$/TON	74.03	73.76	73.58	73.45	74.07	73.87	74.80
32	AMOUNT	$	41,685,981	41,843,275	42,033,333	36,629,596	26,825,678	37,857,110	463,804,628
33	ENDING INVENTORY:								
34	UNITS	TON	768,000	768,000	768,000	768,000	768,000	768,000	
35	UNIT COST	$/TON	74.03	73.76	73.58	73.45	74.07	73.87	
36	AMOUNT	$	56,853,581	56,646,451	56,511,974	56,412,211	56,882,842	56,732,006	
	GAS								
37	BURNED:								
38	UNITS	MCF	11,162,153	11,007,837	8,971,976	7,571,627	6,503,977	6,003,081	90,566,107
39	UNIT COST	$/MCF	9.67	9.77	9.65	9.64	10.38	11.02	10.10
40	AMOUNT	$	107,970,168	107,534,464	86,555,526	72,957,446	67,517,389	66,125,373	914,424,740
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	5,981,281	5,981,281	4,823,614	5,981,281	5,789,305	5,982,282	68,153,115
43	UNIT COST	$/MMBTU	0.37	0.37	0.37	0.37	0.37	0.37	0.37
44	AMOUNT	$	2,189,150	2,189,150	1,765,444	2,189,150	2,118,885	2,189,514	24,944,041

Progress Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jan-08	ECONSALE	--	75,436		75,436	7.664	8.660	5,781,119	6,532,664	751,545
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	209,860		209,860	5.014	5.014	10,521,569	10,521,569	0
	TOTAL		285,296		285,296	5.714	5.978	16,302,688	17,054,233	751,545
Feb-08	ECONSALE	--	66,189		66,189	7.147	8.076	4,730,579	5,345,554	614,975
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	201,876		201,876	5.088	5.088	10,270,543	10,270,543	0
	TOTAL		268,065		268,065	5.596	5.825	15,001,122	15,616,097	614,975
Mar-08	ECONSALE	--	51,586		51,586	5.738	6.484	2,959,986	3,344,784	384,798
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	181,112		181,112	5.597	5.597	10,136,614	10,136,614	0
	TOTAL		232,698		232,698	5.628	5.794	13,096,600	13,481,398	384,798
Apr-08	ECONSALE	--	38,955		38,955	5.801	6.556	2,259,934	2,553,725	293,791
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	242,918		242,918	4.969	4.969	12,070,103	12,070,103	0
	TOTAL		281,873		281,873	5.084	5.188	14,330,037	14,623,828	293,791
May-08	ECONSALE	--	40,975		40,975	5.032	5.687	2,062,021	2,330,084	268,063
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	255,008		255,008	5.269	5.269	13,435,850	13,435,850	0
	TOTAL		295,983		295,983	5.236	5.327	15,497,871	15,765,934	268,063
Jun-08	ECONSALE	--	25,753		25,753	7.230	8.170	1,861,893	2,103,939	242,046
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	272,928		272,928	5.393	5.393	14,719,511	14,719,511	0
	TOTAL		298,681		298,681	5.552	5.633	16,581,404	16,823,450	242,046

Progress Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jul-08	ECONSALE	--	31,358		31,358	7.043	7.959	2,208,605	2,495,724	287,119
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	274,568		274,568	5.624	5.624	15,441,674	15,441,674	0
	TOTAL		305,926		305,926	5.769	5.863	17,650,279	17,937,398	287,119
Aug-08	ECONSALE	--	35,401		35,401	6.465	7.305	2,288,670	2,586,197	297,527
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	314,901		314,901	5.941	5.941	18,707,353	18,707,353	0
	TOTAL		350,302		350,302	5.994	6.079	20,996,023	21,293,550	297,527
Sep-08	ECONSALE	--	23,823		23,823	6.435	7.272	1,533,002	1,732,292	199,290
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	324,344		324,344	6.303	6.303	20,442,107	20,442,107	0
	TOTAL		348,167		348,167	6.312	6.369	21,975,109	22,174,399	199,290
Oct-08	ECONSALE	--	27,032		27,032	6.019	6.802	1,627,177	1,838,711	211,534
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	307,430		307,430	6.152	6.152	18,913,594	18,913,594	0
	TOTAL		334,462		334,462	6.141	6.205	20,540,771	20,752,305	211,534
Nov-08	ECONSALE	--	35,050		35,050	5.504	6.219	1,929,115	2,179,900	250,785
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	258,931		258,931	5.894	5.894	15,262,620	15,262,620	0
	TOTAL		293,981		293,981	5.848	5.933	17,191,735	17,442,520	250,785
Dec-08	ECONSALE	--	35,564		35,564	7.779	8.791	2,766,620	3,126,280	359,660
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(341,984)	(341,984)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	179,008		179,008	4.852	4.852	8,685,419	8,685,419	0
	TOTAL		214,572		214,572	5.337	5.345	11,452,039	11,469,715	17,676
Jan-08	ECONSALE	--	487,122		487,122	6.571	7.425	32,008,721	36,169,854	4,161,133
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-08	SALE OTHER	--	0		0	0.000	0.000	0	(341,984)	(341,984)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	3,022,884		3,022,884	5.578	5.578	168,606,955	168,606,955	0
	TOTAL		3,510,006		3,510,006	5.716	5.824	200,615,676	204,434,825	3,819,149

Progress Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jan-08	C P & LIME	--	94,802			94,802	3.886	3.886	3,684,210
	TECO	--	26,941			26,941	6.169	6.169	1,662,009
	SOUTHERN	UPS	296,856			296,856	2.399	2.399	7,121,574
	SHADY HILLS	--	39,499			39,499	13.884	13.884	5,484,063
	OSCEOLA	--	10,109			10,109	14.941	14.941	1,510,409
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		468,207	0	0	468,207	4.157	4.157	19,462,265
Feb-08	C P & LIME	--	88,099			88,099	3.909	3.909	3,443,621
	TECO	--	22,702			22,702	6.254	6.254	1,419,850
	SOUTHERN	UPS	277,704			277,704	2.362	2.362	6,559,367
	SHADY HILLS	--	37,096			37,096	14.697	14.697	5,452,079
	OSCEOLA	--	7,629			7,629	17.122	17.122	1,306,215
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		433,230	0	0	433,230	4.197	4.197	18,181,132
Mar-08	C P & LIME	--	92,249			92,249	3.921	3.921	3,616,707
	TECO	--	32,371			32,371	6.093	6.093	1,972,261
	SOUTHERN	UPS	296,856			296,856	2.342	2.342	6,952,367
	SHADY HILLS	--	55,713			55,713	13.429	13.429	7,481,666
	OSCEOLA	--	10,949			10,949	14.956	14.956	1,637,536
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		488,138	0	0	488,138	4.437	4.437	21,660,537
Apr-08	C P & LIME	--	91,291			91,291	3.955	3.955	3,610,566
	TECO	--	29,532			29,532	6.129	6.129	1,810,037
	SOUTHERN	UPS	287,280			287,280	2.344	2.344	6,733,845
	SHADY HILLS	--	25,279			25,279	13.475	13.475	3,406,285
	OSCEOLA	--	5,244			5,244	14.942	14.942	783,539
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		438,626	0	0	438,626	3.726	3.726	16,344,272
May-08	C P & LIME	--	94,164			94,164	4.251	4.251	4,002,724
	TECO	--	31,362			31,362	6.105	6.105	1,914,614
	SOUTHERN	UPS	296,856			296,856	2.357	2.357	6,996,897
	SHADY HILLS	--	65,437			65,437	10.978	10.978	7,183,819
	OSCEOLA	--	13,997			13,997	11.776	11.776	1,648,325
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		501,816	0	0	501,816	4.334	4.334	21,746,379
Jun-08	C P & LIME	--	91,930			91,930	4.246	4.246	3,903,330
	TECO	--	30,883			30,883	6.111	6.111	1,887,234
	SOUTHERN	UPS	287,280			287,280	2.370	2.370	6,808,536
	SHADY HILLS	--	67,807			67,807	11.150	11.150	7,560,362
	OSCEOLA	--	9,831			9,831	12.587	12.587	1,237,397
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	15,892			15,892	10.670	10.670	1,695,739
	TOTAL		503,623	0	0	503,623	4.585	4.585	23,092,598

Progress Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-08	C P & LIME	--	92,887			92,887	4.266	4.266	3,962,567
	TECO	--	30,814			30,814	6.112	6.112	1,883,314
	SOUTHERN	UPS	296,856			296,856	2.380	2.380	7,065,172
	SHADY HILLS	--	67,705			67,705	11.385	11.385	7,708,279
	OSCEOLA	--	19,599			19,599	11.595	11.595	2,272,455
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	22,707			22,707	10.869	10.869	2,468,129
	TOTAL		530,568	0	0	530,568	4.780	4.780	25,359,916
Aug-08	C P & LIME	--	94,483			94,483	4.251	4.251	4,016,669
	TECO	--	30,806			30,806	6.112	6.112	1,882,832
	SOUTHERN	UPS	296,856			296,856	2.386	2.386	7,082,987
	SHADY HILLS	--	102,194			102,194	11.136	11.136	11,380,770
	OSCEOLA	--	23,090			23,090	11.420	11.420	2,636,911
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	27,821			27,821	10.791	10.791	3,002,222
	TOTAL		575,250	0	0	575,250	5.216	5.216	30,002,391
Sep-08	C P & LIME	--	91,930			91,930	4.215	4.215	3,875,199
	TECO	--	30,342			30,342	6.118	6.118	1,856,344
	SOUTHERN	UPS	287,280			287,280	2.386	2.386	6,854,501
	SHADY HILLS	--	64,082			64,082	11.156	11.156	7,149,196
	OSCEOLA	--	12,791			12,791	11.906	11.906	1,522,930
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	16,687			16,687	10.587	10.587	1,766,575
	TOTAL		503,112	0	0	503,112	4.576	4.576	23,024,745
Oct-08	C P & LIME	--	43,411			43,411	3.960	3.960	1,719,257
	TECO	--	30,259			30,259	6.119	6.119	1,851,598
	SOUTHERN	UPS	296,856			296,856	2.402	2.402	7,130,479
	SHADY HILLS	--	55,552			55,552	11.112	11.112	6,173,046
	OSCEOLA	--	8,272			8,272	12.790	12.790	1,058,013
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		434,350	0	0	434,350	4.129	4.129	17,932,393
Nov-08	C P & LIME	--	50,434			50,434	3.967	3.967	2,000,902
	TECO	--	30,128			30,128	6.121	6.121	1,844,077
	SOUTHERN	UPS	287,280			287,280	2.413	2.413	6,932,068
	SHADY HILLS	--	11,055			11,055	16.436	16.436	1,816,964
	OSCEOLA	--	562			562	39.977	39.977	224,671
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		379,459	0	0	379,459	3.378	3.378	12,818,682
Dec-08	C P & LIME	--	94,483			94,483	4.003	4.003	3,781,974
	TECO	--	31,204			31,204	6.107	6.107	1,905,564
	SOUTHERN	UPS	296,856			296,856	2.452	2.452	7,278,907
	SHADY HILLS	--	10,495			10,495	18.015	18.015	1,890,651
	OSCEOLA	--	2,906			2,906	19.958	19.958	579,973
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	0			0	0.000	0.000	0
	TOTAL		435,944	0	0	435,944	3.541	3.541	15,437,069
Jan-08	C P & LIME	--	1,020,163			1,020,163	4.080	4.080	41,617,726
THRU	TECO		357,344			357,344	6.126	6.126	21,889,734
Dec-08	SOUTHERN	UPS	3,504,816			3,504,816	2.383	2.383	83,516,700
	SHADY HILLS	--	601,914			601,914	12.076	12.076	72,687,180
	OSCEOLA	--	124,979			124,979	13.137	13.137	16,418,374
	TEA	--	0			0	0.000	0.000	0
	SUMMER PURCH	--	83,107			83,107	10.748	10.748	8,932,665
	TOTAL		5,692,323	0	0	5,692,323	4.305	4.305	245,062,379

Progress Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jan-08	QUAL. FACILITIES	COGEN	385,468			385,468	3.425	7.815	13,200,614
Feb-08	QUAL. FACILITIES	COGEN	357,254			357,254	3.420	7.810	12,217,928
Mar-08	QUAL. FACILITIES	COGEN	275,307			275,307	3.551	7.941	9,775,404
Apr-08	QUAL. FACILITIES	COGEN	360,368			360,368	3.443	7.833	12,408,124
May-08	QUAL. FACILITIES	COGEN	372,839			372,839	3.468	7.858	12,928,410
Jun-08	QUAL. FACILITIES	COGEN	359,828			359,828	3.472	7.862	12,493,131
Jul-08	QUAL. FACILITIES	COGEN	370,394			370,394	3.472	7.862	12,859,334
Aug-08	QUAL. FACILITIES	COGEN	373,359			373,359	3.481	7.871	12,994,979
Sep-08	QUAL. FACILITIES	COGEN	354,237			354,237	3.465	7.855	12,273,870
Oct-08	QUAL. FACILITIES	COGEN	343,932			343,932	3.423	7.813	11,773,889
Nov-08	QUAL. FACILITIES	COGEN	367,667			367,667	3.425	7.816	12,594,058
Dec-08	QUAL. FACILITIES	COGEN	396,989			396,989	3.443	7.833	13,668,599
TOTAL	QUAL. FACILITIES	COGEN	4,317,642			4,317,642	3.455	7.845	149,188,340

Progress Energy Florida
Economy Energy Purchases
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-08	ECONPURCH	--	44,127	7.647	7.647	3,374,580	13.608	6,004,842	2,630,262
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		52,519	7.060	7.060	3,707,839	12.068	6,338,101	2,630,262
Feb-08	ECONPURCH	--	37,842	8.244	8.244	3,119,535	16.354	6,188,713	3,069,178
	SEPA	--	3,891	2.720	2.720	105,825	2.720	105,825	0
	SECI LOAD FOL	--	3,960	5.200	5.200	205,932	5.200	205,932	0
	TOTAL		45,693	7.509	7.509	3,431,292	14.226	6,500,470	3,069,178
Mar-08	ECONPURCH	--	45,024	8.564	8.564	3,855,851	15.311	6,893,731	3,037,880
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		53,416	7.842	7.842	4,189,110	13.530	7,226,990	3,037,880
Apr-08	ECONPURCH	--	46,287	7.319	7.319	3,387,570	16.969	7,854,387	4,466,817
	SEPA	--	4,025	2.720	2.720	109,475	2.720	109,475	0
	SECI LOAD FOL	--	4,097	5.200	5.200	213,034	5.200	213,034	0
	TOTAL		54,409	6.819	6.819	3,710,079	15.029	8,176,896	4,466,817
May-08	ECONPURCH	--	47,857	7.742	7.742	3,705,249	10.330	4,943,511	1,238,262
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		56,249	7.180	7.180	4,038,508	9.381	5,276,770	1,238,262
Jun-08	ECONPURCH	--	45,426	8.079	8.079	3,670,140	10.097	4,586,740	916,600
	SEPA	--	4,025	2.720	2.720	109,475	2.720	109,475	0
	SECI LOAD FOL	--	4,097	5.200	5.200	213,034	5.200	213,034	0
	TOTAL		53,548	7.456	7.456	3,992,649	9.168	4,909,249	916,600

Progress Energy Florida
Economy Energy Purchases
Estimated for the Period of : January Through December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-08	ECONPURCH	--	32,635	7.737	7.737	2,524,985	11.733	3,828,931	1,303,946
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		41,027	6.967	6.967	2,858,244	10.145	4,162,190	1,303,946
Aug-08	ECONPURCH	--	44,338	9.153	9.153	4,058,167	12.517	5,549,618	1,491,451
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		52,730	8.328	8.328	4,391,426	11.157	5,882,877	1,491,451
Sep-08	ECONPURCH	--	58,504	7.988	7.988	4,673,482	9.946	5,819,006	1,145,524
	SEPA	--	4,025	2.720	2.720	109,475	2.720	109,475	0
	SECI LOAD FOL	--	4,097	5.200	5.200	213,034	5.200	213,034	0
	TOTAL		66,626	7.499	7.499	4,995,991	9.218	6,141,515	1,145,524
Oct-08	ECONPURCH	--	59,183	7.447	7.447	4,407,427	12.895	7,631,918	3,224,491
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		67,575	7.015	7.015	4,740,686	11.787	7,965,177	3,224,491
Nov-08	ECONPURCH	--	56,472	7.222	7.222	4,078,601	12.882	7,274,706	3,196,105
	SEPA	--	4,025	2.720	2.720	109,475	2.720	109,475	0
	SECI LOAD FOL	--	4,097	5.200	5.200	213,034	5.200	213,034	0
	TOTAL		64,594	6.813	6.813	4,401,110	11.761	7,597,215	3,196,105
Dec-08	ECONPURCH	--	61,198	6.807	6.807	4,165,584	9.596	5,872,405	1,706,821
	SEPA	--	4,159	2.720	2.720	113,124	2.720	113,124	0
	SECI LOAD FOL	--	4,233	5.200	5.200	220,135	5.200	220,135	0
	TOTAL		69,590	6.465	6.465	4,498,843	8.917	6,205,664	1,706,821
Jan-08	ECONPURCH	--	578,893	7.777	7.777	45,021,171	12.515	72,448,508	27,427,337
THRU	SEPA	--	49,104	2.720	2.720	1,335,593	2.720	1,335,593	0
Dec-08	SECI LOAD FOL	--	49,979	5.200	5.200	2,599,013	5.200	2,599,013	0
	TOTAL		677,976	7.221	7.221	48,955,777	11.266	76,383,114	27,427,337

SCHEDULE E10

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January Through December 2008

	Actual Jan 07 - Dec 07 ($/1000 KWH)	Proposed Jan 08 - Dec 08 ($/1000 KWH)	Difference From Current $	Difference From Current %
Base Rate	$41.18	$43.91	$2.73	6.63%
Fuel Cost Recovery	47.98	42.78	(5.20)	-10.84%
Capacity Cost Recovery	11.32	11.92	0.60	5.30%
Energy Conservation Cost Recovery	1.96	1.97	0.01	0.51%
Environmental Cost Recovery	1.53	1.18	(0.35)	-22.88%
Storm Cost Recovery Surcharge	3.61	3.61	0.00	0.00%
Subtotal	107.58	105.37	(2.21)	-2.05%
Gross Receipts Tax	2.76	2.70	(0.06)	-2.17%
Total	$110.34	$108.07	($2.27)	-2.06%

Calculation of Inverted Residential Fuel Rates

	Annual Units MWH	Levelized Fuel Rate Cents/kwh	Annual Fuel Revenues	Inverted Fuel Rates Cents/kwh	Annual Fuel Revenues
Residential Excluding TOU:					
0 - 1,000 kwh	14,287,631	4.611	$ 658,802,681	4.278	$ 611,180,205
Over 1,000 kwh	7,143,149	4.611	329,370,612	5.278	376,993,088
Total	21,430,781		$ 988,173,293		$ 988,173,293

Rate Differential by Tier - Cents per KWH 1.000

Residential Sales:

Total	21,431,535
Time of Use	754
Levelized	21,430,781

Progress Energy Florida

Generating System Comparative Data by Fuel Type

		2005 Actual	2006 Actual	2007 Act/Est	2008 Projection	2006 vs. 2005	2007 vs. 2006	2008 vs. 2007
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		367,233,000	378,289,147	409,286,091	418,639,555	3.0%	8.2%	2.3%
LIGHT OIL		70,125,980	67,378,098	74,494,464	99,432,868	-3.9%	10.6%	33.5%
COAL		406,632,539	465,428,315	493,947,119	463,804,628	14.5%	6.1%	-6.1%
GAS		605,639,570	607,545,102	714,747,800	914,424,740	0.3%	17.6%	27.9%
NUCLEAR		22,014,242	22,792,753	22,578,535	24,944,041	3.5%	-0.9%	10.5%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,471,645,331	1,541,433,416	1,715,054,009	1,921,245,832	4.7%	11.3%	12.0%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		6,561,036	5,028,218	4,870,318	4,444,519	-23.4%	-3.1%	-8.7%
LIGHT OIL		465,368	270,080	290,812	314,678	-42.0%	7.7%	8.2%
COAL		15,834,368	15,511,295	15,574,553	15,520,789	-2.0%	0.4%	-0.3%
GAS		8,539,766	9,534,272	10,242,317	11,852,959	11.6%	7.4%	15.7%
NUCLEAR		5,828,926	6,342,696	6,028,714	6,633,840	8.8%	-5.0%	10.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	37,229,464	36,686,561	37,006,714	38,766,785	-1.5%	0.9%	4.8%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	10,324,044	8,061,132	7,769,207	7,169,995	-21.9%	-3.6%	-7.7%
LIGHT OIL	BBL	1,093,085	687,554	785,745	981,376	-37.1%	14.3%	24.9%
COAL	TON	6,248,696	6,142,809	6,149,510	6,200,643	-1.7%	0.1%	0.8%
GAS	MCF	68,576,640	74,757,926	79,798,031	90,566,107	9.0%	6.7%	13.5%
NUCLEAR	MMBTU	60,045,672	65,321,852	61,909,010	68,153,115	8.8%	-5.2%	10.1%
OTHER	BBL	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
HEAVY OIL		68,045,395	52,473,143	50,884,386	46,676,668	-22.9%	-3.0%	-8.3%
LIGHT OIL		6,269,167	3,983,556	4,517,770	5,688,084	-36.5%	13.4%	25.9%
COAL		153,353,783	151,455,333	150,795,265	151,183,621	-1.2%	-0.4%	0.3%
GAS		70,972,264	75,569,529	80,591,467	90,566,107	6.5%	6.6%	12.4%
NUCLEAR		60,045,672	65,321,852	61,909,010	68,153,115	8.8%	-5.2%	10.1%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	358,686,281	348,803,413	348,697,898	362,267,595	-2.8%	0.0%	3.9%
GENERATION MIX (% MWH)								
HEAVY OIL		17.62%	13.71%	13.16%	11.47%	-22.1%	-3.6%	-12.9%
LIGHT OIL		1.25%	0.74%	0.79%	0.81%	-40.0%	13.6%	0.0%
COAL		42.53%	42.28%	42.09%	40.04%	-0.7%	-0.5%	-5.0%
GAS		22.94%	25.99%	27.68%	30.58%	13.5%	6.5%	10.5%
NUCLEAR		15.66%	17.29%	16.29%	17.11%	10.2%	-5.8%	4.9%
OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT								
HEAVY OIL	$/BBL	35.57	46.93	52.68	58.39	31.9%	12.3%	10.8%
LIGHT OIL	$/BBL	64.15	98.00	94.81	101.32	52.8%	-3.3%	6.9%
COAL	$/TON	65.07	75.77	80.32	74.80	16.4%	6.0%	-6.9%
GAS	$/MCF	8.83	8.13	8.96	10.10	-8.0%	10.2%	12.7%
NUCLEAR	$/MMBTU	0.37	0.35	0.36	0.37	-4.9%	4.6%	0.3%
OTHER	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
HEAVY OIL		5.40	7.21	8.04	8.97	33.6%	11.6%	11.5%
LIGHT OIL		11.19	16.91	16.49	17.48	51.2%	-2.5%	6.0%
COAL		2.65	3.07	3.28	3.07	15.9%	6.6%	-6.3%
GAS		8.53	8.04	8.87	10.10	-5.8%	10.3%	13.8%
NUCLEAR		0.37	0.35	0.37	0.37	-4.9%	4.6%	0.3%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	$/MMBTU	4.10	4.42	4.92	5.30	7.7%	11.3%	7.8%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		10,371	10,436	10,448	10,502	0.6%	0.1%	0.5%
LIGHT OIL		13,471	14,750	15,535	18,076	9.5%	5.3%	16.4%
COAL		9,685	9,764	9,682	9,741	0.8%	-0.8%	0.6%
GAS		8,311	7,926	7,868	7,641	-4.6%	-0.7%	-2.9%
NUCLEAR		10,301	10,299	10,269	10,274	0.0%	-0.3%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	BTU/KWH	9,634	9,508	9,423	9,345	-1.3%	-0.9%	-0.8%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		5.60	7.52	8.40	9.42	34.4%	11.7%	12.1%
LIGHT OIL		15.07	24.95	25.62	31.60	65.6%	2.7%	23.4%
COAL		2.57	3.00	3.17	2.99	16.9%	5.7%	-5.8%
GAS		7.09	6.37	6.98	7.71	-10.2%	9.5%	10.5%
NUCLEAR		0.38	0.36	0.37	0.38	-4.8%	4.2%	0.3%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	C/KWH	3.95	4.20	4.63	4.96	6.3%	10.3%	6.9%

EXHIBIT TO THE DIRECT TESTIMONY
OF LORI CROSS

FUEL AND CAPACITY COST RECOVERY FACTOR
JANUARY THROUGH DECEMBER 2008

SECTION C - CAPACITY COST RECOVERY SCHEDULES

Schedule E-12 Projected Capacity Payments 2008
Schedule E-12 Calculation of Estimated/Actual True-up 2007
Schedule E-12 Capacity Contract Data
Calculation of Capacity Cost Recovery Factor

Progress Energy Florida
Schedule E12 - Capacity Costs
Projected Capacity Payments
For the Year 2008

		EST Jan-08	EST Feb-08	EST Mar-08	EST Apr-08	EST May-08	EST Jun-08	EST Jul-08	EST Aug-08	EST Sep-08	EST Oct-08	EST Nov-08	EST Dec-08	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	606,050	606,050	606,050	606,050	606,050	606,050	606,050	606,050	606,050	606,050	606,050	606,050	7,272,600
2	Auburndale Power Partners, L.P. (AUBSET)	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	2,816,139	33,793,668
3	Bay County (BAYCOUNT)	0	0	0	0	0	0	0	0	0	0	0	0	-
4	Cargill Fertilizer, Inc. (CARGILLF)	0	0	0	0	0	0	0	0	0	0	0	0	-
5	Jefferson Power L.C. (JEFFPOWR)	0	0	0	0	0	0	0	0	0	0	0	0	-
6	Lake County (LAKCOUNT)	568,140	568,140	568,140	568,140	568,140	568,140	568,140	568,140	568,140	568,140	568,140	568,140	6,817,680
7	Lake Cogen Limited (LAKORDER)	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	2,927,060	35,124,720
8	Metro-Dade County (METRDADE)	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	1,093,490	13,121,880
9	Orange Cogen (ORANGECO)	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	2,509,279	30,111,348
10	Orlando Cogen Limited (ORLACOGL)	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	2,245,430	26,945,160
11	Orlando Cogen Limited (ORLCOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	-
12	Pasco Cogen Limited (PASCCOGL)	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	3,481,959	41,783,508
13	Pasco County Resource Recovery (PASCOUNT)	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	1,025,110	12,301,320
14	Pinellas County Resource Recovery (PINCOUNT)	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	2,440,208	29,282,496
15	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	4,234,229	50,810,748
16	U.S Agri-Chemicals (AGRICHEM)	0	0	0	0	0	0	0	0	0	0	0	0	-
17	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,352
18	Central Power & Lime (133 MW)	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	2,128,000	25,536,000
19	UPS Purchase (414 total mw) - Southern	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	4,935,000	59,220,000
20	incremental Security	155,875	155,875	155,875	1,111,847	155,875	155,875	1,111,847	155,875	155,875	1,111,847	155,875	1,111,847	5,694,388
21	Subtotal - Base Level Capacity Charges	31,966,915	31,966,916	31,966,916	32,922,888	31,966,916	31,966,915	32,922,887	31,966,915	31,966,915	32,922,887	31,966,915	32,922,887	387,426,868
22	Base Production Jurisdictional Responsibility	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	
23	Base Level Jurisdictional Capacity Charges	29,969,942	29,969,942	29,969,942	30,866,194	29,969,942	29,969,942	30,866,194	29,969,942	29,969,942	30,866,194	29,969,942	30,866,194	363,224,312
	Intermediate Production Level Capacity Charges:													
24	TECO Power Purchase (70 mw)	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
25	Schedule H Capacity Sales	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(4,050)	(48,600)
26	Subtotal - Intermediate Level Capacity Charges	655,717	655,717	655,717	655,717	655,717	655,717	655,717	655,717	655,717	655,717	655,717	655,717	7,868,604
27	Intermediate Production Jurisdict. Responsibility	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	
28	Intermediate Level Jurisdict. Capacity Charges	518,318	518,318	518,318	518,318	518,319	518,318	518,318	518,318	518,318	518,318	518,318	518,318	6,219,818
	Peaking Production Level Capacity Charges:													
29	Chattahoochee	12,630	12,630	12,630	12,630	12,630	12,630	12,630	12,630	12,630	12,630	12,630	12,630	151,560
30	Osceola	606,720	606,720	606,720	606,720	606,720	606,720	606,720	606,720	606,720	606,720	606,720	606,720	7,280,640
31	TEA	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Shady Hills	1,954,260	1,954,260	1,395,900	1,395,900	1,954,260	4,187,700	4,187,700	4,187,700	1,954,260	1,395,900	1,395,900	1,954,260	27,918,000
33	Summer Purchases	0	0	0	0	0	2,025,000	2,025,000	2,025,000	2,025,000	0	0	0	8,100,000
34	Other Capacity Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Subtotal -Peaking Level Capacity Charges	2,573,610	2,573,610	2,015,250	2,015,250	2,573,610	6,832,050	6,832,050	6,832,050	4,598,610	2,015,250	2,015,250	2,573,610	43,450,200
36	Peaking Production Jurisdictional Responsibility	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	
37	Peaking Level Jurisdictional Capacity Charges	2,289,972	2,289,972	1,793,149	1,793,149	2,289,972	6,079,090	6,079,090	6,079,090	4,091,797	1,793,149	1,793,149	2,289,972	38,661,553
	Other Capacity Charges:													
38	Retail Wheeling	(81,694)	(71,680)	(55,865)	(42,187)	(44,374)	(27,889)	(33,959)	(38,338)	(25,799)	(29,275)	(37,958)	(38,514)	(527,533)
39	Total Jurisdictional Capacity Payments (Lines 23 + 28 + 37 + 38)	32,696,538	32,706,554	32,225,545	33,135,476	32,733,858	36,539,460	37,429,643	36,529,012	34,554,258	33,148,387	32,243,451	33,635,971	407,578,152
40	Estimated/Actual True-Up Provision for the Period January through December 2008													14,799,865
41	Total (Sum of lines 39 + 40)													422,378,017
42	Revenue Tax Multiplier													1.00072
43	Total Recoverable Capacity Payments													422,682,129

Progress Energy Florida
Schedule E12 - Capacity Costs
Calculation of Est/Act True-Up
For the Year 2007

Exhibit__LC-1P
Section C
Page 2 of 5

		ACTUAL Jan-07	ACTUAL Feb-07	ACTUAL Mar-07	ACTUAL Apr-07	ACTUAL May-07	ACTUAL Jun-07	ESTIMATED Jul-07	ESTIMATED Aug-07	ESTIMATED Sep-07	ESTIMATED Oct-07	ESTIMATED Nov-07	ESTIMATED Dec-07	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	535,840	603,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	569,840	6,838,080
2	Auburndale Power Partners, L.P. (AUBSET)	2,549,254	2,810,603	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	2,679,928	32,159,137
3	Bay County (BAYCOUNT)	263,780	(263,780)	0	0	0	0	0	0	0	0	0	0	-
4	Cargill Fertilizer, Inc. (CARGILLF)	528,300	582,000	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	555,150	6,661,800
5	Jefferson Power L.C. (JEFFPOWR)	0	0	0	0	0	0	0	0	0	0	0	0	-
6	Lake County (LAKCOUNT)	502,478	566,228	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	534,353	6,412,236
7	Lake Cogen Limited (LAKORDER)	2,664,651	2,934,217	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	2,799,434	33,593,208
8	Metro-Dade County (METRDADE)	989,860	1,091,340	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	1,040,600	12,487,200
9	Orange Cogen (ORANGECO)	2,276,516	2,502,988	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	2,389,752	28,677,024
10	Orlando Cogen Limited (ORLACOGL)	2,032,631	2,241,015	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	2,136,823	25,641,876
11	Orlando Cogen Limited (ORLCOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	-
12	Pasco Cogen Limited (PASCCOGL)	3,166,384	3,485,505	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	3,325,945	39,911,339
13	Pasco County Resource Recovery (PASCOUNT)	906,430	1,021,430	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	963,930	11,567,160
14	Pinellas County Resource Recovery (PINCOUNT)	2,157,698	2,431,448	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	2,294,573	27,534,876
15	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	3,832,935	4,224,590	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	4,028,763	48,345,155
16	U.S Agri-Chemicals (AGRICHEM)	0	0	0	0	0	0	0	0	0	0	0	0	-
17	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,352
18	Cargill Power Market	0	0	0	0	0	600,000	(600,000)	0	0	0	0	0	-
19	Central Power & Lime (133 MW)	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	1,357,930	16,295,160
20	UPS Purchase (414 total mw) - Southern	4,888,449	4,989,915	3,202,476	4,684,602	3,720,148	3,659,218	4,618,000	4,735,000	4,828,000	4,687,000	4,607,000	4,727,000	53,147,808
21	Incremental Security	13,977	72,049	42,116	302,628	109,301	63,713	341,573	50,571	23,561	871,087	99,688	871,087	2,861,351
22	Subtotal - Base Level Capacity Charges	29,469,059	31,452,265	28,722,560	30,465,198	29,307,417	29,800,898	29,837,540	30,263,538	30,129,528	31,036,054	30,184,655	31,076,054	361,744,762
23	Base Production Jurisdictional Responsibility	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	
24	Base Level Jurisdictional Capacity Charges	27,628,127	29,487,441	26,928,261	28,562,036	27,476,582	27,939,236	27,973,589	28,372,975	28,247,336	29,097,232	28,299,019	29,134,733	339,146,567
	Intermediate Production Level Capacity Charges:													
25	TECO Powor Purchase (70 mw)	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
26	Schedule H Capacity Sales	(4,601)	(4,156)	(4,601)	(4,453)	(138,617)	(4,050)	(4,601)	(4,601)	(4,453)	(4,453)	(4,453)	(4,453)	(187,691)
27	Subtotal - Intermediate Level Capacity Charges	655,166	655,611	655,166	655,314	520,950	655,717	655,166	655,166	655,314	655,314	655,314	655,314	7,729,513
28	Intermediate Production Jurisdict. Responsibility	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	79.046%	
29	Intermediate Level Jurisdict. Capacity Charges	517,883	518,234	517,883	518,000	411,791	518,318	517,882	517,882	518,000	518,000	518,000	518,000	6,109,872
	Peaking Production Level Capacity Charges:													
30	Chattahoochee	12,500	11,636	13,364	12,231	12,366	12,630	12,630	12,630	12,630	12,630	12,630	12,630	150,507
31	Osceola	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	1,213,440	606,720	606,720	606,720	12,741,120
32	TEA	200,000	200,000	0	0	0	262,500	725,000	725,000	725,000	0	0	0	2,837,500
33	Shady Hills	0	0	0	2,300,650	965,756	3,873,623	4,187,700	4,187,700	1,954,260	1,395,900	1,395,900	1,954,260	22,215,749
34	Cargill	0	0	0	0	0	0	1,200,000	600,000	600,000	0	0	0	2,400,000
35	Summer Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Other Capacity Purchases	862,500	862,500	0	0	0	250,000	0	0	0	0	0	0	1,975,000
37	Subtotal -Peaking Level Capacity Charges	2,288,440	2,287,576	1,226,804	3,526,321	2,191,562	5,612,193	7,338,770	6,738,770	4,505,330	2,015,250	2,015,250	2,573,610	42,319,876
38	Peaking Production Jurisdictional Responsibility	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	88.979%	
39	Peaking Level Jurisdictional Capacity Charges	2,036,231	2,035,462	1,091,598	3,137,685	1,950,030	4,993,673	6,529,964	5,996,090	4,008,798	1,793,149	1,793,149	2,289,972	37,655,802
	Other Capacity Charges:													
40	Retail Wheeling	(51,197)	(201,993)	(58,718)	(52,917)	(30,001)	(35,237)	(34,486)	(38,426)	(24,090)	(23,996)	(35,445)	(45,356)	(631,863)
41	Total Jurisdictional Capacity Payments	30,131,043	31,839,145	28,479,025	32,164,805	29,808,401	33,415,990	34,986,949	34,848,522	32,750,043	31,384,385	30,574,723	31,897,349	382,280,380
42	Capacity Cost Recovery Revenues (net of tax)	26,198,026	27,708,712	26,488,291	26,720,510	28,782,502	32,302,594	37,759,785	38,710,478	38,878,353	34,051,004	29,815,936	29,795,174	377,211,364
43	Prior Period True-Up Provision	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(448,380)	(5,380,565)
44	Current Period Revenues (net of tax) (line 42 + 43)	25,749,646	27,260,332	26,039,911	26,272,130	28,334,122	31,854,214	37,311,405	38,262,098	38,429,973	33,602,624	29,367,556	29,346,794	371,830,799
	True-Up Provision													
45	True-Up Provision - Over/(Under) Recov (line 44 - 41)	(4,381,398)	(4,578,814)	(2,439,114)	(5,892,675)	(1,474,278)	(1,561,777)	2,324,456	3,413,575	5,679,929	2,218,239	(1,207,167)	(2,550,556)	(10,449,581)
46	Interest Provision for the Month	(47,079)	(64,858)	(78,548)	(95,175)	(109,761)	(115,189)	(112,053)	(97,981)	(76,483)	(57,513)	(53,578)	(60,093)	(968,311)
47	Current Cycle Balance - Over/(Under) (line 45 + 46)	(4,428,477)	(9,072,148)	(11,589,811)	(17,577,661)	(19,161,690)	(20,838,656)	(18,626,253)	(15,310,659)	(9,707,212)	(7,546,487)	(8,807,232)	(11,417,881)	(11,417,892)
48	Plus: Prior Period Balance	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)	(8,762,537)
49	Plus Cumulative True up Provision	448,380	896,761	1,345,141	1,793,522	2,241,902	2,690,282	3,138,663	3,587,043	4,035,423	4,483,804	4,932,184	5,380,565	5,380,565
50	Net True-up Over/(Under) (lines 47 through 49)	(12,742,633)	(16,937,924)	(19,007,206)	(24,546,676)	(25,680,335)	(26,910,910)	(24,250,127)	(20,486,152)	(14,434,325)	(11,825,220)	(12,637,584)	(14,799,853)	(14,799,865)

Contract Data:

Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
Auburndale Power Partners, L.P. (AUBRDLFC)	Jan-95	Dec-13	QF	Purch	17.00
Auburndale Power Partners, L.P. (AUBSET)	Aug-94	Dec-13	QF	Purch	114.18
Lake County (LAKCOUNT)	Jan-95	Jun-14	QF	Purch	12.75
Lake Cogen Limited (LAKORDER)	Jul-93	Jul-13	QF	Purch	110.00
Metro-Dade County (METRDADE)	Nov-91	Nov-13	QF	Purch	43.00
Orange Cogen (ORANGECO)	Jul-95	Dec-24	QF	Purch	74.00
Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	79.20
Pasco Cogen Limited (PASCOGL)	Jul-93	Dec-08	QF	Purch	109.00
Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
Polk Power Partners, L. P. (MULBERY)	Aug-94	Aug-24	QF	Purch	79.20
Polk Power Partners, L. P. (ROYSTER)	Aug-94	Aug-09	QF	Purch	30.80
Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
UPS Purchase - Southern	Jul-88	May-10	Other	Purch	414.00
TECO Power Purchase	Mar-93	Feb-11	Other	Purch	70.00
Schedule H Capacity - New Smyrna Beach	Nov-85	(1)	Other	Sale	[redacted]
Reliant - Osceola	Jun-06	Feb-09	Other	Purch	
Shady Hills	Apr-07	Apr-24	Other	Purch	
Summer Purchases	Jun 08	Sep 08	Other	Purch	
Chattahoochee	Oct-02	Dec-17	Other	Purch	
Central Power & Lime	Dec-05	Dec-10	Other	Purch	

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Progress Energy Florida or NSB upon 1 year's written notice.

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Capacity Clause Recovery Factor
Using Current 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2008

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1))	(4) Delivery Efficiency Factor	(5) Sales at Source (Generation) (mWh) (2)/(4)	(6) Avg 12 CP at Source (MW) (3)/(4)	(7) Annual Average Demand (6)/8760hrs	(8) Annual Average Demand Allocator (%)	(9) 12CP Demand Transmission Allocator (%)	(10) 12CP & 1/13 AD Demand Allocator (%)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	0.550	21,431,535	4,448.22	0.9384179	22,837,944	4,740.13	2,607.07	51.727%	61.181%	60.454%
General Service Non-Demand										
GS-1, GST-1										
Secondary	0.658	1,391,472	241.40	0.9384179	1,482,785	257.25	169.27	3.358%	3.320%	3.323%
Primary	0.658	8,958	1.55	0.9668000	9,266	1.61	1.06	0.021%	0.021%	0.021%
Transmission	0.658	3,707	0.64	0.9768000	3,795	0.66	0.43	0.009%	0.008%	0.009%
								3.388%	3.350%	3.352%
General Service										
GS-2 Secondary	1.000	89,286	10.19	0.9384179	95,145	10.86	10.86	0.216%	0.140%	0.146%
General Service Demand										
GSD-1, GSDT-1										
Secondary	0.789	12,946,646	1,873.17	0.9384179	13,796,248	1,996.09	1,574.91	31.248%	25.764%	26.185%
Primary	0.789	2,465,111	356.66	0.9668000	2,549,763	368.91	291.07	5.775%	4.762%	4.839%
Transmission	0.789	0	0.00	0.9768000	0.00	0.00	0.00	0.000%	0.000%	0.000%
SS-1 Primary	1.264	0	0.00	0.9668000	0.00	0.00	0.00	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.264	10,208	0.92	0.9768000	10,450	0.94	1.19	0.024%	0.012%	0.013%
Transm Del/ Primary Mtr	1.264	3,388	0.31	0.9668000	3,504	0.32	0.40	0.008%	0.004%	0.004%
								37.055%	30.541%	31.042%
Curtailable										
CS-1, CST-1, CS-2, CST-2, SS-3										
Secondary	1.093	0	0.00	0.9384179	0.00	0.00	0.00	0.000%	0.000%	0.000%
Primary	1.093	193,300	20.19	0.9668000	199,938	20.88	22.82	0.453%	0.270%	0.284%
SS-3 Primary		2,146	0.00	0.9668000	2,220	0.00	0.25	0.005%	0.000%	0.000%
								0.458%	0.270%	0.284%
Interruptible										
IS-1, IST-1, IS-2, IST-2										
Secondary	0.927	120,638	14.86	0.9384179	128,555	15.83	14.68	0.291%	0.204%	0.211%
Primary Del / Primary Mtr	0.927	1,653,559	203.63	0.9668000	1,710,342	210.62	195.24	3.874%	2.718%	2.807%
Primary Del / Transm Mtr	0.927	2,884	0.36	0.9768000	2,952	0.36	0.34	0.007%	0.005%	0.005%
Transm Del/ Transm Mtr	0.927	457,736	56.37	0.9768000	468,608	57.71	53.49	1.061%	0.745%	0.769%
Transm Del/ Primary Mtr	0.927	410,751	50.58	0.9668000	424,856	52.32	48.50	0.962%	0.675%	0.697%
SS-2 Primary	0.749	0	0.00	0.9668000	0.00	0.00	0.00	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.749	10,516	1.60	0.9768000	10,766	1.64	1.23	0.024%	0.021%	0.021%
Transm Del/ Primary Mtr	0.749	32,837	5.00	0.9668000	33,965	5.18	3.88	0.077%	0.067%	0.068%
								6.297%	4.436%	4.579%
Lighting										
LS-1 (Secondary)	6.746	358,390	6.03	0.9384179	379,777	6.43	43.35	0.860%	0.083%	0.143%
		41,591,068	7,291.69		44,150,879	7,747.73	5,040.05	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed March 31, 2006
(2) Projected kWh sales for the period January 2008 to December 2008
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2006
(5) Column 2 / Column 4
(6) Column 3 / Column 4
(7) Calculated: Column 6 / 8,760 hours
(8) Column 7/ Total Column 7
(9) Column 6/ Total Column 6
(10) Column 8 x 1/13 + Column 9 x 12/13

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Capacity Cost Recovery Clause Factors by Rate Class
Using Current 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2008

Rate Class	(1) 12CP & 1/13 AD Demand Allocator (%)	(2) Production Demand Costs $	(3) Effective Mwh's @ Secondary Level Year 2008	(4) **Capacity Cost Recovery Factor (c/Kwh)**
Residential				
RS-1, RST-1, RSL-1, RSL-2, RSS-1				
Secondary	60.454%	$255,526,958	21,431,535	**1.192**
General Service Non-Demand				
GS-1, GST-1				
Secondary			1,391,472	**1.009**
Primary			8,868	**0.999**
Transmission			3,633	**0.989**
TOTAL GS	3.352%	$14,170,343	**1,403,973**	
General Service				
GS-2 Secondary	0.146%	$617,034	89,286	**0.691**
General Service Demand				
GSD-1, GSDT-1, SS-1				
Secondary			12,946,646	**0.852**
Primary			2,443,814	**0.843**
Transmission			10,004	**0.835**
TOTAL GSD	31.042%	$131,210,459	***15,400,464***	
Curtailable				
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3				
Secondary			-	**0.620**
Primary			193,492	**0.614**
Transmission			-	**0.608**
TOTAL CS	0.284%	$1,200,470	**193,492**	
Interruptible				
IS-1, IST-1, IS-2, IST-2, SS-2				
Secondary			120,638	**0.728**
Primary			2,076,176	**0.721**
Transmission			461,713	**0.713**
TOTAL IS	4.579%	$19,353,550	**2,658,527**	
Lighting				
LS-1 Secondary	0.143%	$603,315	356,390	**0.169**
	100.000%	$422,682,129	41,533,666	**1.018**

Notes:
(1) From Part D-6P, Column 10
(2) Column 1 x Total Production Demand Jurisdictional Dollars from Part D-1P, Total line
(3) Projected kWh sales at effective voltage level for the period January 2008 to December 2008
(4) Column 2/ Column 3 x 100

Progress Energy Florida, Inc.
Docket No. 070001-EI
Witness: McCallister
Exhibit No. JM-1T

PROGRESS ENERGY FLORIDA, INC.

Hedging information provided as part of the 2006 Fuel Clause Final True-up Filing as required by Order No. PSC-02-1484-FOF-EI, Issued October 30, 2002 in Docket No. 011605-EI

Hedging Instrument	Fuel Type	Total 2006 Volume Hedged	Avg Period of Hedge	Total Cost of Hedge	Total Gain/(Loss) of Hedge
OTC Financial Instruments	Heavy Oil	[redacted]			
OTC Financial Instruments	Light Oil				
OTC Financial Instruments	Natural Gas				
Fixed Physical Price Contracts	Natural Gas				
Total Net Savings					$118,999,150

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 9
COMPANY Progress Energy Fla, Inc.
WITNESS Joseph McCallister (JM-1
DATE 11-06-07

Progress Energy Florida, Inc.
Risk Management Plan
Fuel Procurement and Wholesale Power Purchases
For 2008

I. Objectives

Progress Energy Florida, Inc.'s ("PEF") Risk Management Plan objectives for 2008 are to manage overall costs through prudent and competitive fuel procurement and wholesale power purchase activities, provide reliable service by minimizing fuel supply risks, and reduce price risk and volatility. PEF's risk management activities reduce the impact of fuel price volatility to the fuel and purchased power portion of the customer fuel bill.

II. Fuel Procurement and Economy Power Projections

Based on current forecasts, PEF fuel burns and economy purchase and sales activity are as follows:

1. Coal
   PEF forecast to burn approximately [redacted] tons of coal in 2008.

2. Heavy Oil
   PEF forecast to burn approximately [redacted] barrels of heavy oil in 2008.

3. Light Oil
   PEF forecast to burn approximately [redacted] barrels of light oil in 2008.

4. Natural Gas
   PEF forecast to burn approximately [redacted] in 2008 in PEF's generating plants and under purchase power natural gas tolling agreements where PEF has the responsibility to purchase the natural gas.

5. Economy Purchases and Sales
   PEF forecast to purchase approximately [redacted] MWhrs and sell approximately [redacted] MWhrs in 2008 on the spot economy wholesale market.

III. Independent Oversight, Guidelines, and Audit Services

The company has independent oversight processes and structures to ensure the identification of key risks, and independent controls for monitoring and reporting on fuel procurement and wholesale power activities. The key components are described in detail below.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 10
COMPANY Progress Energy Fla, Inc.
WITNESS Joseph McCallister
DATE 11-06-07

1. Independent Oversight

The Company's Board of Directors has established a Risk Management Policy that directs the Risk Management Committee (RMC) to oversee PEF's financial risks. The RMC members are as follows:

- Chief Financial Officer – Progress Energy Inc. (Chair)
- President and Chief Operating Officer
- SVP Corporate Relations & General Counsel – Progress Energy, Inc.
- SVP Financial Services
- Treasurer and Chief Risk Officer (CRO)
- SVP Power Operations

The RMC assesses and monitors financial risks. This includes reviews of hedging and fuel procurement strategies as well as market and credit risk exposures. In addition, the RMC approves the Risk Management and Credit Risk Management Guidelines including approval for any new products.

The company has an established Treasury, Risk and Transaction Oversight Subcommittee (The Subcommittee) which is chaired by the Treasurer and CRO to provide additional independent oversight on the activities of the Regulated Commercial Operations and Regulated Fuels Departments. The Subcommittee reviews and recommends risk and credit guidelines and policies that require the identification of key risks and exposures within Regulated Commercial Operations and Regulated Fuels, and reviews proposed transactions and strategies. The Subcommittee submits guidelines, policies, proposed transactions and strategies to the RMC for review and discussion as required by corporate governance.

The company has an independent Enterprise Risk Management (ERM) group, which is overseen by the Director of Enterprise Management who reports to the Treasurer and CRO. The ERM group is comprised of a corporate credit section and a risk analytics and reporting section. ERM's credit function provides independent credit evaluation of trading and procurement counterparties, performs credit reviews of the company's suppliers and customers, assist in drafting and reviewing credit language in various agreements, and monitors and reports on credit exposures daily. ERM's risk analytics and reporting group independently reports on fuel procurement and hedging activities, and performs independent analysis as required. ERM independently prepares credit and risk summary reports, validates positions, performs mark to market calculations, administers margin activity with counterparties, and performs independent reviews of company activities as required.

2. Guidelines

As part of the overall risk management structure at the company, Risk Management and Credit Risk Management Guidelines have been established and are reviewed, updated and approved by the RMC at least annually.

PEF's Regulated Commercial Operations and Regulated Fuels Risk Management Guidelines (Risk Guidelines) provide the methods to assess, quantify, report, and monitor the activities associated with fuel procurement contracts, fuel hedging activities, and wholesale power activities. In addition, the Risk Guidelines outline approved products, approved periods, and risk parameters. Regulated Commercial Operations and Regulated Fuels Credit Risk Management Guidelines provide the methodology to evaluate, measure, mitigate, and report credit associated with Regulated Commercial Operations and Regulated Fuels activities. In

addition, the Credit Risk Management Guidelines outline specific contract duration criteria for counterparties based on credit metrics.

3. Audit Services
Audit Services provides independent assurance and consulting services that ensure compliance, effective corporate governance, adherence to established procedures and operational effectiveness for all major areas of the company. With respect to Regulated Commercial Operations and Regulated Fuels, Audit Services performs periodic audits that focus, but are not limited to, compliance with established procedures, payment terms under fuel contracts, and trading and procurement activities.

IV. Identification of Primary Risks and Risk Management Activities

As part of the Risk Management Plan, PEF has identified the primary risks associated with the procurement of fuels and wholesale power activity for 2008. The primary risks are fuel prices and volatility, supplier performance and credit risk, product availability and changes in forecasted volumes. These primary risks and the activities that reduce PEF's exposure to these risks are outlined below.

1. Price Risk and Volatility
PEF's customers are exposed to fuel prices and volatility, which could result in significant increases in fuel prices and costs. For natural gas, heavy oil and light oil, the majority of physical fuel contracts executed by PEF are based on published market index pricing. The published market index prices paid by PEF will fluctuate with daily changes in market prices until the respective first of the month market index or daily-published market index price settles. As a result, the projected costs for natural gas, heavy oil and light oil fuel purchases will change and could be volatile as market prices change over time.

PEF manages fuel price risk and volatility for its forecasted natural gas and fuel oil purchases by executing standard industry fixed price physical and financial swap and option agreements over time for a portion of its burn projections. This activity is executed under the approved hedging strategy. For coal, PEF enters into standard industry supply agreements to fix the price of the underlying coal. Because of these actions, PEF reduces its overall fuel price risk and volatility.

2. Supplier Performance and Credit Risk
Supplier performance and credit risk represent the risks of financial loss that PEF could incur if a supplier defaults on a supply obligation or is not able to fulfill the terms of an agreement. Supplier performance and credit risk can vary based on the terms and prices of the agreements, overall credit quality, and the current market value of the specific transaction under contract.

PEF reduces supplier performance and credit risk by conducting business with a number of suppliers, executing agreements within approved contract approval limits and credit parameter limits, monitoring contracts and delivery performance of suppliers and, if possible, incorporating contractual provisions that allow for non-performance remedies. In addition, PEF maintains on-site inventory for coal, heavy oil and light oil.

3. Product Availability and Changes in Forecasted Volumes
PEF must have access to needed physical fuel supplies, adequate product delivery capabilities and on-site inventory to meet its projected fuel requirements. Without access to needed fuel supply, PEF is exposed to the risk of not being able to economically and reliably dispatch the generation fleet.

PEF manages and reduces this risk by executing contracts for the purchase of the appropriate amount of supply and transportation for all of its fuel types. Specifically, PEF enters into short-term and long-term standard industry physical supply contracts and needed pipeline, railroad, barge and trucking agreements for the purchase and delivery of coal, natural gas, heavy oil and light oil that provide the supply and flexibility to meet projected burns. In addition, PEF maintains on-site inventory for coal, heavy oil and light oil to provide supplies to support on-going operations and ensure supplies for unexpected delivery delays, storm curtailments, and events that could affect fuel supply availability. PEF also has off-site natural gas storage contracts beginning in 2008 that will provide access for a portion of its natural gas needs in the event that gas supplies are curtailed due to storms. In addition, PEF's onshore gas supplies continue to increase in 2008 as new supply contracts enter the portfolio. Lastly, PEF actively monitors actual fuel burns versus forecasted fuel burns and will make procurement adjustments to account for changes in weather, fuel-switching capabilities, outages, and purchased power.

V. Fuel Procurement and Wholesale Purchased Power Plans for 2008

1. Coal
PEF forecasted coal requirements for 2008 will be purchased under term coal supply agreements. The coal supply will be delivered to PEF's plants via railroad and barge transportation agreements. Spot purchases will be made as needed.

2. Oil
PEF's forecasted heavy and light fuel oil requirements for 2008 will be purchased under term supply agreements with flexible volume provisions at indexed market prices. Spot market purchases will be utilized as needed.

3. Natural Gas
PEF's forecasted natural gas requirements for 2008 will be purchased primarily under term supply agreements that are primarily based on market index pricing. Spot purchases of natural gas will be utilized as needed.

4. Economy Power and Purchased Power
PEF actively seeks opportunities to make economy and term purchases based on market prices versus dispatch costs, available power and transmission, and overall needs.

Progress Energy Florida
Docket No. 070001-EI
Witness: Oliver
Exhibit No. _____ (RMO-1T)

GPIF REWARD/PENALTY SCHEDULES

Description	Sheet
Index	1
Reward/Penalty Table (Actual)	2
Calculation of Maximum Incentive Dollars (Actual)	3
Calculation of System Actual GPIF Points	4
GPIF Unit Performance Summary	5
Actual Unit Performance Data	6
Adjustments to EAF Actual	7
Adjustments to ANOHR Actual	8
Generating Performance Incentive Points Table	9-20
Actual Unit Performance Data	21-32
Planned Outage Schedules (Actual)	33-34

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 11
COMPANY Progress Energy FL Inc
WITNESS Robert M. Oliver (RMO-1
DATE 11-Dec-07

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Progress Energy Florida
Janauary 2006 - December 2006

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 95,865,141	$ 10,397,272
	9	$ 86,278,627	$ 9,357,545
	8	$ 76,692,113	$ 8,317,818
	7	$ 67,105,599	$ 7,278,091
	6	$ 57,519,085	$ 6,238,363
	5	$ 47,932,571	$ 5,198,636
	4	$ 38,346,057	$ 4,158,909
	3	$ 28,759,542	$ 3,119,182
	2	$ 19,173,028	$ 2,079,454
	1	$ 9,586,514	$ 1,039,727
****	0.584	$ 5,598,524	$ 607,201
	0	$ -	$ -
	-1	$ (7,197,314)	$ (1,039,727)
	-2	$ (14,394,628)	$ (2,079,454)
	-3	$ (21,591,942)	$ (3,119,182)
	-4	$ (28,789,257)	$ (4,158,909)
	-5	$ (35,986,571)	$ (5,198,636)
	-6	$ (43,183,885)	$ (6,238,363)
	-7	$ (50,381,199)	$ (7,278,091)
	-8	$ (57,578,513)	$ (8,317,818)
	-9	$ (64,775,827)	$ (9,357,545)
	-10	$ (71,973,141)	$ (10,397,272)

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Progress Energy Florida
Janauary 2006 - December 2006

1	Beginning of period balance of common equity	$ 2,594,524,998
	END OF MONTH BALANCE OF COMMON EQUITY:	
2	Month of JANUARY 2006	$ 2,619,757,000
3	Month of FEBRUARY 2006	$ 2,639,524,000
4	Month of MARCH 2006	$ 2,589,751,000
5	Month of APRIL 2006	$ 2,610,451,000
6	Month of MAY 2006	$ 2,583,701,000
7	Month of JUNE 2006	$ 2,617,539,000
8	Month of JULY 2006	$ 2,660,531,000
9	Month of AUGUST 2006	$ 2,650,190,000
10	Month of SEPTEMBER 2006	$ 2,683,487,000
11	Month of OCTOBER 2006	$ 2,710,362,000
12	Month of NOVEMBER 2006	$ 2,669,909,000
13	Month of DECEMBER 2006	$ 2,688,815,000
14	Average common equity for the period	$ 2,639,887,846
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum allowed incentive dollars	$ 10,752,091
18	Jurisdictional Sales *	39,431,838 MWH
19	Total Sales *	40,778,292 MWH
20	Jurisdictional Separation Factor	96.7000%
21	Maximum allowed jurisdictional incentive dollars	$ 10,397,272

* Net sales (Sales - Interruptible)

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Progress Energy Florida
Janauary 2006 - December 2006

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Anclote 1	EAF	3.48	8.023	0.279
	ANOHR	4.87	0.000	0.000
Anclote 2	EAF	1.55	3.221	0.050
	ANOHR	2.71	0.000	0.000
Bartow 1	EAF	2.70	10.000	0.270
	ANOHR	1.22	0.000	0.000
Bartow 2	EAF	2.45	5.343	0.131
	ANOHR	1.71	-1.868	-0.032
Bartow 3	EAF	3.02	-10.000	-0.302
	ANOHR	3.30	-4.773	-0.157
Crystal River 1	EAF	8.72	1.653	0.144
	ANOHR	2.74	-3.070	-0.084
Crystal River 2	EAF	11.88	6.871	0.816
	ANOHR	3.92	0.000	0.000
Crystal River 3	EAF	1.44	-10.000	-0.144
	ANOHR	3.79	0.000	0.000
Crystal River 4	EAF	4.50	-1.214	-0.055
	ANOHR	3.59	0.000	0.000
Crystal River 5	EAF	10.65	-1.735	-0.185
	ANOHR	4.32	-8.634	-0.373
Hines 1	EAF	0.88	-10.000	-0.088
	ANOHR	8.92	-0.192	-0.017
Tiger Bay	EAF	0.73	10.000	0.073
	ANOHR	6.93	3.732	0.258
GPIF System		100.00		0.584

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Progress Energy Florida
Janauary 2006 - December 2006

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Anclote 1	3.48	87.67	89.87	83.14	$3,336.0	($3,897.0)	89.44	$2,676.5
Anclote 2	1.55	84.31	86.28	80.25	$1,482.0	($662.0)	84.94	$477.4
Bartow 1	2.70	85.62	90.57	75.54	$2,586.0	($201.0)	91.22	$2,586.0
Bartow 2	2.45	92.62	94.30	89.12	$2,350.0	($1,763.0)	93.52	$1,255.6
Bartow 3	3.02	95.46	97.61	90.99	$2,894.0	($565.0)	85.64	($565.0)
Crystal River 1	8.72	92.72	96.14	85.72	$8,358.0	($2,667.0)	93.28	$1,381.6
Crystal River 2	11.88	82.06	88.52	69.73	$11,387.0	($3,160.0)	86.50	$7,824.0
Crystal River 3	1.44	97.31	98.58	94.67	$1,383.0	($2,622.0)	93.15	($2,622.0)
Crystal River 4	4.50	93.22	95.25	89.06	$4,316.0	($4,216.0)	92.72	($511.8)
Crystal River 5	10.65	87.27	89.64	82.45	$10,211.0	($2,497.0)	86.43	($433.2)
Hines 1	0.88	87.63	89.33	84.08	$846.0	($2,211.0)	83.24	($2,211.0)
Tiger Bay	0.73	88.99	91.44	84.10	$701.0	($1,497.0)	92.09	$701.0
GPIF System	52.00				$49,850.0	($25,958.0)		$10,559.0

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Anclote 1	4.87	10,483.3	39.6	10,055.1	10,911.5	$4,664.9	($4,664.9)	10,515.4	$0.0
Anclote 2	2.71	10,352.3	40.8	10,095.7	10,608.9	$2,598.4	($2,598.4)	10,337.1	$0.0
Bartow 1	1.22	10,942.4	50.2	10,600.6	11,284.1	$1,165.9	($1,165.9)	10,962.8	$0.0
Bartow 2	1.71	10,890.4	59.6	10,437.7	11,343.2	$1,634.9	($1,634.9)	11,036.0	($305.4)
Bartow 3	3.30	10,216.5	57.2	9,750.3	10,682.7	$3,162.9	($3,162.9)	10,478.2	($1,509.7)
Crystal River 1	2.74	10,296.3	69.1	9,983.0	10,609.6	$2,630.3	($2,630.3)	10,444.5	($807.5)
Crystal River 2	3.92	10,115.7	69.6	9,730.8	10,500.7	$3,753.2	($3,753.2)	10,106.0	$0.0
Crystal River 3	3.79	10,259.1	100.1	10,109.1	10,409.1	$3,636.8	($3,636.8)	10,315.4	$0.0
Crystal River 4	3.59	9,511.4	82.6	9,320.9	9,701.9	$3,442.8	($3,442.8)	9,550.5	$0.0
Crystal River 5	4.32	9,512.6	85.9	9,276.5	9,748.8	$4,138.2	($4,138.2)	9,726.8	($3,572.9)
Hines 1	8.92	7,450.1	73.3	7,080.4	7,819.8	$8,547.9	($8,547.9)	7,530.8	($164.1)
Tiger Bay	6.93	8,005.7	87.3	7,275.1	8,736.4	$6,639.0	($6,639.0)	7,686.0	$2,477.7
GPIF System	48.00					$46,015.1	($46,015.1)		($3,881.9)

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida
Janauary 2006 - December 2006

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Anclote 1	85.29	4.15	89.44
Anclote 2	84.81	0.14	84.94
Bartow 1	94.86	-3.64	91.22
Bartow 2	97.25	-3.73	93.52
Bartow 3	85.64	0.00	85.64
Crystal River 1	93.28	0.00	93.28
Crystal River 2	86.57	-0.07	86.50
Crystal River 3	93.15	0.00	93.15
Crystal River 4	91.47	1.25	92.72
Crystal River 5	85.71	0.72	86.43
Hines 1	79.63	3.61	83.24
Tiger Bay	96.51	-4.43	92.09

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Anclote 1	10,338.1	177.3	10,515.4
Anclote 2	10,262.4	74.8	10,337.1
Bartow 1	10,912.8	50.0	10,962.8
Bartow 2	11,112.3	-76.3	11,036.0
Bartow 3	10,477.6	0.6	10,478.2
Crystal River 1	10,401.1	43.4	10,444.5
Crystal River 2	9,939.4	166.5	10,106.0
Crystal River 3	10,307.4	8.0	10,315.4
Crystal River 4	9,493.5	57.0	9,550.5
Crystal River 5	9,733.8	-7.0	9,726.8
Hines 1	7,545.1	-14.4	7,530.8
Tiger Bay	7,880.2	-194.1	7,686.0

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Progress Energy Florida
Janauary 2006 - December 2006

EAF adjustments for Planned Outage Hours			Anclote 1 AN1	Anclote 2 AN2	Bartow 1 BA1	Bartow 2 BA2	Bartow 3 BA3	Crystal River CR1	Crystal River CR2	Crystal River CR3	Crystal River CR4	Crystal River CR5	Hines 1 HN1	Tiger Bay TB
1	Actual POH	Hrs.	1,047.30	1,020.38	0.00	0.00	0.00	0.00	328.70	0.00	331.32	739.72	1114.56	107.25
2	Target POH	Hrs.	672.00	1,008.00	336.00	336.00	0.00	0.00	336.00	0.00	216.00	672.00	768.00	504.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.05	1.00	0.96	0.96	1.00	1.00	1.00	1.00	1.01	1.01	1.05	0.95
4	Actual EUOH	Hrs.	241.67	310.45	450.58	241.04	1,258.20	588.56	847.38	600.00	416.15	512.20	670.03	198.38
5	Adj. EUOH (3*4)	Hrs.	253.43	310.95	433.30	231.80	1,258.20	588.56	846.65	600.00	421.84	516.52	700.40	189.29
6	Actual EAF	%	85.29	84.81	94.86	97.25	85.64	93.28	86.57	93.15	91.47	85.71	79.63	96.51
7	Adjusted EAF (using 2 & 5)	%	89.44	84.94	91.22	93.52	85.64	93.28	86.50	93.15	92.72	86.43	83.24	92.09
8	Difference (7-6)	%	4.15	0.14	-3.64	-3.73	0.00	0.00	-0.07	0.00	1.25	0.72	3.61	-4.43
9	Total adj. to EAF	%	4.15	0.14	-3.64	-3.73	0.00	0.00	-0.07	0.00	1.25	0.72	3.61	-4.43

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Progress Energy Florida
Janauary 2006 - December 2006

ANOHR adjustments for Target NOF			Anclote 1 AN1	Anclote 2 AN2	Bartow 1 BA1	Bartow 2 BA2	Bartow 3 BA3	Crystal River CR1	Crystal River CR2	Crystal River CR3	Crystal River CR4	Crystal River CR5	Hines 1 HN1	Tiger Bay TB
1	Target NOF	%	39.6	40.8	50.2	59.6	57.2	69.1	69.6	100.1	82.6	85.9	73.3	87.3
2	Target ANOHR	Btu/kwh	10483.3	10352.3	10942.4	10890.4	10216.5	10296.3	10115.7	10259.1	9511.4	9512.6	7450.1	8005.7
3	Actual NOF	%	46.7	46.3	55.8	49.8	56.7	71.1	74.9	101.0	86.6	85.3	72.1	80.8
4	Calc. ANOHR (using 3)	Btu/kwh	10,306.0	10,277.5	10,892.3	10,966.7	10,215.8	10,252.9	9,949.2	10,251.1	9,454.4	9,519.7	7,464.5	8,199.8
5	Total adj. to ANOHR (2-4)	Btu/kwh	177.3	74.8	50.0	-76.3	0.6	43.4	166.5	8.0	57.0	-7.0	-14.4	-194.1

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Anclote 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$3,336,000	89.87	10	$4,664,896	10,055.1	
	9	$3,002,400	89.65	9	$4,198,407	10,090.4	
****	8.023	$2,676,473	89.44	8	$3,731,917	10,125.7	
	8	$2,668,800	89.43	7	$3,265,428	10,161.0	
	7	$2,335,200	89.21	6	$2,798,938	10,196.4	
	6	$2,001,600	88.99	5	$2,332,448	10,231.7	
	5	$1,668,000	88.77	4	$1,865,959	10,267.0	
	4	$1,334,400	88.55	3	$1,399,469	10,302.3	
	3	$1,000,800	88.33	2	$932,979	10,337.6	
	2	$667,200	88.11	1	$466,490	10,372.9	
	1	$333,600	87.89	0	$0	10,408.3	
		$0	87.67	0	$0	10,483.3	
	0	$0	87.67	0.000	$0	10,515.4	****
		$0	87.67	0	$0	10,558.3	
	-1	($389,700)	87.22	-1	($466,490)	10,593.6	
	-2	($779,400)	86.77	-2	($932,979)	10,628.9	
	-3	($1,169,100)	86.31	-3	($1,399,469)	10,664.2	
	-4	($1,558,800)	85.86	-4	($1,865,959)	10,699.5	
	-5	($1,948,500)	85.41	-5	($2,332,448)	10,734.9	
	-6	($2,338,200)	84.96	-6	($2,798,938)	10,770.2	
	-7	($2,727,900)	84.50	-7	($3,265,428)	10,805.5	
	-8	($3,117,600)	84.05	-8	($3,731,917)	10,840.8	
	-9	($3,507,300)	83.60	-9	($4,198,407)	10,876.1	
	-10	($3,897,000)	83.14	-10	($4,664,896)	10,911.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.48%	4.87%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,482,000	86.28	10	$2,598,404	10,095.7	
	9	$1,333,800	86.08	9	$2,338,564	10,113.8	
	8	$1,185,600	85.89	8	$2,078,723	10,132.0	
	7	$1,037,400	85.69	7	$1,818,883	10,150.2	
	6	$889,200	85.49	6	$1,559,043	10,168.3	
	5	$741,000	85.29	5	$1,299,202	10,186.5	
	4	$592,800	85.10	4	$1,039,362	10,204.6	
****	3.221	$477,352	84.94	3	$779,521	10,222.8	
	3	$444,600	84.90	2	$519,681	10,241.0	
	2	$296,400	84.70	1	$259,840	10,259.1	
	1	$148,200	84.51	0	$0	10,277.3	
		$0	84.31	0.000	$0	10,337.1	****
	0	$0	84.31	0	$0	10,352.3	
		$0	84.31	0	$0	10,427.3	
	-1	($66,200)	83.90	-1	($259,840)	10,445.4	
	-2	($132,400)	83.50	-2	($519,681)	10,463.6	
	-3	($198,600)	83.09	-3	($779,521)	10,481.8	
	-4	($264,800)	82.69	-4	($1,039,362)	10,499.9	
	-5	($331,000)	82.28	-5	($1,299,202)	10,518.1	
	-6	($397,200)	81.87	-6	($1,559,043)	10,536.2	
	-7	($463,400)	81.47	-7	($1,818,883)	10,554.4	
	-8	($529,600)	81.06	-8	($2,078,723)	10,572.5	
	-9	($595,800)	80.66	-9	($2,338,564)	10,590.7	
	-10	($662,000)	80.25	-10	($2,598,404)	10,608.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.55%	2.71%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Bartow 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$2,586,000	91.22	10	$1,165,855	10,600.6	
	10	$2,586,000	90.57	9	$1,049,269	10,627.3	
	9	$2,327,400	90.08	8	$932,684	10,654.0	
	8	$2,068,800	89.58	7	$816,098	10,680.6	
	7	$1,810,200	89.09	6	$699,513	10,707.3	
	6	$1,551,600	88.59	5	$582,927	10,734.0	
	5	$1,293,000	88.10	4	$466,342	10,760.7	
	4	$1,034,400	87.60	3	$349,756	10,787.3	
	3	$775,800	87.11	2	$233,171	10,814.0	
	2	$517,200	86.61	1	$116,585	10,840.7	
	1	$258,600	86.12	0	$0	10,867.4	
		$0	85.62	0	$0	10,942.4	
	0	$0	85.62	0.000	$0	10,962.8	****
		$0	85.62	0	$0	11,017.4	
	-1	($20,100)	84.61	-1	($116,585)	11,044.0	
	-2	($40,200)	83.60	-2	($233,171)	11,070.7	
	-3	($60,300)	82.60	-3	($349,756)	11,097.4	
	-4	($80,400)	81.59	-4	($466,342)	11,124.0	
	-5	($100,500)	80.58	-5	($582,927)	11,150.7	
	-6	($120,600)	79.57	-6	($699,513)	11,177.4	
	-7	($140,700)	78.57	-7	($816,098)	11,204.1	
	-8	($160,800)	77.56	-8	($932,684)	11,230.7	
	-9	($180,900)	76.55	-9	($1,049,269)	11,257.4	
	-10	($201,000)	75.54	-10	($1,165,855)	11,284.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.70%	1.22%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Bartow 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,350,000	94.30	10	$1,634,895	10,437.7	
	9	$2,115,000	94.13	9	$1,471,405	10,475.4	
	8	$1,880,000	93.96	8	$1,307,916	10,513.2	
	7	$1,645,000	93.80	7	$1,144,426	10,551.0	
	6	$1,410,000	93.63	6	$980,937	10,588.8	
****	5.343	$1,255,605	93.52	5	$817,447	10,626.6	
	5	$1,175,000	93.46	4	$653,958	10,664.3	
	4	$940,000	93.29	3	$490,468	10,702.1	
	3	$705,000	93.13	2	$326,979	10,739.9	
	2	$470,000	92.96	1	$163,489	10,777.7	
	1	$235,000	92.79	0	$0	10,815.4	
		$0	92.62	0	$0	10,890.4	
	0	$0	92.62	0	$0	10,965.4	
		$0	92.62	-1	($163,489)	11,003.2	
	-1	($176,300)	92.27	-1.868	($305,398)	11,036.0	****
	-2	($352,600)	91.92	-2	($326,979)	11,041.0	
	-3	($528,900)	91.57	-3	($490,468)	11,078.8	
	-4	($705,200)	91.22	-4	($653,958)	11,116.6	
	-5	($881,500)	90.87	-5	($817,447)	11,154.3	
	-6	($1,057,800)	90.52	-6	($980,937)	11,192.1	
	-7	($1,234,100)	90.17	-7	($1,144,426)	11,229.9	
	-8	($1,410,400)	89.82	-8	($1,307,916)	11,267.7	
	-9	($1,586,700)	89.47	-9	($1,471,405)	11,305.4	
	-10	($1,763,000)	89.12	-10	($1,634,895)	11,343.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.45%	1.71%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Bartow 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,894,000	97.61	10	$3,162,923	9,750.3	
	9	$2,604,600	97.39	9	$2,846,631	9,789.4	
	8	$2,315,200	97.18	8	$2,530,339	9,828.5	
	7	$2,025,800	96.96	7	$2,214,046	9,867.6	
	6	$1,736,400	96.75	6	$1,897,754	9,906.8	
	5	$1,447,000	96.53	5	$1,581,462	9,945.9	
	4	$1,157,600	96.32	4	$1,265,169	9,985.0	
	3	$868,200	96.10	3	$948,877	10,024.1	
	2	$578,800	95.89	2	$632,585	10,063.2	
	1	$289,400	95.67	1	$316,292	10,102.3	
		$0	95.46	0	$0	10,141.5	
	0	$0	95.46	0	$0	10,216.5	
		$0	95.46	0	$0	10,291.5	
	-1	($56,500)	95.01	-1	($316,292)	10,330.6	
	-2	($113,000)	94.56	-2	($632,585)	10,369.7	
	-3	($169,500)	94.12	-3	($948,877)	10,408.8	
	-4	($226,000)	93.67	-4	($1,265,169)	10,447.9	
	-5	($282,500)	93.22	-4.773	($1,509,663)	10,478.2	****
	-6	($339,000)	92.78	-5	($1,581,462)	10,487.1	
	-7	($395,500)	92.33	-6	($1,897,754)	10,526.2	
	-8	($452,000)	91.88	-7	($2,214,046)	10,565.3	
	-9	($508,500)	91.44	-8	($2,530,339)	10,604.4	
	-10	($565,000)	90.99	-9	($2,846,631)	10,643.5	
****	-10	($565,000)	85.64	-10	($3,162,923)	10,682.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.02%	3.30%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Crystal River 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$8,358,000	96.14	10	$2,630,314	9,983.0	
	9	$7,522,200	95.80	9	$2,367,283	10,006.9	
	8	$6,686,400	95.45	8	$2,104,251	10,030.7	
	7	$5,850,600	95.11	7	$1,841,220	10,054.5	
	6	$5,014,800	94.77	6	$1,578,188	10,078.3	
	5	$4,179,000	94.43	5	$1,315,157	10,102.2	
	4	$3,343,200	94.08	4	$1,052,126	10,126.0	
	3	$2,507,400	93.74	3	$789,094	10,149.8	
	2	$1,671,600	93.40	2	$526,063	10,173.6	
****	1.653	$1,381,577	93.28	1	$263,031	10,197.5	
	1	$835,800	93.06	0	$0	10,221.3	
		$0	92.72	0	$0	10,296.3	
	0	$0	92.72	0	$0	10,371.3	
		$0	92.72	-1	($263,031)	10,395.1	
	-1	($266,700)	92.02	-2	($526,063)	10,419.0	
	-2	($533,400)	91.32	-3	($789,094)	10,442.8	
	-3	($800,100)	90.62	-3.070	($807,506)	10,444.5	****
	-4	($1,066,800)	89.92	-4	($1,052,126)	10,466.6	
	-5	($1,333,500)	89.22	-5	($1,315,157)	10,490.4	
	-6	($1,600,200)	88.52	-6	($1,578,188)	10,514.3	
	-7	($1,866,900)	87.82	-7	($1,841,220)	10,538.1	
	-8	($2,133,600)	87.12	-8	($2,104,251)	10,561.9	
	-9	($2,400,300)	86.42	-9	($2,367,283)	10,585.8	
	-10	($2,667,000)	85.72	-10	($2,630,314)	10,609.6	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.72%	2.74%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Crystal River 2

	Equivalent Availabiiity (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$11,387,000	88.52	10	$3,753,153	9,730.8	
	9	$10,248,300	87.88	9	$3,377,838	9,761.8	
	8	$9,109,600	87.23	8	$3,002,523	9,792.8	
	7	$7,970,900	86.58	7	$2,627,207	9,823.8	
****	6.871	$7,824,008	86.50	6	$2,251,892	9,854.8	
	6	$6,832,200	85.94	5	$1,876,577	9,885.7	
	5	$5,693,500	85.29	4	$1,501,261	9,916.7	
	4	$4,554,800	84.64	3	$1,125,946	9,947.7	
	3	$3,416,100	84.00	2	$750,631	9,978.7	
	2	$2,277,400	83.35	1	$375,315	10,009.7	
	1	$1,138,700	82.70	0	$0	10,040.7	
		$0	82.06	0.000	$0	10,106.0	****
	0	$0	82.06	0	$0	10,115.7	
		$0	82.06	0	$0	10,190.7	
	-1	($316,000)	80.83	-1	($375,315)	10,221.7	
	-2	($632,000)	79.59	-2	($750,631)	10,252.7	
	-3	($948,000)	78.36	-3	($1,125,946)	10,283.7	
	-4	($1,264,000)	77.13	-4	($1,501,261)	10,314.7	
	-5	($1,580,000)	75.89	-5	($1,876,577)	10,345.7	
	-6	($1,896,000)	74.66	-6	($2,251,892)	10,376.7	
	-7	($2,212,000)	73.43	-7	($2,627,207)	10,407.7	
	-8	($2,528,000)	72.20	-8	($3,002,523)	10,438.7	
	-9	($2,844,000)	70.96	-9	($3,377,838)	10,469.7	
	-10	($3,160,000)	69.73	-10	($3,753,153)	10,500.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
11.88%	3.92%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Crystal River 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,383,000	98.58	10	$3,636,786	10,109.1	
	9	$1,244,700	98.46	9	$3,273,107	10,116.6	
	8	$1,106,400	98.33	8	$2,909,429	10,124.1	
	7	$968,100	98.20	7	$2,545,750	10,131.6	
	6	$829,800	98.08	6	$2,182,072	10,139.1	
	5	$691,500	97.95	5	$1,818,393	10,146.6	
	4	$553,200	97.82	4	$1,454,714	10,154.1	
	3	$414,900	97.70	3	$1,091,036	10,161.6	
	2	$276,600	97.57	2	$727,357	10,169.1	
	1	$138,300	97.44	1	$363,679	10,176.6	
		$0	97.31	0	$0	10,184.1	
	0	$0	97.31	0	$0	10,259.1	
		$0	97.31	0.000	$0	10,315.4	****
	-1	($262,200)	97.05	0	$0	10,334.1	
	-2	($524,400)	96.79	-1	($363,679)	10,341.6	
	-3	($786,600)	96.52	-2	($727,357)	10,349.1	
	-4	($1,048,800)	96.26	-3	($1,091,036)	10,356.6	
	-5	($1,311,000)	95.99	-4	($1,454,714)	10,364.1	
	-6	($1,573,200)	95.73	-5	($1,818,393)	10,371.6	
	-7	($1,835,400)	95.46	-6	($2,182,072)	10,379.1	
	-8	($2,097,600)	95.20	-7	($2,545,750)	10,386.6	
	-9	($2,359,800)	94.93	-8	($2,909,429)	10,394.1	
	-10	($2,622,000)	94.67	-9	($3,273,107)	10,401.6	
****	-10	($2,622,000)	93.15	-10	($3,636,786)	10,409.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.44%	3.79%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$4,316,000	95.25	10	$3,442,813	9,320.9	
	9	$3,884,400	95.05	9	$3,098,532	9,332.5	
	8	$3,452,800	94.85	8	$2,754,250	9,344.0	
	7	$3,021,200	94.64	7	$2,409,969	9,355.6	
	6	$2,589,600	94.44	6	$2,065,688	9,367.1	
	5	$2,158,000	94.24	5	$1,721,406	9,378.7	
	4	$1,726,400	94.04	4	$1,377,125	9,390.2	
	3	$1,294,800	93.83	3	$1,032,844	9,401.8	
	2	$863,200	93.63	2	$688,563	9,413.3	
	1	$431,600	93.43	1	$344,281	9,424.9	
		$0	93.22	0	$0	9,436.4	
	0	$0	93.22	0	$0	9,511.4	
		$0	93.22	0.000	$0	9,550.5	****
	-1	($421,600)	92.81	0	$0	9,586.4	
****	-1.214	($511,822)	92.72	-1	($344,281)	9,598.0	
	-2	($843,200)	92.39	-2	($688,563)	9,609.5	
	-3	($1,264,800)	91.98	-3	($1,032,844)	9,621.1	
	-4	($1,686,400)	91.56	-4	($1,377,125)	9,632.6	
	-5	($2,108,000)	91.14	-5	($1,721,406)	9,644.2	
	-6	($2,529,600)	90.73	-6	($2,065,688)	9,655.7	
	-7	($2,951,200)	90.31	-7	($2,409,969)	9,667.3	
	-8	($3,372,800)	89.89	-8	($2,754,250)	9,678.8	
	-9	($3,794,400)	89.48	-9	($3,098,532)	9,690.4	
	-10	($4,216,000)	89.06	-10	($3,442,813)	9,701.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.50%	3.59%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$10,211,000	89.64	10	$4,138,195	9,276.5	
	9	$9,189,900	89.44	9	$3,724,375	9,292.6	
	8	$8,168,800	89.24	8	$3,310,556	9,308.7	
	7	$7,147,700	89.04	7	$2,896,736	9,324.9	
	6	$6,126,600	88.84	6	$2,482,917	9,341.0	
	5	$5,105,500	88.64	5	$2,069,097	9,357.1	
	4	$4,084,400	88.43	4	$1,655,278	9,373.2	
	3	$3,063,300	88.23	3	$1,241,458	9,389.3	
	2	$2,042,200	88.03	2	$827,639	9,405.4	
	1	$1,021,100	87.83	1	$413,819	9,421.5	
		$0	87.63	0	$0	9,437.6	
	0	$0	87.63	0	$0	9,512.6	
		$0	87.63	0	$0	9,587.6	
	-1	($249,700)	87.11	-1	($413,819)	9,603.8	
****	-1.735	($433,230)	86.73	-2	($827,639)	9,619.9	
	-2	($499,400)	86.59	-3	($1,241,458)	9,636.0	
	-3	($749,100)	86.07	-4	($1,655,278)	9,652.1	
	-4	($998,800)	85.56	-5	($2,069,097)	9,668.2	
	-5	($1,248,500)	85.04	-6	($2,482,917)	9,684.3	
	-6	($1,498,200)	84.52	-7	($2,896,736)	9,700.4	
	-7	($1,747,900)	84.00	-8	($3,310,556)	9,716.6	
	-8	($1,997,600)	83.48	-8.634	($3,572,918)	9,726.8	****
	-9	($2,247,300)	82.96	-9	($3,724,375)	9,732.7	
	-10	($2,497,000)	82.45	-10	($4,138,195)	9,748.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.65%	4.32%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$846,000	89.33	10	$8,547,860	7,080.4	
	9	$761,400	89.16	9	$7,693,074	7,109.9	
	8	$676,800	88.99	8	$6,838,288	7,139.3	
	7	$592,200	88.82	7	$5,983,502	7,168.8	
	6	$507,600	88.65	6	$5,128,716	7,198.3	
	5	$423,000	88.48	5	$4,273,930	7,227.8	
	4	$338,400	88.31	4	$3,419,144	7,257.2	
	3	$253,800	88.14	3	$2,564,358	7,286.7	
	2	$169,200	87.97	2	$1,709,572	7,316.2	
	1	$84,600	87.80	1	$854,786	7,345.6	
		$0	87.63	0	$0	7,375.1	
	0	$0	87.63	0	$0	7,450.1	
		$0	87.63	0	$0	7,525.1	
	-1	($221,100)	87.27	-0.192	($164,119)	7,530.8	****
	-2	($442,200)	86.92	-1	($854,786)	7,554.6	
	-3	($663,300)	86.56	-2	($1,709,572)	7,584.1	
	-4	($884,400)	86.21	-3	($2,564,358)	7,613.5	
	-5	($1,105,500)	85.85	-4	($3,419,144)	7,643.0	
	-6	($1,326,600)	85.50	-5	($4,273,930)	7,672.5	
	-7	($1,547,700)	85.14	-6	($5,128,716)	7,701.9	
	-8	($1,768,800)	84.79	-7	($5,983,502)	7,731.4	
	-9	($1,989,900)	84.43	-8	($6,838,288)	7,760.9	
	-10	($2,211,000)	84.08	-9	($7,693,074)	7,790.4	
****	-10	($2,211,000)	83.24	-10	($8,547,860)	7,819.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.88%	8.92%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2006 - December 2006

Unit: Tiger Bay

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$701,000	92.09	10	$6,639,047	7,275.1	
	10	$701,000	91.44	9	$5,975,142	7,340.6	
	9	$630,900	91.20	8	$5,311,237	7,406.2	
	8	$560,800	90.95	7	$4,647,333	7,471.8	
	7	$490,700	90.71	6	$3,983,428	7,537.3	
	6	$420,600	90.46	5	$3,319,523	7,602.9	
	5	$350,500	90.22	4	$2,655,619	7,668.5	
	4	$280,400	89.97	3.732	$2,477,692	7,686.0	****
	3	$210,300	89.73	3	$1,991,714	7,734.0	
	2	$140,200	89.48	2	$1,327,809	7,799.6	
	1	$70,100	89.24	1	$663,905	7,865.2	
		$0	88.99	0	$0	7,930.7	
	0	$0	88.99	0	$0	8,005.7	
		$0	88.99	0	$0	8,080.7	
	-1	($149,700)	88.51	-1	($663,905)	8,146.3	
	-2	($299,400)	88.02	-2	($1,327,809)	8,211.9	
	-3	($449,100)	87.53	-3	($1,991,714)	8,277.4	
	-4	($598,800)	87.04	-4	($2,655,619)	8,343.0	
	-5	($748,500)	86.55	-5	($3,319,523)	8,408.6	
	-6	($898,200)	86.06	-6	($3,983,428)	8,474.1	
	-7	($1,047,900)	85.57	-7	($4,647,333)	8,539.7	
	-8	($1,197,600)	85.08	-8	($5,311,237)	8,605.3	
	-9	($1,347,300)	84.59	-9	($5,975,142)	8,670.8	
	-10	($1,497,000)	84.10	-10	($6,639,047)	8,736.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.73%	6.93%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Anclote 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	99.99	85.25	99.82	74.51	96.18	96.25	96.46	95.55	90.24	0.00	89.57	100.00	85.29
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	456.6	335.4	245.1	541.4	744.0	720.0	744.0	744.0	668.1	0.0	554.9	350.8	6,104.2
4. RSH	287.5	336.6	498.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	393.2	1,606.2
5. UH	0.0	0.0	0.0	177.6	0.0	0.0	0.0	0.0	51.9	745.0	75.1	0.0	1,049.6
6. POH	0.0	0.0	0.0	175.3	0.0	0.0	0.0	0.0	51.9	745.0	75.1	0.0	1,047.3
7. FOH	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	0.0	310.4	0.0	6.9	20.2	14.1	25.8	25.8	26.5	0.0	0.0	0.0	429.7
10. LR PF (MW)	0.0	159.0	0.0	4.0	194.3	15.5	124.0	19.6	23.0	0.0	0.0	0.0	134.6
11. PMOH	1.2	0.0	2.7	17.7	64.3	83.1	59.2	100.5	53.7	0.0	0.0	0.0	382.3
12. LR PM (MW)	17.8	0.0	255.7	159.0	159.0	159.0	167.6	159.0	159.0	0.0	0.0	0.0	160.6
13. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
14. OPER MBTU	1,108,595	571,754	588,748	1,533,111	1,740,134	1,782,825	1,929,755	2,140,699	1,509,266	0	1,001,419	780,857	14,687,165
15. NET GEN (MWH)	105,305	55,867	57,200	154,321	167,716	176,115	182,287	207,323	145,400	0	96,293	72,859	1,420,686
16. ANOHR (BTU/KWH)	10,527.5	10,234.2	10,292.8	9,934.6	10,375.5	10,123.1	10,586.4	10,325.4	10,380.1	0.0	10,399.7	10,717.4	10,338.1
17. NOF (%)	46.32	33.45	46.86	57.24	45.27	49.12	49.20	55.96	43.70	0.00	34.85	41.70	46.73
18. NPC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
ANOHR EQUATION:	ANOHR=	-24.868	x NOF +	11,468.15									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Anclote 2	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	99.89	99.62	98.95	0.00	50.57	98.79	97.13	91.50	93.88	88.71	100.00	98.46	84.81
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	627.5	672.0	584.4	0.0	395.0	720.0	744.0	690.8	696.4	665.3	213.9	623.9	6,633.2
4. RSH	116.5	0.0	159.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	506.1	120.1	902.3
5. UH	0.0	0.0	0.0	719.0	349.0	0.0	0.0	53.2	23.7	79.7	0.0	0.0	1,224.5
6. POH	0.0	0.0	0.0	719.0	301.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,020.4
7. FOH	0.0	0.0	0.0	0.0	4.4	0.0	0.0	53.2	23.7	79.7	0.0	0.0	160.9
8. MOH	0.0	0.0	0.0	0.0	43.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.2
9. PFOH	0.0	0.0	4.0	0.0	34.0	2.2	17.0	4.6	0.0	9.5	0.0	39.2	110.4
10. LR PF (MW)	0.0	0.0	131.1	0.0	63.6	88.1	51.0	431.2	0.0	124.2	0.0	145.0	113.9
11. PMOH	2.5	8.1	21.5	0.0	45.8	26.3	62.3	19.2	64.7	6.5	0.0	0.0	256.8
12. LR PM (MW)	156.0	156.1	156.0	0.0	156.0	156.0	156.0	156.0	156.0	155.9	0.0	0.0	156.0
13. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
14. OPER MBTU	1,363,606	1,419,834	1,319,303	0	924,983	1,946,186	1,953,020	2,009,301	1,575,201	1,566,439	485,956	1,033,350	15,597,178
15. NET GEN (MWH)	136,474	134,931	131,030	0	91,616	192,000	190,504	196,822	148,015	155,277	48,399	94,776	1,519,844
16. ANOHR (BTU/KWH)	9,991.7	10,522.7	10,068.7	0.0	10,096.3	10,136.4	10,251.9	10,208.7	10,642.2	10,088.0	10,040.6	10,903.1	10,262.4
17. NOF (%)	43.94	40.56	45.29	0.00	46.85	53.87	51.73	57.56	42.94	47.15	45.71	30.69	46.29
18. NPC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
ANOHR EQUATION:	ANOHR=	-13.580	x NOF +	10,906.07									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Bartow 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	100.00	90.69	99.06	100.00	99.24	77.81	99.37	94.23	94.90	82.59	100.00	99.78	94.86
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	207.1	76.4	61.6	570.8	744.0	720.0	744.0	707.7	700.3	745.0	81.0	554.9	5,912.9
4. RSH	536.9	533.1	682.4	148.2	0.0	0.0	0.0	0.0	0.0	0.0	639.0	189.1	2,728.6
5. UH	0.0	62.5	0.0	0.0	0.0	0.0	0.0	36.3	19.7	0.0	0.0	0.0	118.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	62.5	0.0	0.0	0.0	0.0	0.0	36.3	19.7	0.0	0.0	0.0	118.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	0.0	0.0	0.0	0.0	7.9	302.8	0.0	0.0	0.0	0.0	0.0	3.0	313.6
10. LR PF (MW)	0.0	0.0	0.0	0.0	71.0	60.3	0.0	0.0	0.0	0.0	0.0	66.0	60.6
11. PMOH	0.0	0.0	23.5	0.0	2.0	17.7	8.0	13.3	33.7	257.3	0.0	0.0	355.3
12. LR PM (MW)	0.0	0.0	36.0	0.0	61.0	61.0	71.0	61.0	61.0	61.0	0.0	0.0	59.6
13. NSC (MW)	121	121	121	121	121	121	121	121	121	121	121	121	121
14. OPER MBTU	166,069	51,371	44,163	431,327	509,525	484,318	578,350	596,482	495,703	562,068	68,115	366,816	4,354,308
15. NET GEN (MWH)	15,862	4,849	4,058	40,545	47,389	42,638	53,154	54,494	45,190	51,143	6,312	33,375	399,009
16. ANOHR (BTU/KWH)	10,469.6	10,594.2	10,883.0	10,638.2	10,752.0	11,358.8	10,880.6	10,945.8	10,969.3	10,990.1	10,791.4	10,990.7	10,912.8
17. NOF (%)	63.30	52.45	54.42	58.70	52.64	48.94	59.04	63.63	53.33	56.73	64.40	49.71	55.77
18. NPC (MW)	121	121	121	121	121	121	121	121	121	121	121	121	121
ANOHR EQUATION:	ANOHR=	-9.034	x NOF +	11,396.17									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Bartow 2	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	99.60	99.75	100.00	100.00	99.86	98.29	97.72	89.75	95.97	95.07	100.00	91.39	97.25
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	208.4	245.5	292.0	590.0	744.0	720.0	734.5	681.6	714.9	745.0	75.9	581.3	6,332.9
4. RSH	535.6	426.5	452.0	129.0	0.0	0.0	0.0	0.0	0.0	0.0	644.2	152.2	2,339.5
5. UH	0.0	0.0	0.0	0.0	0.0	0.0	9.5	62.5	5.1	0.0	0.0	10.5	87.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	9.5	45.5	0.0	0.0	0.0	10.5	65.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	5.1	0.0	0.0	0.0	22.1
9. PFOH	0.0	6.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	187.5	197.1
10. LR PF (MW)	0.0	30.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.9	0.0	34.0	34.3
11. PMOH	6.0	0.0	0.0	0.0	9.0	24.8	13.9	27.8	48.1	70.9	0.0	0.0	200.6
12. LR PM (MW)	59.0	0.0	0.0	0.0	14.0	59.0	64.0	59.0	59.0	59.0	0.0	0.0	57.3
13. NSC (MW)	119	119	119	119	119	119	119	119	119	119	119	119	119
14. OPER MBTU	160,427	164,874	199,479	131,548	496,129	537,279	574,811	551,012	488,215	497,107	58,944	307,423	4,167,248
15. NET GEN (MWH)	15,088	15,126	18,201	11,981	45,696	49,002	50,415	49,560	41,370	45,050	5,558	27,965	375,012
16. ANOHR (BTU/KWH)	10,632.8	10,900.0	10,959.8	10,979.7	10,857.2	10,964.4	11,401.6	11,118.1	11,801.2	11,034.6	10,605.3	10,993.1	11,112.3
17. NOF (%)	60.85	51.78	52.38	17.06	51.61	57.19	57.68	61.11	48.63	50.81	61.58	40.43	49.76
18. NPC (MW)	119	119	119	119	119	119	119	119	119	119	119	119	119
ANOHR EQUATION:	ANOHR=	-7.781	x NOF +	11,353.90									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Bartow 3	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	88.87	81.75	75.73	96.95	71.26	83.01	78.54	65.30	96.78	94.35	98.57	97.22	85.64
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	662.8	460.0	536.3	719.0	530.2	628.3	641.3	538.6	720.0	738.2	720.0	204.2	7,098.9
4. RSH	0.0	89.5	28.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	539.8	657.3
5. UH	81.2	122.5	179.7	0.0	213.8	91.7	102.7	205.4	0.0	6.8	0.0	0.0	1,003.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	81.2	0.0	17.9	0.0	71.1	91.7	102.7	205.4	0.0	6.8	0.0	0.0	576.7
8. MOH	0.0	122.5	161.8	0.0	142.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	427.0
9. PFOH	3.2	0.5	4.2	5.3	0.0	291.3	545.3	213.5	0.0	0.0	0.0	78.2	1,141.4
10. LR PF (MW)	103.9	70.2	44.0	24.0	0.0	19.0	19.0	34.0	0.0	0.0	0.0	54.0	24.6
11. PMOH	0.0	0.0	0.0	73.7	0.0	6.3	12.9	30.7	41.5	63.2	18.4	0.0	246.6
12. LR PM (MW)	0.0	0.0	0.0	59.0	0.0	114.1	98.1	114.0	114.0	114.0	114.0	0.0	96.7
13. NSC (MW)	204	204	204	204	204	204	204	204	204	204	204	204	204
14. OPER MBTU	783,631	524,255	653,855	885,338	674,818	755,599	825,139	702,275	889,132	890,108	783,030	232,840	8,600,020
15. NET GEN (MWH)	78,988	51,767	61,713	84,848	61,777	72,564	79,088	66,694	85,789	84,913	71,679	20,983	820,803
16. ANOHR (BTU/KWH)	9,920.9	10,127.2	10,595.1	10,434.4	10,923.5	10,412.9	10,433.2	10,529.8	10,364.2	10,482.6	10,924.1	11,096.6	10,477.6
17. NOF (%)	58.42	55.16	56.41	57.85	57.12	56.61	60.45	60.70	58.41	56.39	48.80	50.37	56.68
18. NPC (MW)	204	204	204	204	204	204	204	204	204	204	204	204	204
ANOHR EQUATION:	ANOHR=	1.182	x NOF +	10,148.84									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	99.80	99.93	99.00	96.71	96.98	95.26	96.71	75.98	91.32	95.59	91.29	81.51	93.28
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	660.7	720.0	745.0	659.6	681.2	8,553.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.3	0.0	0.0	60.4	62.8	206.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.3	0.0	0.0	60.4	62.8	206.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	8.4	1.5	33.8	155.8	38.4	174.0	189.8	75.7	21.0	49.1	6.8	227.2	981.4
10. LR PF (MW)	67.2	122.0	23.3	43.4	32.9	37.9	25.0	88.2	111.6	91.5	94.1	113.1	61.9
11. PMOH	0.0	0.0	49.1	17.5	75.6	52.3	26.7	376.9	279.3	98.2	1.3	17.5	994.4
12. LR PM (MW)	0.0	0.0	41.6	125.5	95.8	121.5	170.0	78.2	76.5	80.9	189.0	152.0	84.5
13. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
14. OPER MBTU	2,124,998	1,856,322	2,299,700	2,006,691	2,031,933	2,140,271	2,212,916	1,815,400	1,972,775	2,049,411	1,802,438	1,650,071	23,962,926
15. NET GEN (MWH)	211,213	181,654	223,046	193,416	196,031	201,955	209,572	169,927	185,251	199,910	174,444	157,466	2,303,885
16. ANOHR (BTU/KWH)	10,060.9	10,219.0	10,310.4	10,375.0	10,365.4	10,597.8	10,559.2	10,683.4	10,649.2	10,251.7	10,332.5	10,478.9	10,401.1
17. NOF (%)	74.90	71.32	79.10	70.98	69.52	74.01	74.32	67.86	67.89	70.80	69.78	60.99	71.07
18. NPC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
ANOHR EQUATION:	ANOHR=	-21.598	x NOF +	11,787.86									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 2	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	97.57	75.23	98.15	87.34	99.74	82.98	86.16	91.74	80.89	53.13	89.62	95.12	86.57
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	744.0	508.3	744.0	641.8	744.0	614.6	673.9	715.5	603.5	431.6	655.8	744.0	7,820.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	163.7	0.0	77.2	0.0	105.4	70.2	28.5	116.6	313.4	64.2	0.0	939.1
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	264.5	64.2	0.0	328.7
7. FOH	0.0	0.0	0.0	0.0	0.0	105.4	70.2	28.5	75.0	48.9	0.0	0.0	328.0
8. MOH	0.0	163.7	0.0	77.2	0.0	0.0	0.0	0.0	41.5	0.0	0.0	0.0	282.4
9. PFOH	41.8	14.2	68.7	32.3	0.0	11.6	75.7	125.6	226.8	115.1	28.0	62.2	802.0
10. LR PF (MW)	132.7	93.3	93.0	144.7	0.0	33.0	210.9	91.7	36.2	151.0	182.8	184.8	109.7
11. PMOH	31.1	0.0	3.7	16.9	8.4	142.7	0.0	20.4	7.3	0.0	0.0	17.5	247.9
12. LR PM (MW)	104.0	0.0	80.0	123.0	110.6	55.7	0.0	222.1	276.0	0.0	0.0	352.0	109.6
13. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
14. OPER MBTU	2,802,200	1,783,459	2,968,839	2,462,645	2,792,609	2,122,176	2,541,824	2,821,886	2,025,669	1,376,865	2,243,262	2,338,324	28,279,757
15. NET GEN (MWH)	283,337	180,506	305,467	248,153	284,062	210,028	249,835	283,990	197,039	135,502	228,000	239,288	2,845,207
16. ANOHR (BTU/KWH)	9,890.0	9,880.3	9,719.0	9,923.9	9,831.0	10,104.3	10,174.0	9,936.6	10,280.5	10,161.2	9,838.9	9,772.0	9,939.4
17. NOF (%)	78.36	73.07	84.48	79.56	78.56	70.32	76.29	81.67	67.18	64.60	71.54	66.18	74.86
18. NPC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
ANOHR EQUATION:	ANOHR=	-31.756	x NOF +	12,326.28									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 3	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	73.20	100.00	66.24	100.00	99.85	100.00	98.74	83.59	99.08	98.76	99.85	100.00	93.15
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	553.0	672.0	506.5	719.0	744.0	720.0	744.0	633.3	720.0	745.0	720.0	744.0	8,220.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	191.0	0.0	237.5	0.0	0.0	0.0	0.0	110.7	0.0	0.0	0.0	0.0	539.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	191.0	0.0	237.5	0.0	0.0	0.0	0.0	110.7	0.0	0.0	0.0	0.0	539.2
9. PFOH	2.5	0.0	0.0	0.0	10.4	0.0	47.9	0.0	16.5	35.1	12.0	0.0	124.3
10. LR PF (MW)	637.0	0.0	0.0	0.0	61.0	0.0	150.0	0.0	307.9	202.0	71.0	0.0	180.4
11. PMOH	23.0	9.0	32.8	0.0	6.2	0.0	0.0	28.6	0.0	0.0	0.0	0.0	99.7
12. LR PM (MW)	210.5	1.0	321.3	0.0	32.5	0.0	0.0	305.0	0.0	0.0	0.0	0.0	244.1
13. NSC (MW)	769	769	769	769	769	769	769	769	769	769	769	769	769
14. OPER MBTU	4,421,194	5,403,378	4,048,241	5,783,267	5,972,607	5,791,570	5,917,493	5,016,524	5,743,048	5,921,328	5,780,128	5,984,681	65,783,459
15. NET GEN (MWH)	430,369	530,784	388,768	565,103	581,389	557,150	563,303	475,996	553,227	579,727	568,127	588,233	6,382,175
16. ANOHR (BTU/KWH)	10,273.0	10,180.0	10,413.0	10,234.0	10,273.0	10,395.0	10,505.0	10,539.0	10,381.0	10,214.0	10,174.0	10,174.0	10,307.4
17. NOF (%)	101.20	102.71	99.81	102.21	101.62	100.63	98.46	97.74	99.92	101.19	102.61	102.81	100.96
18. NPC (MW)	769	769	769	769	769	769	769	769	769	769	769	769	769
ANOHR EQUATION:	ANOHR=	-9.463	x NOF +	11,206.41									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 4	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	83.28	96.36	99.39	91.74	91.10	88.62	97.32	96.67	97.64	98.16	61.53	95.41	91.47
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	629.0	672.0	744.0	703.0	712.3	643.3	736.5	726.6	720.0	737.0	443.7	740.5	8,207.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	115.0	0.0	0.0	16.0	31.7	76.7	7.5	17.5	0.0	8.0	276.3	3.5	552.1
6. POH	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	276.3	0.0	331.3
7. FOH	60.0	0.0	0.0	16.0	31.7	76.7	0.0	0.0	0.0	8.0	0.0	3.5	195.9
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	7.5	17.5	0.0	0.0	0.0	0.0	24.9
9. PFOH	13.0	38.2	5.7	27.7	14.4	0.9	26.2	19.8	35.1	0.0	0.0	26.7	207.5
10. LR PF (MW)	245.9	82.2	101.0	481.2	338.9	706.8	101.5	143.7	124.7	0.0	0.0	162.8	192.5
11. PMOH	30.9	77.5	14.2	161.0	103.0	31.0	37.0	22.6	61.6	35.3	1.4	207.9	783.4
12. LR PM (MW)	116.0	186.7	188.8	111.4	193.9	101.0	170.0	108.8	127.5	116.2	338.2	85.4	128.6
13. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
14. OPER MBTU	3,678,258	4,031,836	4,699,757	3,575,036	3,844,131	3,798,117	4,446,940	4,642,393	4,437,932	4,679,827	2,573,691	4,194,038	48,601,957
15. NET GEN (MWH)	384,788	433,734	502,957	377,911	400,686	391,389	470,212	477,675	470,824	491,939	272,909	444,487	5,119,511
16. ANOHR (BTU/KWH)	9,559.2	9,295.6	9,344.3	9,460.0	9,593.9	9,704.2	9,457.3	9,718.7	9,425.9	9,513.0	9,430.6	9,435.7	9,493.5
17. NOF (%)	84.96	89.64	93.89	74.66	78.13	84.51	88.67	91.31	90.82	92.70	85.43	83.37	86.63
18. NPC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
ANOHR EQUATION:	ANOHR=	-14.234	x NOF +	10,687.55									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 5	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	71.68	96.28	9.67	86.70	98.39	94.27	92.85	97.24	95.79	92.45	97.38	97.83	85.71
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	545.1	667.4	72.0	657.9	744.0	684.1	718.7	744.0	720.0	745.0	720.0	744.0	7,762.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	198.9	4.6	672.0	61.1	0.0	35.9	25.3	0.0	0.0	0.0	0.0	0.0	997.8
6. POH	67.5	0.0	672.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	739.7
7. FOH	128.9	4.6	0.0	60.9	0.0	35.9	25.3	0.0	0.0	0.0	0.0	0.0	255.6
8. MOH	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5
9. PFOH	19.7	110.9	0.0	12.7	0.0	10.4	75.7	8.2	7.5	43.8	3.0	12.4	304.2
10. LR PF (MW)	72.7	96.2	0.0	388.3	0.0	48.5	60.6	79.8	146.0	214.8	98.0	287.8	122.1
11. PMOH	38.5	17.8	0.0	123.4	50.2	22.0	49.6	80.9	72.3	365.5	66.2	67.3	953.5
12. LR PM (MW)	182.8	224.5	0.0	160.3	171.5	150.0	311.4	174.3	285.6	84.6	199.6	119.2	152.1
13. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
14. OPER MBTU	3,089,177	3,837,739	412,596	3,639,857	4,334,586	4,188,332	4,403,471	4,851,410	4,252,954	4,234,797	4,454,851	4,499,579	46,199,350
15. NET GEN (MWH)	319,155	397,975	37,277	372,539	448,884	425,737	446,649	492,471	436,034	441,272	459,665	468,613	4,746,271
16. ANOHR (BTU/KWH)	9,679.2	9,643.2	11,068.4	9,770.4	9,656.4	9,837.8	9,858.9	9,851.2	9,753.7	9,596.8	9,691.5	9,601.9	9,733.8
17. NOF (%)	81.66	83.16	72.23	78.98	84.15	86.80	86.68	92.32	84.46	82.61	89.04	87.85	85.28
18. NPC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
ANOHR EQUATION:	ANOHR=	-11.484	x NOF +	10,499.06									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 1	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	100.00	99.83	100.00	46.46	93.27	66.61	83.39	81.40	90.79	93.82	45.86	53.76	79.63
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	521.4	672.0	744.0	334.1	694.2	637.2	744.0	686.0	720.0	745.0	342.6	61.7	6,902.1
4. RSH	222.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	338.3	560.9
5. UH	0.0	0.0	0.0	384.9	49.8	82.8	0.0	58.1	0.0	0.0	377.4	344.0	1,297.0
6. POH	0.0	0.0	0.0	384.9	8.2	0.0	0.0	0.0	0.0	0.0	377.4	344.0	1,114.6
7. FOH	0.0	0.0	0.0	0.0	41.6	0.0	0.0	58.1	0.0	0.0	0.0	0.0	99.7
8. MOH	0.0	0.0	0.0	0.0	0.0	82.8	0.0	0.0	0.0	0.0	0.0	0.0	82.8
9. PFOH	0.0	1.7	0.0	0.0	0.7	321.8	230.9	183.5	0.0	176.0	47.4	0.0	961.9
10. LR PF (MW)	0.0	326.5	0.0	0.0	148.6	236.0	236.0	211.0	0.0	126.0	126.0	0.0	205.8
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	21.6	0.0	124.9	0.0	0.0	0.0	146.5
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	236.0	0.0	256.0	0.0	0.0	0.0	253.0
13. NSC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482
14. OPER MBTU	1,297,027	1,408,221	2,254,958	1,072,598	1,914,068	1,468,226	1,862,227	1,845,309	1,894,617	2,112,358	892,197	86,357	18,108,163
15. NET GEN (MWH)	171,066	178,802	306,677	149,694	252,527	183,384	243,769	244,141	259,308	281,281	119,676	9,658	2,399,983
16. ANOHR (BTU/KWH)	7,582.0	7,875.9	7,352.9	7,165.3	7,579.7	8,006.3	7,639.3	7,558.4	7,306.4	7,509.8	7,455.1	8,941.4	7,545.1
17. NOF (%)	68.07	55.20	85.52	92.96	75.47	59.71	67.98	73.84	74.72	78.33	72.48	32.48	72.14
18. NPC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482
ANOHR EQUATION:	ANOHR=	-12.692	x NOF +	8,380.11									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Tiger Bay	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-Dec Period
1. EAF	100.00	99.98	100.00	100.00	88.79	100.00	100.00	100.00	71.49	98.74	99.22	99.76	96.51
2. PH	744.00	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	212.2	165.1	223.7	433.0	652.3	720.0	744.0	744.0	514.8	735.6	714.4	237.9	6,096.9
4. RSH	531.8	506.9	520.3	286.0	8.4	0.0	0.0	0.0	0.0	0.0	0.0	504.3	2,357.7
5. UH	0.0	0.0	0.0	0.0	83.3	0.0	0.0	0.0	205.3	9.4	5.6	1.8	305.4
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	107.3	0.0	0.0	0.0	107.3
7. FOH	0.0	0.0	0.0	0.0	83.3	0.0	0.0	0.0	98.0	9.4	5.6	1.8	198.1
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
10. LR PF (MW)	0.0	157.3	0.0	0.0	164.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	159.9
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
14. OPER MBTU	112,273	225,508	291,164	575,232	840,861	970,416	1,006,322	1,029,087	696,643	1,009,678	960,001	317,217	8,034,404
15. NET GEN (MWH)	13,545	26,850	40,535	73,169	104,850	125,420	129,330	130,060	87,118	126,742	121,134	40,821	1,019,574
16. ANOHR (BTU/KWH)	8,288.9	8,398.8	7,183.0	7,861.7	8,019.7	7,737.3	7,781.0	7,912.4	7,996.5	7,966.4	7,925.1	7,770.9	7,880.2
17. NOF (%)	30.84	78.57	87.55	81.63	77.65	84.15	83.98	84.45	81.76	83.23	81.92	82.91	80.79
18. NPC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
ANOHR EQUATION:	ANOHR=	-29.711	x NOF +	10,600.10									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

PLANNED OUTAGE SCHEDULES
ACTUAL

Progress Energy Florida
Janauary 2006 - December 2006

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 1	4/8 (0001) - 4/15 (2400)	Stack Maintenance
Anclote 1	9/28 (0001) - 11/3 (2400)	Major Boiler Overhaul
Anclote 2	04/01 (0001) - 05/13 (2400)	Major Boiler Overhaul
Crystal River 2	10/21 (0001) - 11/3 (2400)	Minor Boiler Overhaul
Crystal River 4	1/23 (0001) - 1/25 (2400)	Boiler Inpsection
Crystal River 4	11/10 (0001) - 11/21 (2400)	Minor Boiler Overhaul
Crystal River 5	1/8 (0001) - 1/10 (2400)	Boiler Inspection
Crystal River 5	3/3 (0001) - 4/1 (2400)	Major Boiler Overhaul
Hines 1	4/14 (0001) - 4/30 (2400)	Turbine Inspection
Hines 1	11/2 (0001) - 11/4 (2400)	Fuel Sys Insp
Hines 1	11/17 (0001) - 12/14 (2400)	Valve Replacement
Tiger Bay	9/17 (0001) - 9/21 (2400)	Expansion Joints

Planned Outage Schedule - Actual

Progress Energy Florida
Janauary 2006 - December 2006

	January	February	March	April	May	June	July	August	September	October	November	December
Anclote 1				Stack Maintenance 4/8 – 4/15, 8 days					Major Boiler Overhaul 9/28 – 11/3, 37 days			
Anclote 2				Major Boiler Overhaul 4/1 – 5/13, 43 days								
Crystal River 2										Minor Boiler Overhaul 10/21 – 11/3, 14 days		
Crystal River 4	Boiler Inpsection 1/23 – 1/25, 3 days										Minor Boiler Overhaul 11/10 – 11/21, 12 days	
Crystal River 5	Boiler Inspection 1/8 – 1/10, 3 days		Major Boiler Overhaul 3/3 – 4/1, 30 days									
Hines 1				Turbine Inspection 4/14 – 4/30, 17 days						Fuel Sys Insp 11/2 – 11/17, 3 days	Valve Replacement, 28 days	
Tiger Bay									Expansion Joints 9/17 – 9/21, 5 days			

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Progress Energy Florida
Docket No. 070001-EI
Witness: Oliver
Exhibit No. 12 (RMO-1)

GPIF Targets and Ranges for January through December 2008

STANDARD FORM GPIF SCHEDULES

Description	Page
Index	1
Reward/Penalty Table (Estimated)	2
Maximum Incentive Dollars (Estimated)	3
Target and Range Summary	4
Comparison of Targets with Prior Period Performance	5-6
Derivation of Weighting Factors	7
Incentive Points Tables	8-18
Unit Performance Data (Estimated)	19-29
Planned Outage Schedule (Estimated)	30-31
Average Net Operating Heat Rate Curves	32-52
Unplanned Outage Rate Tables and Graphs	53-104

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 12
COMPANY Progress Energy FL, Inc
WITNESS Robert M. Oliver (RMO-1P
DATE 11-06-07

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Progress Energy Florida
Period of: January 2008 - December 2008

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$102,814,332	$13,230,670
9	$92,532,898	$11,907,603
8	$82,251,465	$10,584,536
7	$71,970,032	$9,261,469
6	$61,688,599	$7,938,402
5	$51,407,166	$6,615,335
4	$41,125,733	$5,292,268
3	$30,844,299	$3,969,201
2	$20,562,866	$2,646,134
1	$10,281,433	$1,323,067
0	$0	$0
-1	($17,173,645)	($1,323,067)
-2	($34,347,290)	($2,646,134)
-3	($51,520,935)	($3,969,201)
-4	($68,694,580)	($5,292,268)
-5	($85,868,225)	($6,615,335)
-6	($103,041,870)	($7,938,402)
-7	($120,215,515)	($9,261,469)
-8	($137,389,160)	($10,584,536)
-9	($154,562,805)	($11,907,603)
-10	($171,736,450)	($13,230,670)

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Progress Energy Florida
Period of: January 2008 - December 2008

1	Beginning of period balance of common equity	$3,033,385,553	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2008	$3,059,181,331	
3	Month of FEBRUARY 2008	$3,156,348,980	
4	Month of MARCH 2008	$3,176,303,593	
5	Month of APRIL 2008	$3,195,710,122	
6	Month of MAY 2008	$3,311,413,786	
7	Month of JUNE 2008	$3,351,370,391	
8	Month of JULY 2008	$3,400,049,198	
9	Month of AUGUST 2008	$3,526,013,883	
10	Month of SEPTEMBER 2008	$3,566,333,503	
11	Month of OCTOBER 2008	$3,602,790,236	
12	Month of NOVEMBER 2008	$3,699,767,419	
13	Month of DECEMBER 2008	$3,714,419,725	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$3,368,699,055	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$13,720,492	
18	Jurisdictional Sales	41,591,068	MWH
19	Total Sales	43,130,379	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	96.43%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$13,230,670	

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GPIF TARGET AND RANGE SUMMARY

Progress Energy Florida
Period of: January 2008 - December 2008

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	0.38	91.62	93.51	87.70	393	(2,528)
Anclote 2	0.11	83.03	85.60	77.80	108	(3,912)
Crystal River 1	5.39	92.48	96.01	85.30	5,545	(14,745)
Crystal River 2	12.82	84.16	89.46	73.85	13,176	(27,080)
Crystal River 3	6.93	96.78	98.30	93.65	7,121	(17,381)
Crystal River 4	7.34	83.52	85.87	78.73	7,551	(19,991)
Crystal River 5	10.32	93.17	96.37	86.70	10,609	(23,673)
Hines 1	0.31	83.48	85.21	79.89	322	(2,308)
Hines 2	0.03	88.47	89.79	85.78	35	(1,746)
Tiger Bay	0.37	77.66	78.93	74.99	384	(802)
GPIF System	44.01				45,245	(114,167)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	6.14	10,213	47.4	9,845	10,580	6,308	(6,308)
Anclote 2	3.79	10,298	41.1	10,016	10,581	3,899	(3,899)
Crystal River 1	1.91	10,279	76.0	10,019	10,540	1,960	(1,960)
Crystal River 2	2.63	9,824	78.1	9,540	10,108	2,702	(2,702)
Crystal River 3	6.96	10,321	98.0	10,159	10,482	7,155	(7,155)
Crystal River 4	3.02	9,480	89.3	9,272	9,688	3,103	(3,103)
Crystal River 5	6.34	9,593	88.9	9,201	9,984	6,523	(6,523)
Hines 1	11.32	7,349	80.9	6,788	7,909	11,635	(11,635)
Hines 2	7.34	7,017	80.1	6,608	7,426	7,543	(7,543)
Tiger Bay	6.56	7,973	87.5	7,144	8,802	6,741	(6,741)
GPIF System	55.99					57,569	(57,569)

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Progress Energy Florida
Period of: January 2008 - December 2008

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2007 POF	Actual Performance 1st Prior Period Jan-Jun 2007 EUOF	Actual Performance 1st Prior Period Jan-Jun 2007 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2006 POF	Actual Performance 2nd Prior Period Jan-Dec 2006 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2006 EUOR
Anclote 1	0.38	0.87	4.37	4.01	4.23	7.77	4.00	4.67	11.96	2.89	4.14
Anclote 2	0.11	0.24	11.48	5.50	6.37	0.00	11.66	13.23	11.65	3.54	4.54
Crystal River 1	5.39	12.26	0.00	7.52	7.52	19.41	10.98	13.62	0.00	6.69	6.69
Crystal River 2	12.82	29.12	4.37	11.46	11.99	31.52	5.46	7.97	3.75	9.67	10.04
Crystal River 3	6.93	15.74	0.00	3.22	3.22	0.00	2.09	2.09	0.00	1.73	1.82
Crystal River 4	7.34	16.69	11.48	5.00	5.65	0.00	3.79	3.79	3.78	4.75	4.94
Crystal River 5	10.32	23.45	0.00	6.83	6.83	0.00	4.49	4.49	8.44	5.85	6.39
Hines 1	0.31	0.71	12.84	3.68	4.86	12.15	2.73	4.79	12.72	7.65	9.46
Hines 2	0.03	0.08	8.74	2.78	4.71	8.48	1.47	1.89	5.56	5.81	8.00
Tiger Bay	0.37	0.85	19.67	2.67	4.26	7.53	0.51	0.72	1.22	2.26	3.15
GPIF System Wghtd. Avg.	44.01	100.00	3.52	7.30	7.59	11.78	5.04	6.12	3.94	6.17	6.50

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2005 POF	Actual Performance 3rd Prior Period Jan-Dec 2005 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2005 EUOR	Actual Performance 4th Prior Period Jan-Dec 2004 POF	Actual Performance 4th Prior Period Jan-Dec 2004 EUOF	Actual Performance 4th Prior Period Jan-Dec 2004 EUOR	Actual Performance 5th Prior Period Jan-Dec 2003 POF	Actual Performance 5th Prior Period Jan-Dec 2003 EUOF	Actual Performance 5th Prior Period Jan-Dec 2003 EUOR
Anclote 1	3.32	3.97	4.41	0.00	4.06	4.21	11.48	5.55	6.76
Anclote 2	3.21	4.01	4.55	7.36	4.20	4.94	0.00	6.75	6.75
Crystal River 1	0.00	6.14	6.14	12.87	6.82	7.82	0.00	8.70	8.70
Crystal River 2	0.00	17.45	17.45	0.00	14.88	14.88	12.23	9.77	11.13
Crystal River 3	7.66	4.67	5.18	0.00	2.77	2.77	8.92	2.80	3.08
Crystal River 4	6.29	3.89	4.15	0.00	9.08	9.08	1.55	1.33	1.35
Crystal River 5	0.00	9.03	9.03	2.26	3.33	3.41	0.00	4.52	4.52
Hines 1	7.90	1.96	2.36	14.05	4.53	5.65	8.72	3.89	4.32
Hines 2	8.95	1.69	2.04	4.60	6.15	6.67	N/A	N/A	N/A
Tiger Bay	2.02	2.67	4.74	6.67	4.02	5.49	2.66	6.48	6.97
GPIF System Wghtd. Avg.	2.37	9.42	9.57	2.28	8.02	8.18	5.41	5.78	6.24

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Progress Energy Florida
Period of: January 2008 - December 2008

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2006 - Dec 2006	2nd Prior HR Jan 2005 - Dec 2005	3rd Prior HR Jan 2004 - Dec 2004
Anclote 1	6.14	10.96	10,213	10,329	10,166	10,108
Anclote 2	3.79	6.77	10,298	10,330	10,301	10,294
Crystal River 1	1.91	3.41	10,279	10,325	10,297	10,260
Crystal River 2	2.63	4.69	9,824	9,873	9,816	9,761
Crystal River 3	6.96	12.43	10,321	10,353	10,313	10,328
Crystal River 4	3.02	5.39	9,480	9,467	9,484	9,522
Crystal River 5	6.34	11.33	9,593	9,717	9,586	9,460
Hines 1	11.32	20.21	7,349	7,358	7,262	7,204
Hines 2	7.34	13.10	7,017	7,066	7,008	7,118
Tiger Bay	6.56	11.71	7,973	7,804	8,020	8,403
GPIF System Weighted Avg.	55.99	100.00	8,846	8,871	8,827	8,854

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No:
Order No:

DERIVATION OF WEIGHTING FACTORS

Progress Energy Florida
Period of: January 2008 - December 2008

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Anclote 1 EA	2,842,460	2,842,067	393	0.38
Anclote 1 HR	2,842,460	2,836,152	6,308	6.14
Anclote 2 EA	2,842,460	2,842,352	108	0.11
Anclote 2 HR	2,842,460	2,838,561	3,899	3.79
Crystal River 1 EA	2,842,460	2,836,915	5,545	5.39
Crystal River 1 HR	2,842,460	2,840,500	1,960	1.91
Crystal River 2 EA	2,842,460	2,829,284	13,176	12.82
Crystal River 2 HR	2,842,460	2,839,758	2,702	2.63
Crystal River 3 EA	2,842,460	2,835,339	7,121	6.93
Crystal River 3 HR	2,842,460	2,835,305	7,155	6.96
Crystal River 4 EA	2,842,460	2,834,909	7,551	7.34
Crystal River 4 HR	2,842,460	2,839,357	3,103	3.02
Crystal River 5 EA	2,842,460	2,831,851	10,609	10.32
Crystal River 5 HR	2,842,460	2,835,937	6,523	6.34
Hines 1 EA	2,842,460	2,842,138	322	0.31
Hines 1 HR	2,842,460	2,830,825	11,635	11.32
Hines 2 EA	2,842,460	2,842,425	35	0.03
Hines 2 HR	2,842,460	2,834,917	7,543	7.34
Tiger Bay EA	2,842,460	2,842,076	384	0.37
Tiger Bay HR	2,842,460	2,835,719	6,741	6.56

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No:
Order No.:

INCENTIVE POINTS TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Anclote 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$392,952	93.51	10	$6,308,169	9,845.3
9	$353,657	93.33	9	$5,677,352	9,874.6
8	$314,361	93.14	8	$5,046,535	9,903.8
7	$275,066	92.95	7	$4,415,718	9,933.0
6	$235,771	92.76	6	$3,784,901	9,962.2
5	$196,476	92.57	5	$3,154,084	9,991.5
4	$157,181	92.38	4	$2,523,267	10,020.7
3	$117,886	92.19	3	$1,892,451	10,049.9
2	$78,590	92.00	2	$1,261,634	10,079.1
1	$39,295	91.81	1	$630,817	10,108.4
					10,137.6
0	$0	91.62	0	$0	10,212.6
					10,287.6
-1	($252,822)	91.23	-1	($630,817)	10,316.8
-2	($505,645)	90.84	-2	($1,261,634)	10,346.0
-3	($758,467)	90.44	-3	($1,892,451)	10,375.3
-4	($1,011,290)	90.05	-4	($2,523,267)	10,404.5
-5	($1,264,112)	89.66	-5	($3,154,084)	10,433.7
-6	($1,516,935)	89.27	-6	($3,784,901)	10,462.9
-7	($1,769,757)	88.87	-7	($4,415,718)	10,492.2
-8	($2,022,579)	88.48	-8	($5,046,535)	10,521.4
-9	($2,275,402)	88.09	-9	($5,677,352)	10,550.6
-10	($2,528,224)	87.70	-10	($6,308,169)	10,579.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.38%	6.14%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Anclote 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$108,456	85.60	10	$3,898,679	10,016.4
9	$97,610	85.35	9	$3,508,811	10,037.1
8	$86,764	85.09	8	$3,118,943	10,057.8
7	$75,919	84.83	7	$2,729,075	10,078.5
6	$65,073	84.57	6	$2,339,207	10,099.2
5	$54,228	84.32	5	$1,949,340	10,119.9
4	$43,382	84.06	4	$1,559,472	10,140.6
3	$32,537	83.80	3	$1,169,604	10,161.3
2	$21,691	83.54	2	$779,736	10,182.0
1	$10,846	83.28	1	$389,868	10,202.8
					10,223.5
0	$0	83.03	0	$0	10,298.5
					10,373.5
-1	($391,247)	82.50	-1	($389,868)	10,394.2
-2	($782,493)	81.98	-2	($779,736)	10,414.9
-3	($1,173,740)	81.46	-3	($1,169,604)	10,435.6
-4	($1,564,986)	80.94	-4	($1,559,472)	10,456.3
-5	($1,956,233)	80.41	-5	($1,949,340)	10,477.0
-6	($2,347,479)	79.89	-6	($2,339,207)	10,497.7
-7	($2,738,726)	79.37	-7	($2,729,075)	10,518.4
-8	($3,129,973)	78.85	-8	($3,118,943)	10,539.1
-9	($3,521,219)	78.32	-9	($3,508,811)	10,559.9
-10	($3,912,466)	77.80	-10	($3,898,679)	10,580.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.11%	3.79%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Crystal River 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$5,544,841	96.01	10	$1,960,273	10,019.0
9	$4,990,357	95.65	9	$1,764,246	10,037.6
8	$4,435,873	95.30	8	$1,568,219	10,056.1
7	$3,881,389	94.95	7	$1,372,191	10,074.7
6	$3,326,905	94.59	6	$1,176,164	10,093.2
5	$2,772,421	94.24	5	$980,137	10,111.7
4	$2,217,937	93.89	4	$784,109	10,130.3
3	$1,663,452	93.54	3	$588,082	10,148.8
2	$1,108,968	93.18	2	$392,055	10,167.3
1	$554,484	92.83	1	$196,027	10,185.9
					10,204.4
0	$0	92.48	0	$0	10,279.4
					10,354.4
-1	($1,474,451)	91.76	-1	($196,027)	10,373.0
-2	($2,948,902)	91.04	-2	($392,055)	10,391.5
-3	($4,423,353)	90.32	-3	($588,082)	10,410.0
-4	($5,897,803)	89.61	-4	($784,109)	10,428.6
-5	($7,372,254)	88.89	-5	($980,137)	10,447.1
-6	($8,846,705)	88.17	-6	($1,176,164)	10,465.7
-7	($10,321,156)	87.45	-7	($1,372,191)	10,484.2
-8	($11,795,607)	86.73	-8	($1,568,219)	10,502.7
-9	($13,270,058)	86.02	-9	($1,764,246)	10,521.3
-10	($14,744,509)	85.30	-10	($1,960,273)	10,539.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.39%	1.91%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Crystal River 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$13,175,692	89.46	10	$2,702,182	9,539.9
9	$11,858,122	88.93	9	$2,431,964	9,560.8
8	$10,540,553	88.40	8	$2,161,746	9,581.7
7	$9,222,984	87.87	7	$1,891,527	9,602.6
6	$7,905,415	87.34	6	$1,621,309	9,623.5
5	$6,587,846	86.81	5	$1,351,091	9,644.4
4	$5,270,277	86.28	4	$1,080,873	9,665.3
3	$3,952,707	85.75	3	$810,655	9,686.2
2	$2,635,138	85.22	2	$540,436	9,707.1
1	$1,317,569	84.69	1	$270,218	9,728.0
					9,748.9
0	$0	84.16	0	$0	9,823.9
					9,898.9
-1	($2,708,039)	83.13	-1	($270,218)	9,919.8
-2	($5,416,079)	82.10	-2	($540,436)	9,940.7
-3	($8,124,118)	81.07	-3	($810,655)	9,961.6
-4	($10,832,158)	80.04	-4	($1,080,873)	9,982.4
-5	($13,540,197)	79.01	-5	($1,351,091)	10,003.3
-6	($16,248,237)	77.97	-6	($1,621,309)	10,024.2
-7	($18,956,276)	76.94	-7	($1,891,527)	10,045.1
-8	($21,664,316)	75.91	-8	($2,161,746)	10,066.0
-9	($24,372,355)	74.88	-9	($2,431,964)	10,086.9
-10	($27,080,395)	73.85	-10	($2,702,182)	10,107.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
12.82%	2.63%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Crystal River 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$7,120,913	98.30	10	$7,154,633	10,159.0
9	$6,408,822	98.15	9	$6,439,170	10,167.7
8	$5,696,731	98.00	8	$5,723,707	10,176.3
7	$4,984,639	97.85	7	$5,008,243	10,185.0
6	$4,272,548	97.70	6	$4,292,780	10,193.7
5	$3,560,457	97.54	5	$3,577,317	10,202.3
4	$2,848,365	97.39	4	$2,861,853	10,211.0
3	$2,136,274	97.24	3	$2,146,390	10,219.6
2	$1,424,183	97.09	2	$1,430,927	10,228.3
1	$712,091	96.94	1	$715,463	10,236.9
					10,245.6
0	$0	96.78	0	$0	10,320.6
					10,395.6
-1	($1,738,087)	96.47	-1	($715,463)	10,404.3
-2	($3,476,173)	96.16	-2	($1,430,927)	10,412.9
-3	($5,214,260)	95.84	-3	($2,146,390)	10,421.6
-4	($6,952,347)	95.53	-4	($2,861,853)	10,430.2
-5	($8,690,434)	95.22	-5	($3,577,317)	10,438.9
-6	($10,428,520)	94.90	-6	($4,292,780)	10,447.5
-7	($12,166,607)	94.59	-7	($5,008,243)	10,456.2
-8	($13,904,694)	94.27	-8	($5,723,707)	10,464.9
-9	($15,642,780)	93.96	-9	($6,439,170)	10,473.5
-10	($17,380,867)	93.65	-10	($7,154,633)	10,482.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.93%	6.96%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$7,551,276	85.87	10	$3,103,486	9,271.7
9	$6,796,149	85.64	9	$2,793,137	9,285.0
8	$6,041,021	85.40	8	$2,482,788	9,298.4
7	$5,285,893	85.17	7	$2,172,440	9,311.7
6	$4,530,766	84.93	6	$1,862,091	9,325.0
5	$3,775,638	84.70	5	$1,551,743	9,338.4
4	$3,020,511	84.46	4	$1,241,394	9,351.7
3	$2,265,383	84.23	3	$931,046	9,365.0
2	$1,510,255	83.99	2	$620,697	9,378.4
1	$755,128	83.76	1	$310,349	9,391.7
					9,405.0
0	$0	83.52	0	$0	9,480.0
					9,555.0
-1	($1,999,133)	83.04	-1	($310,349)	9,568.4
-2	($3,998,266)	82.56	-2	($620,697)	9,581.7
-3	($5,997,400)	82.09	-3	($931,046)	9,595.0
-4	($7,996,533)	81.61	-4	($1,241,394)	9,608.4
-5	($9,995,666)	81.13	-5	($1,551,743)	9,621.7
-6	($11,994,799)	80.65	-6	($1,862,091)	9,635.0
-7	($13,993,932)	80.17	-7	($2,172,440)	9,648.4
-8	($15,993,066)	79.69	-8	($2,482,788)	9,661.7
-9	($17,992,199)	79.21	-9	($2,793,137)	9,675.0
-10	($19,991,332)	78.73	-10	($3,103,486)	9,688.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
7.34%	3.02%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$10,609,252	96.37	10	$6,523,432	9,200.9
9	$9,548,327	96.05	9	$5,871,089	9,232.6
8	$8,487,402	95.73	8	$5,218,746	9,264.3
7	$7,426,476	95.41	7	$4,566,403	9,295.9
6	$6,365,551	95.09	6	$3,914,059	9,327.6
5	$5,304,626	94.77	5	$3,261,716	9,359.2
4	$4,243,701	94.45	4	$2,609,373	9,390.9
3	$3,182,776	94.13	3	$1,957,030	9,422.6
2	$2,121,850	93.81	2	$1,304,686	9,454.2
1	$1,060,925	93.49	1	$652,343	9,485.9
					9,517.6
0	$0	93.17	0	$0	9,592.6
					9,667.6
-1	($2,367,338)	92.52	-1	($652,343)	9,699.2
-2	($4,734,677)	91.88	-2	($1,304,686)	9,730.9
-3	($7,102,015)	91.23	-3	($1,957,030)	9,762.5
-4	($9,469,353)	90.58	-4	($2,609,373)	9,794.2
-5	($11,836,691)	89.94	-5	($3,261,716)	9,825.9
-6	($14,204,030)	89.29	-6	($3,914,059)	9,857.5
-7	($16,571,368)	88.64	-7	($4,566,403)	9,889.2
-8	($18,938,706)	87.99	-8	($5,218,746)	9,920.8
-9	($21,306,044)	87.35	-9	($5,871,089)	9,952.5
-10	($23,673,383)	86.70	-10	($6,523,432)	9,984.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.32%	6.34%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$322,497	85.21	10	$11,634,765	6,788.5
9	$290,247	85.04	9	$10,471,288	6,837.0
8	$257,997	84.87	8	$9,307,812	6,885.5
7	$225,748	84.69	7	$8,144,335	6,934.0
6	$193,498	84.52	6	$6,980,859	6,982.5
5	$161,248	84.35	5	$5,817,382	7,031.0
4	$128,999	84.17	4	$4,653,906	7,079.6
3	$96,749	84.00	3	$3,490,429	7,128.1
2	$64,499	83.82	2	$2,326,953	7,176.6
1	$32,250	83.65	1	$1,163,476	7,225.1
					7,273.6
0	$0	83.48	0	$0	7,348.6
					7,423.6
-1	($230,756)	83.12	-1	($1,163,476)	7,472.2
-2	($461,512)	82.76	-2	($2,326,953)	7,520.7
-3	($692,268)	82.40	-3	($3,490,429)	7,569.2
-4	($923,024)	82.04	-4	($4,653,906)	7,617.7
-5	($1,153,780)	81.68	-5	($5,817,382)	7,666.2
-6	($1,384,536)	81.32	-6	($6,980,859)	7,714.7
-7	($1,615,292)	80.96	-7	($8,144,335)	7,763.3
-8	($1,846,048)	80.61	-8	($9,307,812)	7,811.8
-9	($2,076,804)	80.25	-9	($10,471,288)	7,860.3
-10	($2,307,560)	79.89	-10	($11,634,765)	7,908.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.31%	11.32%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$34,759	89.79	10	$7,542,562	6,607.9
9	$31,284	89.65	9	$6,788,306	6,641.3
8	$27,808	89.52	8	$6,034,049	6,674.7
7	$24,332	89.39	7	$5,279,793	6,708.1
6	$20,856	89.26	6	$4,525,537	6,741.5
5	$17,380	89.13	5	$3,771,281	6,774.9
4	$13,904	89.00	4	$3,017,025	6,808.3
3	$10,428	88.87	3	$2,262,769	6,841.6
2	$6,952	88.74	2	$1,508,512	6,875.0
1	$3,476	88.61	1	$754,256	6,908.4
					6,941.8
0	$0	88.47	0	$0	7,016.8
					7,091.8
-1	($174,617)	88.20	-1	($754,256)	7,125.2
-2	($349,233)	87.94	-2	($1,508,512)	7,158.6
-3	($523,850)	87.67	-3	($2,262,769)	7,192.0
-4	($698,466)	87.40	-4	($3,017,025)	7,225.3
-5	($873,083)	87.13	-5	($3,771,281)	7,258.7
-6	($1,047,699)	86.86	-6	($4,525,537)	7,292.1
-7	($1,222,316)	86.59	-7	($5,279,793)	7,325.5
-8	($1,396,932)	86.32	-8	($6,034,049)	7,358.9
-9	($1,571,549)	86.05	-9	($6,788,306)	7,392.3
-10	($1,746,165)	85.78	-10	($7,542,562)	7,425.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.03%	7.34%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2008 - December 2008

Tiger Bay

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$384,436	78.93	10	$6,741,075	7,144.2
9	$345,993	78.80	9	$6,066,968	7,219.6
8	$307,549	78.67	8	$5,392,860	7,295.0
7	$269,106	78.55	7	$4,718,753	7,370.4
6	$230,662	78.42	6	$4,044,645	7,445.8
5	$192,218	78.29	5	$3,370,538	7,521.2
4	$153,775	78.16	4	$2,696,430	7,596.6
3	$115,331	78.04	3	$2,022,323	7,672.0
2	$76,887	77.91	2	$1,348,215	7,747.4
1	$38,444	77.78	1	$674,108	7,822.8
					7,898.1
0	$0	77.66	0	$0	7,973.1
					8,048.1
-1	($80,229)	77.39	-1	($674,108)	8,123.5
-2	($160,458)	77.12	-2	($1,348,215)	8,198.9
-3	($240,687)	76.86	-3	($2,022,323)	8,274.3
-4	($320,917)	76.59	-4	($2,696,430)	8,349.7
-5	($401,146)	76.32	-5	($3,370,538)	8,425.1
-6	($481,375)	76.05	-6	($4,044,645)	8,500.5
-7	($561,604)	75.79	-7	($4,718,753)	8,575.9
-8	($641,833)	75.52	-8	($5,392,860)	8,651.3
-9	($722,062)	75.25	-9	($6,066,968)	8,726.6
-10	($802,291)	74.99	-10	($6,741,075)	8,802.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.37%	6.56%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Anclote 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.77	95.77	95.77	95.77	95.77	95.77	95.77	95.77	95.77	52.76	89.45	95.95	91.62
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.16	6.67	0.00	4.37
3. EUOF	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	2.08	3.89	4.05	4.01
4. EUOR	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	731.7	684.5	731.7	708.1	731.7	708.1	731.7	731.7	708.1	358.9	650.1	700.6	8,176.7
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	10.9	31.6	85.5
8. UH	12.3	11.5	12.3	11.9	12.3	11.9	12.3	12.3	11.9	342.1	59.0	11.8	521.8
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	336.0	48.0	0.0	384.0
10. FOH & PFOH	19.1	17.9	19.1	18.5	19.1	18.5	19.1	19.1	18.5	9.4	17.0	18.3	213.5
11. MOH & PMOH	12.4	11.6	12.4	12.0	12.4	12.0	12.4	12.4	12.0	6.1	11.0	11.9	138.5
12. Oper. Btu(MBtu)	1,575,114	1,442,781	1,861,667	1,411,255	1,792,798	1,837,058	1,874,446	1,993,248	1,949,767	920,753	1,605,477	1,433,529	19,716,466
13. Net Gen. (MWH)	152,992.0	139,945.0	183,066.0	136,408.0	175,765.0	180,937.0	184,426.0	197,149.0	193,034.0	90,602.0	157,496.0	138,785.0	1,930,605.0
14. ANOHR (Btu/KWH)	10,295	10,310	10,169	10,346	10,200	10,153	10,164	10,110	10,101	10,163	10,194	10,329	10,213
15. NOF (%)	42.0	41.1	50.2	38.7	48.2	51.3	50.6	54.1	54.7	50.7	48.6	39.8	47.4
16. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
17. ANOHR Equation	ANOHR=	-15.269 x NOF +		10,936.5									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Anclote 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.18	94.29	21.21	37.88	93.63	93.63	93.63	93.63	93.63	93.63	93.63	93.63	83.03
2. POF	0.00	0.00	77.42	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.48
3. EUOF	5.82	5.71	1.37	2.12	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	5.50
4. EUOR	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	656.9	603.4	154.4	231.7	718.9	695.7	718.9	718.9	695.7	718.9	695.7	718.9	7,328.0
7. RSH	64.2	71.5	8.2	48.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	192.1
8. UH	22.9	21.1	581.4	440.1	25.1	24.3	25.1	25.1	24.3	25.1	24.3	25.1	1263.9
9. POH	0.0	0.0	576.0	432.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1008.0
10. FOH & PFOH	15.0	13.8	3.5	5.3	16.5	15.9	16.5	16.5	15.9	16.5	15.9	16.5	167.9
11. MOH & PMOH	28.2	25.9	6.6	10.0	30.9	29.9	30.9	30.9	29.9	30.9	29.9	30.9	315.0
12. Oper. Btu(MBtu)	1,249,322	1,129,425	330,421	477,897	1,504,395	1,584,072	1,632,627	1,882,556	1,730,106	1,595,810	1,457,273	1,124,960	15,714,114
13. Net Gen. (MWH)	120,608.0	108,955.0	32,081.0	46,313.0	145,897.0	154,313.0	159,020.0	184,949.0	169,413.0	155,240.0	141,334.0	107,746.0	1,525,869.0
14. ANOHR (Btu/KWH)	10,359	10,366	10,300	10,319	10,311	10,265	10,267	10,179	10,212	10,280	10,311	10,441	10,298
15. NOF (%)	36.2	35.6	41.0	39.4	40.0	43.7	43.6	50.7	48.0	42.6	40.1	29.6	41.1
16. NSC (MW)	507	507	507	507	507	507	507	507	507	507	507	507	507
17. ANOHR Equation	ANOHR=	-12.372 x NOF +		10,806.6									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Crystal River 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48	92.48
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52
4. EUOR	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	721.4	674.9	721.4	698.1	721.4	698.1	721.4	721.4	698.1	721.4	698.1	721.4	8,517.3
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	22.6	21.1	22.6	21.9	22.6	21.9	22.6	22.6	21.9	22.6	21.9	22.6	266.7
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	28.9	27.0	28.9	28.0	28.9	28.0	28.9	28.9	28.0	28.9	28.0	28.9	341.0
11. MOH & PMOH	27.1	25.3	27.1	26.2	27.1	26.2	27.1	27.1	26.2	27.1	26.2	27.1	319.8
12. Oper. Btu(MBtu)	2,114,053	1,840,003	2,044,753	2,006,449	2,058,523	2,053,212	2,163,631	2,198,749	2,150,064	2,129,644	2,093,392	2,358,545	25,218,899
13. Net Gen. (MWH)	205,371.0	177,109.0	197,772.0	194,416.0	199,276.0	199,557.0	210,854.0	214,762.0	210,320.0	207,091.0	204,003.0	232,806.0	2,453,337.0
14. ANOHR (Btu/KWH)	10,294	10,389	10,339	10,320	10,330	10,289	10,261	10,238	10,223	10,284	10,262	10,131	10,279
15. NOF (%)	75.1	69.2	72.3	73.5	72.9	75.4	77.1	78.5	79.5	75.7	77.1	85.1	76.0
16. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
17. ANOHR Equation	ANOHR=	-16.232 x NOF +		11,513.1									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Crystal River 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	88.01	88.01	88.01	88.01	88.01	88.01	88.01	88.01	88.01	42.59	88.01	88.01	84.16
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.61	0.00	0.00	4.37
3. EUOF	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	5.80	11.99	11.99	11.46
4. EUOR	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99	11.99
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	688.4	644.0	688.4	666.2	688.4	666.2	688.4	688.4	666.2	333.1	666.2	688.4	7,772.3
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	55.6	52.0	55.6	53.8	55.6	53.8	55.6	55.6	53.8	410.9	53.8	55.6	1011.7
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	384.0	0.0	0.0	384.0
10. FOH & PFOH	50.2	47.0	50.2	48.6	50.2	48.6	50.2	50.2	48.6	24.3	48.6	50.2	567.1
11. MOH & PMOH	39.0	36.5	39.0	37.7	39.0	37.7	39.0	39.0	37.7	18.9	37.7	39.0	439.9
12. Oper. Btu(MBtu)	2,603,604	2,191,537	2,402,591	2,368,632	2,555,936	2,592,512	2,615,771	2,685,860	2,614,146	1,248,302	2,619,298	2,780,124	29,297,604
13. Net Gen. (MWH)	265,221.0	218,581.0	240,764.0	238,215.0	259,333.0	265,784.0	266,733.0	275,518.0	268,518.0	126,908.0	269,171.0	287,541.0	2,982,287.0
14. ANOHR (Btu/KWH)	9,817	10,026	9,979	9,943	9,856	9,754	9,807	9,748	9,735	9,836	9,731	9,669	9,824
15. NOF (%)	78.5	69.1	71.2	72.8	76.7	81.3	78.9	81.5	82.1	77.6	82.3	85.1	78.1
16. NSC (MW)	491	491	491	491	491	491	491	491	491	491	491	491	491
17. ANOHR Equation	ANOHR=	-22.430 x NOF +		11,576.7									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Crystal River 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78	96.78
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22
4. EUOR	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	729.0	681.9	729.0	705.4	729.0	705.4	729.0	729.0	705.4	729.0	705.4	729.0	8,606.4
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	15.0	14.1	15.0	14.6	15.0	14.6	15.0	15.0	14.6	15.0	14.6	15.0	177.6
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	14.7	13.8	14.7	14.2	14.7	14.2	14.7	14.7	14.2	14.7	14.2	14.7	173.6
11. MOH & PMOH	9.2	8.6	9.2	8.9	9.2	8.9	9.2	9.2	8.9	9.2	8.9	9.2	108.8
12. Oper. Btu(MBtu)	5,710,747	5,394,968	5,743,639	5,071,339	5,716,277	5,543,279	5,719,050	5,666,832	5,543,279	5,754,825	5,422,004	5,666,688	66,959,591
13. Net Gen. (MWH)	553,927.0	524,103.0	557,618.0	485,767.0	554,547.0	537,937.0	554,858.0	549,011.0	537,937.0	558,875.0	524,381.0	548,995.0	6,487,956.0
14. ANOHR (Btu/KWH)	10,310	10,294	10,300	10,440	10,308	10,305	10,307	10,322	10,305	10,297	10,340	10,322	10,321
15. NOF (%)	98.8	99.9	99.5	89.5	98.9	99.2	99.0	97.9	99.2	99.7	96.7	97.9	98.0
16. NSC (MW)	769	769	769	769	769	769	769	769	769	769	769	769	769
17. ANOHR Equation	ANOHR=	-14.054 x NOF +		11,698.4									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.35	94.35	94.35	94.35	94.35	94.35	94.35	94.35	94.35	94.35	0.00	57.83	83.52
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	38.71	11.48
3. EUOF	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	0.00	3.46	5.00
4. EUOR	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	5.65	0.00	5.65	5.65
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	723.0	676.3	723.0	699.7	723.0	699.7	723.0	723.0	699.7	723.0	0.0	443.1	7,556.4
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	21.0	19.7	21.0	20.3	21.0	20.3	21.0	21.0	20.3	21.0	720.0	300.9	1227.6
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	720.0	288.0	1008.0
10. FOH & PFOH	20.0	18.7	20.0	19.4	20.0	19.4	20.0	20.0	19.4	20.0	0.0	12.3	209.2
11. MOH & PMOH	22.0	20.6	22.0	21.3	22.0	21.3	22.0	22.0	21.3	22.0	0.0	13.5	230.1
12. Oper. Btu(MBtu)	4,388,942	4,009,683	4,354,239	4,064,705	4,295,205	4,378,345	4,433,398	4,429,821	4,478,611	4,471,280	-	2,853,156	46,161,914
13. Net Gen. (MWH)	462,664.0	421,666.0	458,631.0	426,596.0	451,787.0	463,029.0	467,841.0	467,424.0	474,807.0	472,262.0	-	302,680.0	4,869,387.0
14. ANOHR (Btu/KWH)	9,486	9,509	9,494	9,528	9,507	9,456	9,476	9,477	9,432	9,468	-	9,426	9,480
15. NOF (%)	88.6	86.4	87.9	84.4	86.5	91.7	89.6	89.5	94.0	90.5	0.0	94.6	89.3
16. NSC (MW)	722	722	722	722	722	722	722	722	722	722	722	722	722
17. ANOHR Equation	ANOHR=	-10.032 x NOF +		10,375.4									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17	93.17
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
4. EUOR	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	717.7	671.4	717.7	694.5	717.7	694.5	717.7	717.7	694.5	717.7	694.5	717.7	8,473.1
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	26.3	24.6	26.3	25.5	26.3	25.5	26.3	26.3	25.5	26.3	25.5	26.3	310.9
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	19.5	18.2	19.5	18.8	19.5	18.8	19.5	19.5	18.8	19.5	18.8	19.5	229.7
11. MOH & PMOH	31.3	29.3	31.3	30.3	31.3	30.3	31.3	31.3	30.3	31.3	30.3	31.3	370.1
12. Oper. Btu(MBtu)	4,490,898	4,081,598	4,297,929	4,165,909	4,212,916	4,379,632	4,404,142	4,497,455	4,362,020	4,434,468	4,245,995	4,490,155	52,072,529
13. Net Gen. (MWH)	470,746.0	424,140.0	444,691.0	431,226.0	433,483.0	460,190.0	458,923.0	471,647.0	457,760.0	463,035.0	441,948.0	470,644.0	5,428,433.0
14. ANOHR (Btu/KWH)	9,540	9,623	9,665	9,661	9,719	9,517	9,597	9,536	9,529	9,577	9,607	9,540	9,593
15. NOF (%)	91.0	87.6	85.9	86.1	83.8	91.9	88.7	91.2	91.4	89.5	88.3	91.0	88.9
16. NSC (MW)	721	721	721	721	721	721	721	721	721	721	721	721	721
17. ANOHR Equation	ANOHR=	-24.828 x NOF +		11,798.7									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.75	98.31	87.12	9.51	95.36	95.21	95.17	95.16	95.18	95.45	41.25	95.20	83.48
2. POF	0.00	0.00	9.68	90.00	0.00	0.00	0.00	0.00	0.00	0.00	56.67	0.00	12.84
3. EUOF	3.25	1.69	3.20	0.49	4.64	4.79	4.83	4.84	4.82	4.55	2.08	4.80	3.68
4. EUOR	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	489.4	238.6	482.4	70.9	699.1	698.1	727.7	728.8	702.9	685.2	303.6	722.8	6,549.6
7. RSH	246.8	453.6	181.9	0.0	33.8	10.8	4.8	3.6	6.0	47.9	3.6	9.7	1002.5
8. UH	7.8	3.8	79.7	649.1	11.1	11.1	11.5	11.6	11.1	10.9	412.8	11.5	1231.9
9. POH	0.0	0.0	72.0	648.0	0.0	0.0	0.0	0.0	0.0	0.0	408.0	0.0	1128.0
10. FOH & PFOH	17.3	8.4	17.1	2.5	24.7	24.7	25.7	25.8	24.9	24.2	10.7	25.6	231.8
11. MOH & PMOH	6.8	3.3	6.8	1.0	9.8	9.8	10.2	10.2	9.8	9.6	4.2	10.1	91.7
12. Oper. Btu(MBtu)	1,278,061	591,961	1,264,035	191,099	1,911,192	1,947,851	2,043,454	2,045,537	1,965,958	1,906,938	844,205	2,033,576	18,033,711
13. Net Gen. (MWH)	170,244.0	77,430.0	168,589.0	25,777.0	259,280.0	266,608.0	280,512.0	280,721.0	269,389.0	260,708.0	115,377.0	279,386.0	2,454,021.0
14. ANOHR (Btu/KWH)	7,507	7,645	7,498	7,414	7,371	7,306	7,285	7,287	7,298	7,314	7,317	7,279	7,349
15. NOF (%)	75.1	70.1	75.5	78.6	80.1	82.5	83.3	83.2	82.8	82.2	82.1	83.5	80.9
16. NSC (MW)	463	463	463	463	463	463	463	463	463	463	463	463	463
17. ANOHR Equation	ANOHR=	-27.353 x NOF +		9,562.2									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.56	98.69	47.98	96.54	96.05	95.89	95.57	95.47	95.75	46.97	97.53	98.39	88.47
2. POF	0.00	0.00	51.61	0.00	0.00	0.00	0.00	0.00	0.00	51.61	0.00	0.00	8.74
3. EUOF	1.44	1.31	0.40	3.46	3.95	4.11	4.43	4.53	4.25	1.42	2.47	1.61	2.78
4. EUOR	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	223.2	189.2	62.4	518.2	611.3	616.3	686.3	702.2	636.7	219.8	370.8	250.0	5,086.5
7. RSH	516.3	503.0	296.3	191.3	120.3	91.2	43.8	27.6	70.4	135.7	341.7	488.9	2826.5
8. UH	4.5	3.8	385.3	10.5	12.4	12.5	13.9	14.2	12.9	388.5	7.5	5.1	871.0
9. POH	0.0	0.0	384.0	0.0	0.0	0.0	0.0	0.0	0.0	384.0	0.0	0.0	768.0
10. FOH & PFOH	3.0	2.5	0.8	6.9	8.2	8.3	9.2	9.4	8.5	2.9	5.0	3.4	68.2
11. MOH & PMOH	7.7	6.6	2.2	18.0	21.2	21.4	23.8	24.3	22.1	7.6	12.8	8.7	176.2
12. Oper. Btu(MBtu)	541,919	425,783	142,076	1,283,249	1,712,925	1,763,916	2,046,684	2,061,058	1,921,590	560,403	909,310	630,345	14,000,022
13. Net Gen. (MWH)	77,167.0	60,602.0	20,223.0	182,752.0	244,149.0	251,456.0	291,857.0	293,871.0	274,044.0	79,824.0	129,490.0	89,780.0	1,995,215.0
14. ANOHR (Btu/KWH)	7,023	7,026	7,025	7,022	7,016	7,015	7,013	7,013	7,012	7,020	7,022	7,021	7,017
15. NOF (%)	70.6	65.4	66.1	72.0	81.5	83.3	86.8	85.4	87.8	74.1	71.3	73.3	80.1
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-0.620 x NOF +		7,066.4									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2008 - December 2008

PLANT/UNIT **Tiger Bay**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.61	98.63	66.18	0.00	40.49	96.35	95.83	96.08	96.38	52.82	95.90	96.25	77.66
2. POF	0.00	0.00	32.26	100.00	58.06	0.00	0.00	0.00	0.00	45.16	0.00	0.00	19.67
3. EUOF	2.39	1.37	1.56	0.00	1.44	3.65	4.17	3.92	3.62	2.01	4.10	3.75	2.67
4. EUOR	4.26	4.26	4.26	0.00	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	400.5	213.9	260.5	0.0	241.5	591.1	697.3	655.4	585.8	336.9	663.9	627.7	5,274.4
7. RSH	325.7	472.6	231.9	0.0	59.8	102.6	15.7	59.5	108.2	56.1	26.6	88.4	1547.1
8. UH	17.8	9.5	251.6	720.0	442.7	26.3	31.0	29.1	26.0	351.0	29.5	27.9	1962.5
9. POH	0.0	0.0	240.0	720.0	432.0	0.0	0.0	0.0	0.0	336.0	0.0	0.0	1728.0
10. FOH & PFOH	17.8	9.5	11.6	0.0	10.7	26.3	31.0	29.1	26.1	15.0	29.5	27.9	234.6
11. MOH & PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. Oper. Btu(MBtu)	542,950	268,203	351,109	-	337,080	852,208	1,002,567	936,331	840,054	476,710	964,422	899,997	7,472,722
13. Net Gen. (MWH)	67,713.0	33,142.0	43,756.0	-	42,195.0	107,135.0	125,991.0	117,567.0	105,532.0	59,779.0	121,368.0	113,059.0	937,237.0
14. ANOHR (Btu/KWH)	8,018	8,093	8,024	-	7,989	7,955	7,957	7,964	7,960	7,975	7,946	7,960	7,973
15. NOF (%)	83.3	76.3	82.7	0.0	86.1	89.3	89.0	88.4	88.7	87.4	90.1	88.7	87.5
16. NSC (MW)	203	203	203	203	203	203	203	203	203	203	203	203	203
17. ANOHR Equation	ANOHR=	-10.656 x NOF +		8,905.9									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

PLANNED OUTAGE SCHEDULES

Progress Energy Florida
Period of: January 2008 - December 2008

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 1	10/18 (0001) - 11/02 (2400)	Boiler Inspection
Anclote 2	03/08 (0001) - 04/18 (2400)	Boiler Inspection, Turbine Valve Replacement
Crystal River 2	10/11 (0001) - 10/26 (2400)	Boiler Inspection
Crystal River 3	04/17 (0001) - 04/30 (2400)	20% Derate for Water Box Maintenance
Crystal River 4	11/01 (0001) - 12/12 (2400)	Major Maintenance Outage
Hines 1	03/29 (0001) - 04/27 (2400)	Hot Gas Path Inspection and BOP Maintenance
Hines 1	11/01 (0001) - 11/17 (2400)	BOP Maintenance
Hines 2	02/16 (0001) - 02/29 (2400)	2B Hot Gas Path Inspection
Hines 2	03/01 (0001) - 03/16 (2400)	Hot Gas Path Inspection and BOP Maintenance
Hines 2	10/11 (0001) - 10/26 (2400)	BOP Maintenance
Tiger Bay	03/22 (0001) - 05/18 (2400)	Rotor Replacement
Tiger Bay	10/18 (0001) - 10/31 (2400)	BOP Maintenance

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

AVERAGE NET OPERATING HEAT RATE CURVES

PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 1

ANOHR -15.269 * NOF + 10,936.50

TABLE OF RESIDUALS

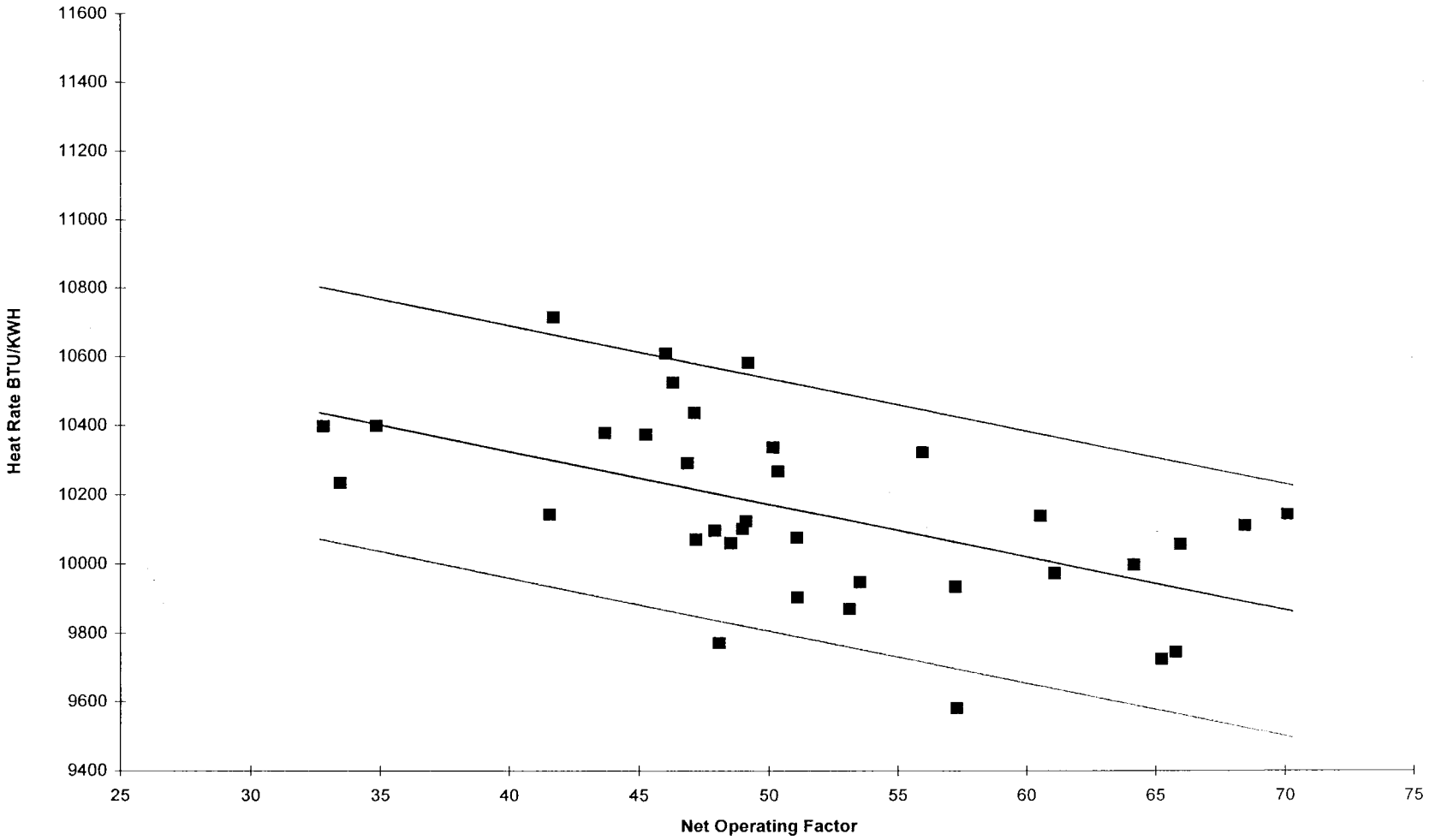
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	64.1	9,998	9,957	41.4	367.3
Aug-04	65.9	10,058	9,930	128.1	367.3
Sep-04	65.8	9,745	9,932	-187.4	367.3
Oct-04	65.2	9,723	9,941	-217.2	367.3
Nov-04	48.5	10,059	10,196	-136.5	367.3
Dec-04	53.1	9,870	10,125	-255.4	367.3
Jan-05	47.9	10,096	10,205	-109.4	367.3
Feb-05	48.1	9,771	10,202	-431.5	367.3
Mar-05	53.5	9,947	10,119	-172.1	367.3
Apr-05	47.2	10,070	10,216	-146.3	367.3
May-05	49.0	10,101	10,189	-87.9	367.3
Jun-05	50.2	10,339	10,171	168.7	367.3
Jul-05	70.1	10,145	9,866	278.4	367.3
Aug-05	68.4	10,112	9,892	220.9	367.3
Sep-05	61.1	9,973	10,004	-31.0	367.3
Oct-05	60.5	10,139	10,012	127.0	367.3
Nov-05	50.3	10,269	10,168	101.1	367.3
Dec-05	57.3	9,581	10,062	-481.2	367.3
Jan-06	46.3	10,527	10,229	298.2	367.3
Feb-06	33.5	10,234	10,426	-191.5	367.3
Mar-06	46.9	10,293	10,221	71.8	367.3
Apr-06	57.2	9,935	10,063	-128.0	367.3
May-06	45.3	10,375	10,245	130.1	367.3
Jun-06	49.1	10,123	10,187	-63.4	367.3
Jul-06	49.2	10,586	10,185	401.1	367.3
Aug-06	56.0	10,325	10,082	243.3	367.3
Sep-06	43.7	10,380	10,269	110.8	367.3
Nov-06	34.8	10,400	10,404	-4.7	367.3
Dec-06	41.7	10,717	10,300	417.6	367.3
Jan-07	32.8	10,398	10,436	-37.3	367.3
Feb-07	51.1	9,903	10,156	-253.0	367.3
Mar-07	41.6	10,142	10,302	-159.7	367.3
Apr-07	51.1	10,075	10,157	-81.2	367.3
May-07	47.1	10,439	10,217	222.1	367.3
Jun-07	46.0	10,613	10,234	379.5	367.3

Regression Output:

Constant	10936.50
Std Err of Y Est	226.5119771
R Squared	0.297545287
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-15.26867475
Std Err of Coef.	4.083917893

Anclote Unit 1

ANOHR -15.269 * NOF + 10,936.50



PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 2

ANOHR -12.372 * NOF + 10,806.61

TABLE OF RESIDUALS

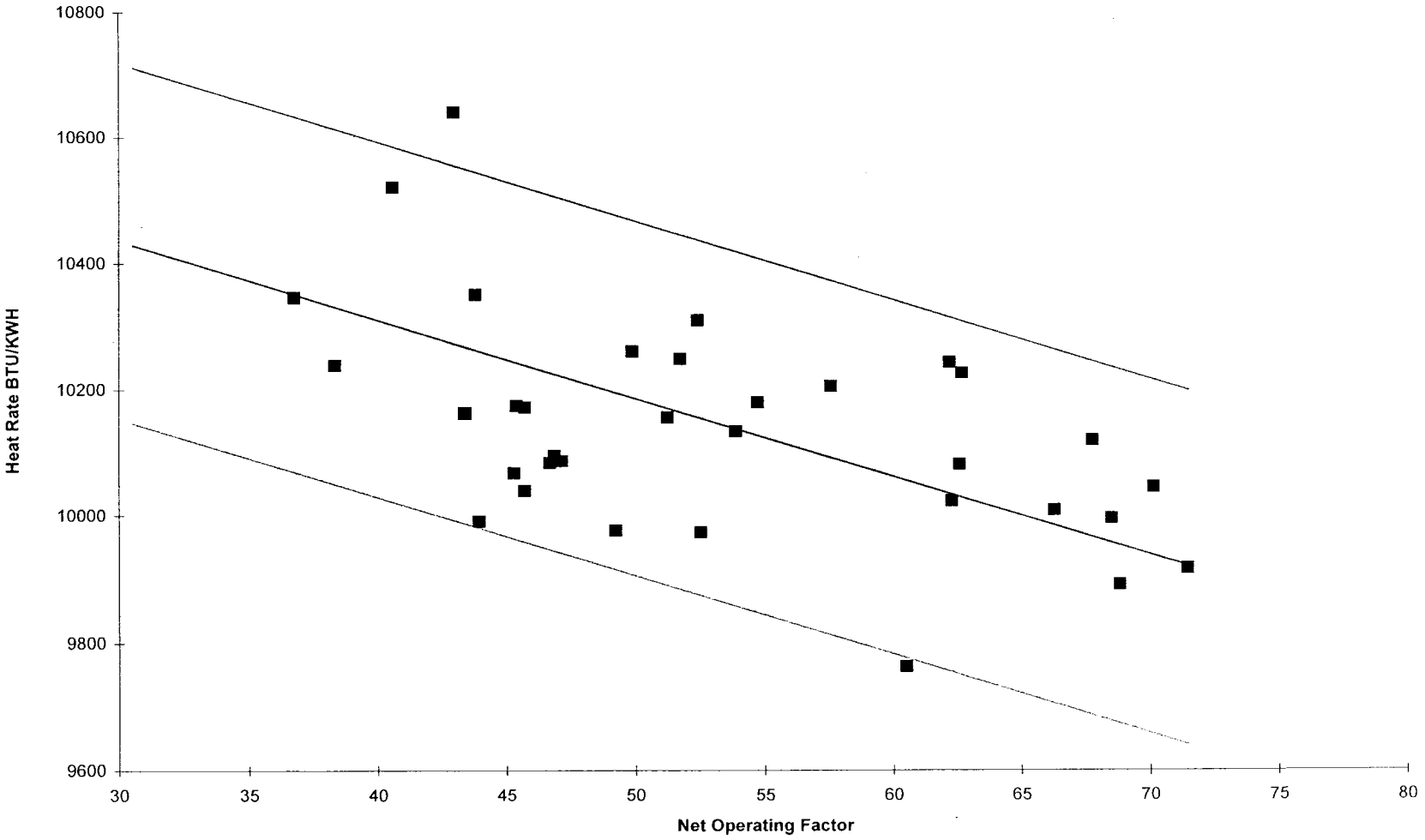
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	68.5	9,998	9,959	39.1	282.1
Aug-04	71.4	9,918	9,923	-4.6	282.1
Sep-04	66.3	10,012	9,987	25.0	282.1
Oct-04	68.8	9,892	9,955	-62.9	282.1
Nov-04	62.3	10,026	10,036	-10.6	282.1
Dec-04	51.2	10,158	10,173	-14.4	282.1
Jan-05	46.7	10,085	10,229	-143.7	282.1
Feb-05	45.7	10,174	10,241	-67.4	282.1
Mar-05	60.5	9,762	10,058	-296.1	282.1
Apr-05	49.2	9,977	10,197	-220.1	282.1
May-05	52.4	10,313	10,158	155.3	282.1
Jun-05	54.7	10,183	10,130	52.9	282.1
Jul-05	70.1	10,049	9,939	109.8	282.1
Aug-05	67.8	10,123	9,968	155.1	282.1
Sep-05	62.7	10,231	10,031	199.4	282.1
Oct-05	62.6	10,085	10,033	52.1	282.1
Nov-05	52.5	9,975	10,157	-182.1	282.1
Dec-05	62.2	10,248	10,037	210.4	282.1
Jan-06	43.9	9,992	10,263	-271.3	282.1
Feb-06	40.6	10,523	10,305	217.9	282.1
Mar-06	45.3	10,069	10,246	-177.5	282.1
May-06	46.9	10,096	10,227	-130.6	282.1
Jun-06	53.9	10,136	10,140	-3.7	282.1
Jul-06	51.7	10,252	10,167	85.3	282.1
Aug-06	57.6	10,209	10,094	114.2	282.1
Sep-06	42.9	10,642	10,275	366.9	282.1
Oct-06	47.1	10,088	10,223	-135.2	282.1
Nov-06	45.7	10,041	10,241	-200.4	282.1
Dec-06	30.7	10,903	10,427	476.2	282.1
Jan-07	38.3	10,240	10,332	-92.3	282.1
Feb-07	45.4	10,176	10,245	-68.8	282.1
Mar-07	36.7	10,347	10,352	-4.6	282.1
Apr-07	43.4	10,164	10,270	-105.6	282.1
May-07	43.8	10,353	10,265	87.9	282.1
Jun-07	49.9	10,263	10,190	74.0	282.1

Regression Output:

Constant	10806.61
Std Err of Y Est	173.9903945
R Squared	0.368213976
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-12.37242597
Std Err of Coef.	2.8211928

Anclote Unit 2

ANOHR -12.372 * NOF + 10,806.61



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 1

ANOHR -16.232 * NOF + 11,513.10

TABLE OF RESIDUALS

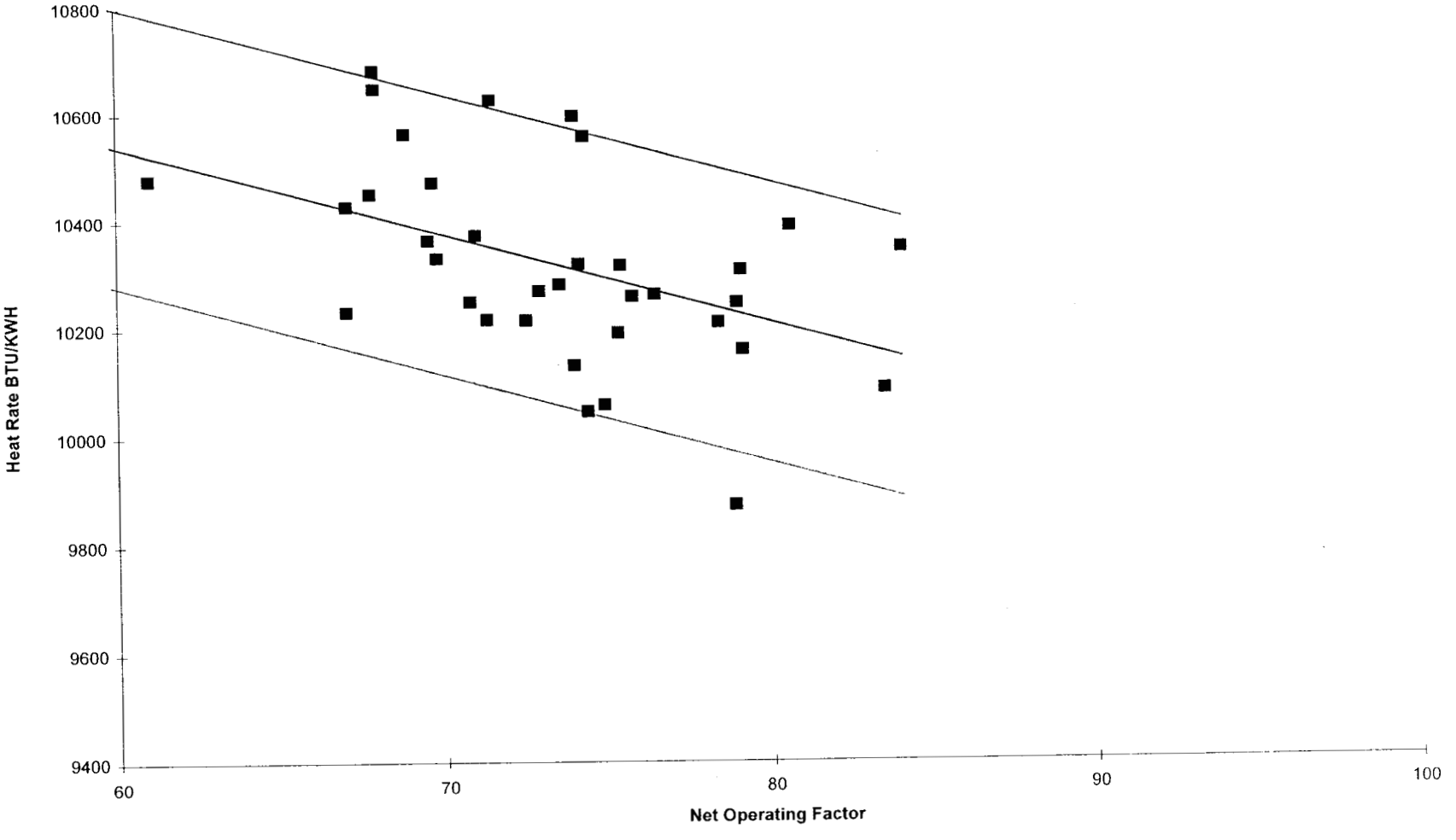
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	69.7	10,474	10,382	91.3	260.4
Aug-04	75.4	10,319	10,289	30.4	260.4
Sep-04	67.0	10,429	10,425	3.7	260.4
Oct-04	72.9	10,272	10,329	-57.3	260.4
Nov-04	72.5	10,218	10,336	-118.4	260.4
Dec-04	79.1	10,163	10,229	-65.6	260.4
Jan-05	74.0	10,134	10,312	-177.7	260.4
Feb-05	73.6	10,284	10,319	-35.2	260.4
Mar-05	83.5	10,090	10,158	-68.2	260.4
Apr-05	75.3	10,194	10,290	-96.2	260.4
May-05	67.7	10,452	10,413	39.0	260.4
Jun-05	74.1	10,322	10,310	12.3	260.4
Jul-05	71.5	10,628	10,353	274.9	260.4
Aug-05	56.5	10,502	10,596	-94.3	260.4
Sep-05	80.6	10,394	10,205	188.8	260.4
Oct-05	78.4	10,213	10,241	-27.2	260.4
Nov-05	76.5	10,265	10,272	-7.3	260.4
Dec-05	84.0	10,351	10,149	202.4	260.4
Jan-06	74.9	10,061	10,297	-236.3	260.4
Feb-06	71.3	10,219	10,355	-136.3	260.4
Mar-06	79.1	10,310	10,229	81.3	260.4
Apr-06	71.0	10,375	10,361	14.1	260.4
May-06	69.5	10,365	10,385	-19.2	260.4
Jun-06	74.0	10,598	10,312	286.1	260.4
Jul-06	74.3	10,559	10,307	252.6	260.4
Aug-06	67.9	10,683	10,412	271.9	260.4
Sep-06	67.9	10,649	10,411	238.1	260.4
Oct-06	70.8	10,252	10,364	-112.2	260.4
Nov-06	69.8	10,332	10,380	-47.9	260.4
Dec-06	61.0	10,479	10,523	-44.2	260.4
Jan-07	79.0	10,250	10,231	18.4	260.4
Feb-07	68.8	10,564	10,396	168.1	260.4
Mar-07	67.0	10,233	10,426	-192.4	260.4
Apr-07	78.9	9,875	10,233	-358.1	260.4
May-07	74.4	10,048	10,305	-257.3	260.4
Jun-07	75.8	10,261	10,283	-22.0	260.4

Regression Output:

Constant	11513.10
Std Err of Y Est	160.5399111
R Squared	0.255289821
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-16.2323984
Std Err of Coef.	4.754667269

Crystal River Unit 1

ANOHR -16.232 * NOF + 11,513.10



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 2

ANOHR -22.430 * NOF + 11,576.74

TABLE OF RESIDUALS

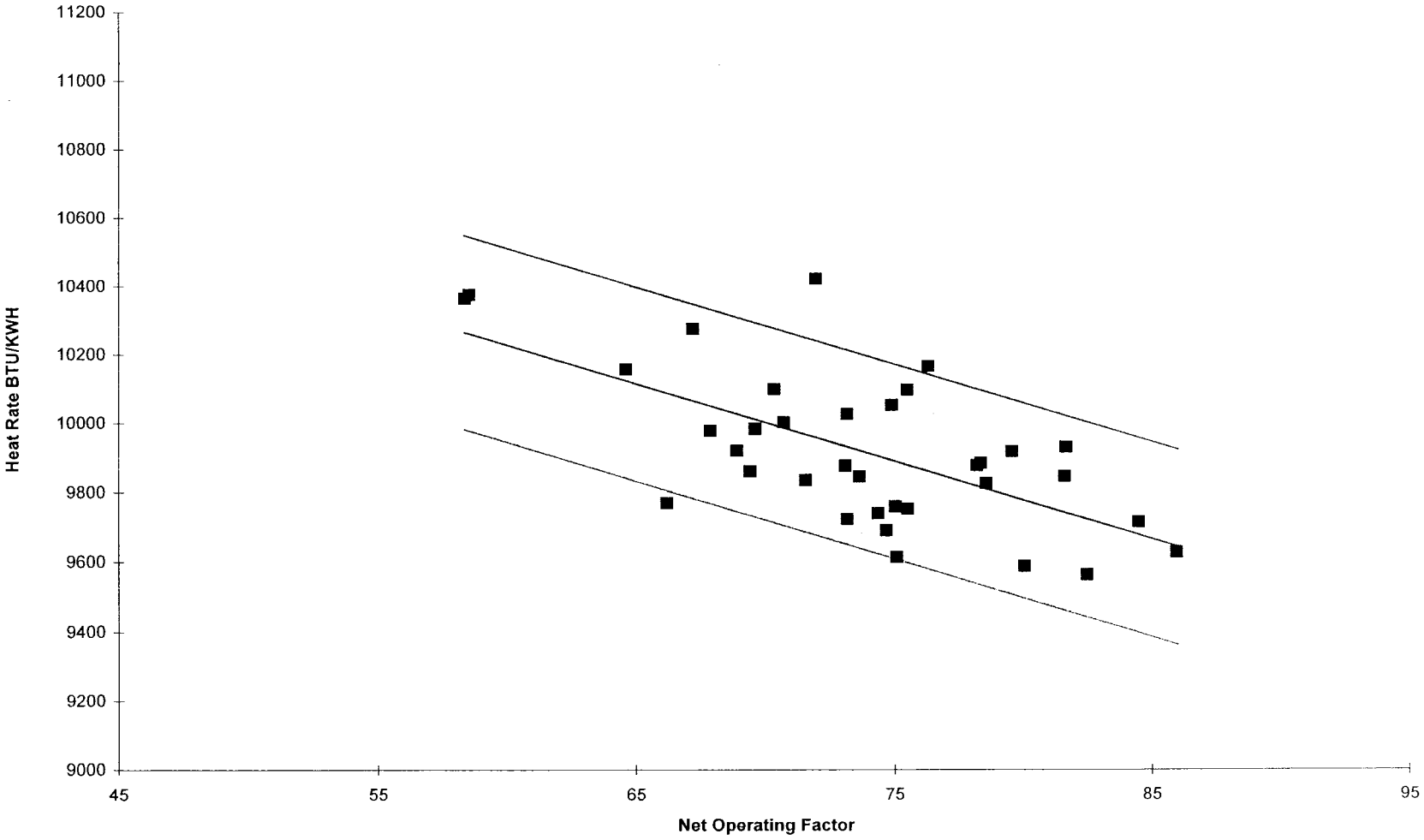
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	70.7	10,007	9,991	15.8	283.9
Aug-04	73.1	10,031	9,936	95.3	283.9
Sep-04	67.9	9,983	10,055	-72.2	283.9
Oct-04	73.6	9,850	9,925	-75.5	283.9
Nov-04	73.1	9,725	9,936	-210.7	283.9
Dec-04	75.5	9,756	9,883	-127.1	283.9
Jan-05	74.7	9,693	9,902	-208.7	283.9
Feb-05	75.1	9,615	9,893	-277.7	283.9
Mar-05	82.5	9,565	9,727	-161.4	283.9
Apr-05	74.3	9,742	9,909	-166.8	283.9
May-05	69.6	9,988	10,016	-28.2	283.9
Jun-05	75.5	10,104	9,884	220.0	283.9
Jul-05	58.5	10,378	10,264	114.3	283.9
Aug-05	58.4	10,368	10,268	99.6	283.9
Sep-05	74.9	10,059	9,897	162.0	283.9
Oct-05	78.2	9,883	9,823	59.9	283.9
Nov-05	81.6	9,852	9,746	105.5	283.9
Dec-05	86.0	9,631	9,649	-18.2	283.9
Jan-06	78.4	9,890	9,819	70.9	283.9
Feb-06	73.1	9,880	9,938	-57.4	283.9
Mar-06	84.5	9,719	9,682	37.2	283.9
Apr-06	79.6	9,924	9,792	131.6	283.9
May-06	78.6	9,831	9,815	16.4	283.9
Jun-06	70.3	10,104	9,999	104.8	283.9
Jul-06	76.3	10,174	9,866	308.4	283.9
Aug-06	81.7	9,937	9,745	191.6	283.9
Sep-06	67.2	10,281	10,070	210.8	283.9
Oct-06	64.6	10,161	10,128	33.5	283.9
Nov-06	71.5	9,839	9,972	-133.3	283.9
Dec-06	66.2	9,772	10,092	-320.4	283.9
Jan-07	68.9	9,924	10,032	-107.3	283.9
Feb-07	80.0	9,589	9,781	-192.0	283.9
Mar-07	69.4	9,865	10,020	-155.7	283.9
May-07	71.9	10,430	9,963	466.3	283.9
Jun-07	75.0	9,763	9,894	-131.5	283.9

Regression Output:

Constant	11576.74
Std Err of Y Est	175.1289439
R Squared	0.410161649
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-22.43011321
Std Err of Coef.	4.682345688

Crystal River Unit 2

ANOHR -22.430 * NOF + 11,576.74



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 3

ANOHR -14.054 * NOF + 11,698.36

TABLE OF RESIDUALS

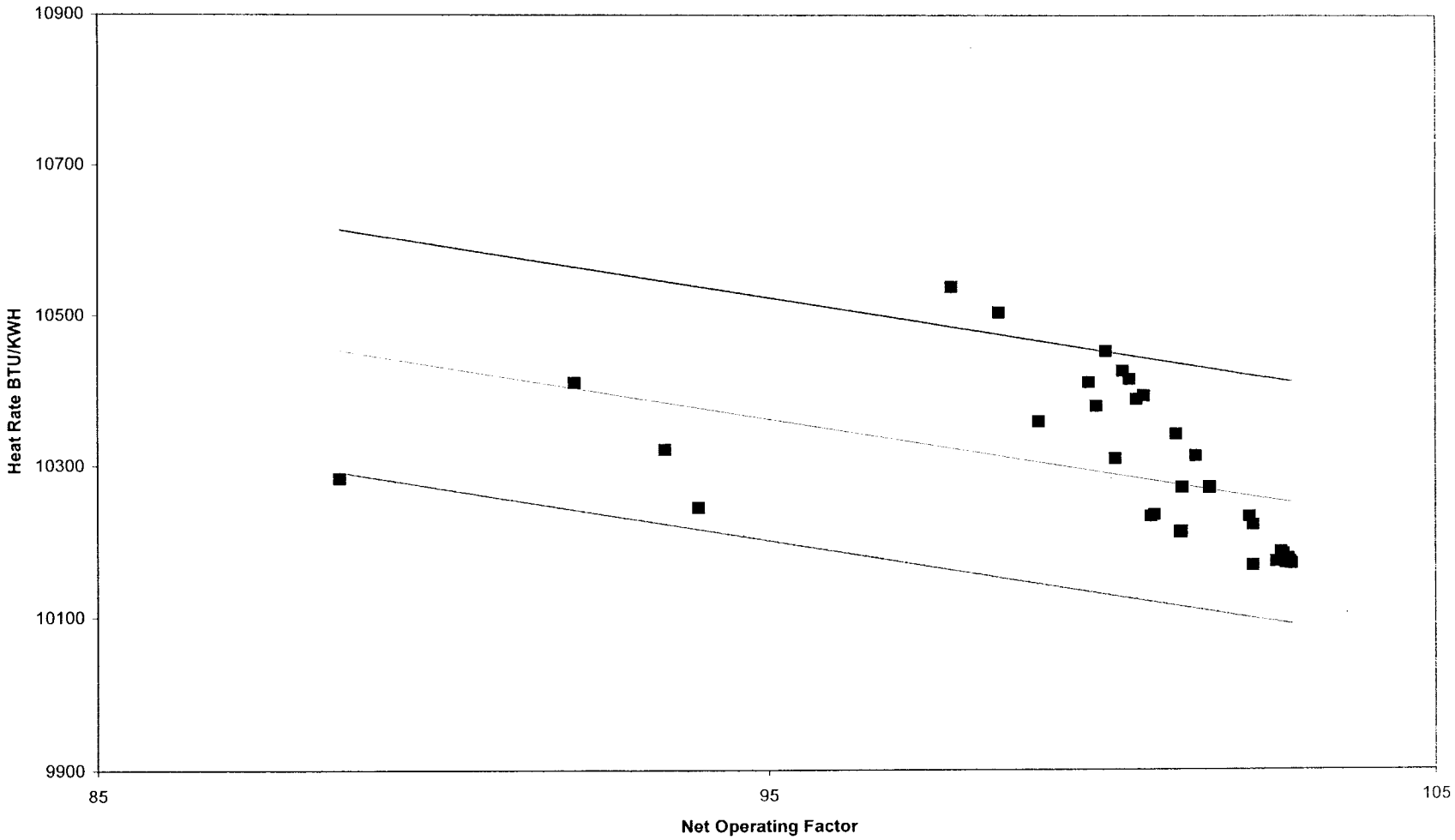
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	100.3	10,428	10,289	139.6	161.6
Aug-04	100.5	10,390	10,286	104.8	161.6
Sep-04	100.2	10,311	10,290	21.0	161.6
Oct-04	100.7	10,234	10,283	-48.4	161.6
Nov-04	102.8	10,171	10,253	-82.0	161.6
Dec-04	102.3	10,169	10,261	-91.9	161.6
Jan-05	102.8	10,178	10,254	-76.1	161.6
Feb-05	102.8	10,178	10,254	-76.1	161.6
Mar-05	102.7	10,184	10,255	-70.6	161.6
Apr-05	88.6	10,283	10,453	-170.0	161.6
May-05	100.8	10,236	10,282	-45.6	161.6
Jun-05	99.1	10,360	10,306	54.1	161.6
Jul-05	100.4	10,417	10,287	130.1	161.6
Aug-05	100.1	10,454	10,292	161.9	161.6
Sep-05	101.1	10,344	10,277	66.8	161.6
Oct-05	93.5	10,322	10,385	-62.8	161.6
Dec-05	92.1	10,411	10,404	7.3	161.6
Jan-06	101.2	10,273	10,276	-3.0	161.6
Feb-06	102.7	10,180	10,255	-74.8	161.6
Mar-06	99.8	10,413	10,296	117.4	161.6
Apr-06	102.2	10,234	10,262	-27.9	161.6
May-06	101.6	10,273	10,270	2.8	161.6
Jun-06	100.6	10,395	10,284	110.9	161.6
Jul-06	98.5	10,505	10,315	190.4	161.6
Aug-06	97.7	10,539	10,325	214.4	161.6
Sep-06	99.9	10,381	10,294	86.9	161.6
Oct-06	101.2	10,214	10,276	-62.2	161.6
Nov-06	102.6	10,174	10,256	-82.2	161.6
Dec-06	102.8	10,174	10,253	-79.4	161.6
Jan-07	102.8	10,178	10,254	-75.9	161.6
Feb-07	94.0	10,245	10,378	-132.8	161.6
Mar-07	102.8	10,172	10,254	-82.2	161.6
Apr-07	102.7	10,187	10,255	-68.3	161.6
May-07	102.3	10,223	10,261	-38.1	161.6
Jun-07	101.4	10,315	10,273	41.9	161.6

Regression Output:

Constant	11698.36
Std Err of Y Est	99.65182268
R Squared	0.186153876
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-14.0544934
Std Err of Coef.	5.115561778

Crystal River Unit 3

ANOHR -14.054 * NOF + 11,698.36



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 4

ANOHR -10.032 * NOF + 10,375.43

TABLE OF RESIDUALS

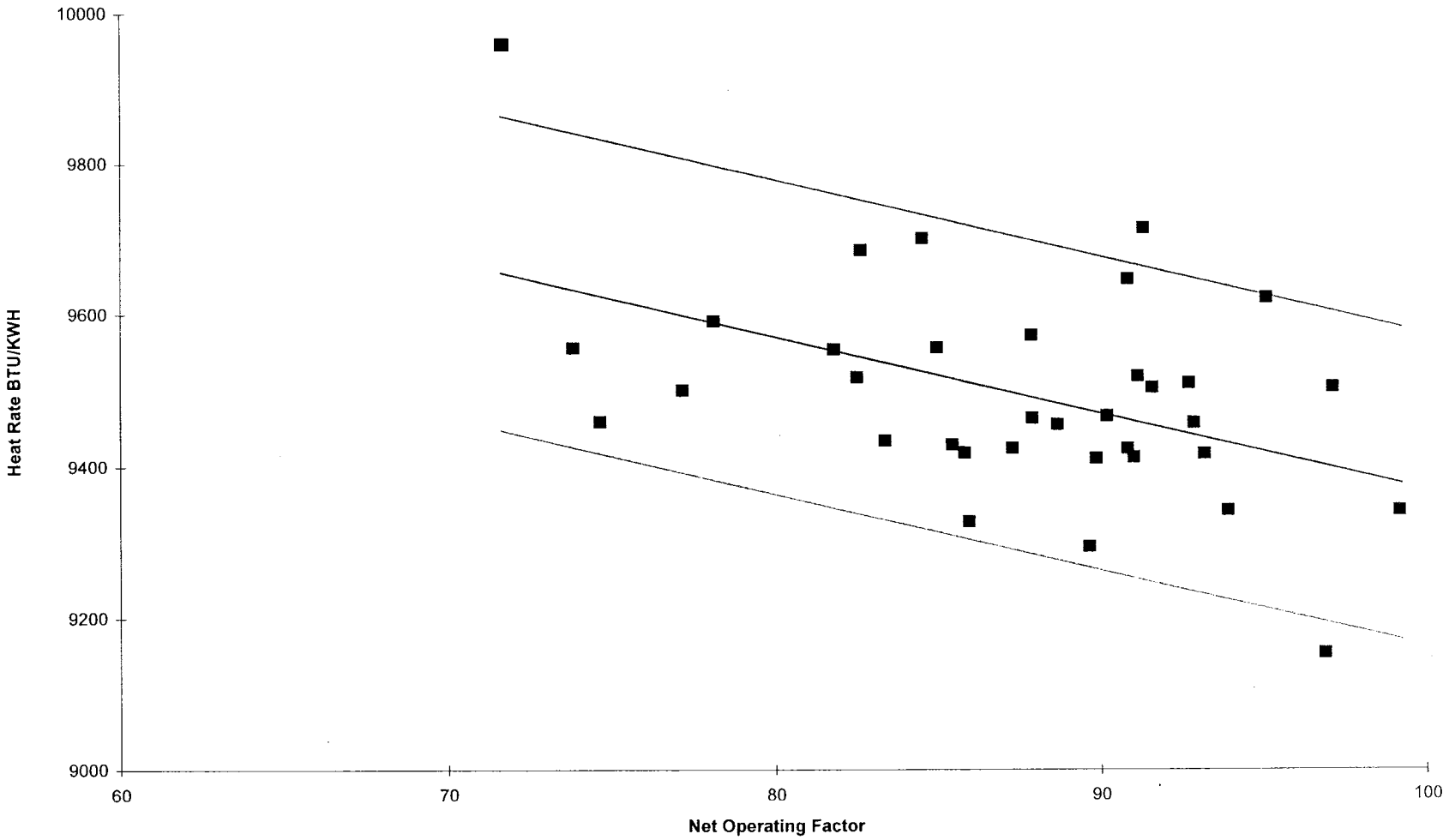
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	90.2	9,469	9,471	-1.4	208.3
Aug-04	81.8	9,557	9,555	2.0	208.3
Sep-04	71.7	9,962	9,656	305.2	208.3
Nov-04	73.8	9,558	9,635	-76.9	208.3
Dec-04	93.2	9,419	9,441	-21.5	208.3
Jan-05	91.6	9,507	9,457	50.5	208.3
Feb-05	91.0	9,414	9,462	-48.0	208.3
Mar-05	77.2	9,502	9,601	-99.4	208.3
Apr-05	90.8	9,651	9,464	186.9	208.3
May-05	85.9	9,328	9,513	-185.0	208.3
Jun-05	87.9	9,466	9,494	-27.7	208.3
Jul-05	96.9	9,153	9,404	-250.9	208.3
Aug-05	95.1	9,627	9,422	204.9	208.3
Sep-05	99.2	9,344	9,381	-36.6	208.3
Oct-05	91.1	9,522	9,461	61.1	208.3
Nov-05	97.1	9,508	9,401	107.1	208.3
Dec-05	87.9	9,576	9,494	82.2	208.3
Jan-06	85.0	9,559	9,523	36.1	208.3
Feb-06	89.6	9,296	9,476	-180.5	208.3
Mar-06	93.9	9,344	9,433	-89.2	208.3
Apr-06	74.7	9,460	9,626	-166.4	208.3
May-06	78.1	9,594	9,592	2.2	208.3
Jun-06	84.5	9,704	9,528	176.6	208.3
Jul-06	88.7	9,457	9,486	-28.6	208.3
Aug-06	91.3	9,719	9,459	259.4	208.3
Sep-06	90.8	9,426	9,464	-38.4	208.3
Oct-06	92.7	9,513	9,445	67.6	208.3
Nov-06	85.4	9,431	9,518	-87.8	208.3
Dec-06	83.4	9,436	9,539	-103.4	208.3
Jan-07	82.5	9,520	9,548	-28.2	208.3
Feb-07	92.9	9,460	9,444	16.1	208.3
Mar-07	85.8	9,420	9,515	-94.7	208.3
Apr-07	82.6	9,688	9,547	141.5	208.3
May-07	87.3	9,426	9,500	-73.6	208.3
Jun-07	89.9	9,413	9,474	-61.3	208.3

Regression Output:

Constant	10375.43
Std Err of Y Est	128.4954106
R Squared	0.219267409
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-10.03217079
Std Err of Coef.	3.295353877

Crystal River Unit 4

ANOHR -10.032 * NOF + 10,375.43



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 5

ANOHR -24.828 * NOF + 11,798.72

TABLE OF RESIDUALS

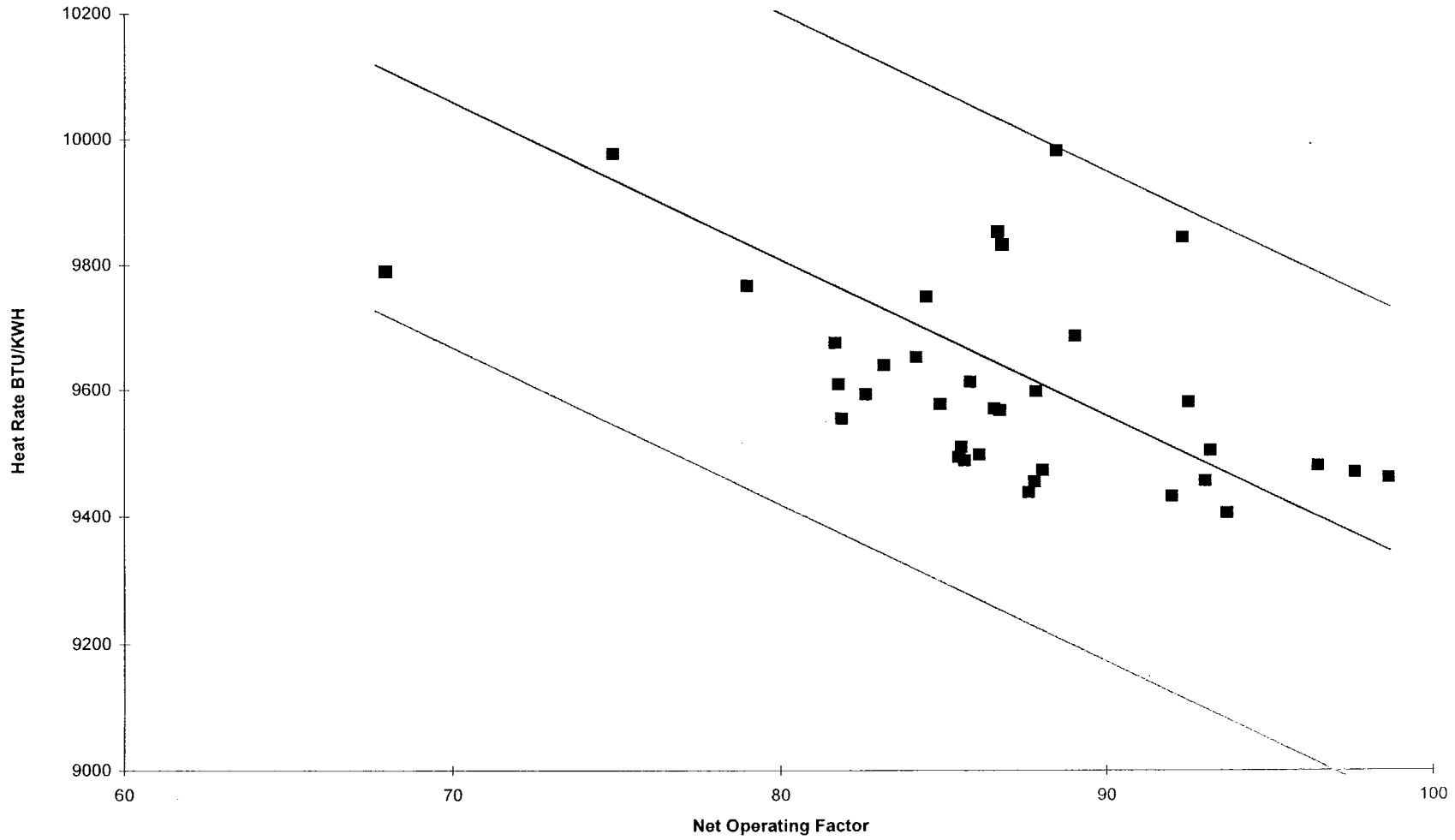
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	93.7	9,409	9,473	-63.6	391.6
Aug-04	85.5	9,513	9,675	-162.2	391.6
Sep-04	74.9	9,980	9,939	40.7	391.6
Oct-04	67.9	9,791	10,112	-320.6	391.6
Nov-04	85.5	9,497	9,677	-180.2	391.6
Dec-04	84.9	9,581	9,691	-110.0	391.6
Jan-05	87.6	9,441	9,623	-182.5	391.6
Feb-05	86.6	9,574	9,650	-75.3	391.6
Mar-05	96.5	9,485	9,404	81.3	391.6
Apr-05	88.5	9,988	9,603	385.3	391.6
May-05	86.1	9,501	9,661	-160.1	391.6
Jun-05	92.5	9,586	9,502	84.4	391.6
Jul-05	98.6	9,466	9,350	116.2	391.6
Aug-05	97.6	9,474	9,375	99.2	391.6
Sep-05	85.6	9,491	9,672	-181.1	391.6
Oct-05	88.0	9,476	9,613	-136.5	391.6
Nov-05	93.0	9,460	9,489	-29.1	391.6
Dec-05	92.0	9,436	9,515	-78.9	391.6
Jan-06	81.7	9,679	9,771	-92.0	391.6
Feb-06	83.2	9,643	9,734	-90.8	391.6
Mar-06	72.2	11,068	10,005	1062.9	391.6
Apr-06	79.0	9,770	9,838	-67.5	391.6
May-06	84.1	9,656	9,710	-53.1	391.6
Jun-06	86.8	9,838	9,644	194.1	391.6
Jul-06	86.7	9,859	9,647	212.2	391.6
Aug-06	92.3	9,851	9,507	344.5	391.6
Sep-06	84.5	9,754	9,702	52.1	391.6
Oct-06	82.6	9,597	9,748	-150.9	391.6
Nov-06	89.0	9,692	9,588	103.5	391.6
Dec-06	87.8	9,602	9,618	-15.8	391.6
Jan-07	85.8	9,617	9,668	-50.8	391.6
Feb-07	93.2	9,509	9,485	23.6	391.6
Mar-07	81.8	9,612	9,768	-156.0	391.6
Apr-07	81.9	9,558	9,766	-208.4	391.6
May-07	87.8	9,458	9,619	-160.8	391.6
Jun-07	86.7	9,572	9,645	-73.6	391.6

Regression Output:

Constant	11798.72
Std Err of Y Est	241.4402593
R Squared	0.314469106
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-24.82792317
Std Err of Coef.	6.286739385

Crystal River Unit 5

ANOHR -24.828 * NOF + 11,798.72



PROGRESS ENERGY FLORIDA

HINES UNIT 1

ANOHR -27.353 * NOF + 9,562.17

TABLE OF RESIDUALS

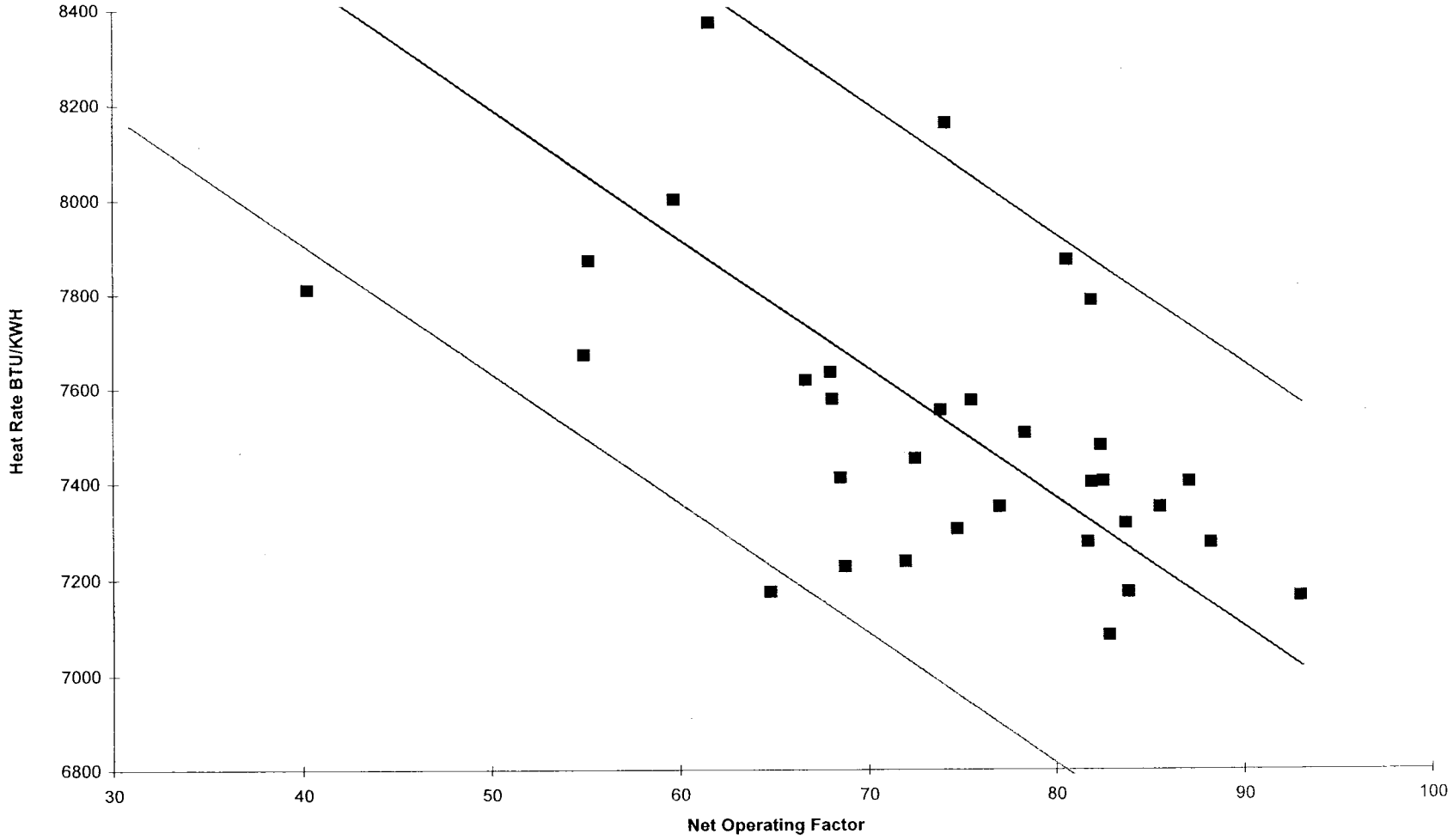
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	64.8	7,175	7,791	-615.3	560.2
Aug-04	61.6	8,378	7,878	499.4	560.2
Sep-04	66.7	7,622	7,739	-117.1	560.2
Oct-04	82.8	7,082	7,297	-214.5	560.2
Dec-04	68.5	7,414	7,689	-274.1	560.2
Jan-05	80.6	7,880	7,358	522.1	560.2
Feb-05	71.9	7,239	7,594	-355.3	560.2
Mar-05	88.2	7,278	7,149	128.8	560.2
Apr-05	83.8	7,174	7,269	-95.4	560.2
May-05	82.4	7,484	7,309	175.2	560.2
Jun-05	81.7	7,280	7,328	-48.0	560.2
Jul-05	86.9	6,650	7,185	-534.7	560.2
Aug-05	87.1	7,407	7,180	226.6	560.2
Sep-05	81.9	7,405	7,322	82.9	560.2
Oct-05	77.0	7,353	7,457	-103.1	560.2
Nov-05	54.9	7,674	8,060	-385.2	560.2
Dec-05	40.2	7,812	8,462	-649.4	560.2
Jan-06	68.1	7,582	7,700	-118.3	560.2
Feb-06	55.2	7,876	8,052	-176.4	560.2
Mar-06	85.5	7,353	7,223	129.9	560.2
Apr-06	93.0	7,165	7,019	145.9	560.2
May-06	75.5	7,580	7,498	81.9	560.2
Jun-06	59.7	8,006	7,929	77.4	560.2
Jul-06	68.0	7,639	7,703	-63.5	560.2
Aug-06	73.8	7,558	7,542	16.0	560.2
Sep-06	74.7	7,306	7,518	-211.9	560.2
Oct-06	78.3	7,510	7,420	90.2	560.2
Nov-06	72.5	7,455	7,580	-124.6	560.2
Dec-06	32.5	8,941	8,674	267.6	560.2
Jan-07	74.1	8,169	7,535	633.3	560.2
Feb-07	81.9	7,794	7,322	471.7	560.2
Mar-07	31.0	9,558	8,715	843.1	560.2
Apr-07	68.7	7,228	7,682	-454.6	560.2
May-07	83.7	7,319	7,272	46.6	560.2
Jun-07	82.5	7,407	7,305	102.5	560.2

Regression Output:

Constant	9562.17
Std Err of Y Est	345.5044166
R Squared	0.591552082
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-27.35305397
Std Err of Coef.	3.956586841

Hines Unit 1

ANOHR -27.353 * NOF + 9,562.17



PROGRESS ENERGY FLORIDA

HINES UNIT 2

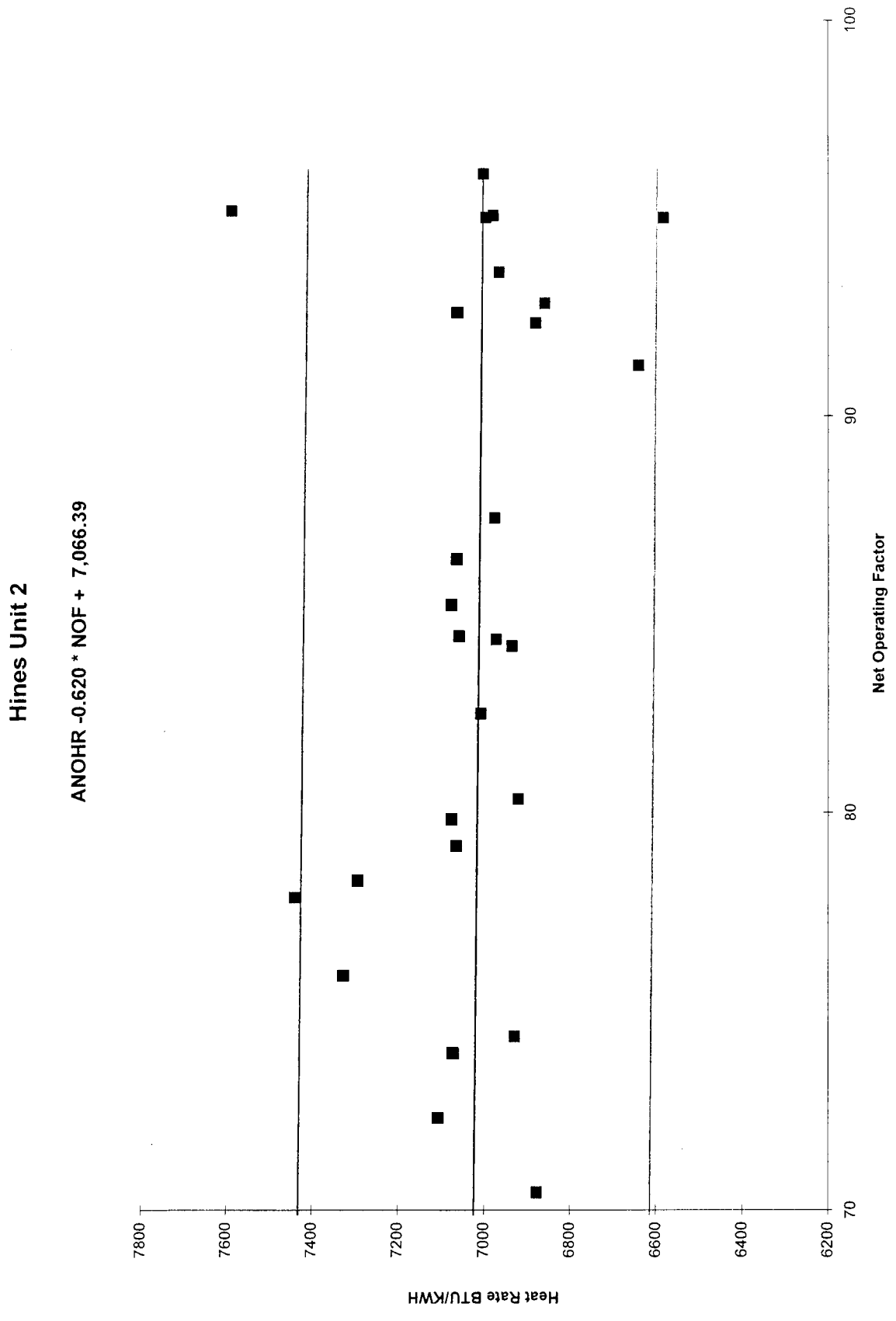
ANOHR -0.620 * NOF + 7,066.39

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	95.0	6,583	7,008	-424.5	408.9
Aug-04	95.2	7,595	7,007	587.3	408.9
Sep-04	85.2	7,079	7,014	65.5	408.9
Oct-04	78.3	7,295	7,018	277.0	408.9
Nov-04	73.9	7,071	7,021	50.0	408.9
Dec-04	42.7	7,095	7,040	54.9	408.9
Jan-05	91.3	6,641	7,010	-369.1	408.9
Feb-05	84.4	6,974	7,014	-40.2	408.9
Mar-05	86.4	7,067	7,013	54.3	408.9
Apr-05	84.4	7,061	7,014	46.8	408.9
May-05	92.6	7,068	7,009	59.2	408.9
Jun-05	95.0	7,000	7,008	-7.3	408.9
Jul-05	95.1	6,983	7,007	-24.6	408.9
Aug-05	96.1	7,006	7,007	-1.0	408.9
Sep-05	87.4	6,978	7,012	-34.3	408.9
Oct-05	79.2	7,066	7,017	48.2	408.9
Nov-05	72.3	7,105	7,022	83.3	408.9
Dec-05	58.2	7,113	7,030	82.9	408.9
Jan-06	80.4	6,921	7,017	-95.5	408.9
Feb-06	75.9	7,326	7,019	306.8	408.9
Mar-06	50.1	7,178	7,035	143.0	408.9
Apr-06	70.4	6,877	7,023	-146.2	408.9
May-06	79.8	7,076	7,017	59.2	408.9
Jun-06	92.4	6,883	7,009	-126.6	408.9
Jul-06	92.9	6,861	7,009	-147.4	408.9
Aug-06	93.6	6,969	7,008	-39.4	408.9
Sep-06	74.3	6,929	7,020	-91.4	408.9
Oct-06	77.9	7,441	7,018	422.5	408.9
Nov-06	56.5	7,209	7,031	177.1	408.9
Dec-06	51.9	7,160	7,034	126.0	408.9
Jan-07	56.1	6,075	7,032	-956.1	408.9
Feb-07	69.7	6,853	7,023	-169.8	408.9
Mar-07	62.5	7,026	7,028	-1.2	408.9
Apr-07	64.8	7,141	7,026	114.5	408.9
May-07	84.2	6,937	7,014	-77.6	408.9
Jun-07	82.5	7,009	7,015	-6.2	408.9

Regression Output:

Constant	7066.39
Std Err of Y Est	252.0667869
R Squared	0.00134235
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-0.619523469
Std Err of Coef.	2.897968695


Hines Unit 2
ANOHR -0.620 * NOF + 7,066.39
Heat Rate BTU/KWH
7800
7600
7400
7200
7000
6800
6600
6400
6200
70
80
90
100
Net Operating Factor

PROGRESS ENERGY FLORIDA

TIGER BAY

ANOHR -10.656 * NOF + 8,905.93

TABLE OF RESIDUALS

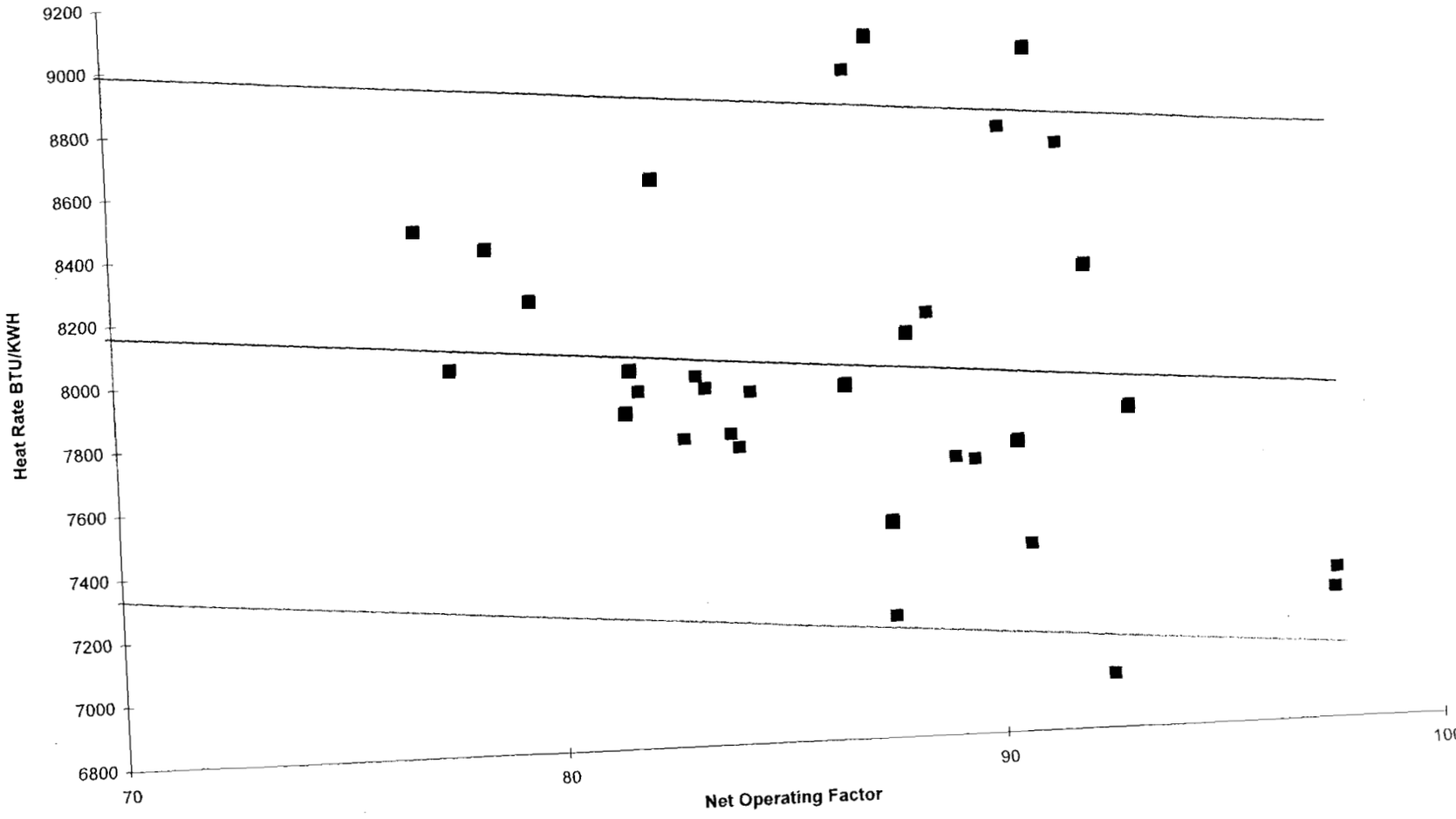
DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-04	92.5	6,970	7,920	-950.1	828.9
Aug-04	91.0	8,969	7,936	1033.2	828.9
Sep-04	92.2	8,273	7,923	349.7	828.9
Oct-04	90.3	8,719	7,943	776.3	828.9
Nov-04	86.8	8,919	7,980	938.4	828.9
Jan-05	88.5	8,137	7,962	174.3	828.9
Feb-05	87.4	9,027	7,975	1051.9	828.9
Mar-05	93.1	7,820	7,914	-94.4	828.9
Apr-05	91.7	8,660	7,929	730.7	828.9
May-05	89.1	7,676	7,957	-280.5	828.9
Jun-05	90.5	7,724	7,941	-216.9	828.9
Jul-05	97.7	7,273	7,865	-592.6	828.9
Aug-05	82.4	8,601	8,028	572.9	828.9
Sep-05	97.6	7,211	7,866	-655.4	828.9
Oct-05	89.5	7,666	7,952	-285.6	828.9
Nov-05	88.1	8,079	7,967	111.5	828.9
Jan-06	30.8	8,289	8,577	-288.4	828.9
Feb-06	78.6	8,399	8,069	330.2	828.9
Mar-06	87.5	7,183	7,973	-789.9	828.9
Apr-06	81.6	7,862	8,036	-174.4	828.9
May-06	77.6	8,020	8,078	-58.8	828.9
Jun-06	84.2	7,737	8,009	-271.9	828.9
Jul-06	84.0	7,781	8,011	-230.0	828.9
Aug-06	84.5	7,912	8,006	-93.6	828.9
Sep-06	81.8	7,997	8,035	-38.1	828.9
Oct-06	83.2	7,966	8,019	-52.6	828.9
Nov-06	81.9	7,925	8,033	-107.9	828.9
Dec-06	82.9	7,771	8,022	-251.5	828.9
Jan-07	77.0	8,464	8,086	377.7	828.9
Feb-07	83.4	7,928	8,017	-88.7	828.9
Mar-07	79.5	8,229	8,059	170.0	828.9
Apr-07	86.6	7,924	7,983	-58.6	828.9
May-07	90.7	7,391	7,939	-547.7	828.9
Jun-07	87.6	7,484	7,973	-489.3	828.9

Regression Output:

Constant	8905.93
Std Err of Y Est	511.463692
R Squared	0.050513411
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-10.65632325
Std Err of Coef.	8.167205218

Tiger Bay

ANOHR -10.656 * NOF + 8,905.93



UNPLANNED OUTAGE RATE TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Progress Energy Florida
Period of: January 2008 - December 2008

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Anclote 1	FOR	0.87	3.32	1.66
	MOR	0.00	0.00	0.00
	FOR&MOR	0.87	3.32	1.66
	PFOR	0.49	1.85	0.92
	PMOR	0.89	3.39	1.69
	EUOR	2.23	8.38	4.23
	EUOF	2.11	7.93	4.01
Anclote 2	FOR	0.87	3.31	1.66
	MOR	0.93	3.55	1.78
	FOR&MOR	1.79	6.63	3.37
	PFOR	0.32	1.21	0.61
	PMOR	1.31	4.98	2.49
	EUOR	3.38	12.42	6.37
	EUOF	2.92	10.72	5.50
Crystal River 1	FOR	1.20	4.56	2.28
	MOR	0.42	1.59	0.79
	FOR&MOR	1.60	6.00	3.04
	PFOR	0.88	3.34	1.67
	PMOR	1.55	5.91	2.96
	EUOR	3.99	14.70	7.52
	EUOF	3.99	14.70	7.52
Crystal River 2	FOR	2.39	9.09	4.54
	MOR	1.68	6.42	3.21
	FOR&MOR	3.99	14.34	7.47
	PFOR	1.33	5.07	2.54
	PMOR	1.23	4.69	2.35
	EUOR	6.45	22.78	11.99
	EUOF	6.17	21.78	11.46
Crystal River 3	FOR	0.83	3.17	1.59
	MOR	0.24	0.90	0.45
	FOR&MOR	1.06	4.01	2.02
	PFOR	0.21	0.81	0.41
	PMOR	0.43	1.62	0.81
	EUOR	1.70	6.35	3.22
	EUOF	1.70	6.35	3.22
Crystal River 4	FOR	0.88	3.35	1.68
	MOR	0.62	2.38	1.19
	FOR&MOR	1.49	5.57	2.82
	PFOR	0.56	2.13	1.06
	PMOR	0.97	3.69	1.84
	EUOR	3.00	11.06	5.65
	EUOF	2.65	9.79	5.00
Crystal River 5	FOR	0.92	3.50	1.75
	MOR	0.97	3.71	1.85
	FOR&MOR	1.87	6.95	3.54
	PFOR	0.49	1.86	0.93
	PMOR	1.30	4.96	2.48
	EUOR	3.63	13.30	6.83
	EUOF	3.63	13.30	6.83
Hines 1	FOR	0.60	2.30	1.15
	MOR	0.22	0.84	0.42
	FOR&MOR	0.82	3.10	1.56
	PFOR	1.25	4.75	2.38
	PMOR	0.51	1.95	0.98
	EUOR	2.57	9.60	4.86
	EUOF	1.94	7.27	3.68
Hines 2	FOR	0.51	1.94	0.97
	MOR	0.54	2.07	1.03
	FOR&MOR	1.05	3.93	1.99
	PFOR	0.19	0.72	0.36
	PMOR	1.27	4.84	2.42
	EUOR	2.49	9.27	4.71
	EUOF	1.47	5.48	2.78
Tiger Bay	FOR	2.23	8.51	4.26
	MOR	0.00	0.00	0.00
	FOR&MOR	2.23	8.51	4.26
	PFOR	0.00	0.01	0.00
	PMOR	0.00	0.00	0.00
	EUOR	2.24	8.52	4.26
	EUOF	1.40	5.34	2.67

Anclote
Unit 1

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	741.50	697.37	678.00	720.00	688.42	648.22	167.70	620.92	547.26	744.00	713.87	735.32	660.80	720.00	653.18	720.00	744.00
RSH	0.00	1.87	0.00	0.00	0.00	55.58	25.23	283.98	0.00	169.87	0.00	6.13	8.68	0.00	0.00	91.82	0.00	0.00
UH	0.00	0.63	22.63	67.00	0.00	0.00	70.55	220.32	123.08	1.87	0.00	0.00	0.00	83.20	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	70.55	220.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.63	22.63	67.00	0.00	0.00	0.00	0.00	123.08	1.87	0.00	0.00	0.00	83.20	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	10.17	30.57	15.10	9.80	108.02	400.37	2.43	0.00	4.83	0.00	2.43	0.00	3.38	15.85	0.00	62.00	32.00	0.00
LRPF	373.48	70.55	120.05	328.07	4.00	4.00	135.26	0.00	110.12	0.00	65.99	0.00	66.74	268.64	0.00	159.00	159.00	0.00
EFOH	7.63	4.33	3.64	6.46	0.87	3.22	0.66	0.00	1.07	0.00	0.32	0.00	0.45	8.55	0.00	19.79	10.22	0.00
PMOH	22.42	20.80	32.07	36.02	11.67	0.00	0.00	8.10	0.00	12.67	5.77	53.62	23.17	24.23	72.10	35.83	24.32	31.52
LRPM	159.00	160.67	209.37	172.90	158.96	0.00	0.00	158.99	0.00	158.95	158.89	158.98	158.96	159.02	174.54	159.02	158.98	207.31
EMOH	7.16	6.71	13.48	12.51	3.73	0.00	0.00	2.59	0.00	4.04	1.84	17.12	7.40	7.74	25.27	11.44	7.76	13.12
NPC	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	0.08	3.14	8.99	0.00	0.00	0.00	0.00	16.54	0.34	0.00	0.00	0.00	11.18	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.03	0.58	0.52	0.95	0.12	0.47	0.10	0.00	0.17	0.00	0.04	0.00	0.06	1.29	0.00	3.03	1.42	0.00
PMOR	0.96	0.91	1.93	1.84	0.52	0.00	0.00	1.54	0.00	0.74	0.25	2.40	1.01	1.17	3.51	1.75	1.08	1.76
EUOR	1.99	1.57	5.52	11.54	0.64	0.47	0.10	1.54	16.69	1.08	0.29	2.40	1.07	13.37	3.51	4.78	2.50	1.76
EUOF	1.99	1.57	5.52	11.54	0.64	0.43	0.09	0.38	16.69	0.82	0.29	2.38	1.05	13.37	3.51	4.19	2.50	1.76
POF	0.00	0.00	0.00	0.00	0.00	0.00	9.48	32.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.01	98.43	94.48	88.46	99.36	99.57	90.43	66.83	83.31	99.18	99.71	97.62	98.95	86.63	96.49	95.81	97.50	98.24

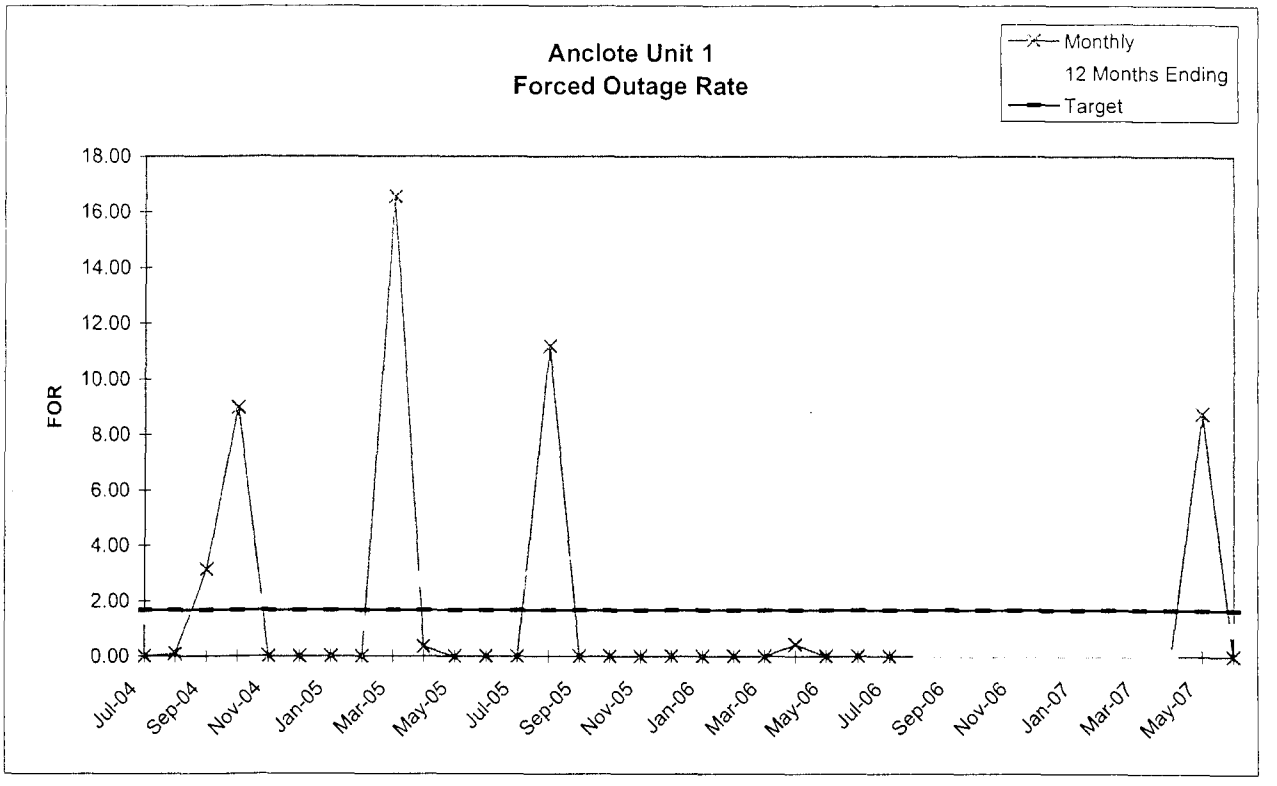
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	1.40	1.40	1.71	2.49	1.98	1.90	1.13	1.19	2.71	2.79	2.79	2.72	2.72	3.76	3.47	2.66	2.66	2.64
MOR	0.73	0.73	0.73	0.71	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.57	0.53	0.57	0.64	0.59	0.60	0.51	0.48	0.50	0.51	0.37	0.37	0.27	0.33	0.28	0.46	0.58	0.54
PMOR	2.34	2.11	2.01	1.91	1.79	1.77	1.75	1.66	1.64	1.60	1.17	0.90	0.90	0.92	1.08	1.07	1.12	1.28
EUOR	4.95	4.70	4.94	5.63	4.93	4.21	3.37	3.30	4.78	4.83	4.28	3.94	3.86	4.97	4.79	4.14	4.31	4.41
EUOF	4.24	4.02	4.22	5.03	4.78	4.06	3.25	3.05	4.43	4.38	3.88	3.57	3.49	4.49	4.33	3.70	3.85	3.97
POF	11.44	11.44	11.44	7.60	0.00	0.00	0.80	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32
EAF	84.32	84.54	84.33	87.37	95.22	95.94	95.95	93.63	92.25	92.30	92.80	93.11	93.19	92.19	92.35	92.98	92.83	92.71

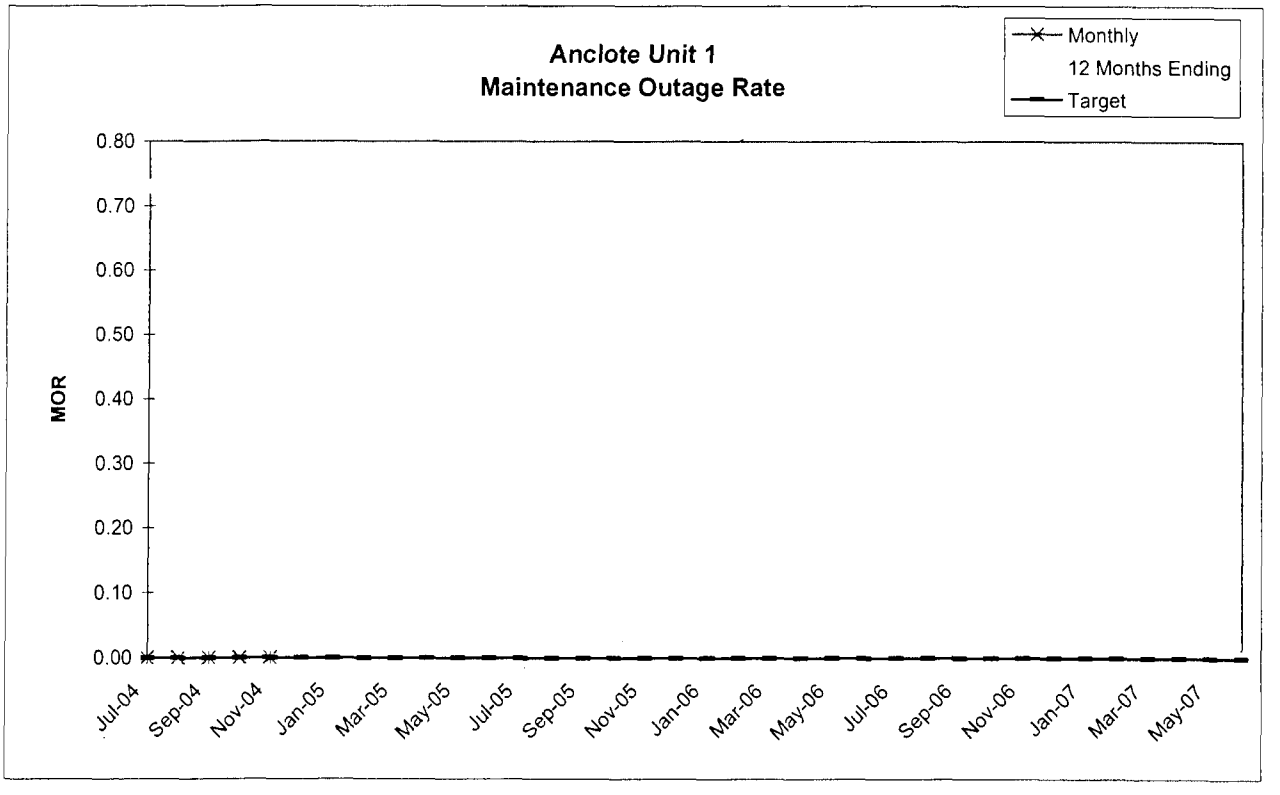
Anclote
Unit 1

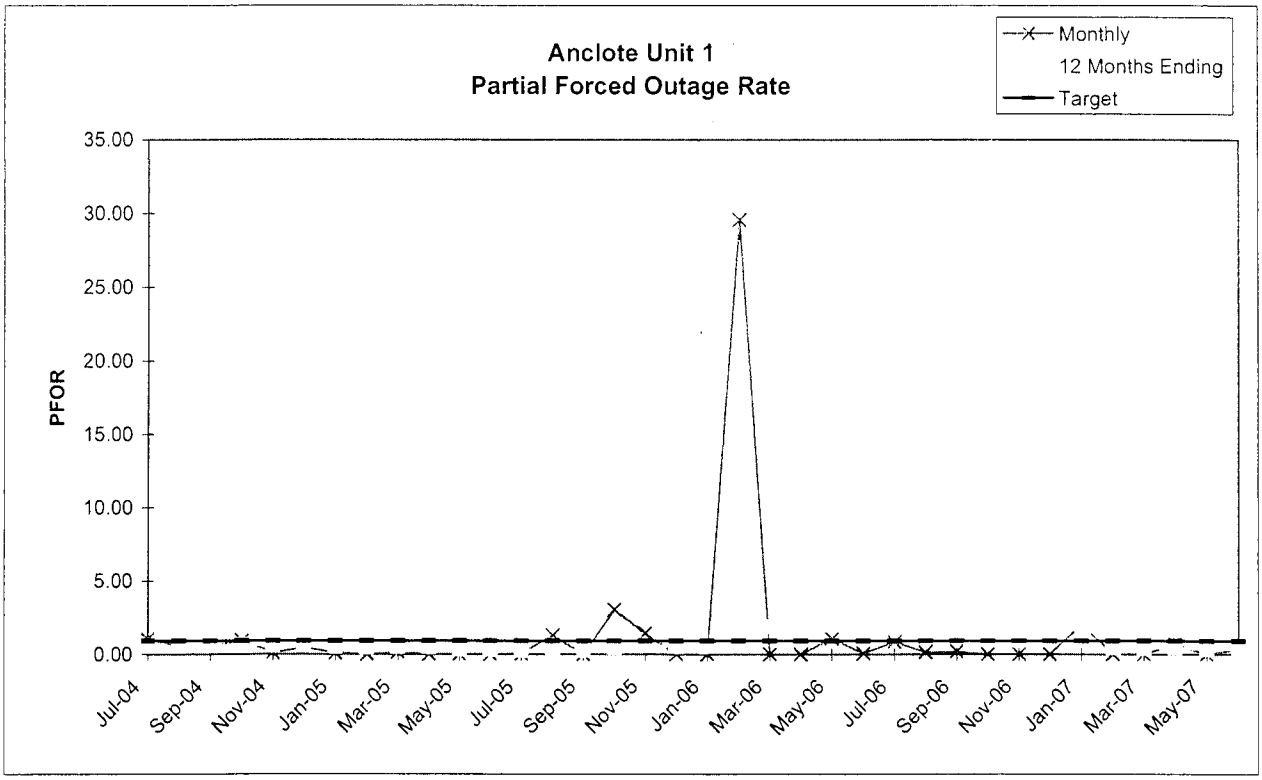
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	456.55	335.36	245.12	541.40	744.00	720.00	744.00	744.00	668.12	0.00	554.88	350.81	582.80	551.47	713.54	408.18	678.80	720.00
RSH	287.45	336.64	498.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	90.02	393.19	161.20	120.53	3.78	0.00	0.00	0.00
UH	0.00	0.00	0.00	177.60	0.00	0.00	0.00	0.00	51.88	745.00	75.10	0.00	0.00	0.00	25.68	311.82	65.20	0.00
POH	0.00	0.00	0.00	175.32	0.00	0.00	0.00	0.00	51.88	745.00	75.10	0.00	0.00	0.00	25.68	311.82	0.00	0.00
FOH	0.00	0.00	0.00	2.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.20	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	310.38	0.00	6.92	20.22	13.25	25.77	25.75	26.50	0.00	0.00	0.00	23.18	0.00	0.00	5.35	0.00	5.49
LRPF	0.00	159.00	0.00	4.03	194.27	15.64	123.97	19.65	23.02	0.00	0.00	0.00	256.04	0.00	0.00	266.48	0.00	240.80
EFOH	0.00	99.10	0.00	0.06	7.89	0.42	6.42	1.02	1.23	0.00	0.00	0.00	11.92	0.00	0.00	2.86	0.00	2.65
PMOH	1.20	0.00	2.67	17.67	64.28	118.89	59.20	100.45	53.67	0.00	0.00	0.00	6.17	19.49	61.00	12.53	218.43	91.99
LRPM	17.84	0.00	255.72	158.95	159.01	158.99	167.61	159.01	159.00	0.00	0.00	0.00	158.91	158.95	147.54	159.04	74.54	152.13
EMOH	0.04	0.00	1.37	5.64	20.53	37.96	19.92	32.07	17.14	0.00	0.00	0.00	1.97	6.22	18.07	4.00	32.69	28.10
NPC	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00

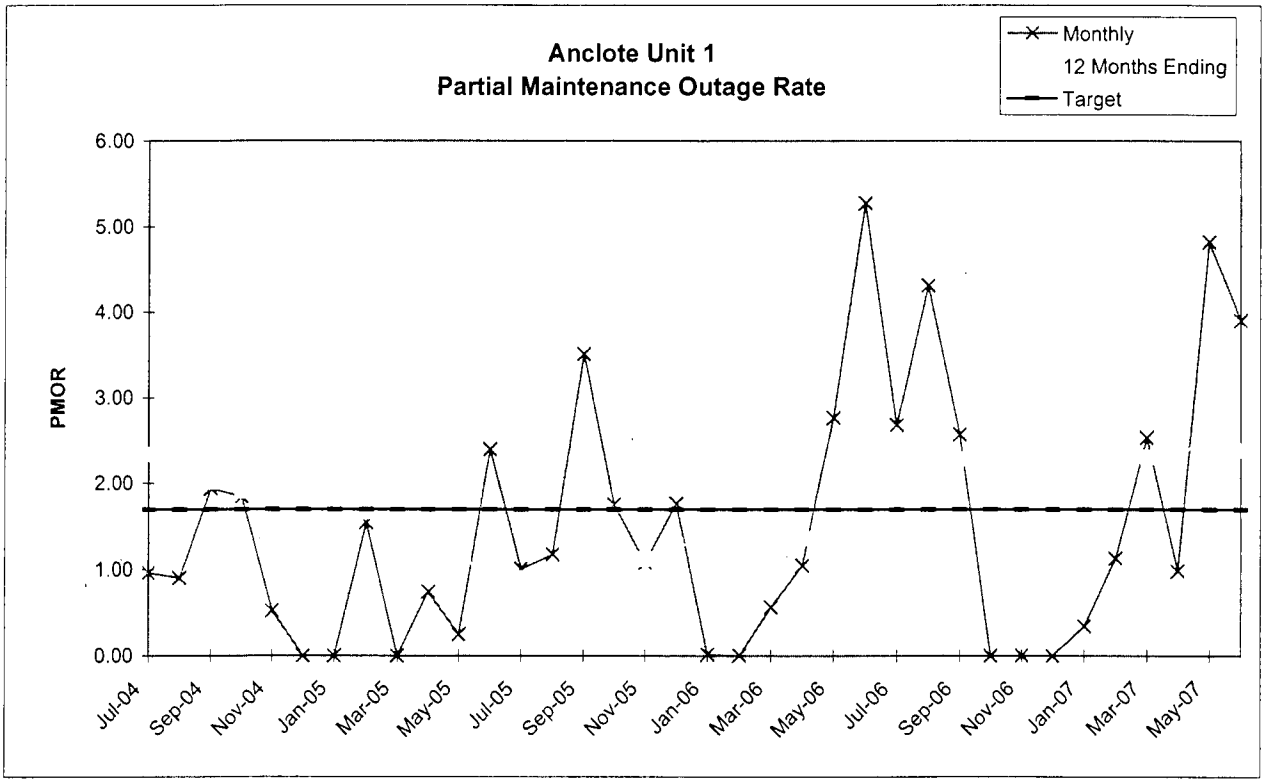
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.76	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	29.55	0.00	0.01	1.06	0.06	0.86	0.14	0.18	0.00	0.00	0.00	2.04	0.00	0.00	0.70	0.00	0.37
PMOR	0.01	0.00	0.56	1.04	2.76	5.27	2.68	4.31	2.56	0.00	0.00	0.00	0.34	1.13	2.53	0.98	4.82	3.90
EUOR	0.01	29.55	0.56	1.47	3.82	5.33	3.54	4.45	2.75	0.00	0.00	0.00	2.38	1.13	2.53	1.68	13.16	4.27
EUOF	0.01	14.75	0.18	1.11	3.82	5.33	3.54	4.45	2.55	0.00	0.00	0.00	1.87	0.93	2.43	0.95	13.16	4.27
POF	0.00	0.00	0.00	24.38	0.00	0.00	0.00	0.00	7.21	100.00	10.43	0.00	0.00	0.00	3.46	43.31	0.00	0.00
EAF	99.99	85.25	99.82	74.51	96.18	94.67	96.46	95.55	90.24	0.00	89.57	100.00	98.13	99.07	94.11	55.74	86.84	95.73

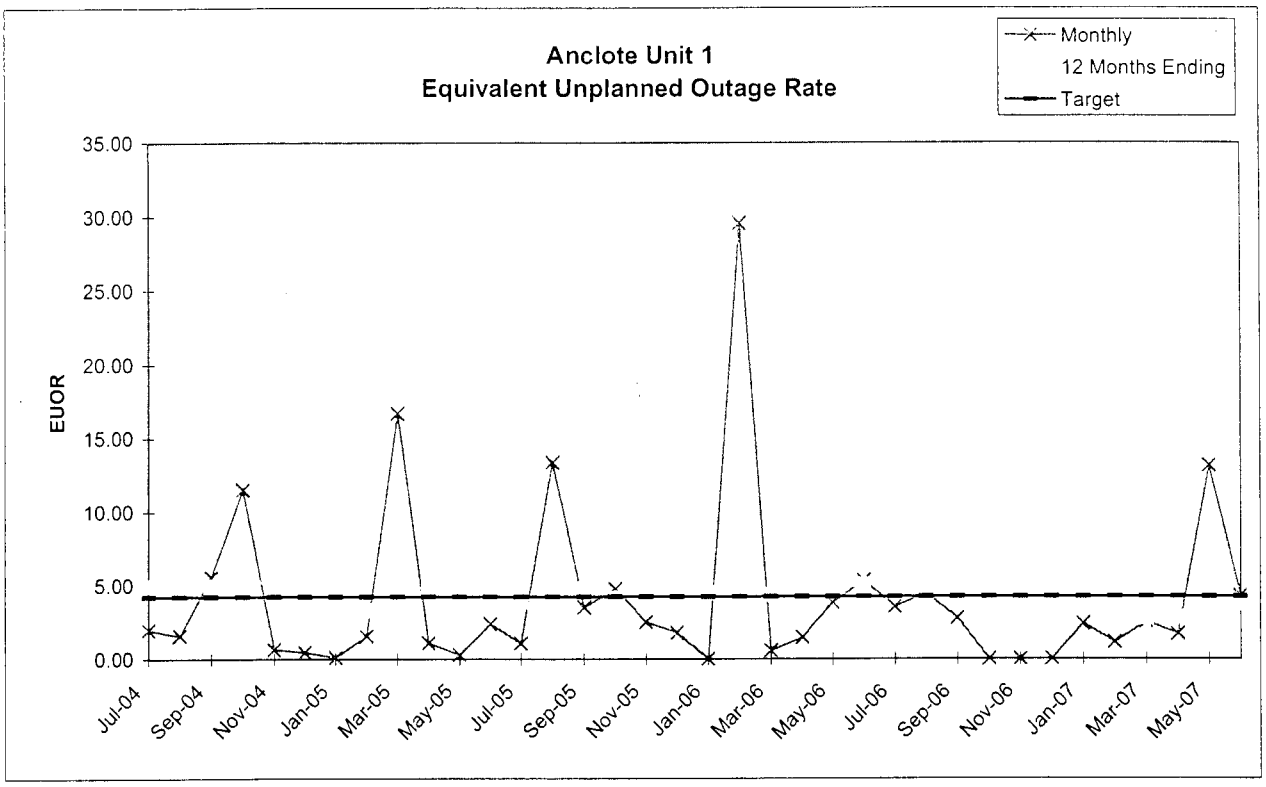
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	2.71	2.65	1.16	1.16	1.16	1.16	1.16	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.03	0.00	0.96	0.96
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.54	1.82	1.90	1.91	2.01	2.01	2.09	1.97	2.00	1.90	1.79	1.90	2.05	0.45	0.42	0.47	0.36	0.39
PMOR	1.31	1.25	1.34	1.36	1.62	1.90	2.07	2.38	2.28	2.33	2.27	2.21	2.19	2.22	2.31	2.33	2.53	2.39
EUOR	4.51	5.64	4.36	4.39	4.74	5.03	5.27	4.37	4.31	4.26	4.10	4.14	4.28	2.70	2.76	2.80	3.82	3.71
EUOF	3.96	5.06	3.66	3.68	3.98	4.23	4.44	3.68	3.60	3.24	3.04	2.89	3.05	1.99	2.18	2.16	2.96	2.87
POF	2.52	0.00	0.00	2.00	2.00	2.00	2.00	2.00	2.59	11.10	11.96	11.96	11.96	11.96	12.25	13.81	13.81	13.81
EAF	93.52	94.94	96.34	94.31	94.02	93.77	93.56	94.32	93.81	85.66	85.01	85.16	85.00	86.06	85.57	84.03	83.24	83.32

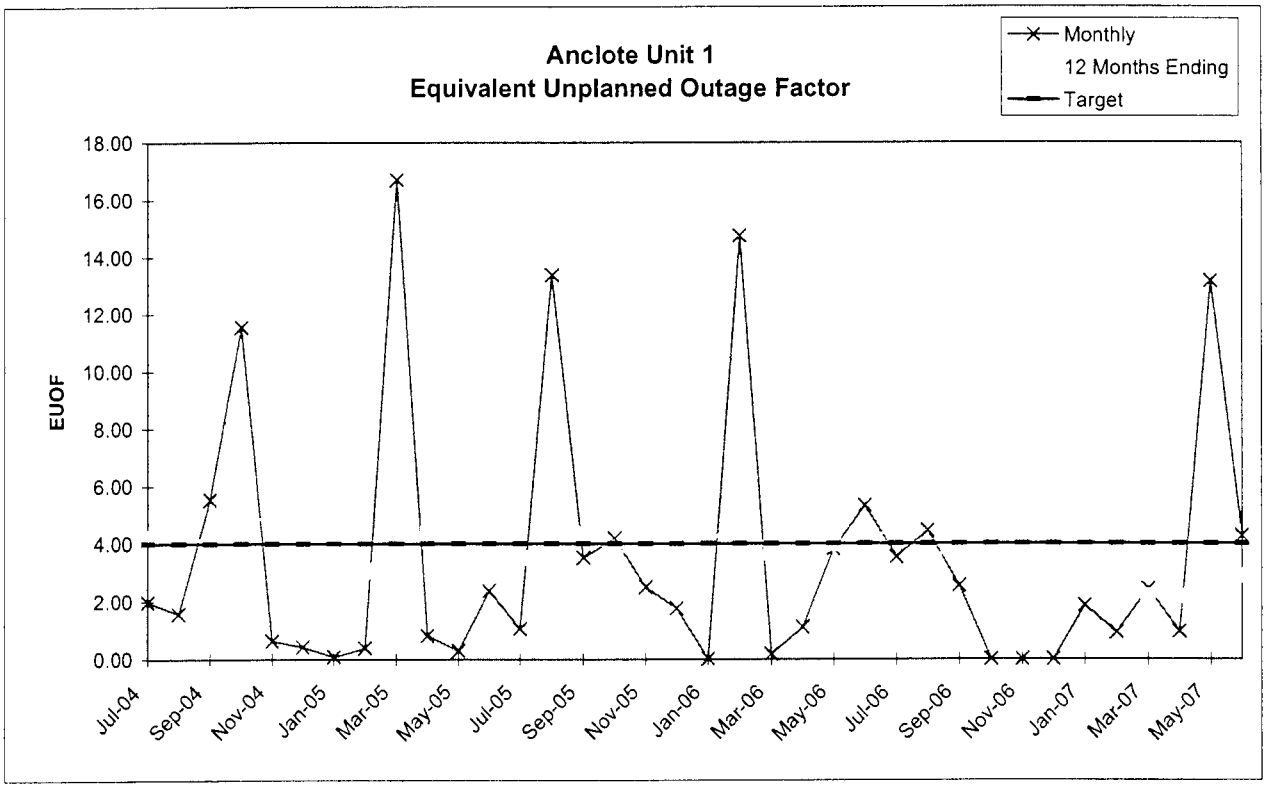

Anclote Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Anclote
Unit 2

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	701.18	703.13	745.00	232.50	345.50	278.35	672.00	457.13	609.39	651.55	692.53	744.00	677.67	720.00	745.00	711.00	584.97
RSH	0.00	42.82	0.00	0.00	142.92	398.50	165.78	0.00	215.70	100.98	87.92	27.47	0.00	0.00	0.00	0.00	9.00	149.90
UH	0.00	0.00	16.87	0.00	344.58	0.00	299.87	0.00	71.17	8.63	4.53	0.00	0.00	66.33	0.00	0.00	0.00	9.13
POH	0.00	0.00	0.00	0.00	344.58	0.00	281.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	16.87	0.00	0.00	0.00	18.37	0.00	71.17	8.63	4.53	0.00	0.00	66.33	0.00	0.00	0.00	9.13
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	9.62	0.00	117.82	13.77	108.02	709.25	56.94	6.03	0.37	0.00	0.00	31.87	7.95	16.98	0.00	20.32	0.00	1.87
LRPF	393.74	0.00	135.94	222.23	10.00	12.08	58.99	168.20	105.70	0.00	0.00	155.99	42.65	101.83	0.00	22.44	0.00	164.65
EFOH	7.65	0.00	32.36	6.18	2.18	17.31	6.79	2.05	0.08	0.00	0.00	10.04	0.69	3.49	0.00	0.92	0.00	0.62
PMOH	93.35	124.87	79.90	133.96	18.30	0.88	0.00	0.00	0.00	0.00	65.53	81.35	78.38	78.35	83.30	45.88	39.20	0.00
LRPM	156.00	155.99	156.00	156.01	156.02	146.25	0.00	0.00	0.00	0.00	156.00	156.00	155.94	155.99	156.00	156.02	154.32	0.00
EMOH	29.42	39.35	25.18	42.22	5.77	0.26	0.00	0.00	0.00	0.00	20.65	25.64	24.69	24.69	26.25	14.46	12.22	0.00
NPC	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	0.00	2.34	0.00	0.00	0.00	6.19	0.00	13.47	1.40	0.69	0.00	0.00	8.92	0.00	0.00	0.00	1.54
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.03	0.00	4.60	0.83	0.94	5.01	2.44	0.30	0.02	0.00	0.00	1.45	0.09	0.52	0.00	0.12	0.00	0.11
PMOR	3.95	5.61	3.58	5.67	2.48	0.08	0.00	0.00	0.00	0.00	3.17	3.70	3.32	3.64	3.65	1.94	1.72	0.00
EUOR	4.98	5.61	10.33	6.50	3.42	5.08	8.48	0.30	13.49	1.40	3.84	5.15	3.41	12.70	3.65	2.06	1.72	1.64
EUOF	4.98	5.29	10.33	6.50	1.10	2.36	3.38	0.30	9.58	1.20	3.38	4.96	3.41	12.70	3.65	2.06	1.70	1.31
POF	0.00	0.00	0.00	0.00	47.86	0.00	37.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	95.02	94.71	89.67	93.50	51.04	97.64	58.78	99.70	90.42	98.80	96.62	95.04	96.59	87.30	96.35	97.94	98.30	98.69

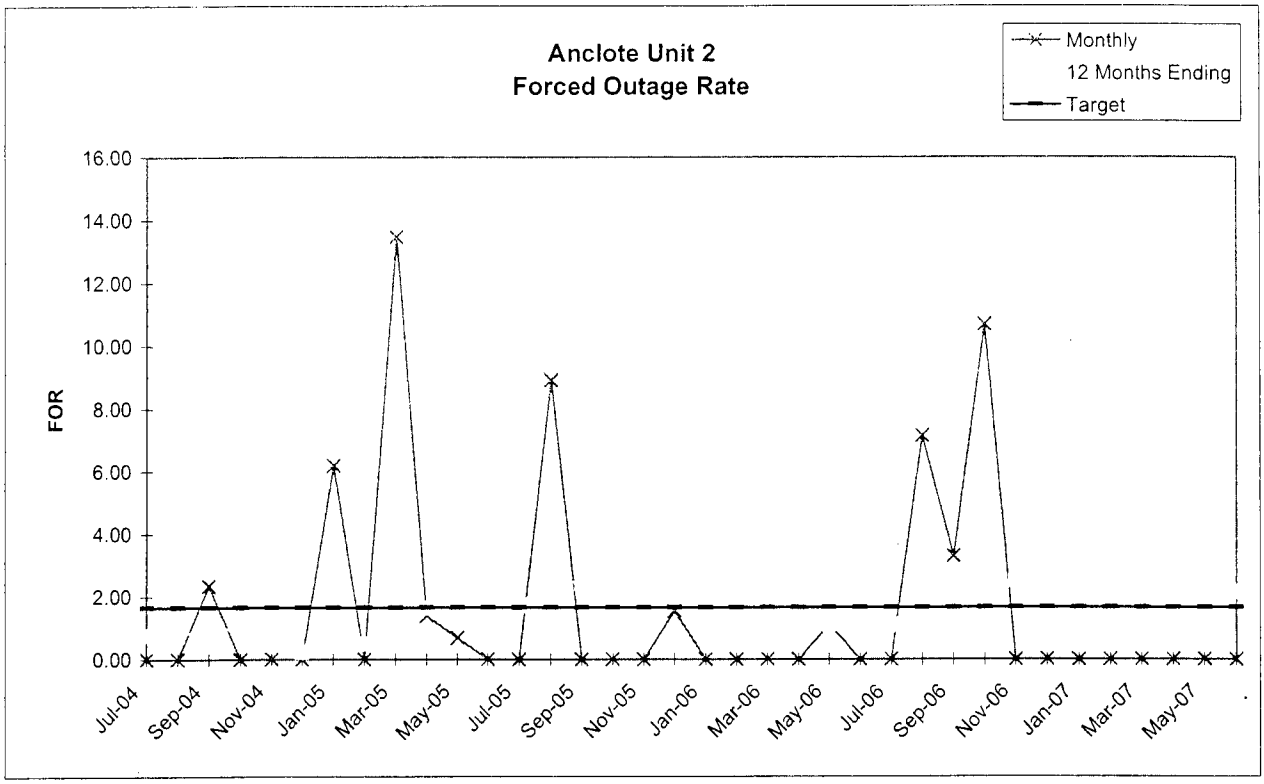
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.76	0.77	0.97	0.97	1.03	0.23	0.50	0.50	1.55	1.65	1.71	1.72	1.72	2.66	2.42	2.42	2.26	2.31
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.37	1.37	1.11	1.18	1.09	1.29	1.46	1.49	1.54	1.43	1.12	1.24	1.14	1.19	0.72	0.64	0.57	0.33
PMOR	2.51	2.76	2.91	3.27	3.32	3.43	3.48	3.27	3.10	2.89	2.90	2.76	2.69	2.48	2.49	2.09	2.04	1.97
EUOR	4.62	4.87	4.95	5.37	5.40	4.94	5.41	5.24	6.12	5.90	5.66	5.65	5.48	6.24	5.55	5.08	4.81	4.55
EUOF	4.42	4.63	4.71	5.11	4.84	4.20	4.38	4.23	4.79	4.70	4.51	4.48	4.35	4.98	4.43	4.05	4.10	4.01
POF	3.43	3.43	3.43	3.43	7.36	7.36	10.56	10.59	10.59	8.12	7.15	7.15	7.15	7.15	7.15	7.15	3.21	3.21
EAF	92.15	91.93	91.86	91.45	87.80	88.44	85.06	85.18	84.62	87.17	88.34	88.37	88.50	87.87	88.42	88.80	92.69	92.77

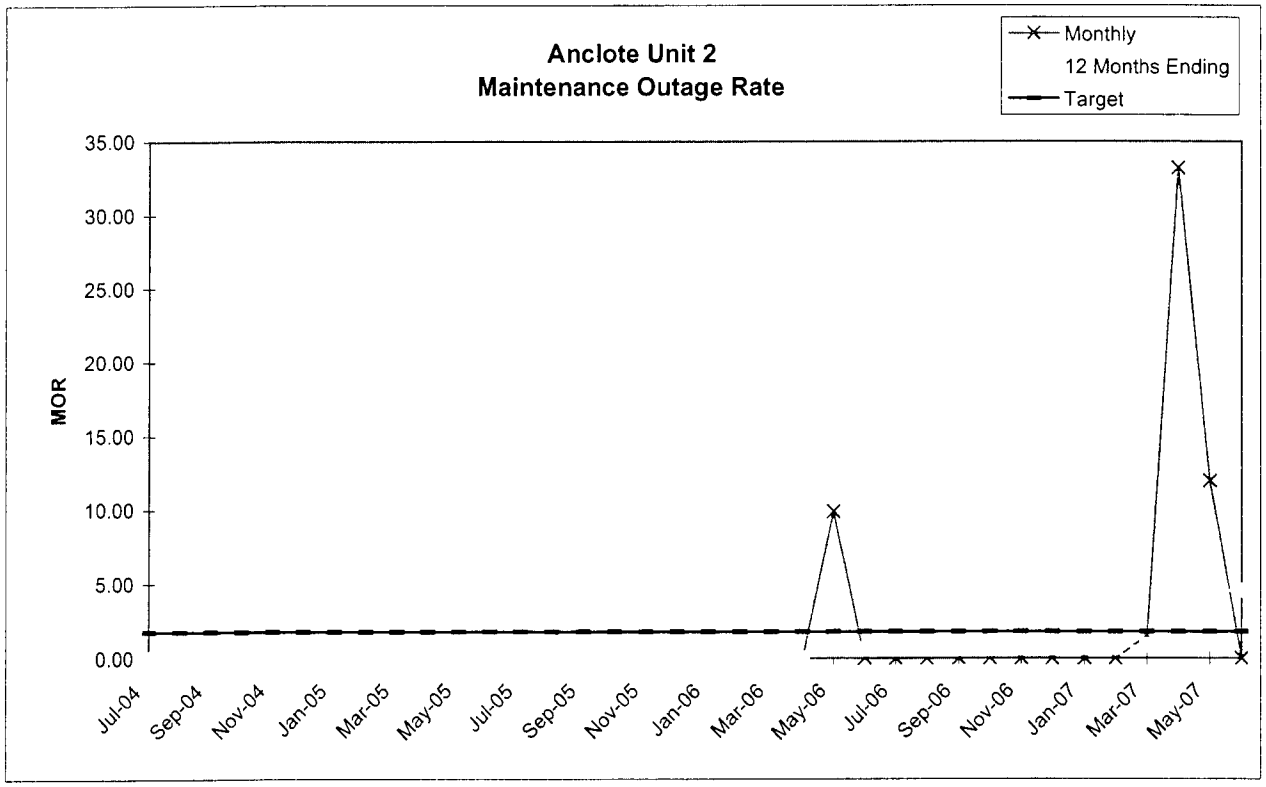
Anclote
Unit 2

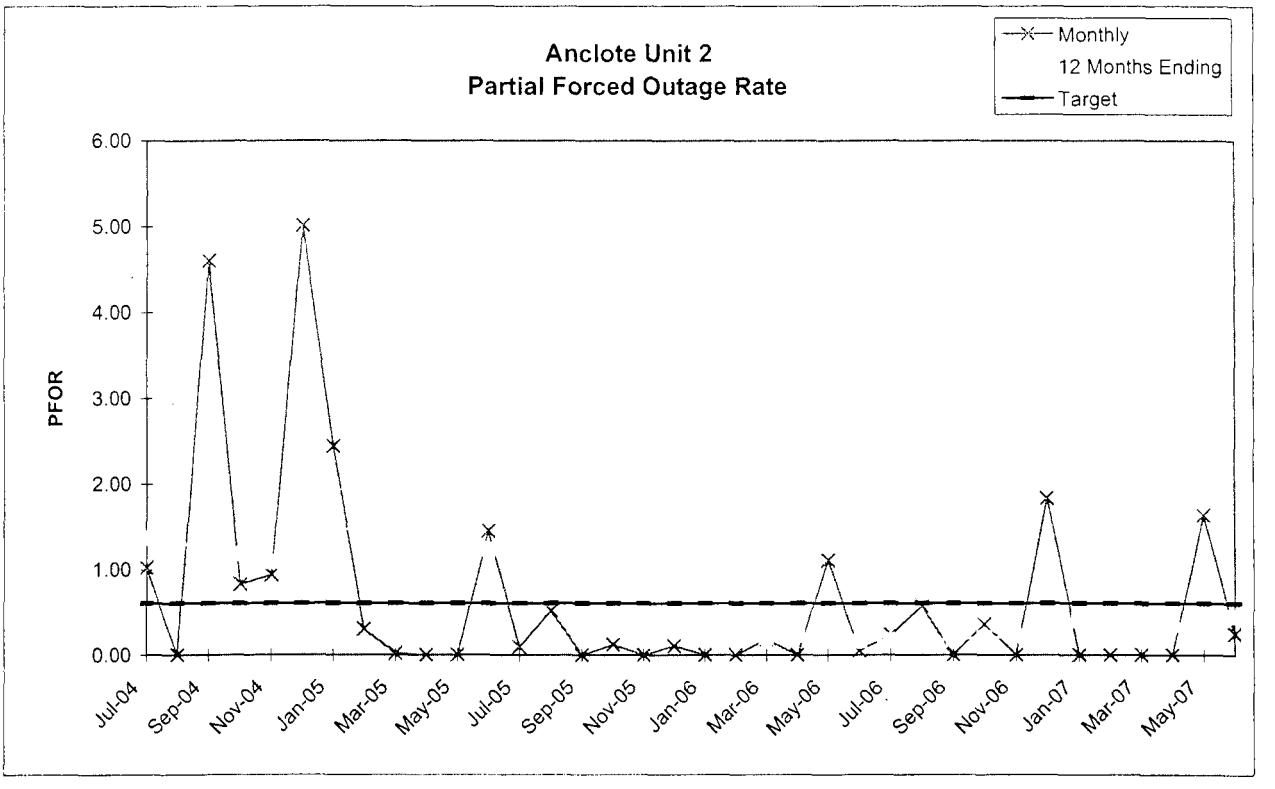
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	627.52	672.00	584.42	0.00	395.02	720.00	744.00	690.82	696.35	665.32	213.90	623.87	310.17	588.60	731.97	481.02	655.00	720.00
RSH	116.48	0.00	159.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	506.10	120.13	433.83	83.40	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	719.00	348.98	0.00	0.00	53.18	23.65	79.68	0.00	0.00	0.00	0.00	11.03	238.98	89.00	0.00
POH	0.00	0.00	0.00	719.00	301.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	4.37	0.00	0.00	53.18	23.65	79.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	43.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.03	238.98	89.00	0.00
PFOH	0.00	0.00	4.03	0.00	33.98	2.18	16.98	4.58	0.00	9.50	0.00	39.17	0.00	0.90	0.00	0.00	35.38	2.30
LRPF	0.00	0.00	131.06	0.00	63.56	88.10	51.02	431.23	0.00	124.17	0.00	144.99	0.00	3.00	0.00	0.00	149.92	383.04
EFOH	0.00	0.00	1.07	0.00	4.36	0.39	1.75	3.99	0.00	2.38	0.00	11.47	0.00	0.01	0.00	0.00	10.72	1.78
PMOH	2.50	8.13	21.48	0.00	45.75	26.33	62.27	19.17	64.68	6.47	0.00	0.00	0.00	14.60	100.33	157.29	146.72	103.08
LRPM	156.02	156.05	156.01	0.00	156.02	156.02	155.99	155.97	156.01	155.92	0.00	0.00	0.00	183.46	184.66	108.68	137.71	175.18
EMOH	0.79	2.56	6.77	0.00	14.42	8.30	19.62	6.04	20.38	2.04	0.00	0.00	0.00	5.41	37.43	34.53	40.82	36.48
NPC	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

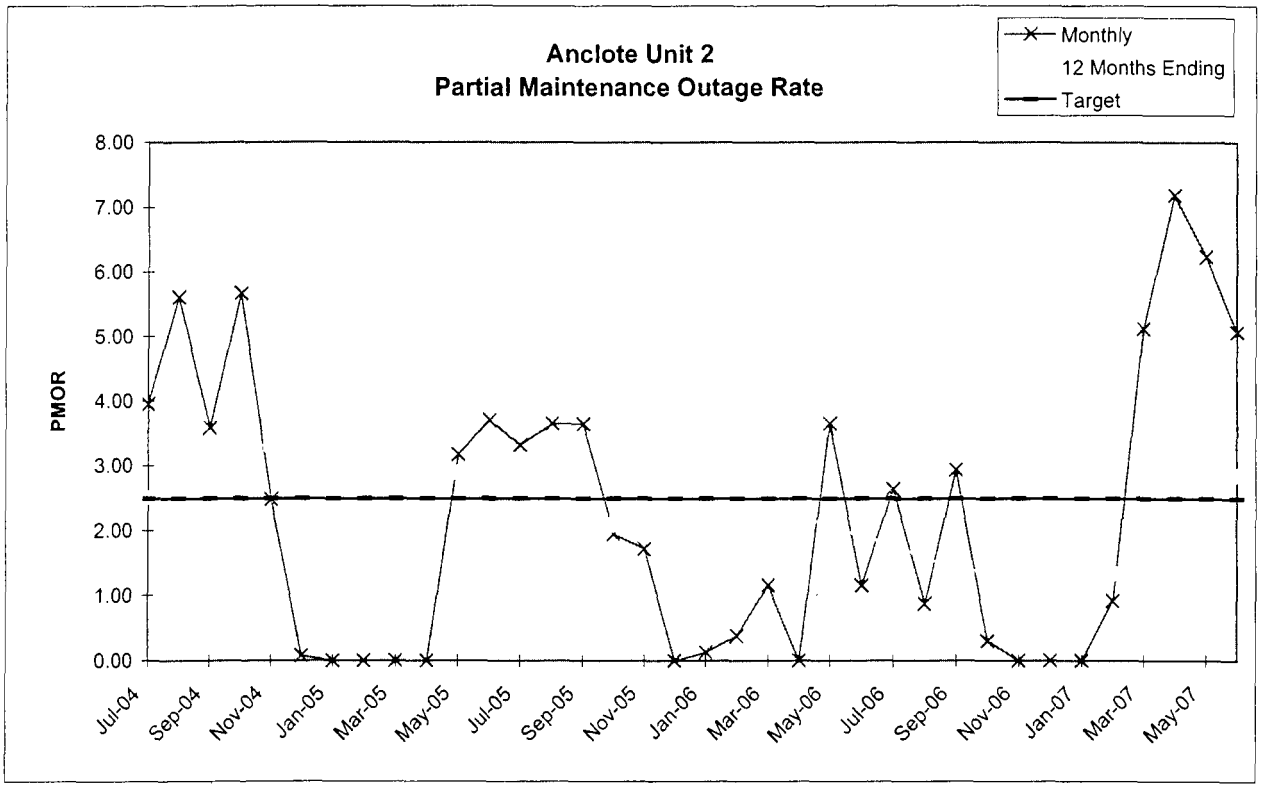
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	1.09	0.00	0.00	7.15	3.28	10.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	9.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.48	33.19	11.96	0.00
PFOR	0.00	0.00	0.18	0.00	1.10	0.05	0.24	0.58	0.00	0.36	0.00	1.84	0.00	0.00	0.00	0.00	1.64	0.25
PMOR	0.13	0.38	1.16	0.00	3.65	1.15	2.64	0.87	2.93	0.31	0.00	0.00	0.00	0.92	5.11	7.18	6.23	5.07
EUOR	0.13	0.38	1.34	0.00	15.00	1.21	2.87	8.50	6.12	11.29	0.00	1.84	0.00	0.92	6.52	37.99	18.89	5.31
EUOF	0.11	0.38	1.05	0.00	8.92	1.21	2.87	8.50	6.12	11.29	0.00	1.54	0.00	0.81	6.52	37.99	18.89	5.31
POF	0.00	0.00	0.00	100.00	40.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.89	99.62	98.95	0.00	50.57	98.79	97.13	91.50	93.88	88.71	100.00	98.46	100.00	99.19	93.48	62.01	81.11	94.69

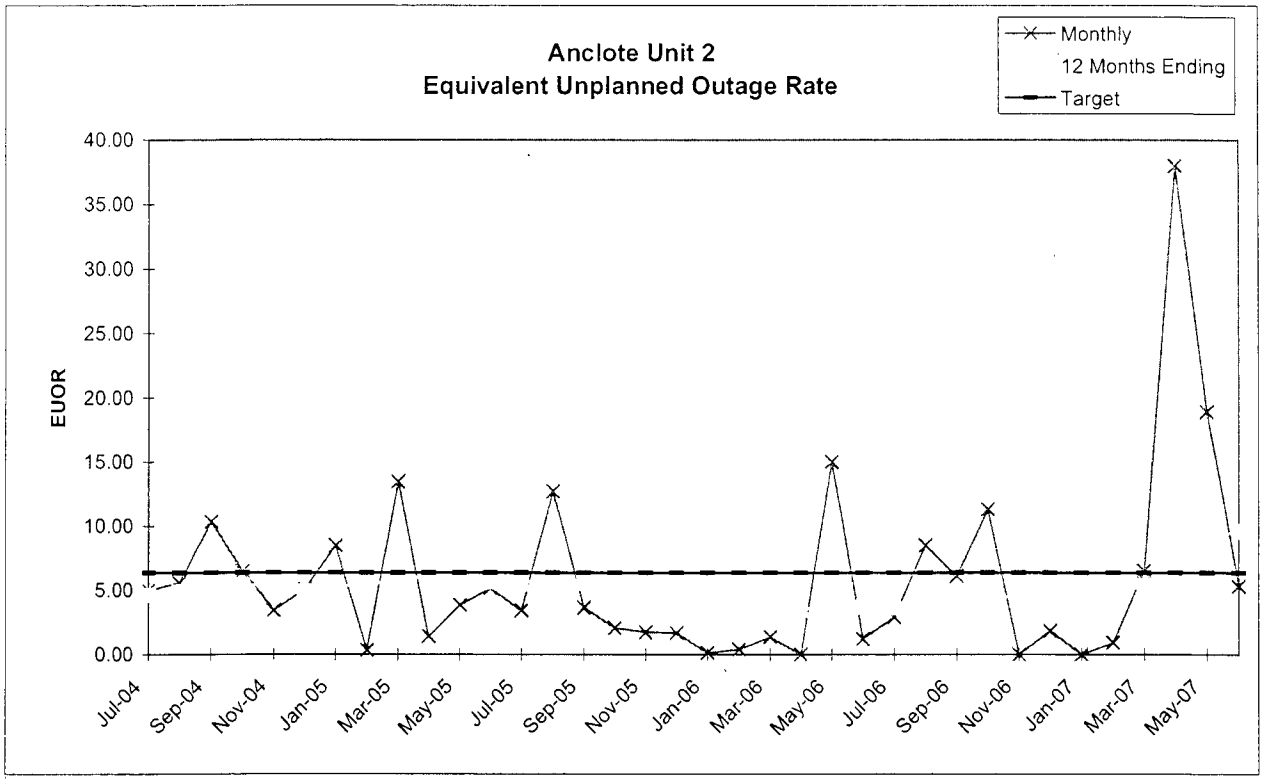
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	1.98	1.98	1.09	1.07	1.10	1.10	1.10	0.92	1.24	2.34	2.51	2.37	2.48	2.52	2.46	2.29	2.15	2.15
MOR	0.00	0.00	0.00	0.00	0.60	0.60	0.60	0.60	0.60	0.61	0.65	0.65	0.68	0.69	0.84	4.10	4.54	4.54
PFOR	0.23	0.20	0.21	0.23	0.30	0.16	0.18	0.18	0.18	0.21	0.22	0.38	0.40	0.41	0.38	0.35	0.43	0.45
PMOR	1.89	1.93	1.98	2.14	2.13	1.88	1.81	1.55	1.47	1.31	1.23	1.22	1.27	1.33	1.78	2.16	2.45	2.85
EUOR	4.06	4.07	3.26	3.41	4.08	3.69	3.64	3.21	3.45	4.39	4.54	4.54	4.75	4.86	5.35	8.57	9.20	9.59
EUOF	3.73	3.74	3.02	2.92	3.39	3.08	3.03	2.68	2.88	3.66	3.52	3.54	3.53	3.57	4.03	7.15	8.00	8.34
POF	0.00	0.00	0.00	8.21	11.65	11.65	11.65	11.65	11.65	11.65	11.65	11.65	11.65	11.65	11.65	3.44	0.00	0.00
EAF	96.27	96.26	96.98	88.88	84.96	85.27	85.32	85.68	85.47	84.69	84.83	84.81	84.82	84.78	84.32	89.41	92.00	91.66

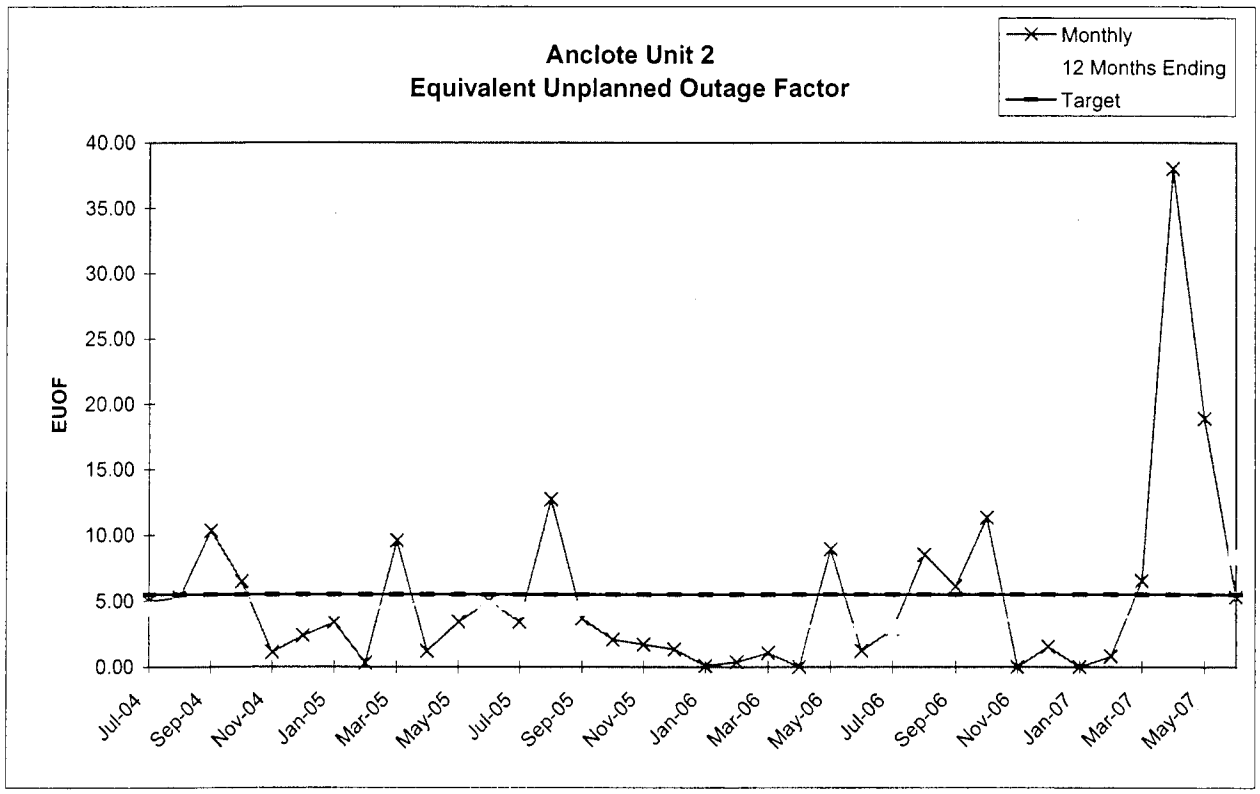

Anclote Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Anclote Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Crystal River
Unit 1

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	674.95	653.62	720.00	745.00	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.05	90.38	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.05	90.38	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	21.55	48.13	206.25	79.12	30.17	23.30	5.32	5.50	63.68	3.15	71.58	74.27	31.82	17.95	4.38	9.08	50.95	185.12
LRPF	111.57	171.74	106.62	105.95	143.28	128.75	76.23	265.02	31.07	93.97	99.74	106.56	92.95	188.99	94.06	77.55	158.31	36.36
EFOH	6.34	21.81	58.02	22.12	11.41	7.92	1.07	3.85	5.22	0.78	18.84	20.88	7.80	8.95	1.09	1.86	21.28	17.76
PMOH	376.23	157.40	49.33	42.08	76.95	10.87	39.95	47.27	50.20	22.33	129.17	20.95	17.15	15.98	34.68	120.25	206.02	0.00
LRPM	89.34	92.52	94.74	137.86	127.77	136.15	183.87	167.53	176.19	198.70	152.79	131.32	202.61	160.10	116.54	205.03	79.39	0.00
EMOH	88.69	38.42	12.33	15.31	25.94	3.91	19.38	20.90	23.34	11.71	52.07	7.26	9.17	6.75	10.66	65.05	43.15	0.00
NPC	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.28	12.15	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.85	2.93	8.06	2.97	1.58	1.06	0.14	0.57	0.70	0.11	2.53	2.90	1.16	1.37	0.15	0.25	2.96	2.39
PMOR	11.92	5.16	1.71	2.05	3.60	0.52	2.61	3.11	3.14	1.63	7.00	1.01	1.36	1.03	1.48	8.73	5.99	0.00
EUOR	12.77	8.10	9.77	5.02	5.19	1.59	2.75	3.68	3.84	1.74	9.53	3.91	11.56	14.26	1.63	8.98	8.95	2.39
EUOF	12.77	8.10	9.77	5.02	5.19	1.59	2.75	3.68	3.84	1.74	9.53	3.91	11.56	14.26	1.63	8.98	8.95	2.39
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	87.23	91.90	90.23	94.98	94.81	98.41	97.25	96.32	96.16	98.26	90.47	96.09	88.44	85.74	98.37	91.02	91.05	97.61

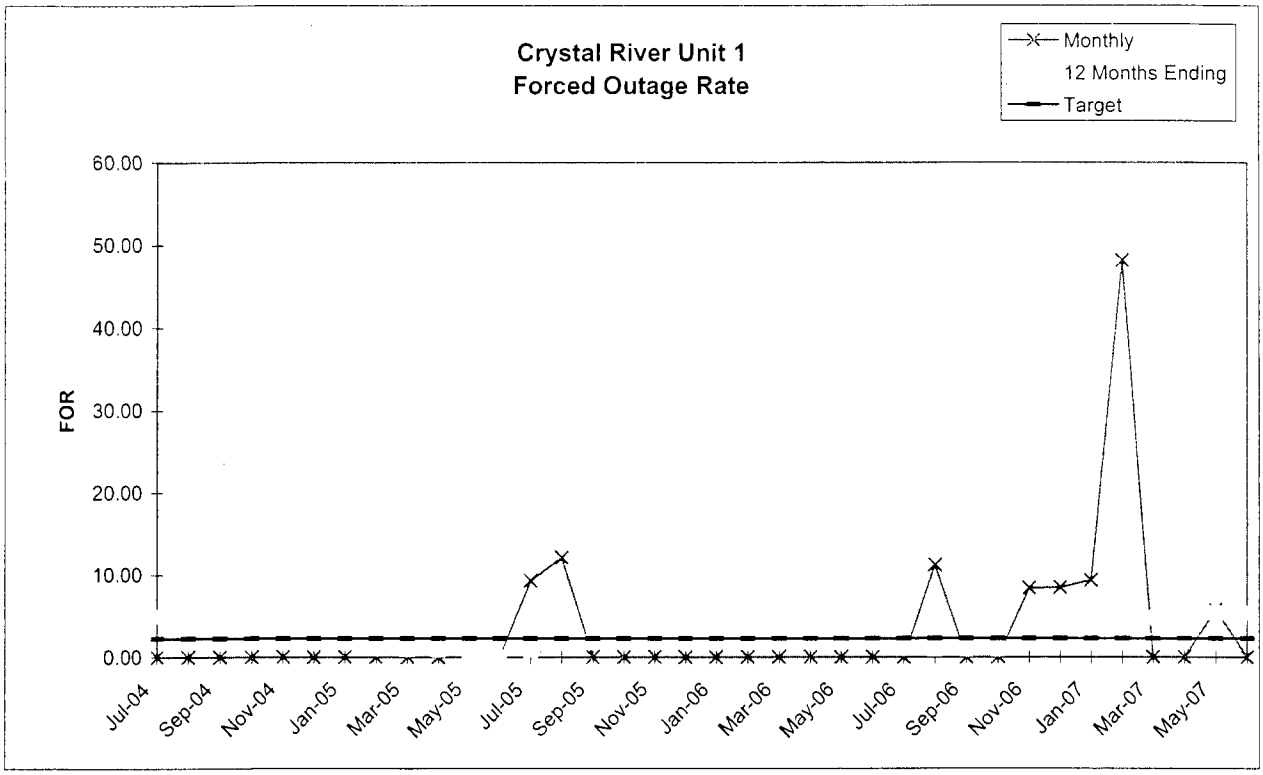
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	4.95	4.62	4.62	4.62	4.51	1.94	1.94	1.04	0.96	0.87	0.00	0.00	0.79	1.82	1.82	1.82	1.82	1.82
MOR	0.87	0.87	0.87	0.87	0.87	0.84	0.84	0.84	0.77	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.64	0.87	1.47	1.77	1.81	1.79	1.79	1.83	1.75	1.66	1.85	2.03	2.07	1.94	1.28	1.04	1.16	1.27
PMOR	3.73	3.74	3.74	3.41	3.58	3.43	3.47	3.63	3.64	3.56	3.99	3.64	2.76	2.42	2.40	2.98	3.18	3.13
EUOR	9.85	9.76	10.34	10.31	10.40	7.82	7.87	7.22	7.02	6.73	5.84	5.68	5.58	6.10	5.43	5.77	6.08	6.14
EUOF	8.58	8.50	9.01	8.98	9.06	6.82	6.86	6.29	6.62	6.73	5.84	5.68	5.58	6.10	5.43	5.77	6.08	6.14
POF	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.91	5.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	78.54	78.62	78.12	78.15	78.07	80.31	80.27	80.80	87.61	93.27	94.16	94.32	94.42	93.90	94.57	94.23	93.92	93.86

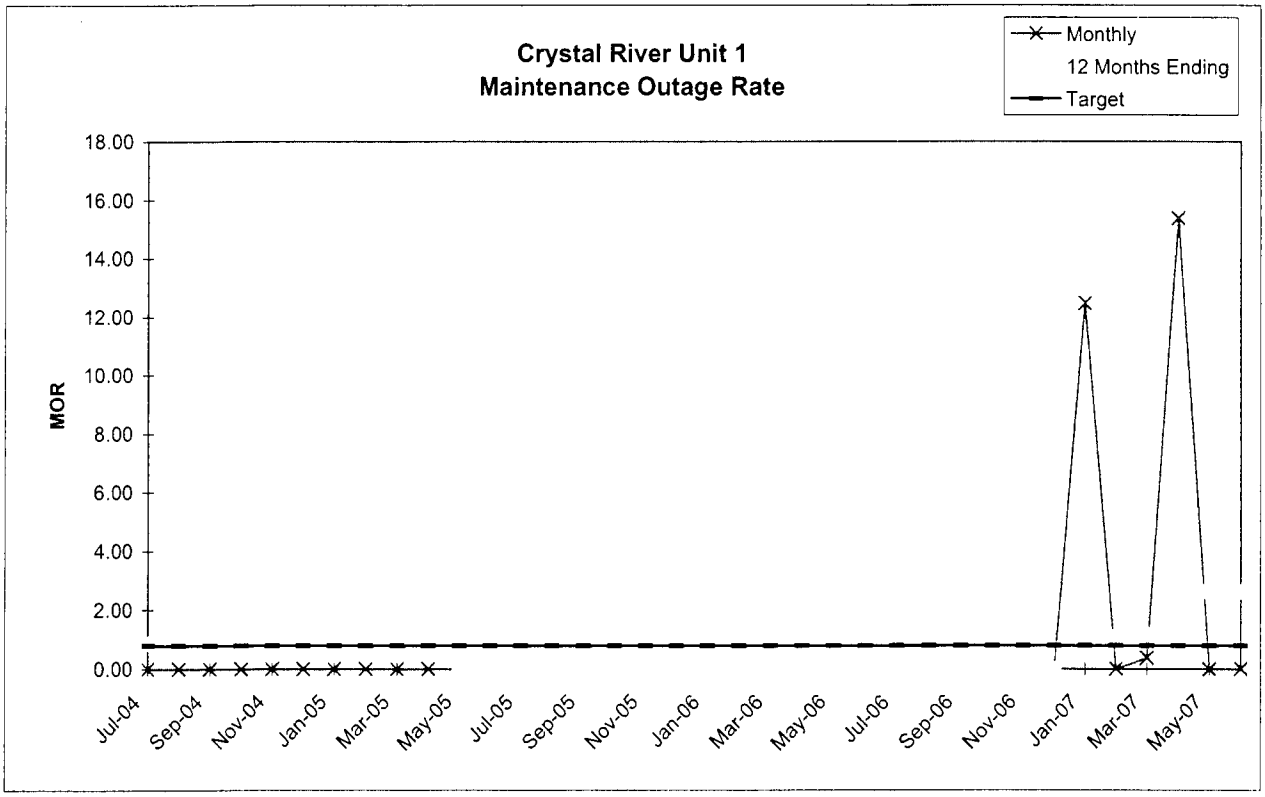
Crystal River
Unit 1

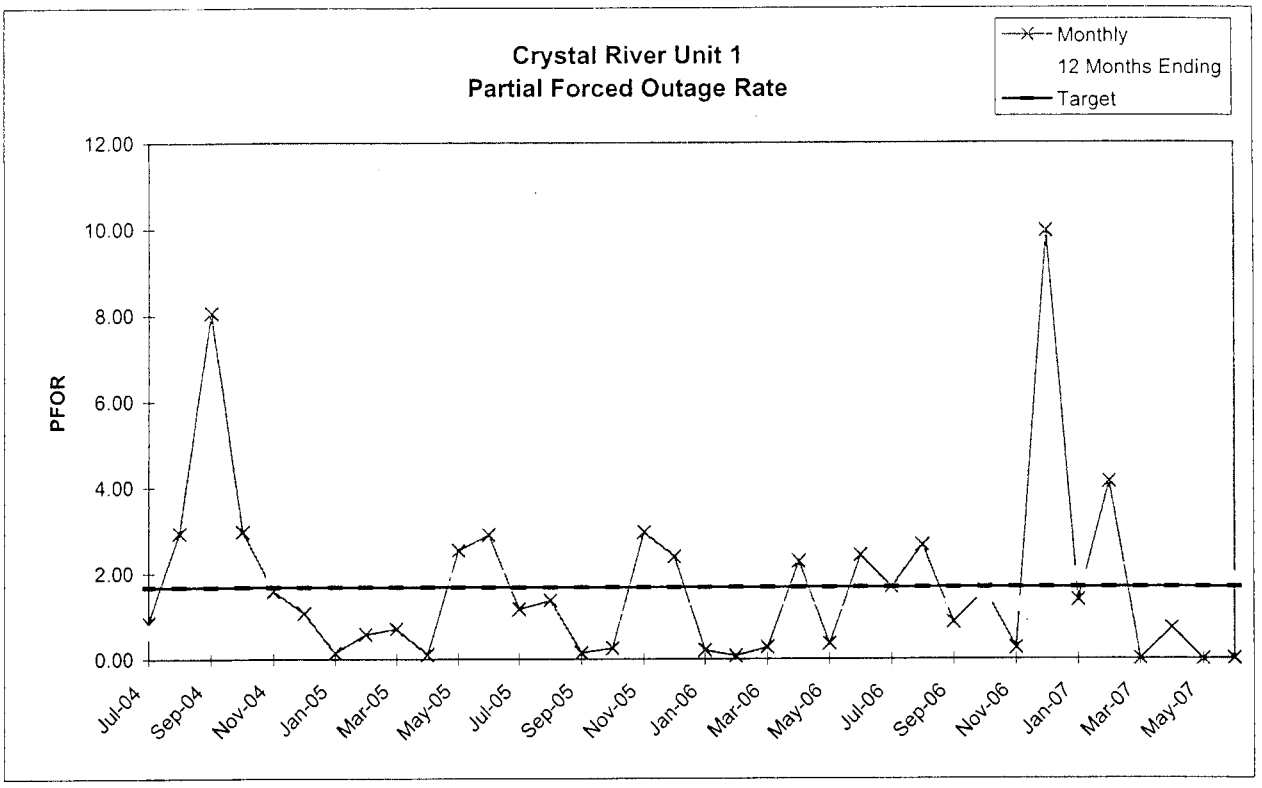
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	660.68	720.00	745.00	659.60	681.23	597.26	113.18	352.33	609.27	701.63	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.32	0.00	0.00	60.40	62.77	146.74	558.82	390.67	110.73	42.37	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	453.58	389.37	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.32	0.00	0.00	60.40	62.77	61.64	105.24	0.00	0.00	42.37	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	85.10	0.00	1.30	110.73	0.00	0.00
PFOH	8.40	1.50	33.78	147.35	34.25	174.03	189.78	75.67	20.95	49.13	6.83	227.17	36.23	18.98	0.00	14.35	0.00	0.35
LRPF	67.18	122.04	23.26	42.18	29.01	37.88	25.03	88.20	111.64	91.52	94.06	113.09	85.77	93.27	0.00	113.43	0.00	113.00
EFOH	1.49	0.48	2.07	16.40	2.62	17.40	12.53	17.61	6.17	11.86	1.70	67.79	8.20	4.67	0.00	4.29	0.00	0.10
PMOH	0.00	0.00	49.12	17.53	75.55	52.30	26.70	376.90	279.30	98.22	1.25	17.50	0.00	0.00	126.77	0.00	40.41	9.50
LRPM	0.00	0.00	41.59	125.50	95.83	121.45	170.00	78.23	76.46	80.95	189.03	151.99	0.00	0.00	113.00	0.00	126.42	75.00
EMOH	0.00	0.00	5.39	5.81	19.10	16.76	11.98	77.79	56.35	20.98	0.62	7.02	0.00	0.00	37.80	0.00	13.48	1.88
NPC	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

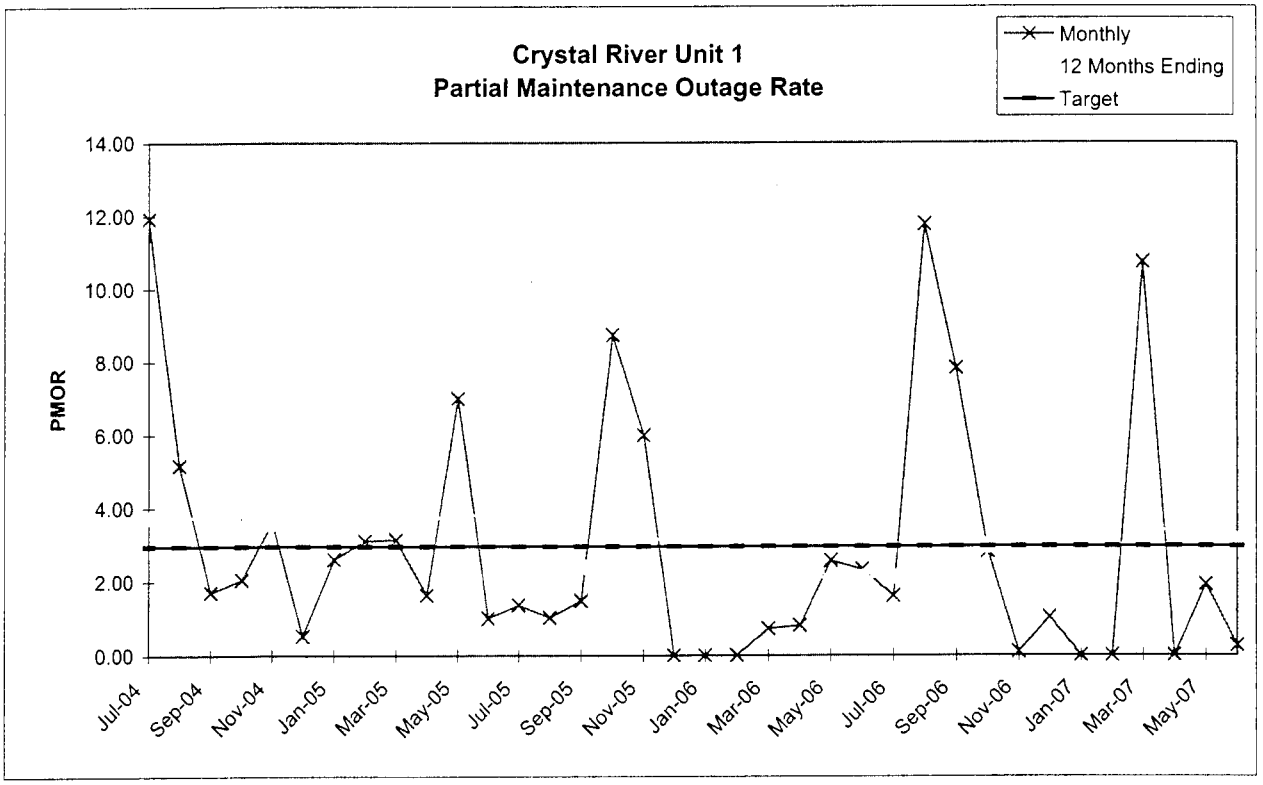
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.20	0.00	0.00	8.39	8.44	9.35	48.18	0.00	0.00	5.69	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.47	0.00	0.37	15.38	0.00	0.00
PFOR	0.20	0.07	0.28	2.28	0.35	2.42	1.68	2.67	0.86	1.59	0.26	9.95	1.37	4.13	0.00	0.70	0.00	0.01
PMOR	0.00	0.00	0.72	0.81	2.57	2.33	1.61	11.77	7.83	2.82	0.09	1.03	0.00	0.00	10.73	0.00	1.92	0.26
EUOR	0.20	0.07	1.00	3.09	2.92	4.74	3.29	24.02	8.68	4.41	8.71	18.49	20.83	50.32	11.06	15.98	7.51	0.28
EUOF	0.20	0.07	1.00	3.09	2.92	4.74	3.29	24.02	8.68	4.41	8.71	18.49	20.83	16.36	5.26	15.98	7.51	0.28
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.50	52.41	0.00	0.00	0.00
EAF	99.80	99.93	99.00	96.91	97.08	95.26	96.71	75.98	91.32	95.59	91.29	81.51	79.17	16.15	42.33	84.02	92.49	99.72

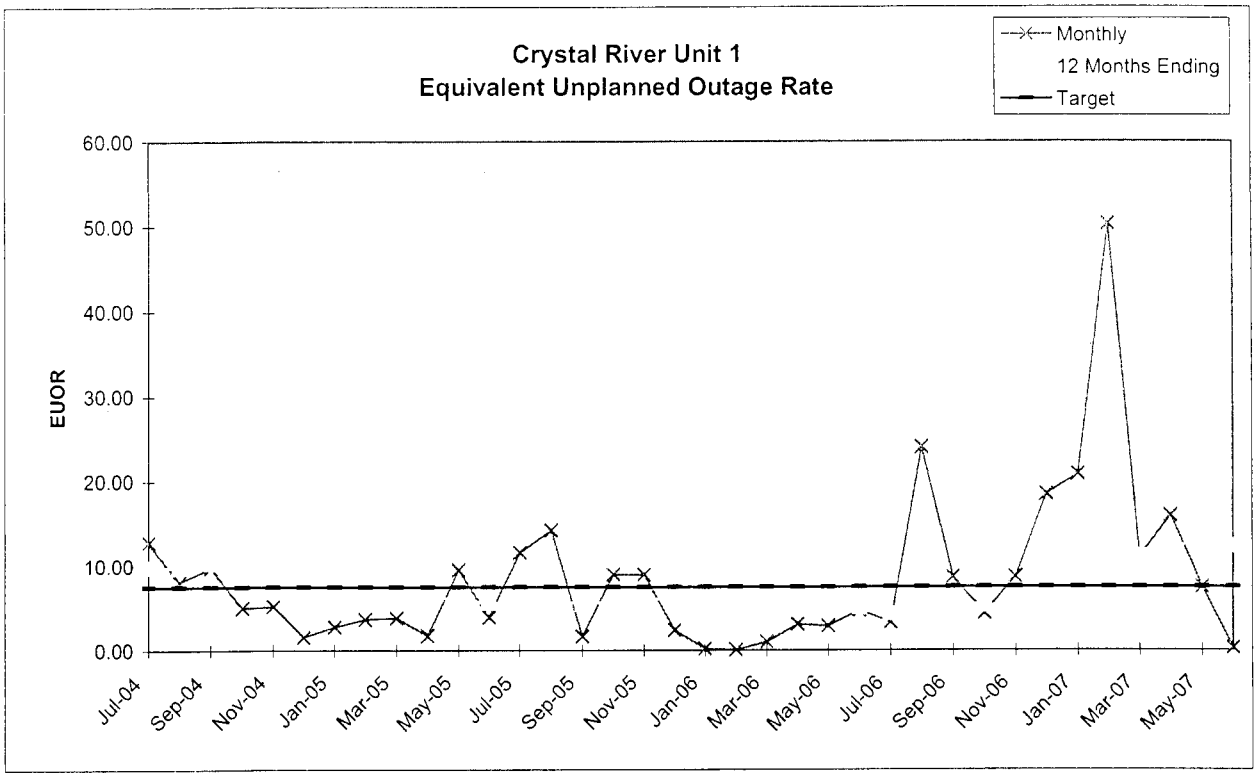
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	1.82	1.82	1.82	1.82	1.82	1.82	1.03	0.95	0.95	0.95	1.64	2.36	3.09	4.54	4.77	4.84	5.39	5.39
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.07	1.15	2.61	2.63	2.63
PFOR	1.28	1.24	1.20	1.38	1.19	1.15	1.20	1.30	1.36	1.47	1.25	1.85	1.96	2.15	2.24	2.11	2.08	1.85
PMOR	2.91	2.66	2.46	2.39	2.00	2.11	2.13	2.95	3.47	2.97	2.49	2.59	2.64	2.83	3.41	3.38	3.32	3.12
EUOR	5.93	5.65	5.41	5.52	4.96	5.03	4.33	5.16	5.73	5.35	5.33	6.69	8.45	10.22	11.13	12.30	12.73	12.32
EUOF	5.93	5.65	5.41	5.52	4.96	5.03	4.33	5.16	5.73	5.35	5.33	6.69	8.45	9.69	10.06	11.12	11.51	11.14
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.18	9.62	9.62	9.62	9.62
EAF	94.07	94.35	94.59	94.48	95.04	94.97	95.67	94.84	94.27	94.65	94.67	93.31	91.55	85.13	80.32	79.26	78.87	79.24

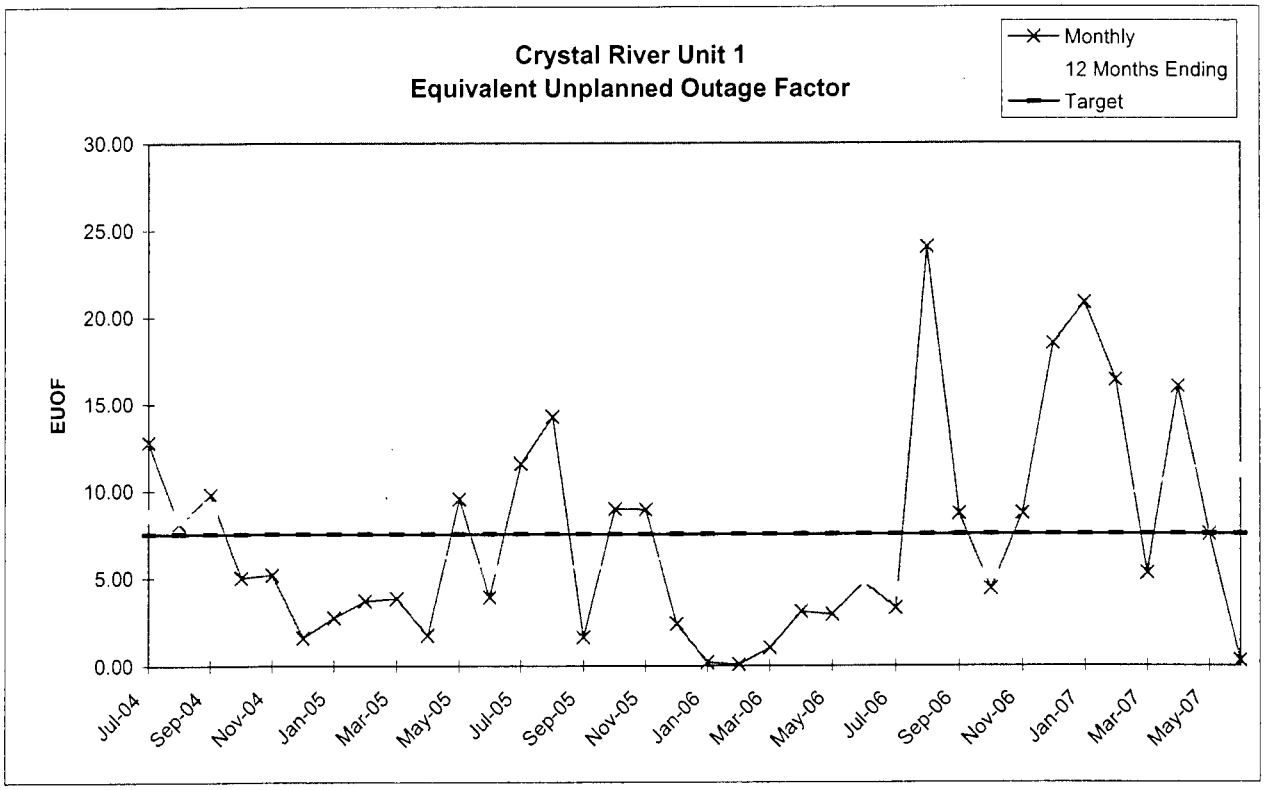

Crystal River Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Crystal River
Unit 2

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	712.17	744.00	720.00	745.00	720.00	744.00	648.03	345.47	646.02	704.48	607.93	718.78	584.85	744.00	585.87	684.33	718.58	655.68
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	31.83	0.00	0.00	0.00	0.00	0.00	95.97	326.53	97.98	14.52	136.07	1.22	159.15	0.00	134.13	60.67	1.42	88.32
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	31.83	0.00	0.00	0.00	0.00	0.00	95.97	130.53	97.98	14.52	82.50	1.22	68.82	0.00	134.13	60.67	1.42	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	196.00	0.00	0.00	53.57	0.00	90.33	0.00	0.00	0.00	0.00	88.32
PFOH	247.57	302.55	140.70	25.42	99.73	10.77	15.07	6.90	59.55	31.13	70.42	51.85	231.62	8.67	29.25	9.57	22.22	143.68
LRPF	31.30	40.75	100.15	159.99	57.14	243.14	85.01	193.98	32.97	110.28	85.90	106.29	182.26	160.94	244.38	122.95	379.24	41.65
EFOH	15.94	25.37	29.00	8.37	11.73	5.39	2.64	2.75	4.04	7.06	12.45	11.34	86.86	2.87	14.71	2.42	17.34	12.31
PMOH	609.97	146.35	112.88	27.12	38.03	96.48	21.78	11.65	50.73	48.07	99.55	71.37	149.00	0.00	41.97	67.22	38.92	0.00
LRPM	64.05	110.01	135.02	294.97	206.45	148.88	117.84	231.32	118.83	207.29	209.45	227.81	165.37	0.00	267.57	232.70	119.74	0.00
EMOH	80.39	33.13	31.36	16.46	16.16	29.56	5.28	5.55	12.40	20.50	42.90	33.45	50.70	0.00	23.11	32.19	9.59	0.00
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	4.28	0.00	0.00	0.00	0.00	0.00	12.90	27.42	13.17	2.02	11.95	0.17	10.53	0.00	18.63	8.14	0.20	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.20	0.00	0.00	8.10	0.00	13.38	0.00	0.00	0.00	0.00	11.87
PFOR	2.24	3.41	4.03	1.12	1.63	0.72	0.41	0.80	0.63	1.00	2.05	1.58	14.85	0.39	2.51	0.35	2.41	1.88
PMOR	11.29	4.45	4.36	2.21	2.24	3.97	0.81	1.61	1.92	2.91	7.06	4.65	8.67	0.00	3.94	4.70	1.33	0.00
EUOR	17.23	7.86	8.38	3.33	3.87	4.70	13.96	49.83	15.38	5.85	25.73	6.39	39.88	0.39	23.88	12.79	3.94	13.53
EUOF	17.23	7.86	8.38	3.33	3.87	4.70	13.96	49.83	15.38	5.85	25.73	6.39	39.88	0.39	23.88	12.79	3.94	13.53
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	82.77	92.14	91.62	96.67	96.13	95.30	86.04	50.17	84.62	94.15	74.27	93.61	60.12	99.61	76.12	87.21	96.06	86.47

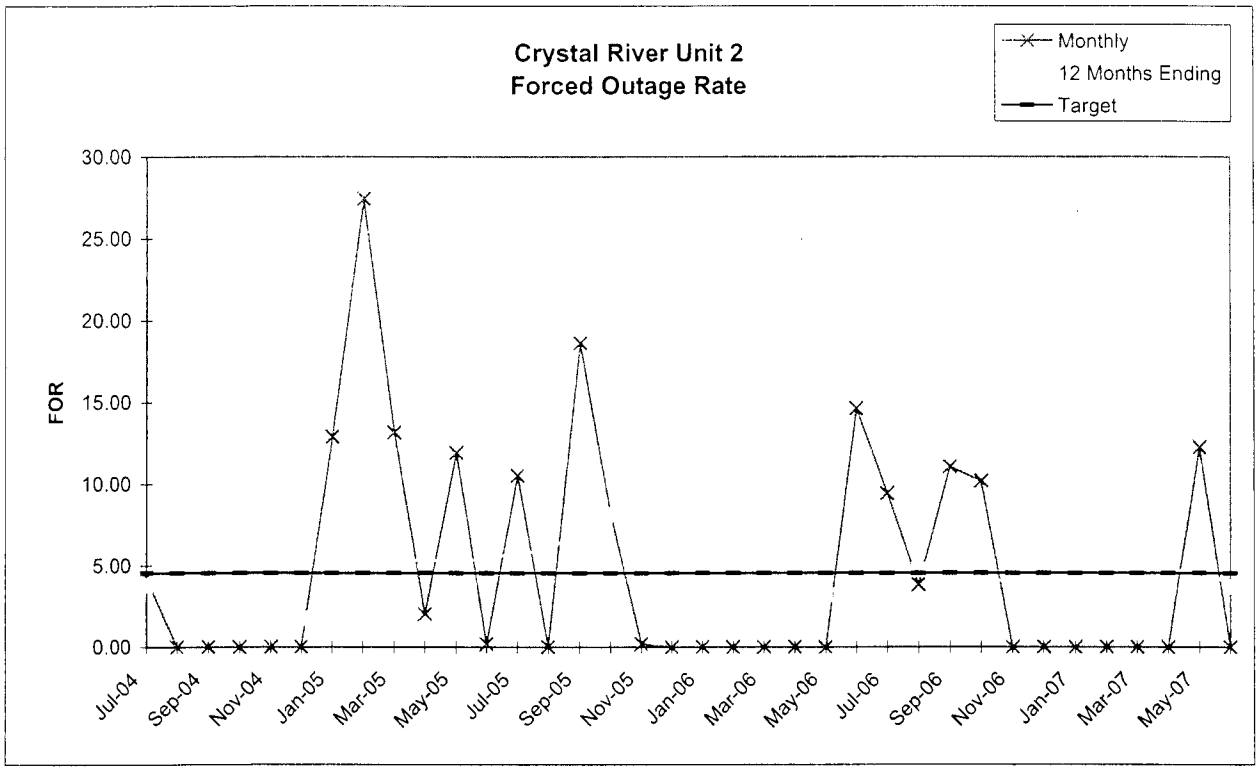
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	3.79	3.58	1.75	1.75	1.75	1.75	2.93	4.31	5.41	5.28	5.33	5.34	5.84	5.84	7.43	8.15	8.17	8.25
MOR	7.86	7.84	7.71	7.71	7.71	7.71	7.79	2.65	2.36	2.36	3.00	3.00	4.11	4.11	4.18	4.21	4.21	5.30
PFOR	1.46	1.75	2.05	2.09	1.92	1.89	1.76	1.48	1.45	1.53	1.55	1.69	2.61	2.33	2.18	2.12	2.20	2.31
PMOR	3.79	4.02	4.10	4.13	4.13	4.37	4.13	4.05	4.01	4.08	4.44	4.06	3.75	3.33	3.29	3.51	3.43	3.08
EUOR	15.75	16.03	14.78	14.84	14.69	14.88	15.57	11.90	12.58	12.60	13.53	13.33	15.25	14.61	15.89	16.69	16.70	17.45
EUOF	15.75	16.03	14.78	14.84	14.69	14.88	15.57	11.90	12.58	12.60	13.53	13.33	15.25	14.61	15.89	16.69	16.70	17.45
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	84.25	83.97	85.22	85.16	85.31	85.12	84.43	88.10	87.42	87.40	86.47	86.67	84.75	85.39	84.11	83.31	83.30	82.55

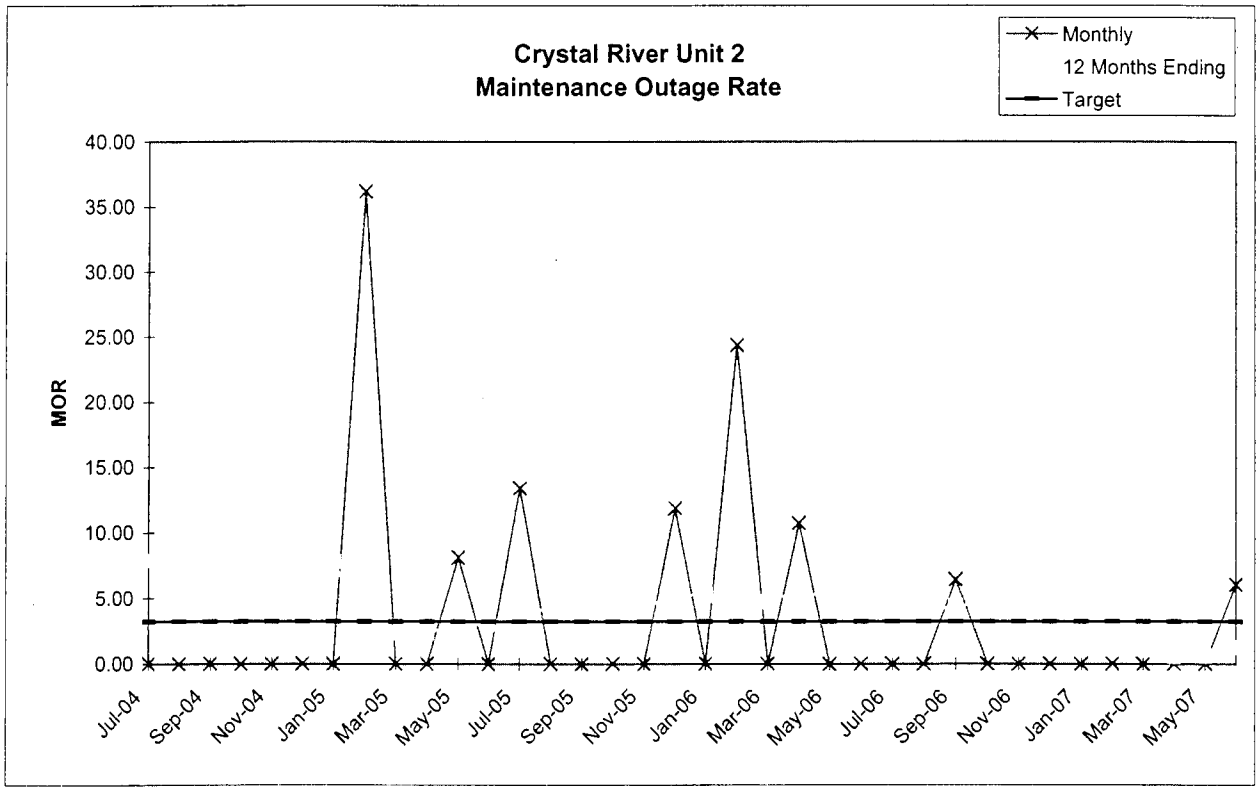
Crystal River
Unit 2

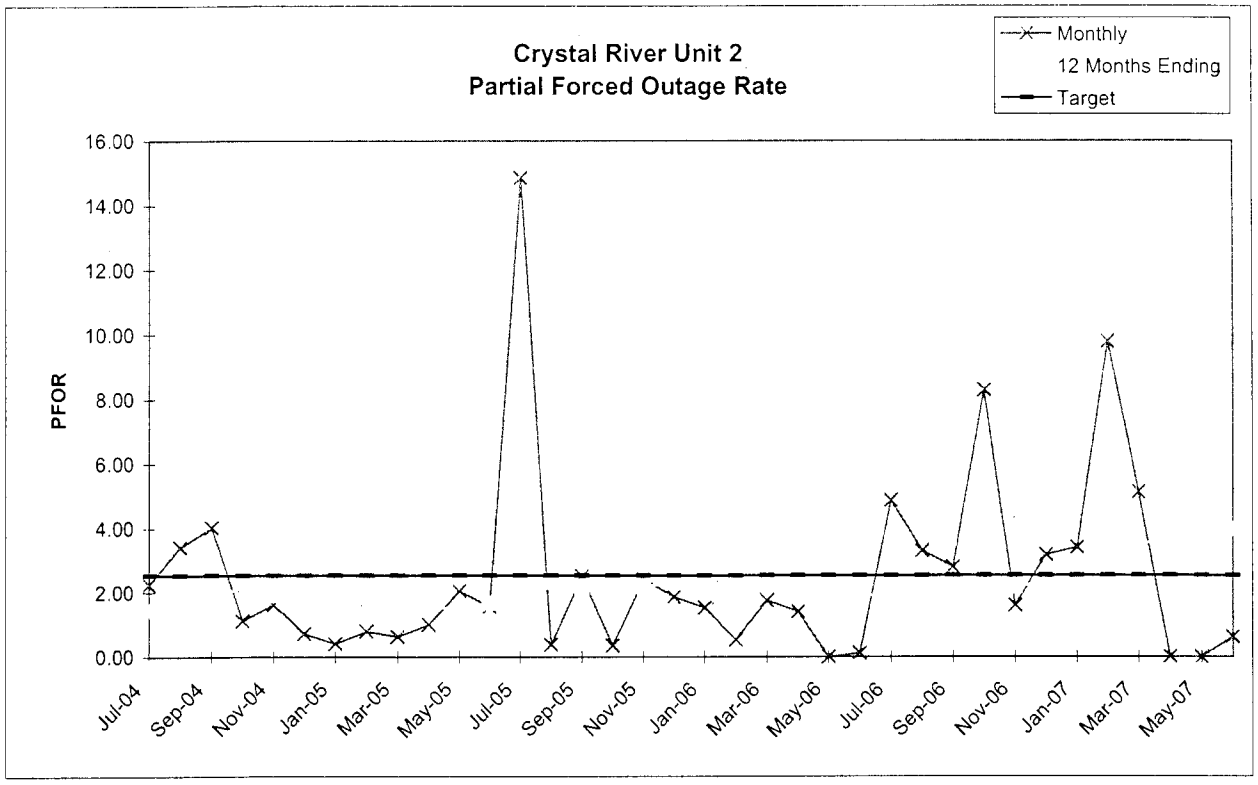
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	508.27	744.00	641.82	744.00	614.60	673.85	715.52	603.46	431.58	655.78	744.00	744.00	672.00	551.12	0.00	251.93	676.55
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	163.73	0.00	77.18	0.00	105.40	70.15	28.48	116.55	313.41	64.22	0.00	0.00	0.00	191.88	720.00	492.07	43.45
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	264.48	64.22	0.00	0.00	0.00	191.88	720.00	456.82	0.00
FOH	0.00	0.00	0.00	0.00	0.00	105.40	70.15	28.48	75.02	48.93	0.00	0.00	0.00	0.00	0.00	0.00	35.25	0.00
MOH	0.00	163.73	0.00	77.18	0.00	0.00	0.00	0.00	41.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.45
PFOH	41.83	14.23	68.65	26.40	0.00	11.57	75.72	125.57	226.82	115.10	28.03	62.18	293.18	1360.16	607.40	0.00	0.00	19.26
LRPF	132.71	93.34	93.02	166.73	0.00	32.97	210.85	91.67	36.24	151.00	182.77	184.80	42.00	23.50	22.65	0.00	0.00	107.55
EFOH	11.42	2.73	13.14	9.06	0.00	0.79	32.85	23.68	16.91	35.76	10.54	23.64	25.34	65.76	28.30	0.00	0.00	4.26
PMOH	31.12	0.00	3.65	16.85	8.42	142.72	0.00	20.37	7.25	0.00	0.00	17.50	0.00	0.00	763.32	0.00	0.00	37.23
LRPM	103.98	0.00	80.02	122.99	110.65	55.68	0.00	222.12	275.98	0.00	0.00	352.00	0.00	0.00	14.00	0.00	0.00	166.95
EMOH	6.66	0.00	0.60	4.26	1.92	16.35	0.00	9.31	4.12	0.00	0.00	12.68	0.00	0.00	21.99	0.00	0.00	12.79
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

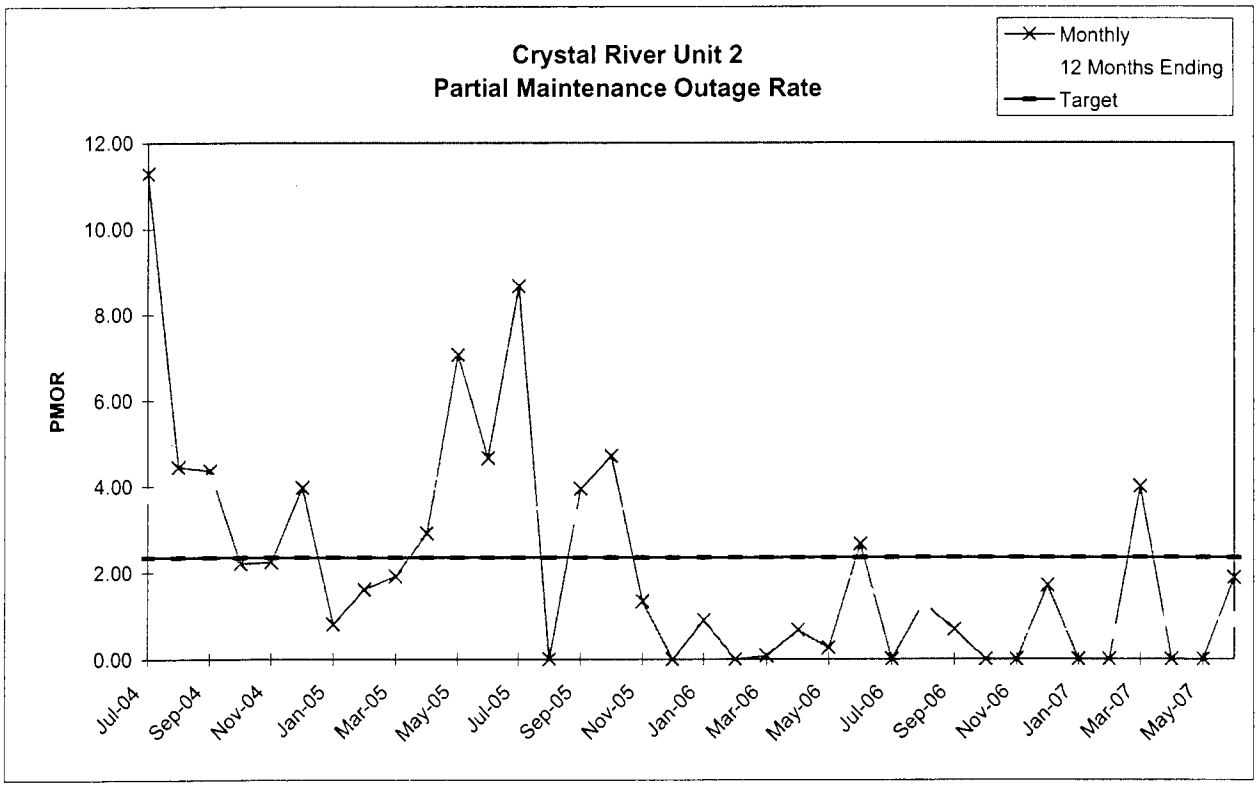
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	0.00	14.64	9.43	3.83	11.06	10.18	0.00	0.00	0.00	0.00	0.00	0.00	12.27	0.00
MOR	0.00	24.36	0.00	10.73	0.00	0.00	0.00	0.00	6.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.03
PFOR	1.54	0.54	1.77	1.41	0.00	0.13	4.88	3.31	2.80	8.29	1.61	3.18	3.41	9.79	5.14	0.00	0.00	0.63
PMOR	0.89	0.00	0.08	0.66	0.26	2.66	0.00	1.30	0.68	0.00	0.00	1.70	0.00	0.00	3.99	0.00	0.00	1.89
EUOR	2.43	24.77	1.85	12.59	0.26	17.02	13.84	8.26	19.11	17.63	1.61	4.88	3.41	9.79	9.13	0.00	12.27	8.40
EUOF	2.43	24.77	1.85	12.59	0.26	17.02	13.84	8.26	19.11	11.37	1.46	4.88	3.41	9.79	6.77	0.00	4.74	8.40
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.50	8.92	0.00	0.00	0.00	25.83	100.00	61.40	0.00
EAF	97.57	75.23	98.15	87.41	99.74	82.98	86.16	91.74	80.89	53.13	89.62	95.12	96.59	90.21	67.41	0.00	33.86	91.60

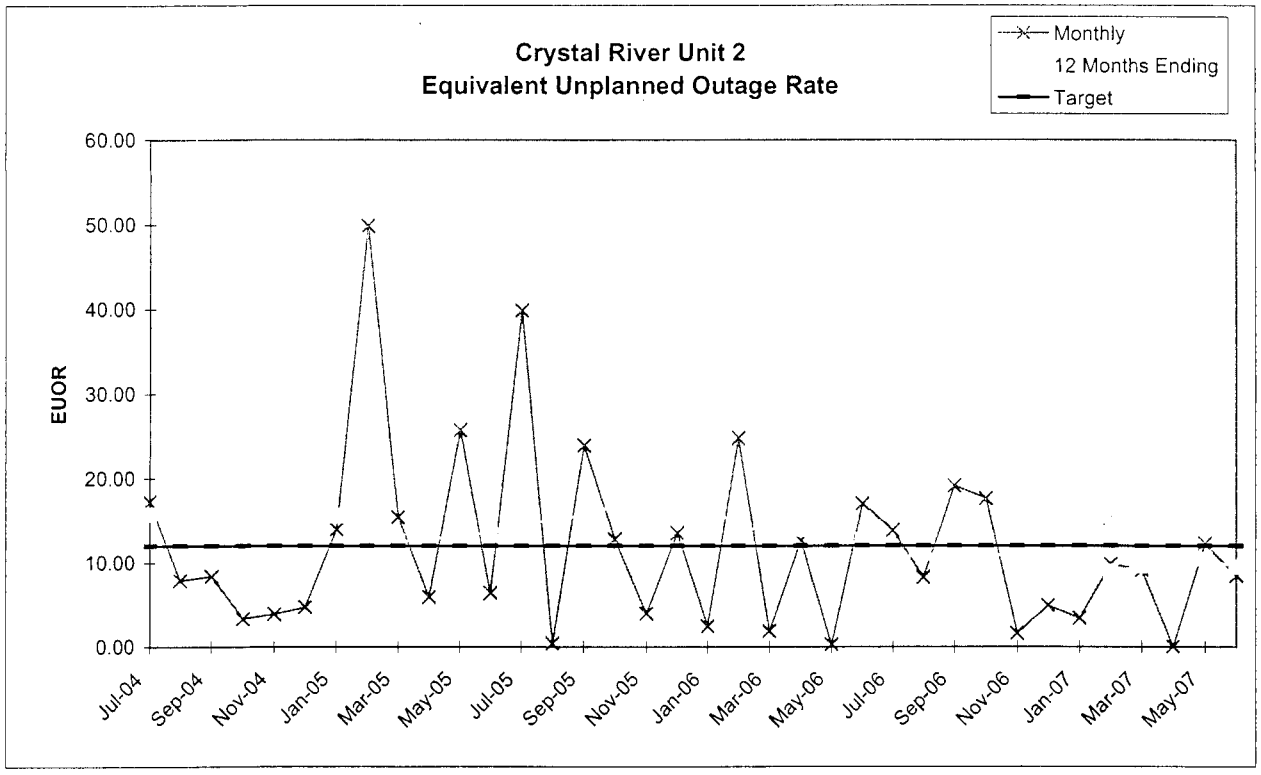
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	7.10	5.51	4.34	4.21	3.19	4.44	4.41	4.75	4.07	4.05	4.07	4.02	4.02	3.95	4.04	4.39	5.17	3.70
MOR	5.24	4.77	4.72	5.62	4.94	5.00	3.92	3.94	4.40	4.54	4.58	3.49	3.49	1.46	1.50	0.58	0.62	1.25
PFOR	2.40	2.35	2.43	2.48	2.28	2.18	1.48	1.75	1.77	2.26	2.19	2.31	2.49	3.22	3.50	3.69	3.96	3.97
PMOR	3.06	2.93	2.75	2.56	2.01	1.82	1.17	1.29	1.06	0.68	0.56	0.71	0.63	0.62	0.91	0.93	0.97	0.91
EUOR	16.47	14.55	13.40	13.95	11.79	12.66	10.45	11.12	10.73	10.93	10.81	10.04	10.13	8.94	9.59	9.30	10.38	9.50
EUOF	16.47	14.55	13.40	13.95	11.79	12.66	10.45	11.12	10.73	10.60	10.40	9.67	9.75	8.60	9.02	7.98	8.37	7.66
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.02	3.75	3.75	3.75	3.75	5.94	14.16	19.38	19.38
EAF	83.53	85.45	86.60	86.05	88.21	87.34	89.55	88.88	89.27	86.38	85.85	86.58	86.50	87.65	85.04	77.85	72.26	72.97

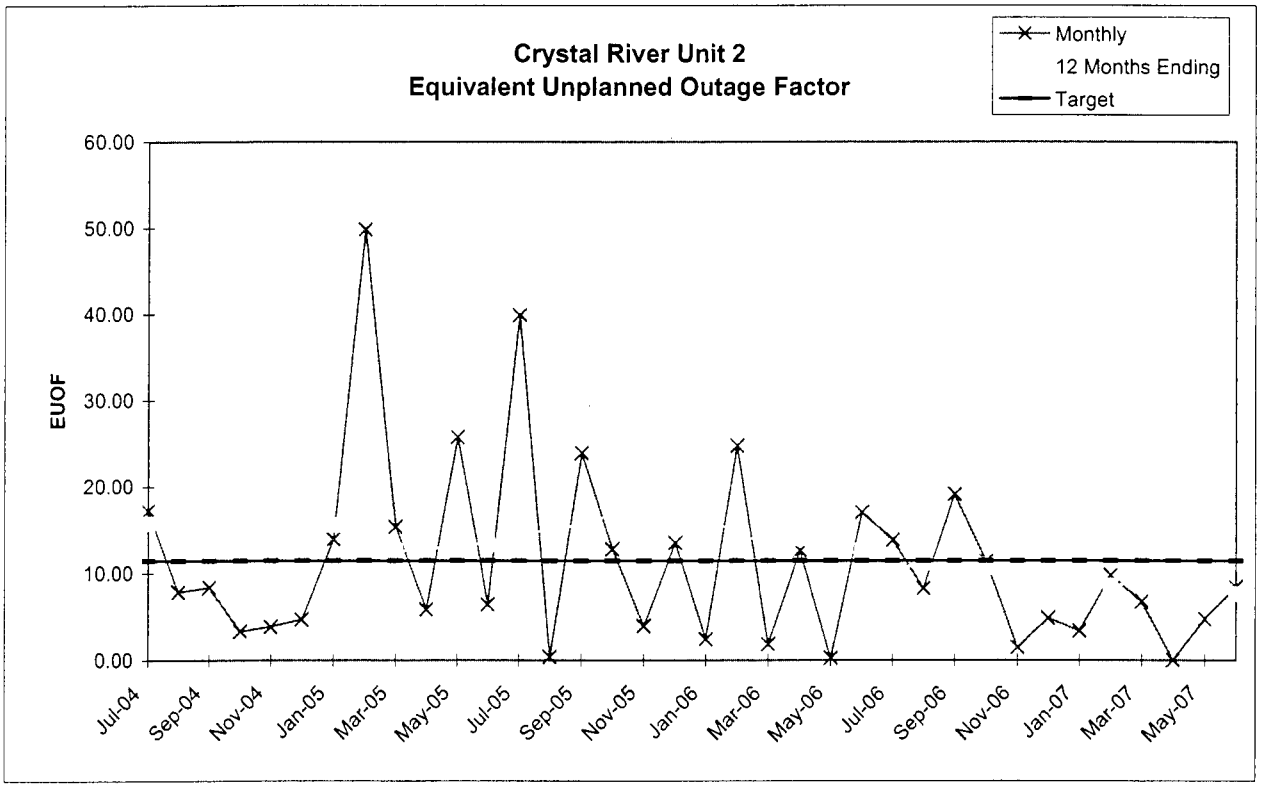

Crystal River Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Crystal River
Unit 3

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	592.65	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	673.43	0.00	446.73
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	127.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.57	606.00	297.27
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.75	600.00	0.00
FOH	0.00	0.00	127.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.82	6.00	220.10
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	1.97	22.85	0.00	0.00	14.78	0.00	0.00	0.00	194.95	0.00	68.63	0.00	0.00	0.00	0.00	0.00	18.02
LRPF	0.00	96.81	250.99	0.00	0.00	40.01	0.00	0.00	0.00	127.00	0.00	146.00	0.00	0.00	0.00	0.00	0.00	119.98
EFOH	0.00	0.25	7.46	0.00	0.00	0.77	0.00	0.00	0.00	32.20	0.00	13.03	0.00	0.00	0.00	0.00	0.00	2.81
PMOH	0.00	6.17	0.00	98.38	0.00	24.62	0.00	0.00	0.00	329.53	61.77	28.35	0.00	0.00	0.00	481.18	0.00	46.02
LRPM	0.00	37.02	0.00	104.16	0.00	76.99	0.00	0.00	0.00	142.45	129.49	14.00	0.00	0.00	0.00	71.51	0.00	295.27
EMOH	0.00	0.30	0.00	13.33	0.00	2.47	0.00	0.00	0.00	61.04	10.40	0.52	0.00	0.00	0.00	44.74	0.00	17.67
NPC	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	0.00	17.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	100.00	33.01
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.03	1.26	0.00	0.00	0.10	0.00	0.00	0.00	4.48	0.00	1.81	0.00	0.00	0.00	0.00	0.00	0.63
PMOR	0.00	0.04	0.00	1.79	0.00	0.33	0.00	0.00	0.00	8.49	1.40	0.07	0.00	0.00	0.00	6.64	0.00	3.96
EUOR	0.00	0.07	18.72	1.79	0.00	0.43	0.00	0.00	0.00	12.97	1.40	1.88	0.00	0.00	0.00	6.76	100.00	36.08
EUOF	0.00	0.07	18.72	1.79	0.00	0.43	0.00	0.00	0.00	12.97	1.40	1.88	0.00	0.00	0.00	6.12	0.83	32.34
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.50	83.33	0.00
EAF	100.00	99.93	81.28	98.21	100.00	99.57	100.00	100.00	100.00	87.03	98.60	98.12	100.00	100.00	100.00	84.39	15.83	67.66

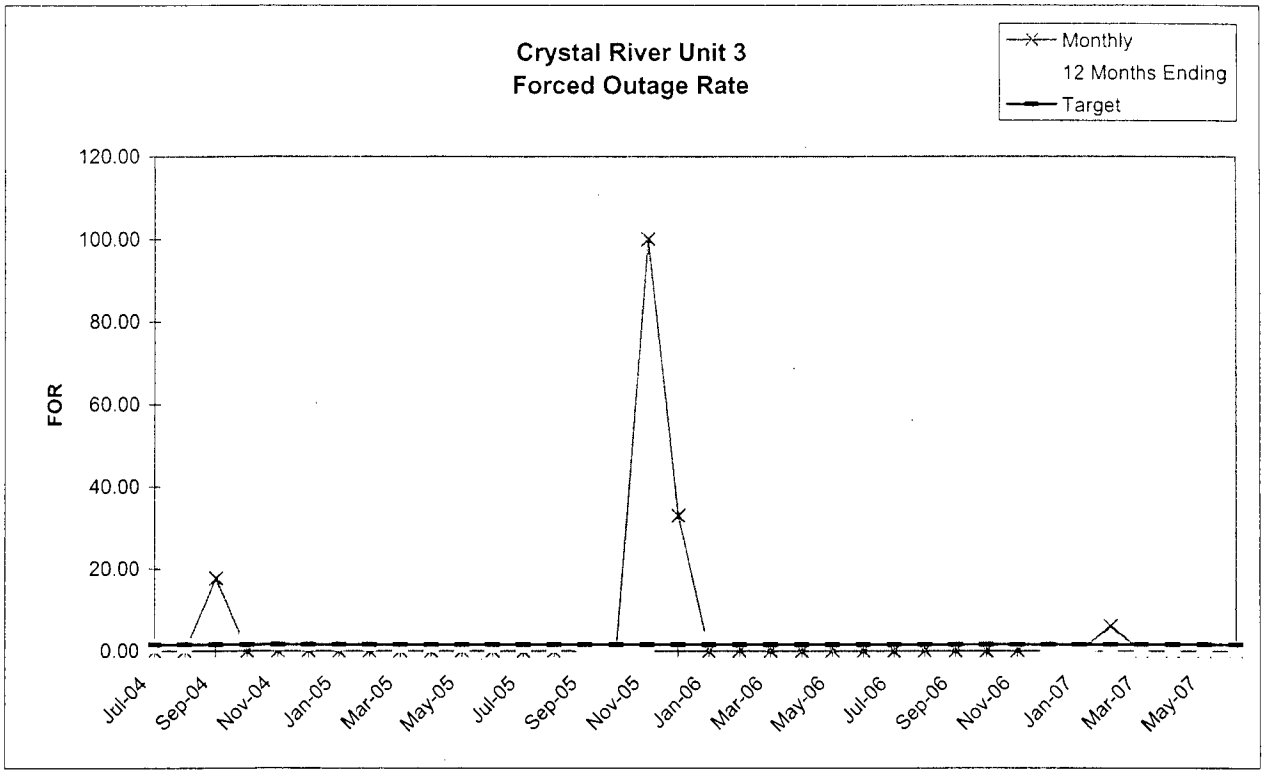
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	1.28	1.28	2.88	2.65	1.96	1.86	1.86	1.86	1.45	1.45	1.45	1.45	1.45	1.45	0.00	0.01	0.09	2.87
MOR	0.46	0.46	0.47	0.43	0.42	0.42	0.42	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.39	0.39	0.44	0.40	0.21	0.21	0.21	0.21	0.10	0.47	0.47	0.62	0.62	0.62	0.53	0.53	0.58	0.63
PMOR	1.87	1.86	0.67	0.55	0.27	0.30	0.30	0.30	0.19	0.89	1.02	1.02	1.02	1.02	1.00	1.37	1.50	1.75
EUOR	3.94	3.94	4.39	3.99	2.85	2.77	2.77	2.78	1.74	2.80	2.92	3.07	3.07	3.07	1.53	1.91	2.16	5.18
EUOF	3.59	3.59	4.00	3.94	2.85	2.77	2.77	2.78	1.74	2.80	2.92	3.07	3.07	3.07	1.53	1.89	1.96	4.67
POF	8.89	8.89	8.89	1.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.81	7.66	7.66
EAF	87.52	87.52	87.11	94.83	97.15	97.23	97.23	97.22	98.26	97.20	97.08	96.93	96.93	96.93	98.47	97.30	90.38	87.67

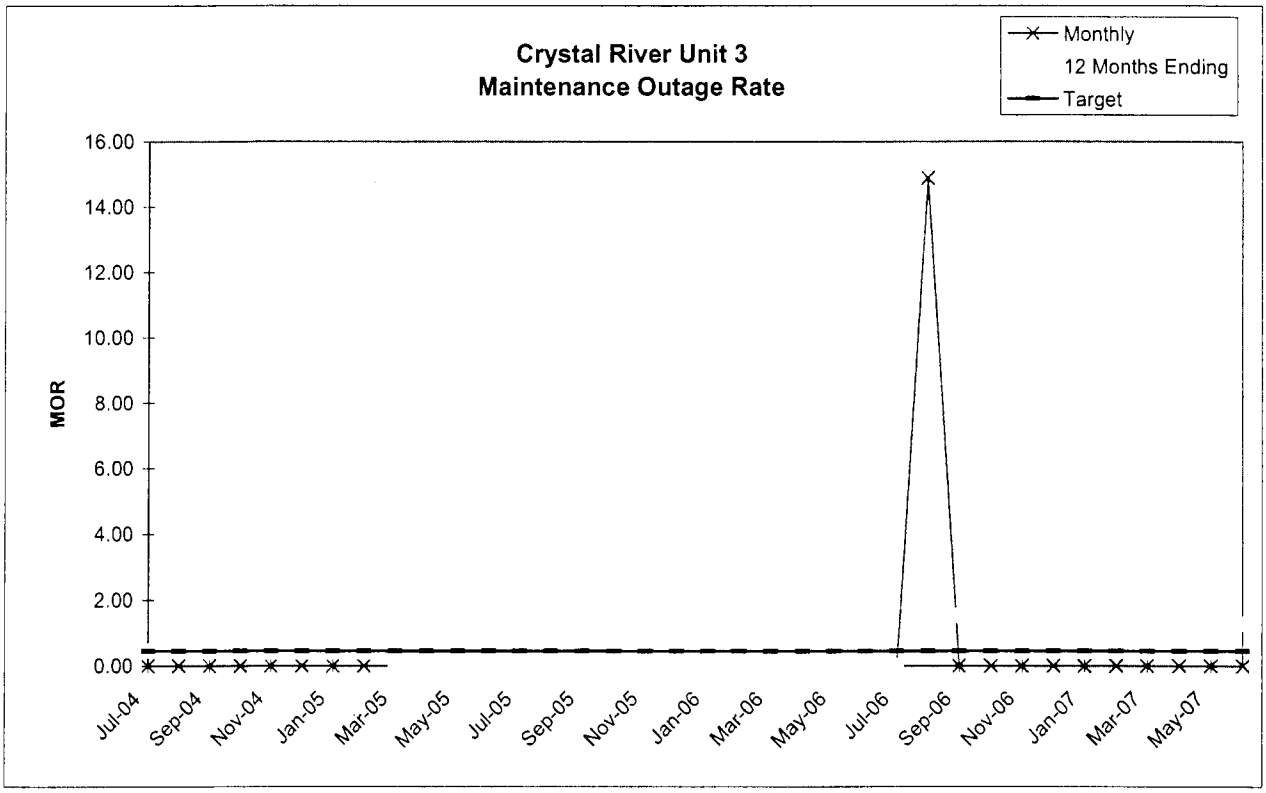
Crystal River
Unit 3

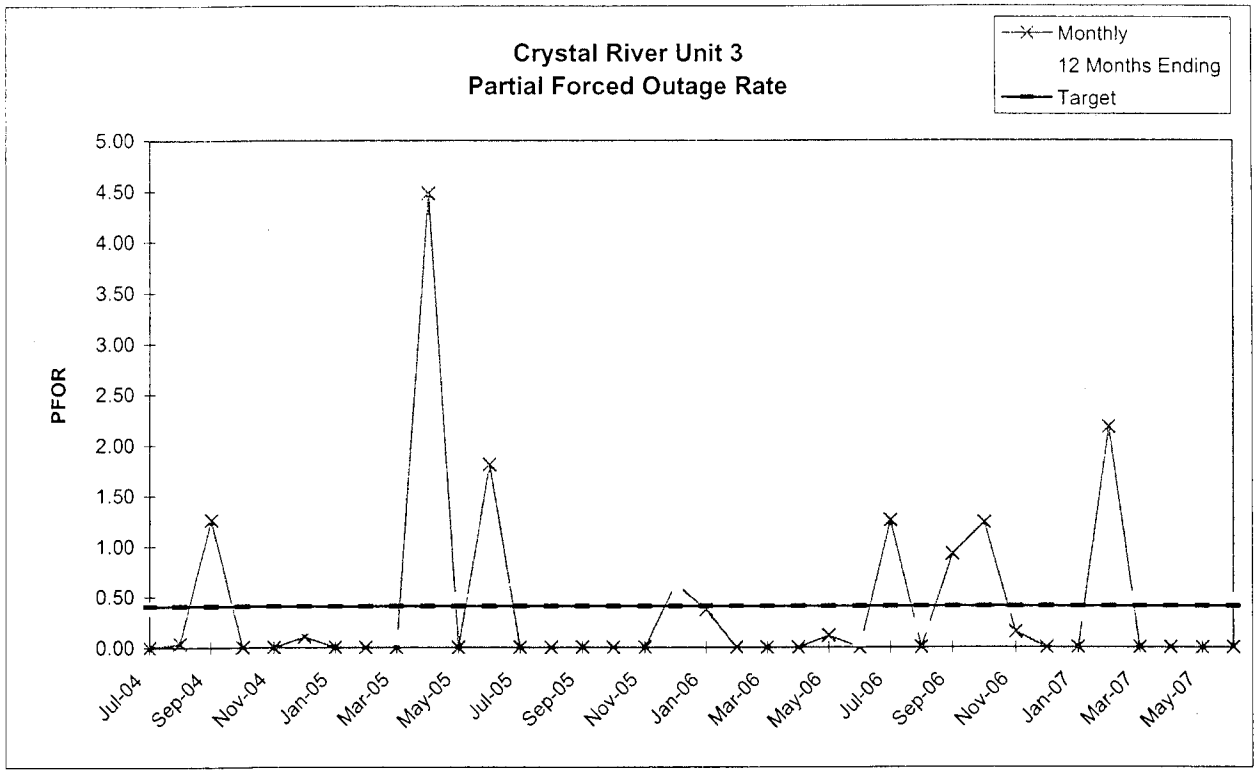
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	553.00	672.00	506.52	719.00	744.00	720.00	744.00	633.27	720.00	745.00	720.00	744.00	744.00	631.80	743.00	720.00	744.00	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	191.00	0.00	237.48	0.00	0.00	0.00	0.00	110.73	0.00	0.00	0.00	0.00	0.00	40.20	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.20	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	2.50	0.00	0.00	0.00	10.40	0.00	47.88	0.00	16.52	35.05	11.95	0.00	0.00	41.05	0.00	0.00	0.00	0.00
LRPF	637.04	0.00	0.00	0.00	61.00	0.00	150.01	0.00	307.93	202.00	70.98	0.00	0.00	258.00	0.00	0.00	0.00	0.00
EFOH	2.07	0.00	0.00	0.00	0.83	0.00	9.34	0.00	6.62	9.21	1.10	0.00	0.00	13.77	0.00	0.00	0.00	0.00
PMOH	0.00	9.00	0.00	0.00	6.22	0.00	0.00	28.63	0.00	0.00	0.00	0.00	0.00	162.33	0.00	0.00	6.18	0.00
LRPM	0.00	1.03	0.00	0.00	32.52	0.00	0.00	304.97	0.00	0.00	0.00	0.00	0.00	173.07	0.00	0.00	29.02	0.00
EMOH	0.00	0.01	0.00	0.00	0.26	0.00	0.00	11.35	0.00	0.00	0.00	0.00	0.00	36.53	0.00	0.00	0.23	0.00
NPC	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00	769.00

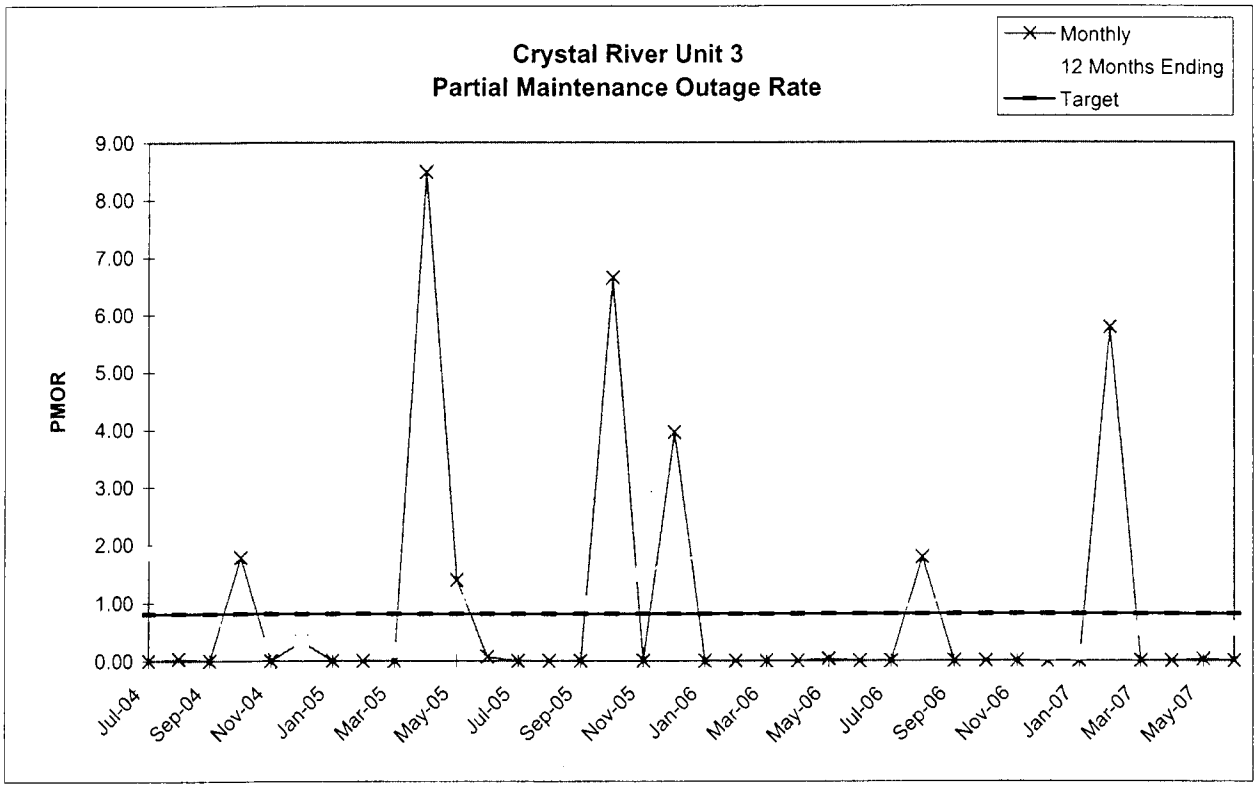
MONTHLY	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06**	**Dec-06**	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.98	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.37	0.00	0.00	0.00	0.11	0.00	1.26	0.00	0.92	1.24	0.15	0.00	0.00	2.18	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.04	0.00	0.00	1.79	0.00	0.00	0.00	0.00	0.00	5.78	0.00	0.00	0.03	0.00
EUOR	0.37	0.00	0.00	0.00	0.15	0.00	1.26	16.41	0.92	1.24	0.15	0.00	0.00	13.47	0.00	0.00	0.03	0.00
EUOF	0.28	0.00	0.00	0.00	0.15	0.00	1.26	16.41	0.92	1.24	0.15	0.00	0.00	13.47	0.00	0.00	0.03	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.72	100.00	100.00	100.00	99.85	100.00	98.74	83.59	99.08	98.76	99.85	100.00	100.00	86.53	100.00	100.00	99.97	100.00

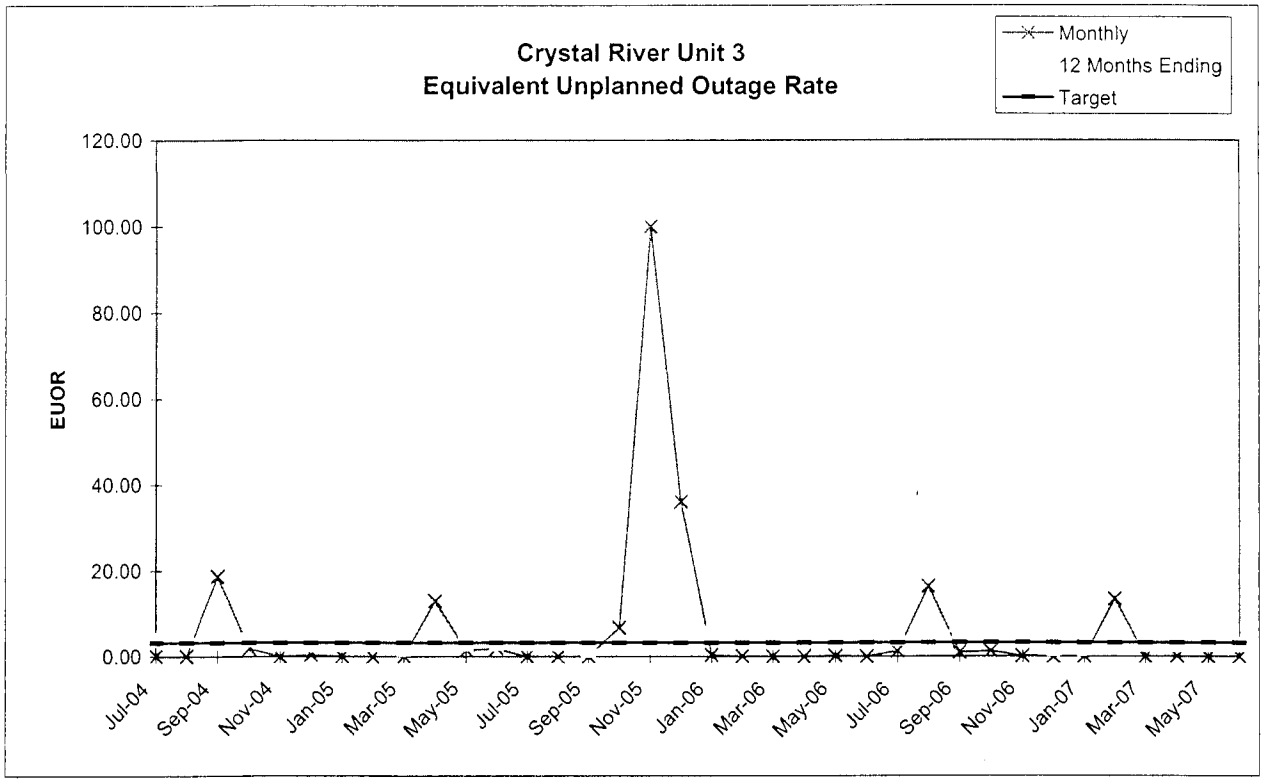
12 MONTHS	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06**	**Dec-06**	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**
FOR	2.94	2.94	3.04	3.04	3.04	3.04	3.04	3.08	3.08	3.04	2.70	0.00	0.00	0.48	0.46	0.46	0.46	0.46
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.53	1.53	1.51	1.38	1.33	1.30	1.31	1.27	1.27	1.27	1.27
PFOR	0.67	0.67	0.69	0.25	0.26	0.08	0.21	0.21	0.30	0.43	0.40	0.35	0.32	0.49	0.47	0.47	0.47	0.47
PMOR	1.80	1.80	1.86	1.01	0.87	0.87	0.87	1.04	1.04	0.41	0.37	0.14	0.14	0.58	0.56	0.56	0.56	0.56
EUOR	5.34	5.34	5.51	4.26	4.13	3.95	4.08	5.71	5.80	5.26	4.75	1.82	1.75	2.82	2.74	2.74	2.73	2.73
EUOF	4.70	4.70	4.70	3.63	3.53	3.37	3.48	4.87	4.95	4.53	4.48	1.73	1.71	2.74	2.74	2.74	2.73	2.73
POF	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	6.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	87.65	87.65	87.65	88.71	88.82	88.97	88.87	87.47	87.40	88.62	95.52	98.27	98.29	97.26	97.26	97.26	97.27	97.27

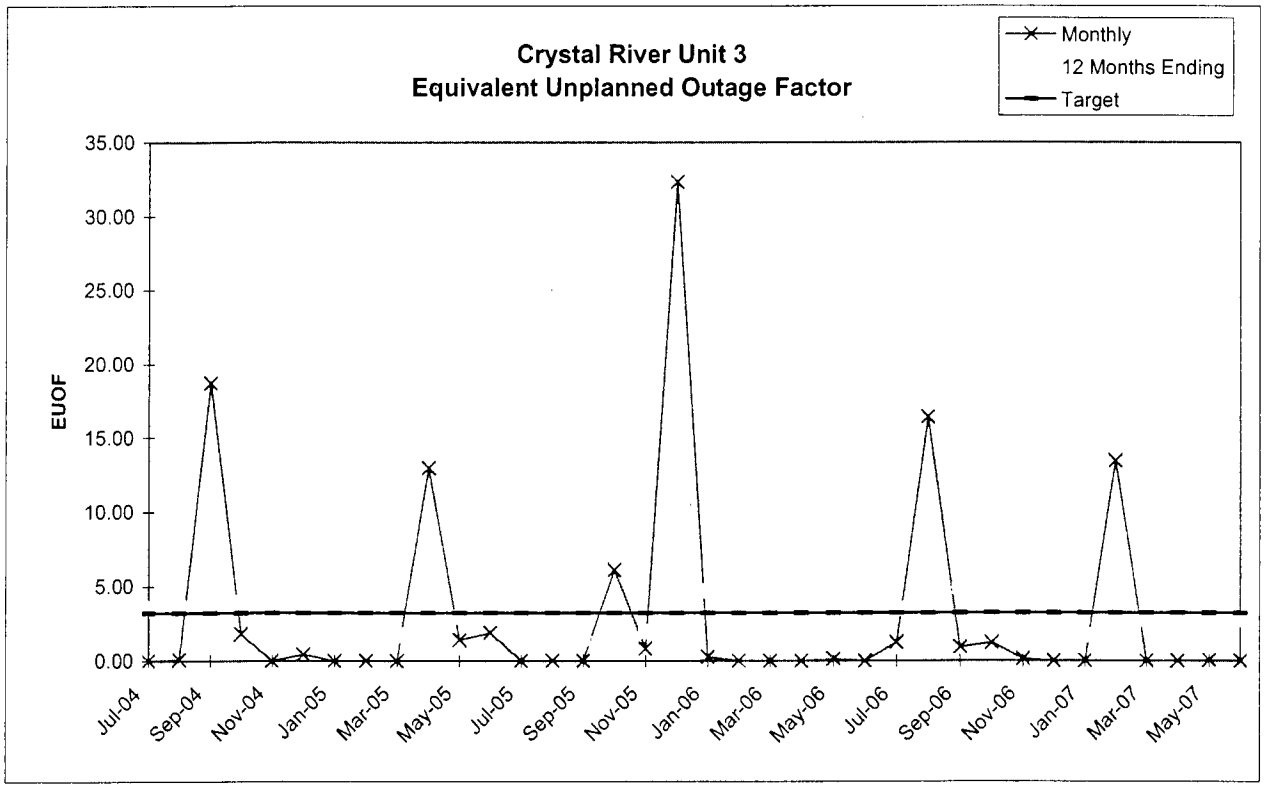

Crystal River Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Crystal River
Unit 4

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	737.45	727.07	699.67	687.67	584.48	684.13	744.00	672.00	187.20	719.00	742.73	664.20	744.00	744.00	623.95	724.92	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	6.55	16.93	20.33	57.33	135.52	59.87	0.00	0.00	556.80	0.00	1.27	55.80	0.00	0.00	96.05	20.08	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	551.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	6.55	16.93	20.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.27	55.80	0.00	0.00	96.05	20.08	0.00	0.00
MOH	0.00	0.00	0.00	57.33	135.52	59.87	0.00	0.00	5.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	179.48	31.00	452.55	206.82	134.75	0.00	2.15	0.00	10.42	10.48	0.00	18.53	4.82	12.82	0.90	70.60	0.00	1.62
LRPF	103.26	98.43	66.99	151.19	90.55	0.00	58.94	0.00	605.85	23.02	0.00	60.73	100.98	28.31	113.60	309.27	0.00	129.78
EFOH	25.74	4.24	42.11	43.43	16.95	0.00	0.18	0.00	8.77	0.34	0.00	1.56	0.68	0.50	0.14	30.33	0.00	0.29
PMOH	0.00	54.77	10.28	132.25	259.08	17.70	13.58	15.22	12.13	97.73	33.65	48.77	71.18	34.00	80.53	2.17	10.80	146.52
LRPM	0.00	197.98	102.05	109.30	124.82	136.39	168.44	75.36	152.07	97.73	209.77	222.10	149.82	227.39	164.28	114.47	120.73	133.39
EMOH	0.00	15.06	1.46	20.08	44.91	3.35	3.18	1.59	2.56	13.27	9.80	15.04	14.81	10.74	18.37	0.35	1.81	27.14
NPC	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.88	2.28	2.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	7.75	0.00	0.00	13.34	2.70	0.00	0.00
MOR	0.00	0.00	0.00	7.70	18.82	8.05	0.00	0.00	2.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	3.49	0.58	6.02	6.32	2.90	0.00	0.02	0.00	4.68	0.05	0.00	0.24	0.09	0.07	0.02	4.18	0.00	0.04
PMOR	0.00	2.07	0.21	2.92	7.68	0.49	0.43	0.24	1.37	1.84	1.32	2.26	1.99	1.44	2.94	0.05	0.25	3.65
EUOR	4.34	4.87	8.87	16.22	27.41	8.50	0.45	0.24	8.83	1.89	1.49	10.06	2.08	1.51	15.91	6.81	0.25	3.69
EUOF	4.34	4.87	8.87	16.22	27.41	8.50	0.45	0.24	2.29	1.89	1.49	10.06	2.08	1.51	15.91	6.81	0.25	3.69
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	95.66	95.13	91.13	83.78	72.59	91.50	99.55	99.76	23.64	98.11	98.51	89.94	97.92	98.49	84.09	93.19	99.75	96.31

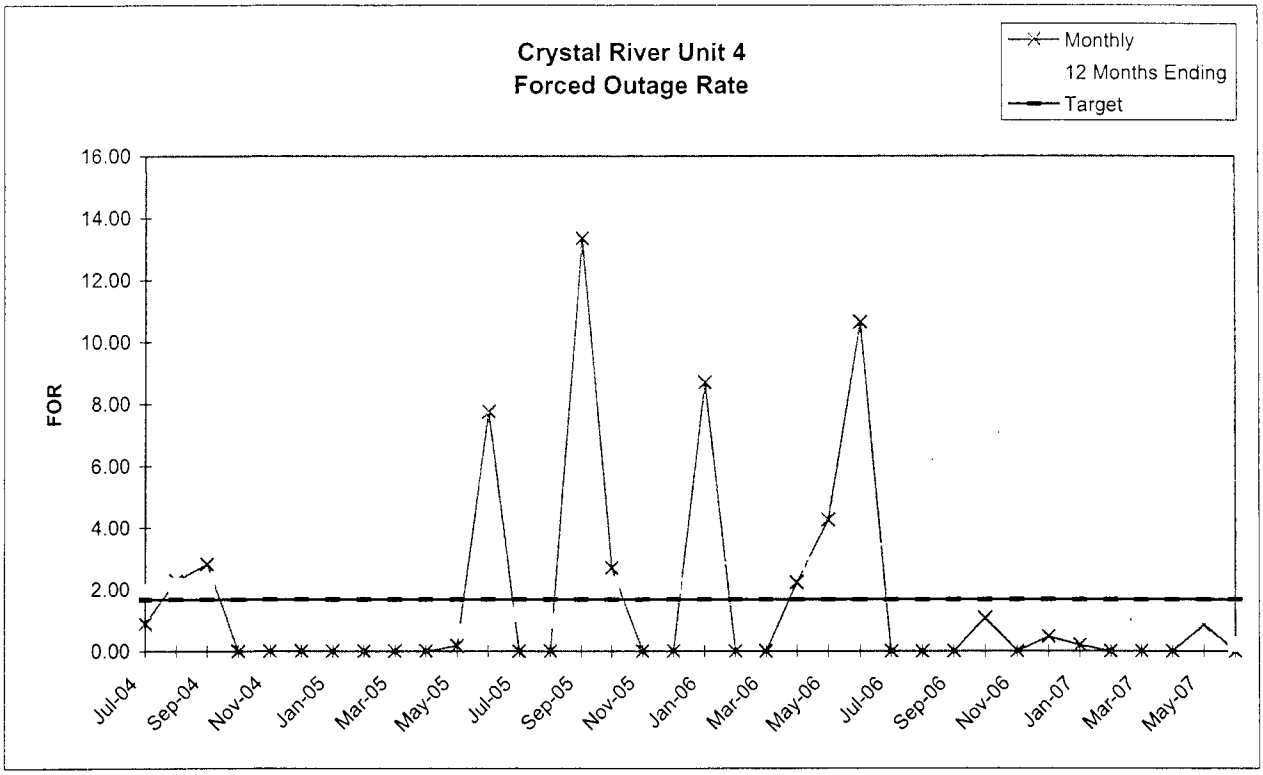
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	1.95	2.15	2.29	2.31	2.34	2.24	1.97	0.62	0.66	0.63	0.64	1.27	1.19	0.97	1.93	2.16	2.13	2.11
MOR	0.00	0.00	0.00	0.68	2.28	2.94	2.93	2.90	3.17	3.17	3.17	3.19	3.18	3.18	3.21	2.50	0.82	0.07
PFOR	1.36	1.41	1.81	2.34	2.49	2.47	2.43	2.37	2.09	1.98	1.87	1.83	1.51	1.45	0.93	0.76	0.53	0.53
PMOR	1.01	0.94	0.96	1.20	1.76	1.77	1.79	1.26	1.38	1.55	1.47	1.66	1.85	1.79	2.02	1.76	1.19	1.48
EUOR	4.27	4.44	5.00	6.38	8.58	9.08	8.81	6.99	7.12	7.15	6.98	7.71	7.51	7.20	7.82	6.96	4.58	4.15
EUOF	4.21	4.38	4.92	6.28	8.45	9.08	8.81	6.99	6.67	6.70	6.55	7.22	7.03	6.75	7.33	6.53	4.29	3.89
POF	1.55	1.55	1.55	1.55	1.49	0.00	0.00	0.00	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
EAF	94.24	94.07	93.53	92.17	90.06	90.92	91.19	93.01	87.04	87.01	87.16	86.48	86.68	86.96	86.38	87.18	89.42	89.82

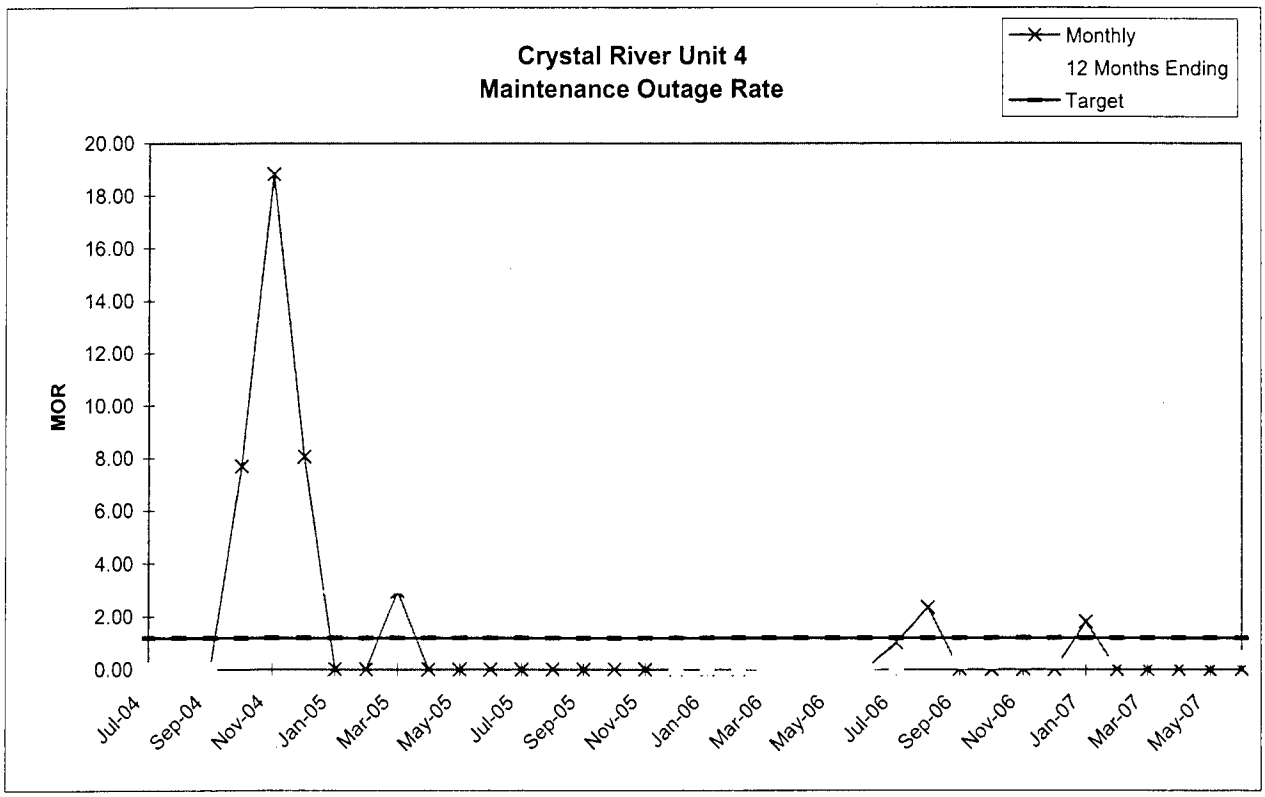
Crystal River
Unit 4

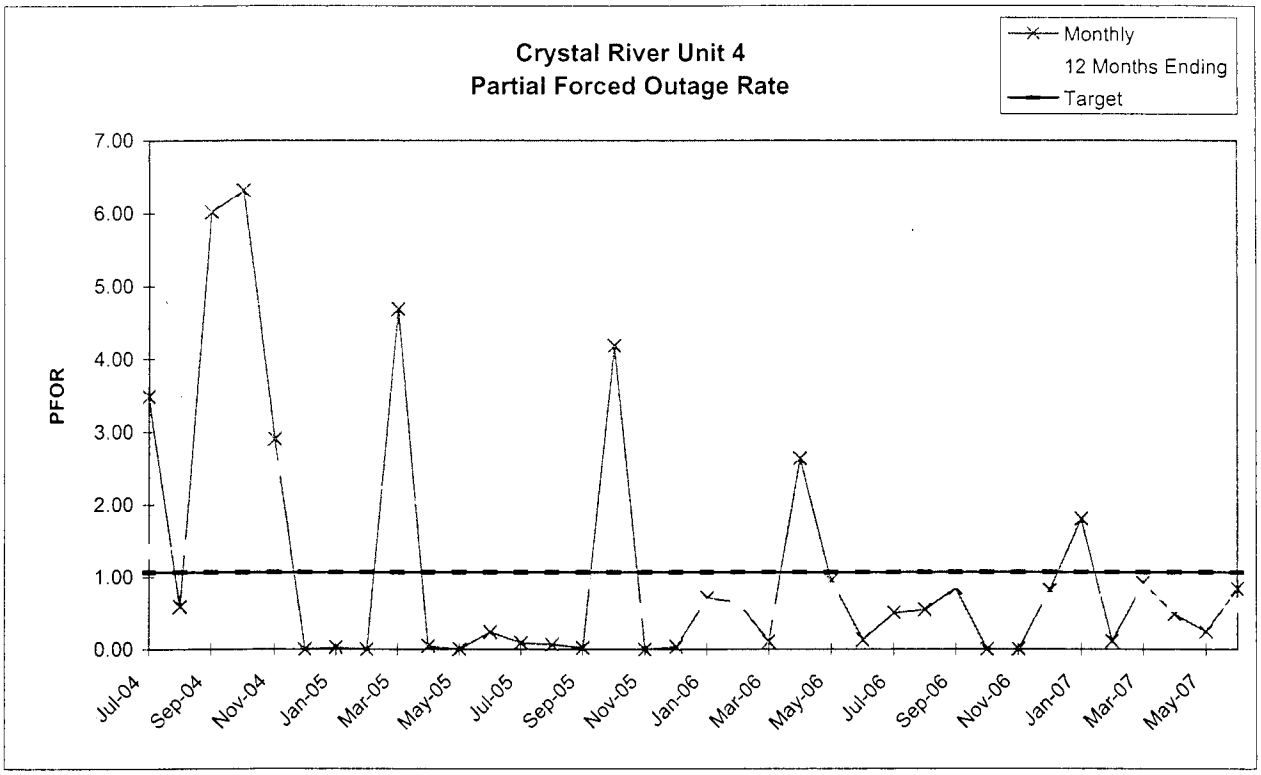
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	629.00	672.00	744.00	703.00	712.32	643.27	736.52	726.55	720.00	737.03	443.68	740.53	729.28	672.00	743.00	720.00	737.60	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	115.00	0.00	0.00	16.00	31.68	76.73	7.48	17.45	0.00	7.97	276.32	3.47	14.72	0.00	0.00	0.00	6.40	0.00
POH	55.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	276.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	60.00	0.00	0.00	16.00	31.68	76.73	0.00	0.00	0.00	7.97	0.00	3.47	1.40	0.00	0.00	0.00	6.40	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	7.48	17.45	0.00	0.00	0.00	0.00	13.32	0.00	0.00	0.00	0.00	0.00
PFOH	13.00	38.20	5.67	27.70	14.37	0.87	26.17	19.75	35.08	0.00	0.00	26.67	25.67	2.40	15.79	9.38	4.58	47.23
LRPF	245.85	82.16	100.95	481.23	338.91	706.76	101.47	143.74	124.71	0.00	0.00	162.84	367.72	220.17	309.96	267.82	287.21	91.87
EFOH	4.44	4.36	0.80	18.51	6.76	0.85	3.69	3.94	6.08	0.00	0.00	6.03	13.11	0.73	6.80	3.49	1.83	6.03
PMOH	30.85	77.53	14.17	160.98	103.02	31.00	37.03	22.57	61.62	35.33	1.42	207.90	51.01	11.57	50.33	114.78	125.67	16.30
LRPM	116.04	186.74	188.76	111.42	193.91	101.01	169.98	108.81	127.45	116.24	338.20	85.43	101.27	117.39	136.08	415.78	121.48	239.71
EMOH	4.97	20.11	3.72	24.91	27.75	4.35	8.74	3.41	10.91	5.70	0.67	24.67	7.17	1.89	9.51	66.28	21.20	5.43
NPC	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00

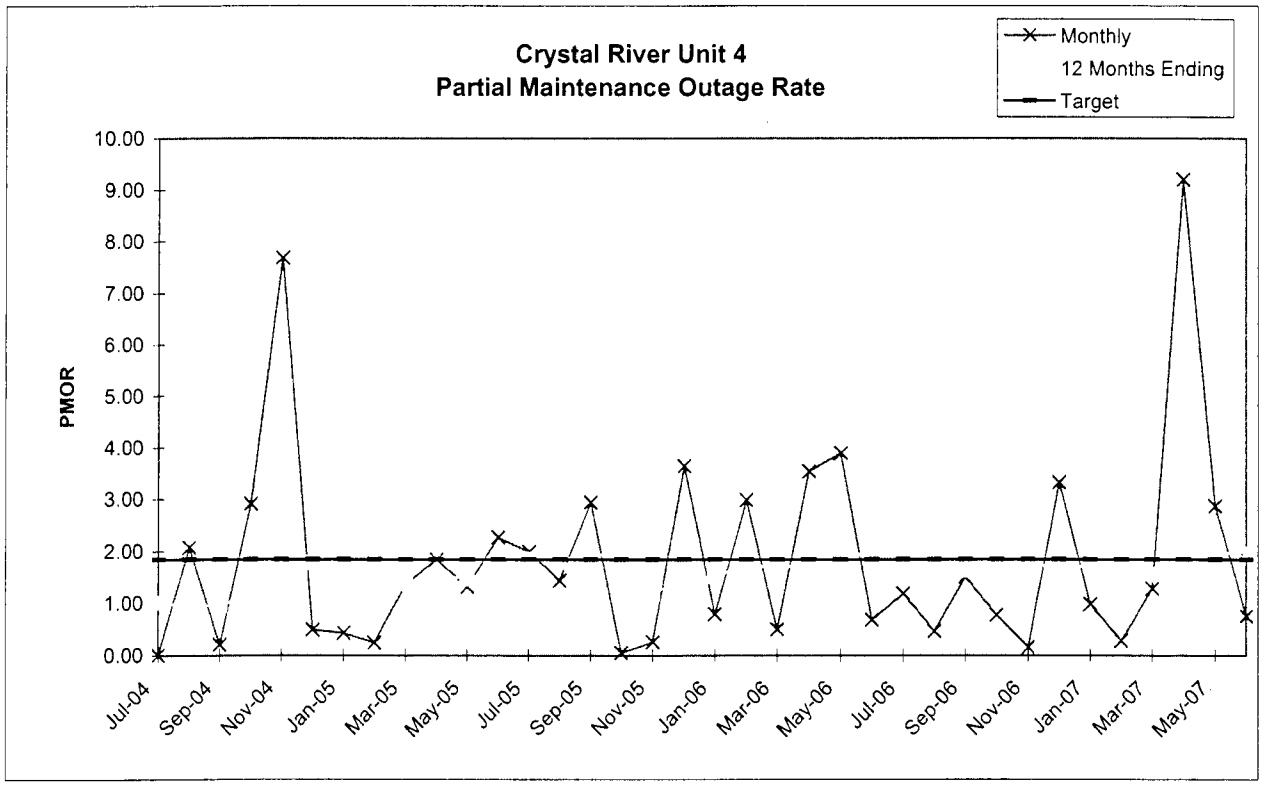
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	8.71	0.00	0.00	2.23	4.26	10.66	0.00	0.00	0.00	1.07	0.00	0.47	0.19	0.00	0.00	0.00	0.86	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	1.01	2.35	0.00	0.00	0.00	0.00	1.79	0.00	0.00	0.00	0.00	0.00
PFOR	0.71	0.65	0.11	2.63	0.95	0.13	0.50	0.54	0.84	0.00	0.00	0.81	1.80	0.11	0.91	0.48	0.25	0.84
PMOR	0.79	2.99	0.50	3.54	3.90	0.68	1.19	0.47	1.52	0.77	0.15	3.33	0.98	0.28	1.28	9.21	2.87	0.75
EUOR	10.07	3.64	0.61	8.26	8.90	11.38	2.68	3.33	2.36	1.84	0.15	4.59	4.70	0.39	2.20	9.69	3.96	1.59
EUOF	9.33	3.64	0.61	8.26	8.90	11.38	2.68	3.33	2.36	1.84	0.09	4.59	4.70	0.39	2.20	9.69	3.96	1.59
POF	7.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	83.28	96.36	99.39	91.74	91.10	88.62	97.32	96.67	97.64	98.16	61.53	95.41	95.30	99.61	97.80	90.31	96.04	98.41

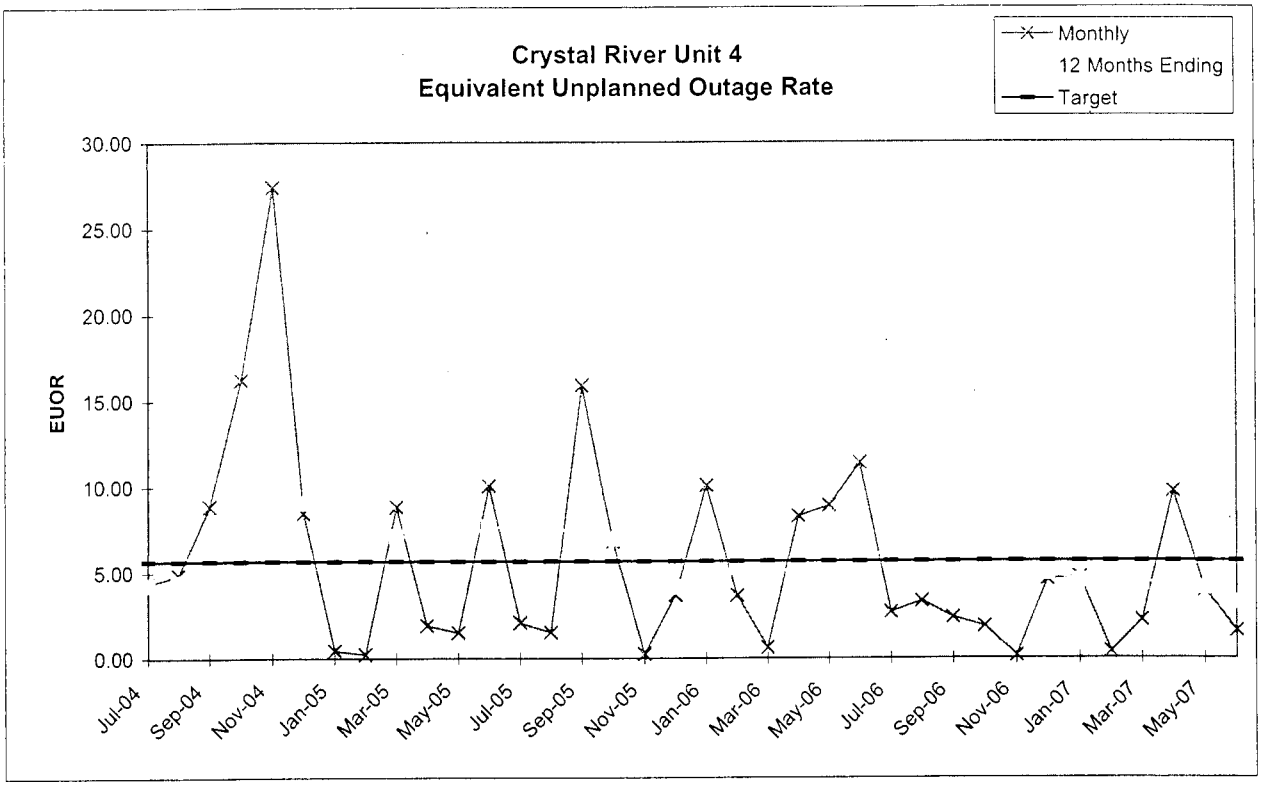
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	2.86	2.86	2.68	2.86	3.21	3.45	3.46	3.46	2.36	2.22	2.29	2.33	1.63	1.63	1.63	1.44	1.14	0.23
MOR	0.07	0.07	0.00	0.00	0.00	0.00	0.09	0.30	0.29	0.29	0.30	0.30	0.46	0.46	0.46	0.46	0.46	0.45
PFOR	0.59	0.65	0.51	0.73	0.81	0.81	0.84	0.88	0.94	0.59	0.61	0.68	0.77	0.73	0.80	0.62	0.56	0.61
PMOR	1.52	1.76	1.65	1.79	2.01	1.89	1.82	1.74	1.63	1.69	1.73	1.70	1.71	1.49	1.56	2.05	1.97	1.97
EUOR	4.98	5.26	4.79	5.31	5.95	6.06	6.11	6.26	5.14	4.72	4.86	4.94	4.50	4.24	4.38	4.50	4.07	3.24
EUOF	4.64	4.90	4.76	5.28	5.91	6.02	6.07	6.22	5.11	4.69	4.67	4.75	4.36	4.11	4.24	4.36	3.94	3.14
POF	6.92	6.92	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	3.78	3.78	3.15	3.15	3.15	3.15	3.15	3.15
EAF	88.44	88.18	94.61	94.09	93.46	93.35	93.30	93.15	94.26	94.69	91.54	91.47	92.49	92.74	92.60	92.48	92.90	93.71

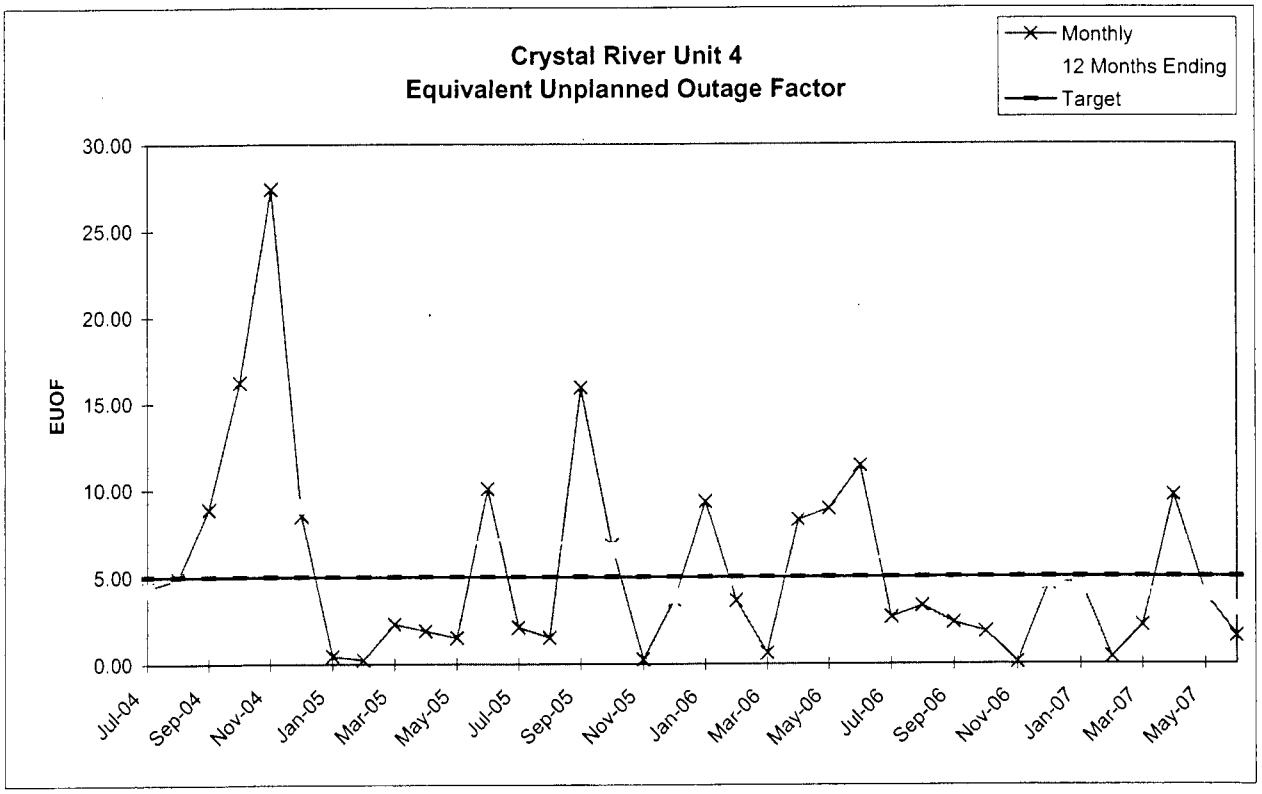

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Crystal River
Unit 5

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	730.33	744.00	667.15	745.00	720.00	722.05	652.63	658.60	717.95	442.00	703.50	639.57	744.00	744.00	720.00	745.00	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	13.67	0.00	52.85	0.00	0.00	21.95	91.37	13.40	26.05	277.00	40.50	80.43	0.00	0.00	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	13.67	0.00	52.85	0.00	0.00	21.95	0.00	13.40	0.00	0.00	0.00	80.43	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	91.37	0.00	26.05	277.00	40.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	9.12	10.93	114.78	87.37	60.60	40.58	13.17	149.77	32.43	10.92	35.37	0.00	5.87	11.50	113.15	2.00	0.00	28.87
LRPF	111.79	215.23	105.52	244.56	51.86	289.47	24.01	60.56	91.29	35.98	97.53	0.00	97.96	30.92	275.79	97.87	0.00	111.86
EFOH	1.42	3.28	16.89	29.80	4.38	16.38	0.44	12.65	4.13	0.55	4.81	0.00	0.80	0.50	43.52	0.27	0.00	4.50
PMOH	0.00	0.00	8.00	51.25	129.33	86.43	40.97	61.23	89.27	16.25	71.80	18.52	47.92	50.75	95.92	204.00	57.48	45.78
LRPM	0.00	0.00	40.78	297.74	113.94	353.71	206.73	111.89	98.00	102.98	116.96	146.96	258.63	136.84	71.10	231.00	352.11	133.88
EMOH	0.00	0.00	0.46	21.28	20.55	42.64	11.81	9.56	12.20	2.33	11.71	3.80	17.29	9.69	9.51	65.73	28.23	8.55
NPC	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00

MONTHLY	**Jul-04**	**Aug-04**	**Sep-04**	**Oct-04**	**Nov-04**	**Dec-04**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**
FOR	1.84	0.00	7.34	0.00	0.00	2.95	0.00	1.99	0.00	0.00	0.00	11.17	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	12.28	0.00	3.50	38.53	5.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.19	0.44	2.53	4.00	0.61	2.27	0.07	1.92	0.58	0.12	0.68	0.00	0.11	0.07	6.04	0.04	0.00	0.61
PMOR	0.00	0.00	0.07	2.86	2.85	5.91	1.81	1.45	1.70	0.53	1.66	0.59	2.32	1.30	1.32	8.82	3.92	1.15
EUOR	2.03	0.44	9.75	6.86	3.46	10.88	13.93	5.30	5.70	38.93	7.66	11.70	2.43	1.37	7.37	8.86	3.92	1.75
EUOF	2.03	0.44	9.75	6.86	3.46	10.88	13.93	5.30	5.70	38.93	7.66	11.70	2.43	1.37	7.37	8.86	3.92	1.75
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.97	99.56	90.25	93.14	96.54	89.12	86.07	94.70	94.30	61.07	92.34	88.30	97.57	98.63	92.63	91.14	96.08	98.25

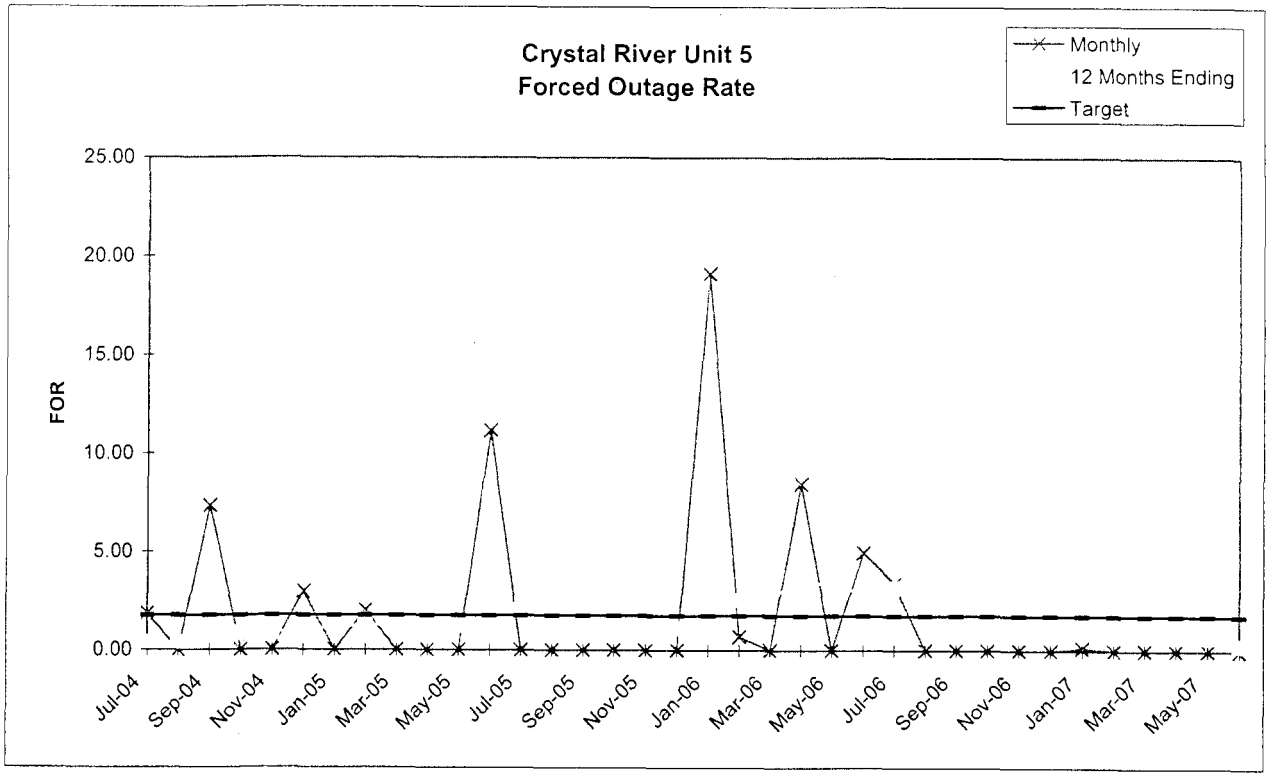
12 MONTHS	**Jul-04**	**Aug-04**	**Sep-04**	**Oct-04**	**Nov-04**	**Dec-04**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**
FOR	0.38	0.38	1.00	0.84	0.84	1.10	1.11	1.27	1.27	1.26	1.22	2.19	2.03	2.03	1.39	1.39	1.39	1.13
MOR	0.00	0.00	0.00	0.00	0.00	0.00	1.08	1.08	1.39	4.60	5.02	5.07	5.06	5.06	5.03	5.03	5.03	5.02
PFOR	0.25	0.29	0.38	0.71	0.74	0.93	0.94	1.04	1.10	1.12	1.16	1.16	1.15	1.12	1.44	1.08	1.02	0.88
PMOR	0.51	0.49	0.49	0.73	0.91	1.41	1.57	1.44	1.59	1.52	1.62	1.67	1.88	2.00	2.10	2.64	2.73	2.31
EUOR	1.14	1.16	1.86	2.28	2.48	3.41	4.62	4.75	5.24	8.24	8.74	9.68	9.72	9.80	9.60	9.77	9.81	9.03
EUOF	1.11	1.13	1.82	2.23	2.42	3.33	4.51	4.64	5.12	8.16	8.74	9.68	9.72	9.80	9.60	9.77	9.81	9.03
POF	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	96.63	96.61	95.92	95.52	95.32	94.41	93.23	93.10	92.61	90.97	91.26	90.32	90.28	90.20	90.40	90.23	90.19	90.97

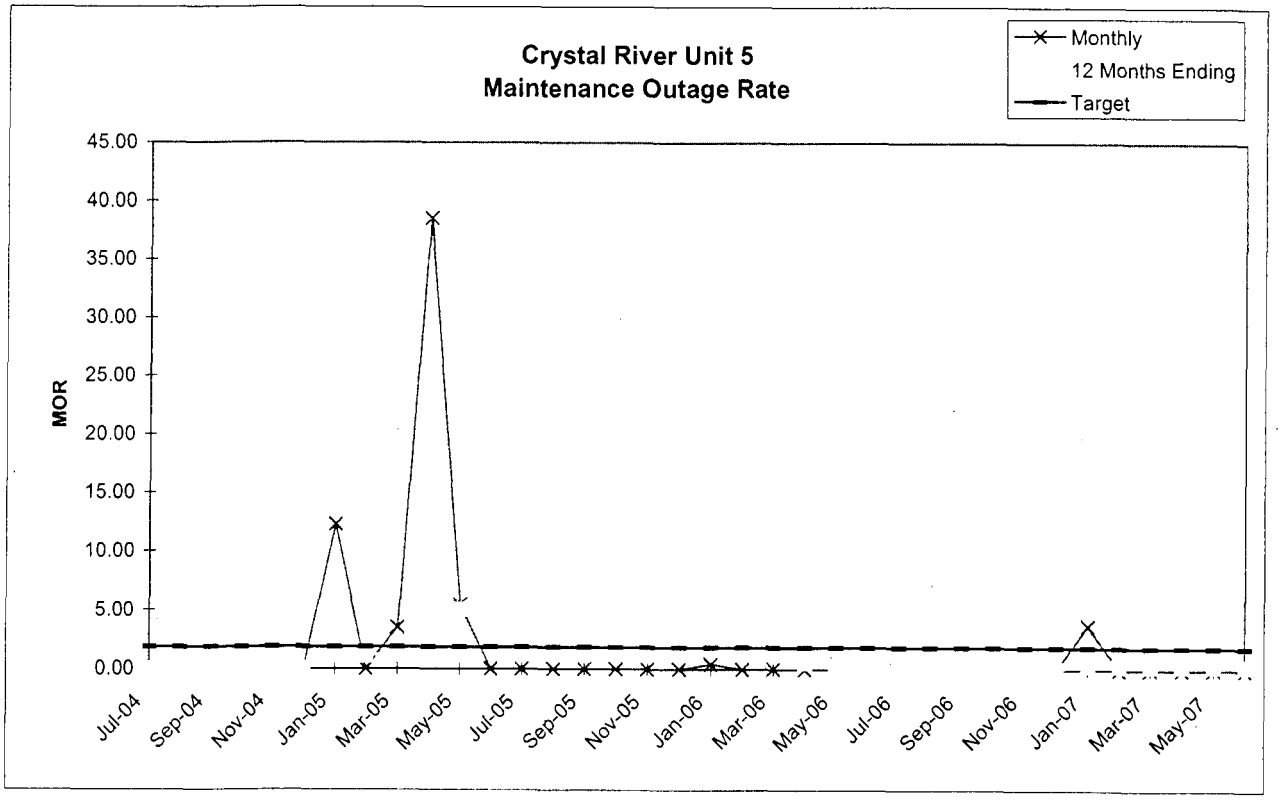
Crystal River
Unit 5

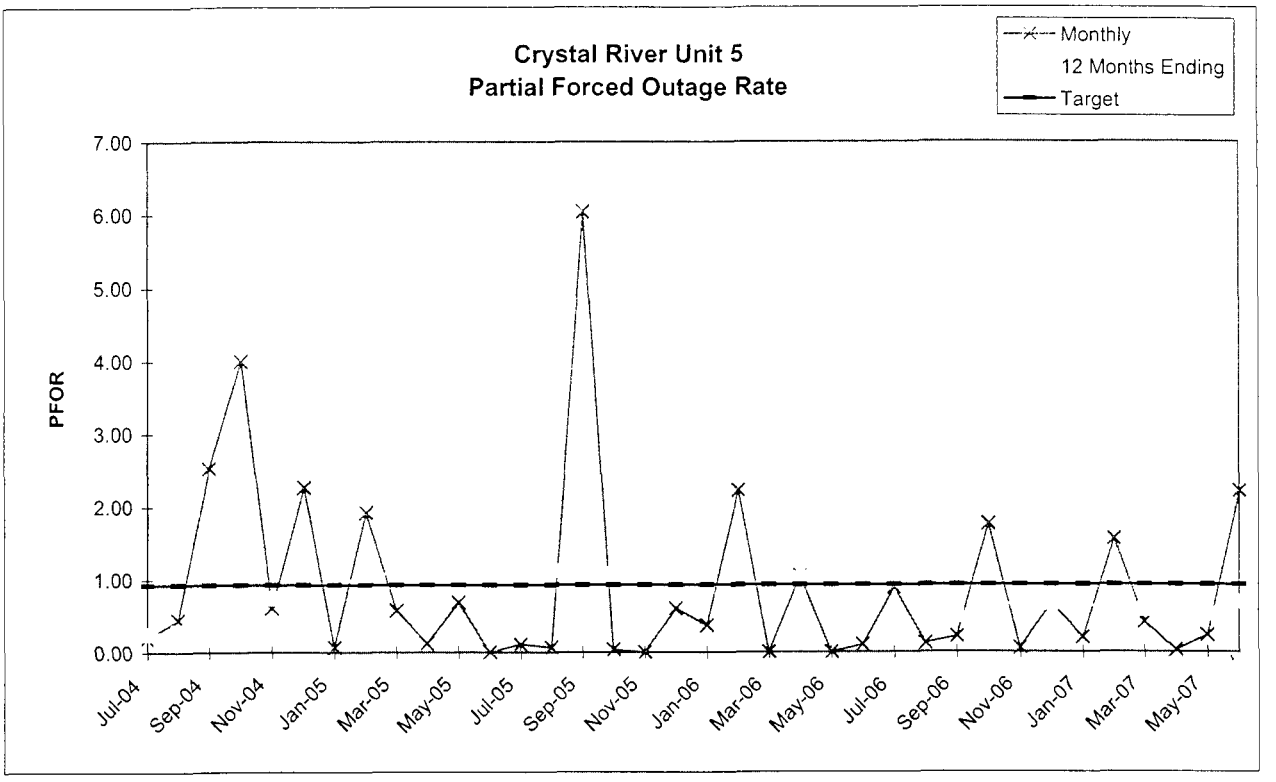
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	545.10	667.43	71.98	657.88	744.00	684.07	718.70	744.00	720.00	745.00	720.00	744.00	715.30	672.00	743.00	720.00	744.00	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	198.90	4.57	672.02	61.12	0.00	35.93	25.30	0.00	0.00	0.00	0.00	0.00	28.70	0.00	0.00	0.00	0.00	0.00
POH	67.50	0.00	672.02	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	128.90	4.57	0.00	60.92	0.00	35.93	25.30	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00
MOH	2.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.70	0.00	0.00	0.00	0.00	0.00
PFOH	19.65	110.93	0.00	12.73	0.00	10.35	75.67	8.18	7.50	43.77	2.97	12.42	10.33	21.96	9.16	1.33	13.43	135.16
LRPF	72.68	96.22	0.00	388.30	0.00	48.49	60.62	79.76	145.98	214.77	98.01	287.78	98.03	341.92	241.17	99.25	92.66	84.60
EFOH	1.99	14.89	0.00	6.89	0.00	0.70	6.40	0.91	1.53	13.11	0.41	4.99	1.41	10.47	3.08	0.18	1.74	15.95
PMOH	38.45	17.77	0.00	123.37	50.15	22.00	49.58	80.87	72.27	365.47	66.23	67.30	22.25	9.51	67.24	235.94	27.45	33.49
LRPM	182.80	224.54	0.00	160.33	171.49	150.05	311.38	174.26	285.60	84.58	199.60	119.22	127.10	102.33	359.11	222.09	366.28	154.33
EMOH	9.80	5.57	0.00	27.59	12.00	4.60	21.53	19.66	28.79	43.11	18.44	11.19	3.94	1.36	33.68	73.08	14.02	7.21
NPC	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00

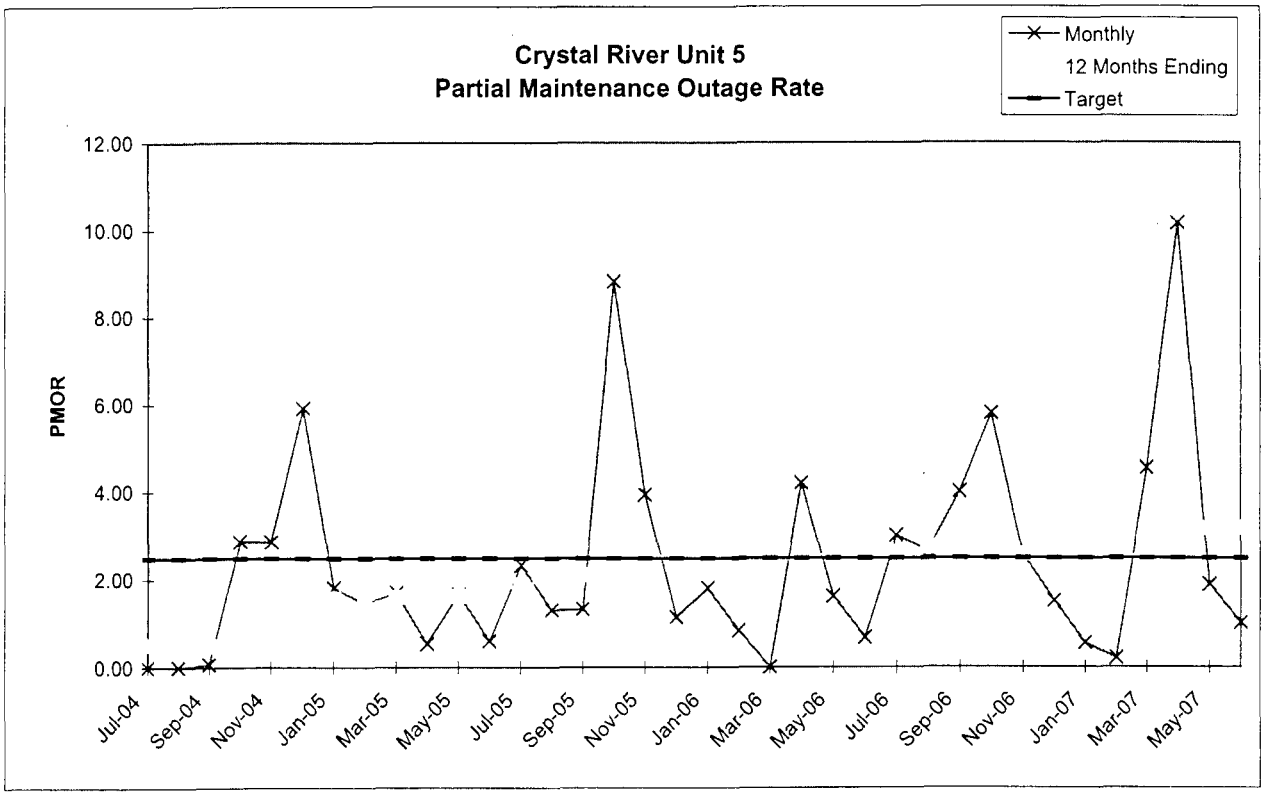
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	19.12	0.68	0.00	8.48	0.00	4.99	3.40	0.00	0.00	0.00	0.00	0.00	0.14	0.00	0.00	0.00	0.00	0.00
MOR	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.73	0.00	0.00	0.00	0.00	0.00
PFOR	0.37	2.23	0.00	1.05	0.00	0.10	0.89	0.12	0.21	1.76	0.06	0.67	0.20	1.56	0.41	0.03	0.23	2.21
PMOR	1.80	0.83	0.00	4.19	1.61	0.67	3.00	2.64	4.00	5.79	2.56	1.50	0.55	0.20	4.53	10.15	1.88	1.00
EUOR	21.17	3.72	0.00	13.27	1.61	5.73	7.15	2.76	4.21	7.55	2.62	2.17	4.58	1.76	4.95	10.18	2.12	3.22
EUOF	19.25	3.72	0.00	13.27	1.61	5.73	7.15	2.76	4.21	7.55	2.62	2.17	4.58	1.76	4.95	10.18	2.12	3.22
POF	9.07	0.00	90.33	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	71.68	96.28	9.67	86.70	98.39	94.27	92.85	97.24	95.79	92.45	97.38	97.83	95.42	98.24	95.05	89.82	97.88	96.78

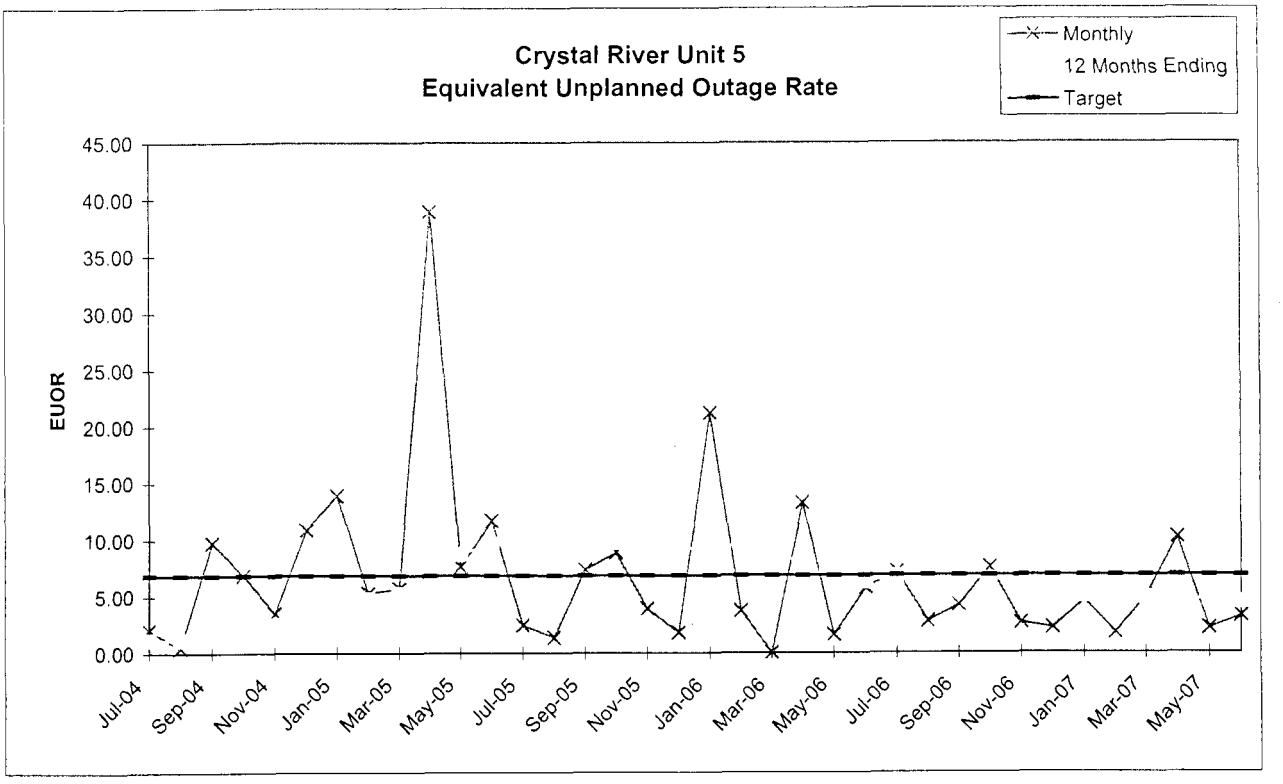
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	2.67	2.56	2.78	3.45	3.43	2.87	3.19	3.19	3.19	3.19	3.19	3.19	1.58	1.53	1.41	0.71	0.71	0.30
MOR	4.09	4.08	4.10	0.56	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.35	0.35	0.32	0.32	0.32	0.32
PFOR	0.91	0.93	0.96	1.02	0.95	0.95	1.03	1.03	0.49	0.66	0.66	0.67	0.65	0.59	0.58	0.50	0.52	0.69
PMOR	2.32	2.27	2.30	2.56	2.55	2.55	2.61	2.74	2.99	2.70	2.57	2.61	2.48	2.42	2.62	3.13	3.15	3.17
EUOR	9.56	9.44	9.70	7.40	6.84	6.30	6.74	6.87	6.59	6.46	6.35	6.39	4.98	4.82	4.87	4.62	4.66	4.45
EUOF	9.49	9.36	8.88	6.77	6.26	5.77	6.17	6.29	6.03	5.92	5.81	5.85	4.60	4.45	4.87	4.62	4.66	4.45
POF	0.77	0.77	8.44	8.44	8.44	8.44	8.44	8.44	8.44	8.44	8.44	8.44	7.67	7.67	0.00	0.00	0.00	0.00
EAF	89.74	89.87	82.68	84.78	85.30	85.79	85.38	85.27	85.53	85.64	85.74	85.71	87.73	87.88	95.13	95.38	95.34	95.55

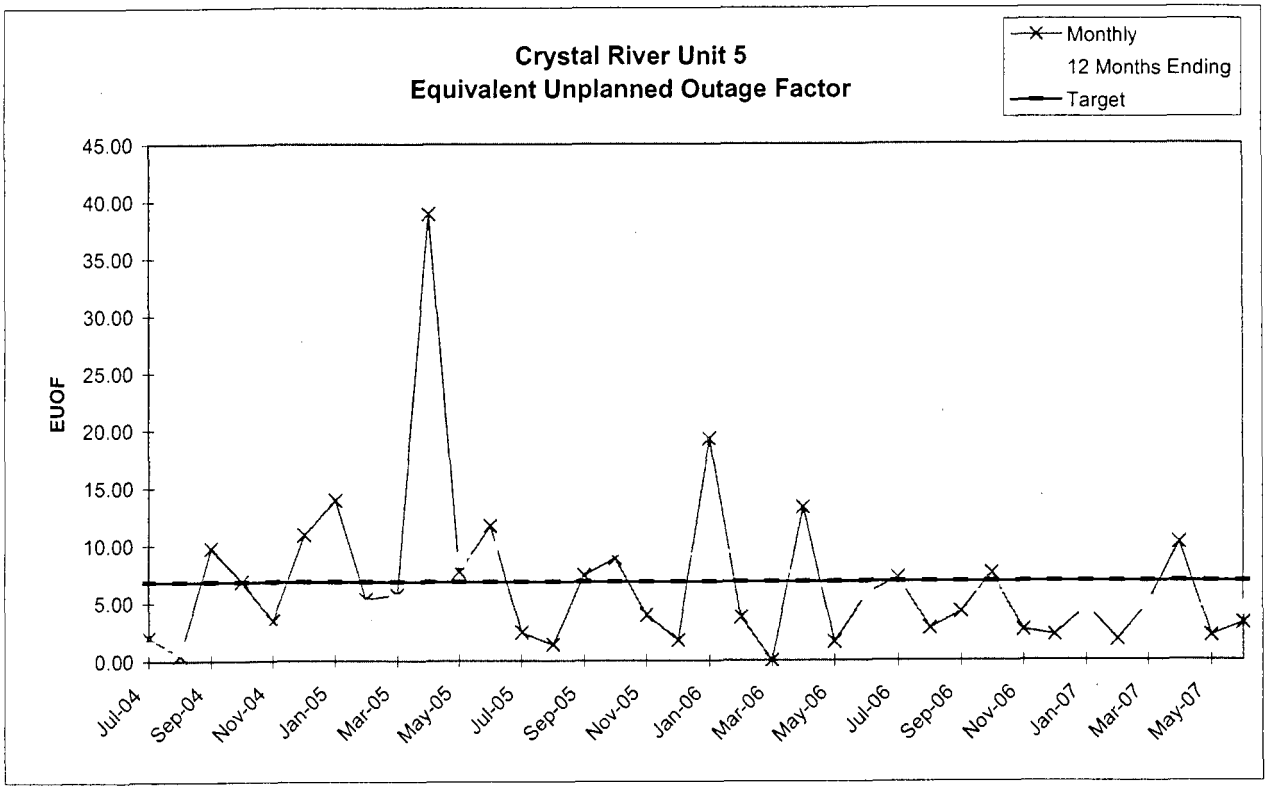

Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Hines
Unit 1

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	603.98	651.37	411.25	37.81	588.67	520.70	672.00	744.00	714.80	447.52	599.47	744.00	744.00	720.00	744.80	226.35	269.00
RSH	0.00	140.02	68.63	0.00	142.87	155.33	223.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	102.00	468.00
UH	0.00	0.00	0.00	333.75	539.32	0.00	0.00	0.00	0.00	4.20	296.48	120.53	0.00	0.00	0.00	0.00	391.65	7.27
POH	0.00	0.00	0.00	333.75	539.32	0.00	0.00	0.00	0.00	4.20	296.48	0.00	0.00	0.00	0.00	0.00	391.65	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	120.53	0.00	0.00	0.00	0.00	0.00	7.27
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	2.77	1.47	0.00	12.43	5.45	0.45	3.95	0.00	0.00	0.00	2.22	0.00	11.00	7.73	0.00	55.13
LRPF	0.00	0.00	335.66	185.59	0.00	110.40	215.97	224.93	236.00	0.00	0.00	0.00	235.79	0.00	236.00	231.09	0.00	216.01
EFOH	0.00	0.00	1.93	0.57	0.00	2.85	2.44	0.21	1.93	0.00	0.00	0.00	1.09	0.00	5.39	3.71	0.00	24.71
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	225.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.74	0.00	0.00	0.00	0.00	0.00	2.63
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.30	0.14	0.00	0.48	0.47	0.03	0.26	0.00	0.00	0.00	0.15	0.00	0.75	0.50	0.00	9.18
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	0.00	0.30	0.14	0.00	0.48	0.47	0.03	0.26	0.66	0.00	16.74	0.15	0.00	0.75	0.50	0.00	11.57
EUOF	0.00	0.00	0.27	0.08	0.00	0.38	0.33	0.03	0.26	0.66	0.00	16.74	0.15	0.00	0.75	0.50	0.00	4.30
POF	0.00	0.00	0.00	44.80	74.91	0.00	0.00	0.00	0.00	0.58	39.85	0.00	0.00	0.00	0.00	0.00	54.40	0.00
EAF	100.00	100.00	99.73	55.13	25.09	99.62	99.67	99.97	99.74	98.76	60.15	83.26	99.85	100.00	99.25	99.50	45.60	95.70

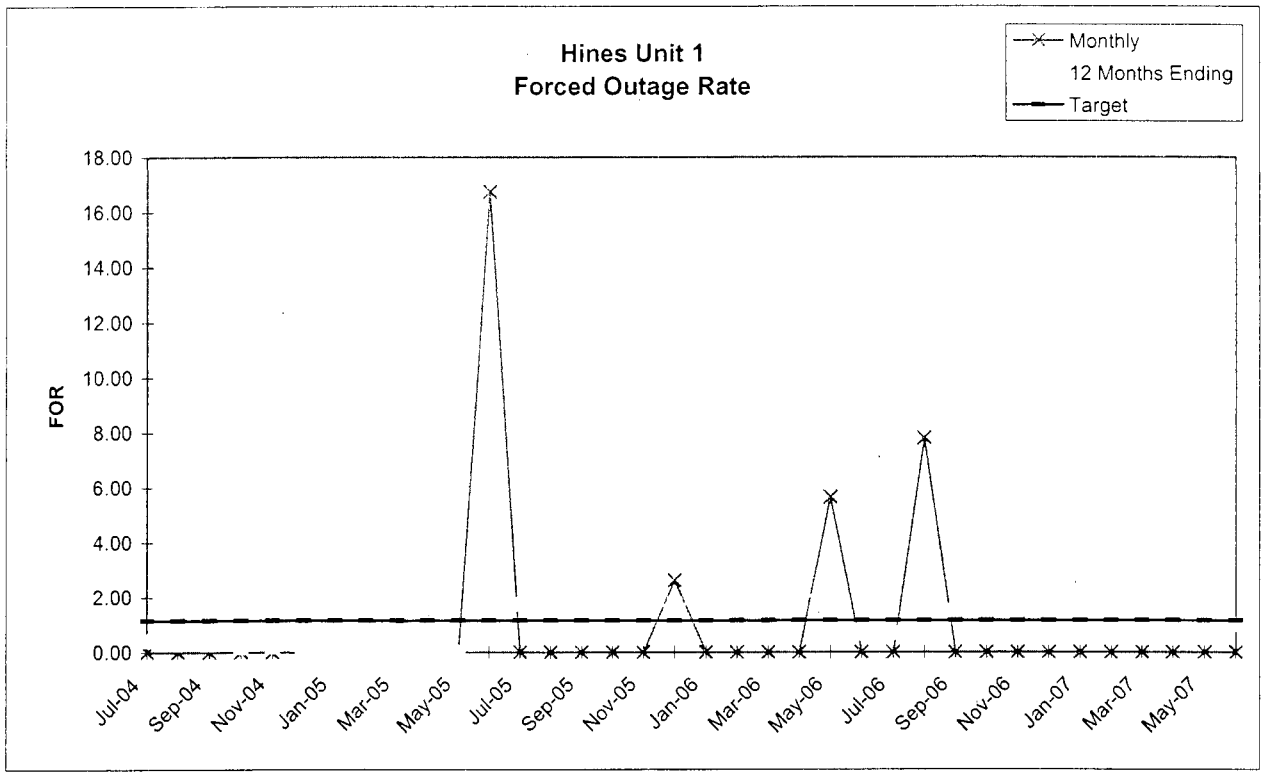
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.41	0.30	0.30	0.18	0.19	0.00	0.00	0.00	0.00	0.00	0.00	1.76	1.76	1.72	1.71	1.63	1.59	1.76
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.42	0.43	0.45	0.42	0.44	0.49	0.54	0.55	0.56	0.55	0.55	0.15	0.16	0.16	0.21	0.24	0.24	0.55
PMOR	5.70	5.79	5.84	6.10	5.06	5.16	5.33	5.35	5.25	1.86	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.07
EUOR	6.51	6.50	6.58	6.69	5.68	5.65	5.87	5.89	5.82	2.41	0.62	1.97	1.99	1.95	1.98	1.93	1.88	2.36
EUOF	5.94	5.83	5.85	5.70	4.65	4.53	4.56	4.57	4.59	1.96	0.49	1.54	1.56	1.56	1.60	1.63	1.63	1.96
POF	8.00	8.00	8.00	11.80	14.05	14.05	14.05	14.08	12.69	10.01	13.40	13.40	13.40	13.40	13.40	9.59	7.90	7.90
EAF	86.06	86.17	86.15	82.50	81.30	81.42	81.40	81.34	82.71	88.02	86.11	85.06	85.05	85.05	85.01	88.78	90.47	90.13

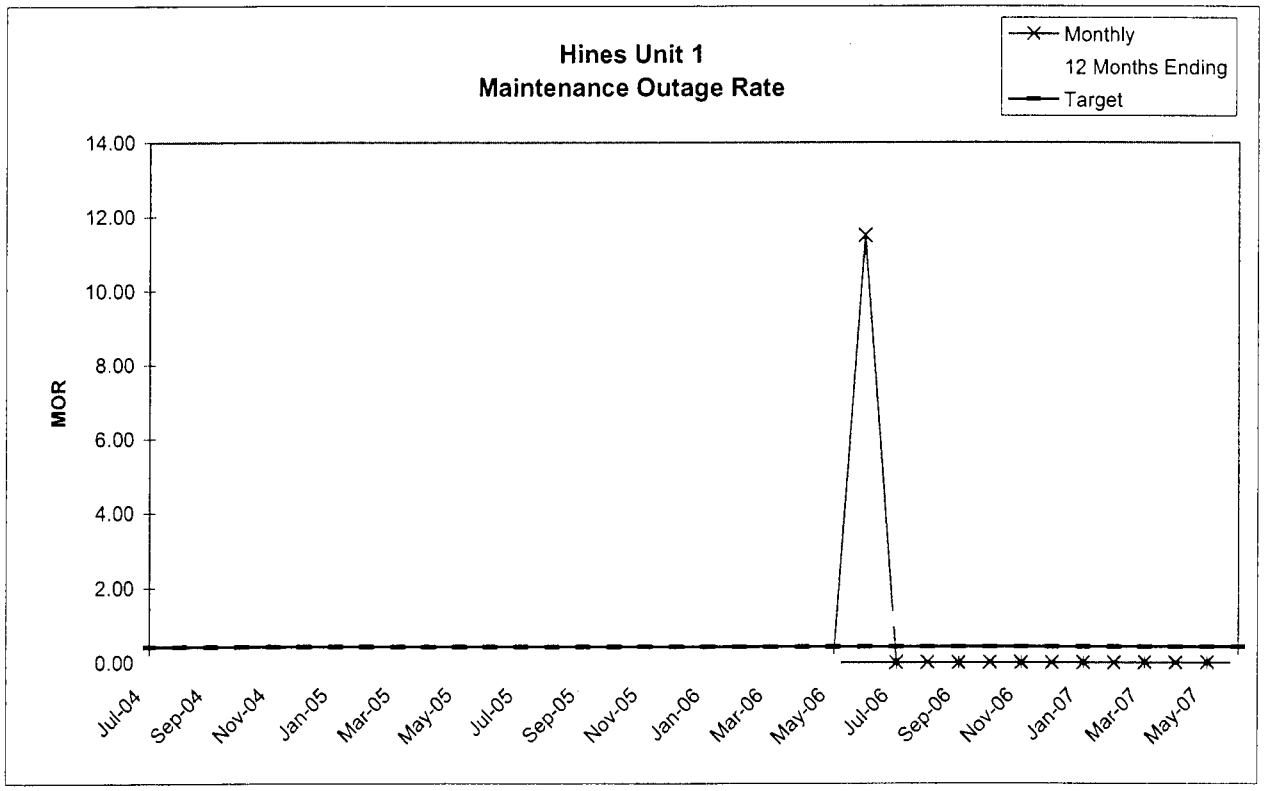
Hines
Unit 1

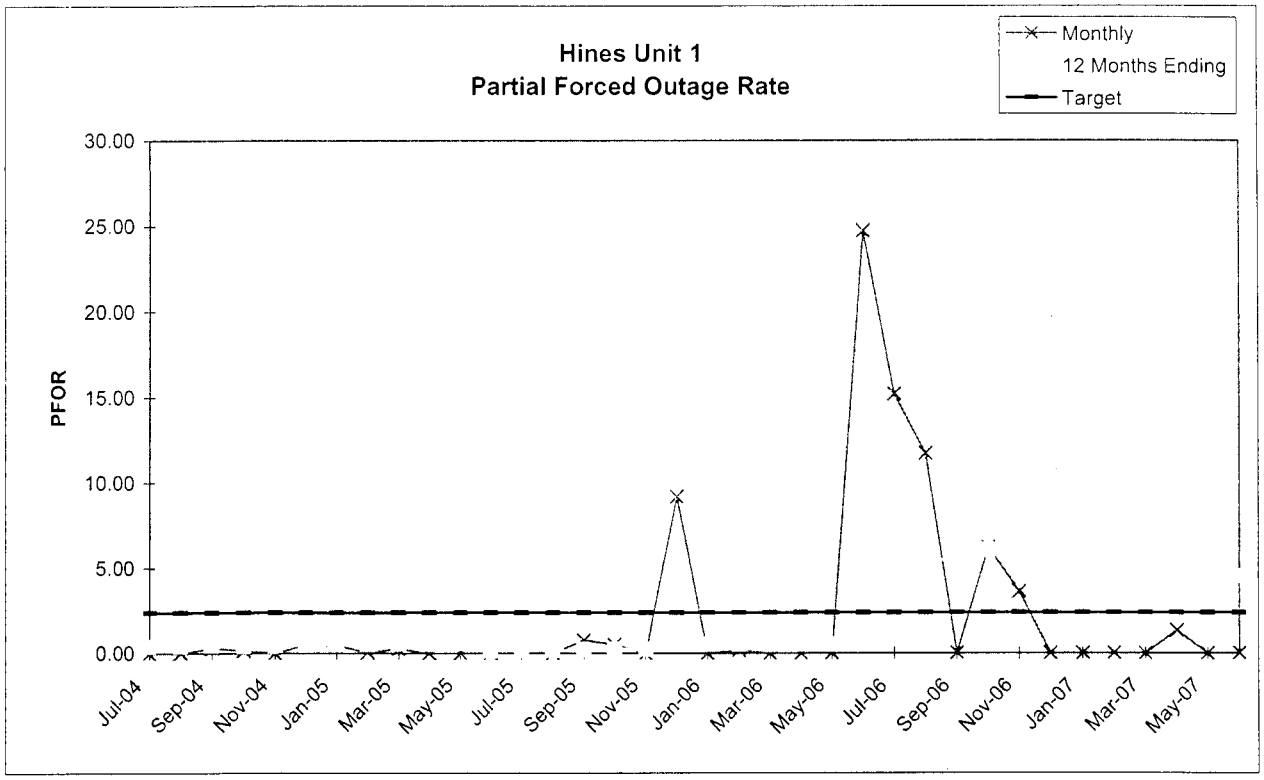
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	521.42	672.00	744.00	334.08	694.18	637.20	744.00	685.95	720.00	745.00	342.58	61.70	63.82	255.55	38.72	711.83	687.25	720.00
RSH	222.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	338.30	680.18	188.03	405.08	8.17	56.75	0.00
UH	0.00	0.00	0.00	384.92	49.82	82.80	0.00	58.05	0.00	0.00	377.42	344.00	0.00	228.42	299.20	0.00	0.00	0.00
POH	0.00	0.00	0.00	384.92	8.22	0.00	0.00	0.00	0.00	0.00	377.42	344.00	0.00	228.42	299.20	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	41.60	0.00	0.00	58.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	82.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	1.68	0.00	0.00	0.73	321.83	230.85	183.45	0.00	176.00	47.40	0.00	0.00	0.00	0.00	20.69	0.00	0.00
LRPF	0.00	326.50	0.00	0.00	148.56	236.00	236.00	211.00	0.00	126.00	126.00	0.00	0.00	0.00	0.00	216.72	0.00	0.00
EFOH	0.00	1.14	0.00	0.00	0.23	157.58	113.03	80.31	0.00	46.01	12.39	0.00	0.00	0.00	0.00	9.30	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	21.62	0.00	124.87	0.00	0.00	0.00	0.00	0.00	36.00	200.85	0.00	9.33
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	235.96	0.00	255.99	0.00	0.00	0.00	0.00	0.00	212.00	213.45	0.00	236.08
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	66.32	0.00	0.00	0.00	0.00	0.00	15.83	88.95	0.00	4.57
NPC	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00

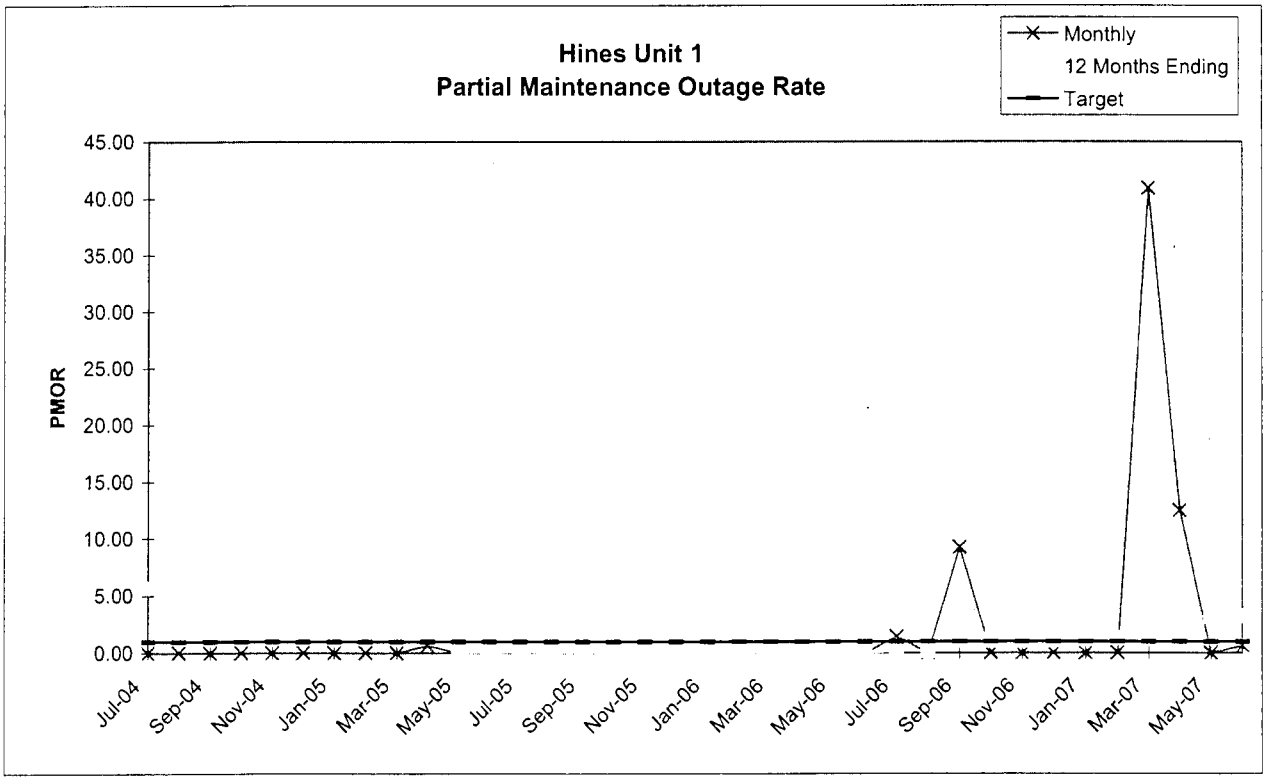
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	5.65	0.00	0.00	7.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	11.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.17	0.00	0.00	0.03	24.73	15.19	11.71	0.00	6.18	3.62	0.00	0.00	0.00	0.00	1.31	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	1.42	0.00	9.21	0.00	0.00	0.00	0.00	0.00	40.89	12.50	0.00	0.63
EUOR	0.00	0.17	0.00	0.00	5.68	33.39	16.61	18.60	9.21	6.18	3.62	0.00	0.00	0.00	40.89	13.80	0.00	0.63
EUOF	0.00	0.17	0.00	0.00	5.62	33.39	16.61	18.60	9.21	6.18	1.72	0.00	0.00	0.00	2.13	13.65	0.00	0.63
POF	0.00	0.00	0.00	53.54	1.10	0.00	0.00	0.00	0.00	0.00	52.42	46.24	0.00	33.99	40.27	0.00	0.00	0.00
EAF	100.00	99.83	100.00	46.46	93.27	66.61	83.39	81.40	90.79	93.82	45.86	53.76	100.00	66.01	57.60	86.35	100.00	99.37

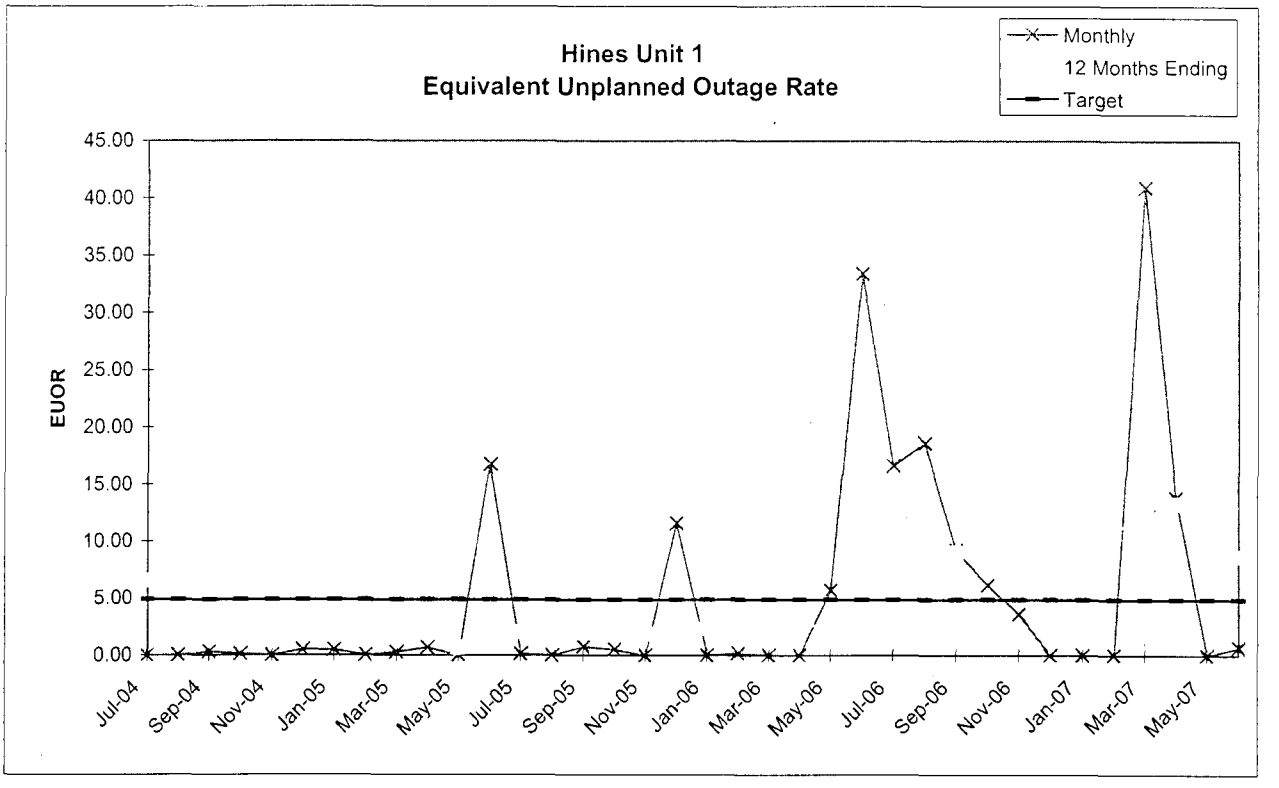
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	1.76	1.76	1.76	1.85	2.36	0.69	0.69	1.51	1.51	1.51	1.48	1.42	1.52	1.63	1.84	1.72	1.01	0.99
MOR	0.00	0.00	0.00	0.00	0.00	1.16	1.16	1.17	1.17	1.17	1.15	1.19	1.27	1.35	1.53	1.43	1.43	0.00
PFOR	0.52	0.53	0.50	0.53	0.52	2.75	4.34	5.52	5.44	6.05	6.12	5.95	6.37	6.79	7.69	7.35	7.35	4.52
PMOR	0.07	0.07	0.07	0.00	0.00	0.00	0.15	0.15	1.10	1.10	1.08	1.11	1.19	1.28	1.74	3.19	3.19	3.22
EUOR	2.33	2.34	2.32	2.38	2.86	4.53	6.24	8.16	9.01	9.60	9.62	9.46	10.11	10.77	12.44	13.31	12.70	8.66
EUOF	1.94	1.95	1.92	1.87	2.35	3.72	5.11	6.69	7.39	7.87	8.01	7.65	7.65	7.64	7.82	8.94	8.46	5.77
POF	7.90	7.90	7.90	12.25	8.96	8.96	8.96	8.96	8.96	8.96	8.80	12.72	12.72	15.33	18.75	14.35	14.26	14.26
EAF	90.16	90.15	90.17	85.88	88.69	87.33	85.93	84.35	83.65	83.17	83.19	79.63	79.63	77.03	73.43	76.71	77.28	79.97

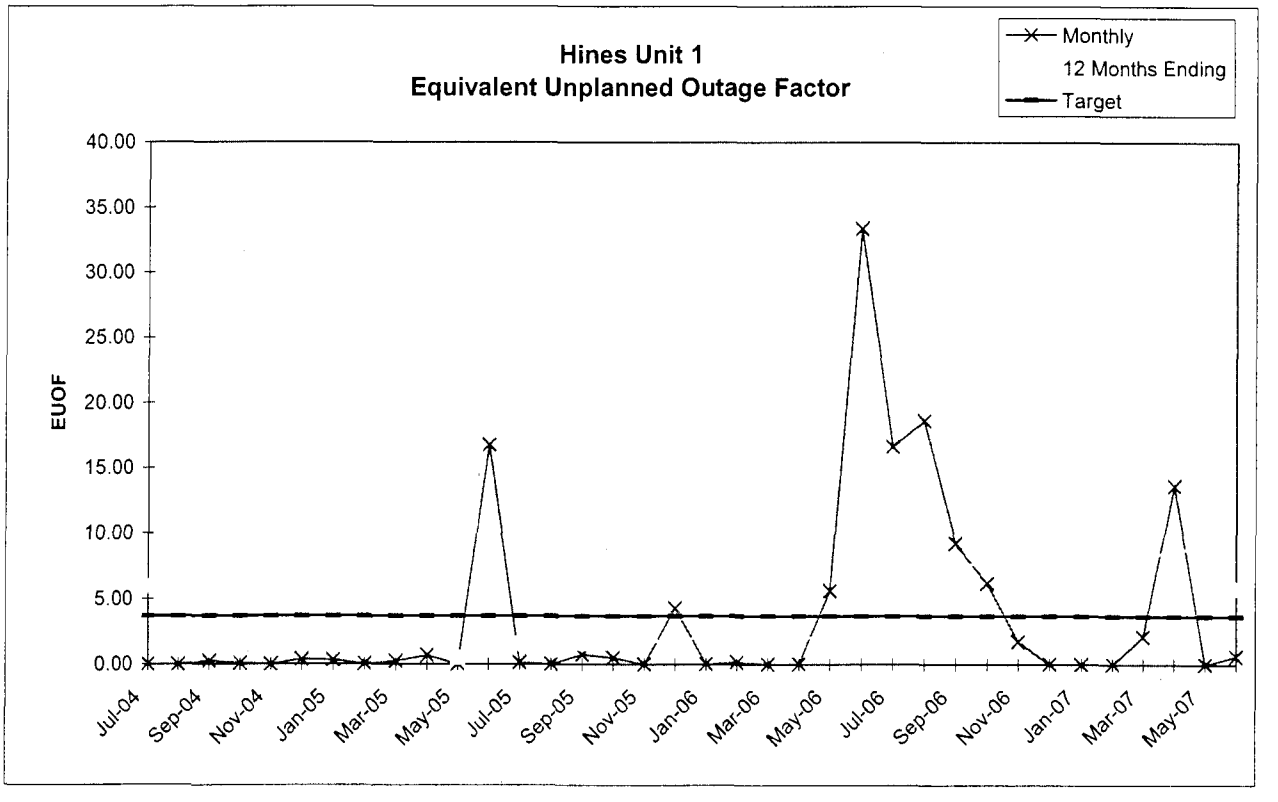

Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Hines
Unit 2

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	642.17	676.45	644.50	541.72	720.00	740.62	435.38	334.57	723.67	327.77	744.00	720.00	690.22	707.70	717.95	352.37	720.00	744.00
RSH	0.00	67.55	75.50	0.00	0.00	0.00	308.62	337.43	20.33	0.00	0.00	0.00	0.00	36.30	0.00	0.00	0.00	0.00
UH	101.83	0.00	0.00	203.28	0.00	3.38	0.00	0.00	0.00	391.23	0.00	0.00	53.78	0.00	2.05	392.63	0.00	0.00
POH	0.00	0.00	0.00	203.28	0.00	0.00	0.00	0.00	0.00	391.23	0.00	0.00	0.00	0.00	0.00	392.63	0.00	0.00
FOH	101.83	0.00	0.00	0.00	0.00	3.38	0.00	0.00	0.00	0.00	0.00	0.00	53.78	0.00	2.05	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	3.93	0.17	4.73	10.95	14.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.97	0.00	4.07	3.75
LRPF	214.18	239.24	153.11	114.66	223.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.97	0.00	223.82	324.00
EFOH	1.72	0.08	1.48	2.56	6.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.08	0.00	1.86	2.48
PMOH	0.00	0.00	143.33	193.64	0.00	0.00	0.00	0.00	0.00	44.28	0.00	8.07	0.00	0.00	0.00	18.00	94.95	0.00
LRPM	0.00	0.00	224.01	223.99	0.00	0.00	0.00	0.00	0.00	224.02	0.00	239.90	0.00	0.00	0.00	224.00	224.00	0.00
EMOH	0.00	0.00	65.52	88.52	0.00	0.00	0.00	0.00	0.00	20.24	0.00	3.95	0.00	0.00	0.00	8.23	43.41	0.00
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

MONTHLY	**Jul-04**	**Aug-04**	**Sep-04**	**Oct-04**	**Nov-04**	**Dec-04**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**
FOR	13.69	0.00	0.00	0.00	0.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	7.23	0.00	0.28	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.27	0.01	0.23	0.47	0.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.68	0.00	0.26	0.33
PMOR	0.00	0.00	10.17	16.34	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.55	0.00	0.00	0.00	2.34	6.03	0.00
EUOR	13.92	0.01	10.40	16.81	0.89	0.45	0.00	0.00	0.00	6.18	0.00	0.55	7.23	0.00	1.96	2.34	6.29	0.33
EUOF	13.92	0.01	9.31	12.23	0.89	0.45	0.00	0.00	0.00	2.82	0.00	0.55	7.23	0.00	1.96	1.10	6.29	0.33
POF	0.00	0.00	0.00	27.29	0.00	0.00	0.00	0.00	0.00	54.41	0.00	0.00	0.00	0.00	0.00	52.70	0.00	0.00
EAF	86.08	99.99	90.69	60.49	99.11	99.55	100.00	100.00	100.00	42.77	100.00	99.45	92.77	100.00	98.04	46.19	93.71	99.67

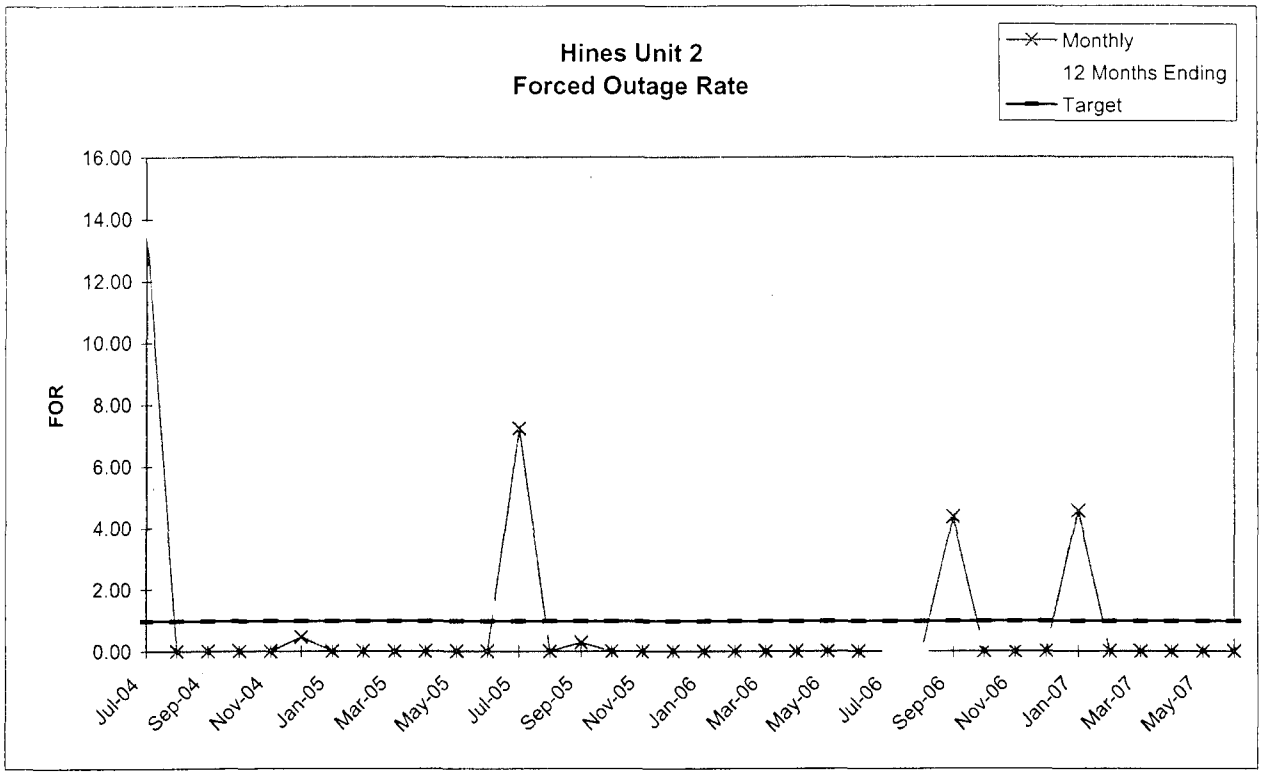
12 MONTHS	**Jul-04**	**Aug-04**	**Sep-04**	**Oct-04**	**Nov-04**	**Dec-04**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**
FOR	13.69	7.17	4.93	3.91	3.06	2.58	2.33	2.17	1.89	1.79	1.59	1.43	0.78	0.77	0.79	0.81	0.81	0.77
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.27	0.14	0.17	0.23	0.38	0.31	0.28	0.26	0.22	0.21	0.19	0.17	0.14	0.14	0.28	0.26	0.19	0.23
PMOR	0.00	0.00	3.34	6.15	4.78	3.88	3.50	3.25	2.82	3.01	2.67	2.46	2.44	2.43	1.52	0.45	1.05	1.05
EUOR	13.92	7.30	8.26	10.04	8.06	6.67	6.02	5.61	4.88	4.95	4.40	4.02	3.34	3.33	2.59	1.51	2.05	2.04
EUOF	13.92	6.96	7.73	8.86	7.30	6.15	5.26	4.65	4.13	4.00	3.63	3.38	2.81	2.81	2.20	1.26	1.70	1.69
POF	0.00	0.00	0.00	6.88	5.53	4.60	3.94	3.48	3.09	8.15	7.39	6.79	6.79	6.79	6.79	8.95	8.95	8.95
EAF	86.08	93.04	92.27	84.25	87.17	89.25	90.80	91.86	92.78	87.85	88.98	89.84	90.41	90.41	91.01	89.79	89.35	89.36

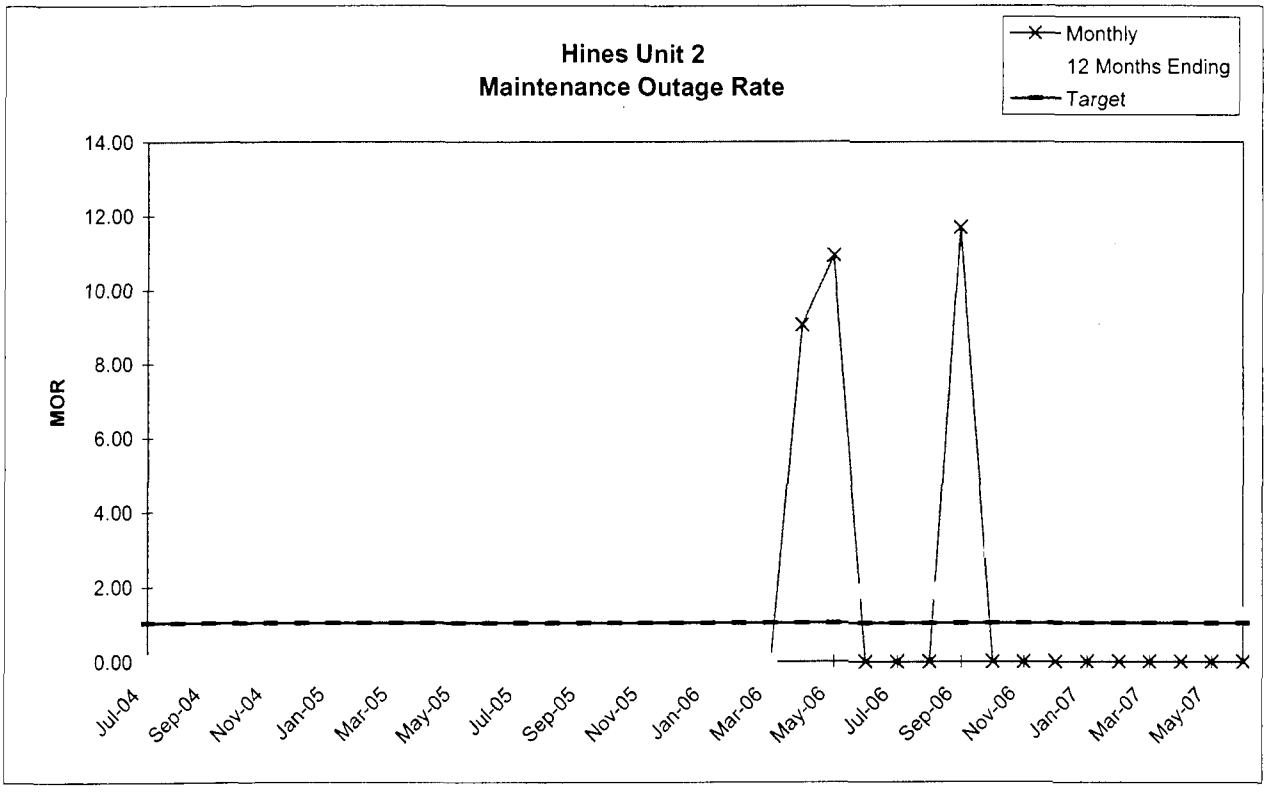
Hines
Unit 2

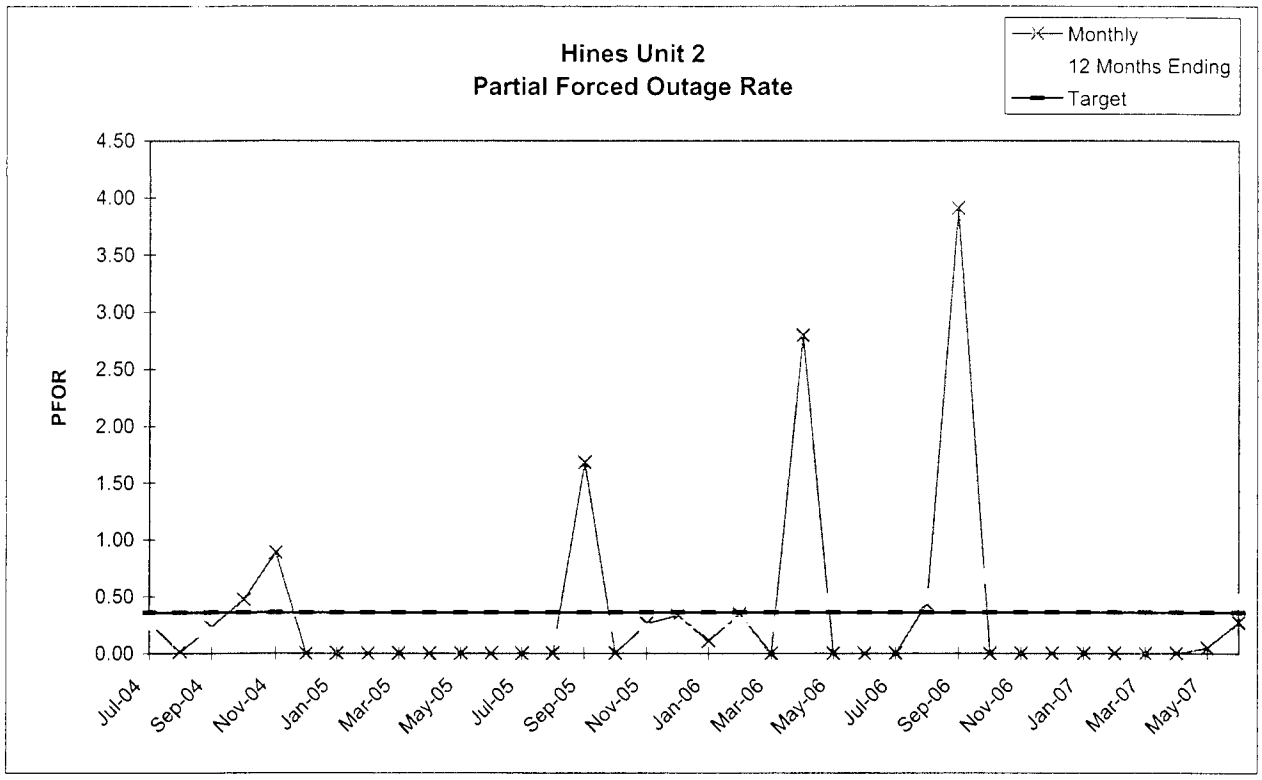
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	443.68	171.87	579.90	539.40	662.72	720.00	744.00	744.00	611.20	364.62	318.01	222.23	287.49	542.08	743.00	318.51	744.00	720.00
RSH	300.32	500.13	164.10	125.93	0.00	0.00	0.00	0.00	0.00	116.45	179.17	521.77	442.76	129.92	0.00	33.06	0.00	0.00
UH	0.00	0.00	0.00	53.67	81.28	0.00	0.00	0.00	108.80	263.93	222.82	0.00	13.75	0.00	0.00	368.43	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	263.93	222.82	0.00	0.00	0.00	0.00	368.43	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.88	0.00	0.00	0.00	13.75	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	53.67	81.28	0.00	0.00	0.00	80.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	1.53	1.37	0.00	33.00	0.00	0.00	0.00	6.53	52.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.80	4.17
LRPF	154.33	213.48	0.00	224.00	0.00	0.00	0.00	244.12	223.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	224.00	233.81
EFOH	0.48	0.60	0.00	15.09	0.00	0.00	0.00	3.25	23.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	1.99
PMOH	0.00	0.00	336.00	150.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.90	0.00	9.17
LRPM	0.00	0.00	224.00	224.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	220.00	0.00	223.92
EMOH	0.00	0.00	153.60	68.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.51	0.00	4.19
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

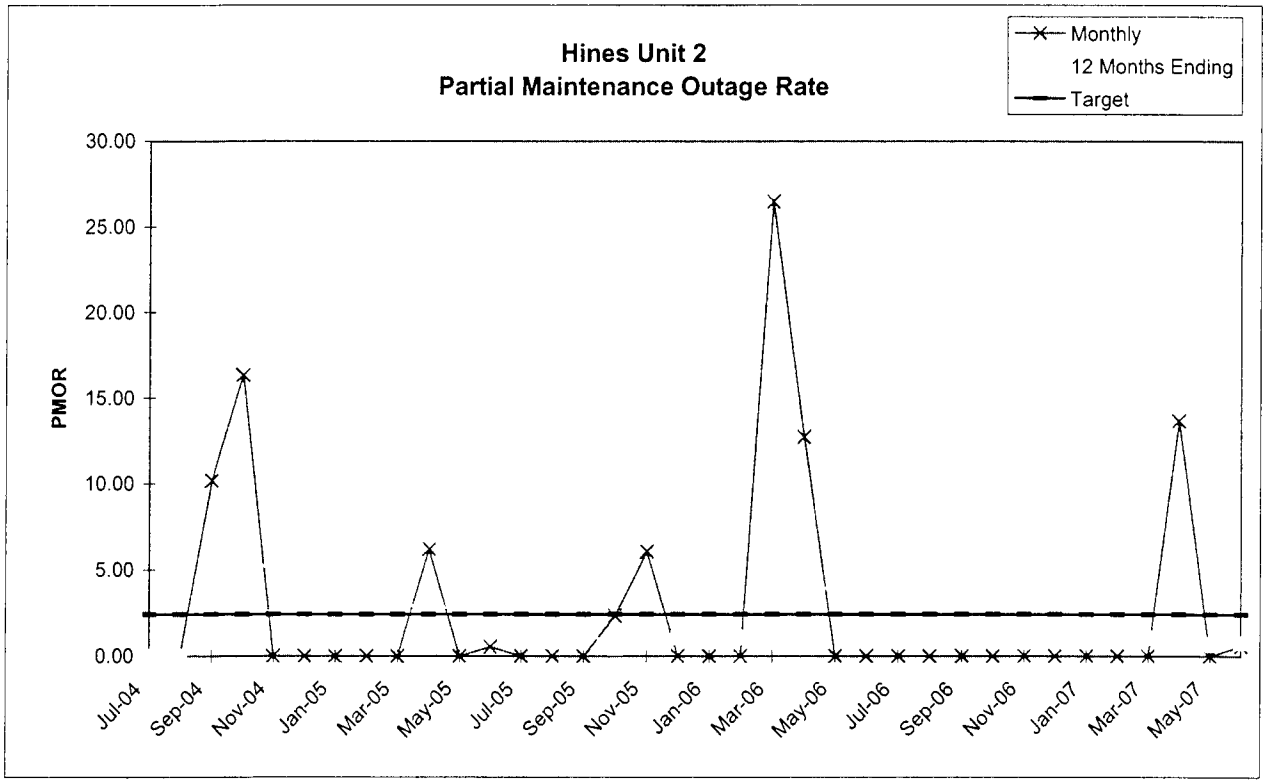
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.36	0.00	0.00	0.00	4.56	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	9.05	10.92	0.00	0.00	0.00	11.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.11	0.35	0.00	2.80	0.00	0.00	0.00	0.44	3.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.28
PMOR	0.00	0.00	26.49	12.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.66	0.00	0.58
EUOR	0.11	0.35	26.49	23.17	10.92	0.00	0.00	0.44	18.43	0.00	0.00	0.00	4.56	0.00	0.00	13.66	0.05	0.86
EUOF	0.06	0.09	20.65	19.11	10.92	0.00	0.00	0.44	18.43	0.00	0.00	0.00	1.85	0.00	0.00	6.04	0.05	0.86
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.43	30.95	0.00	0.00	0.00	0.00	51.17	0.00	0.00
EAF	99.94	99.91	79.35	80.89	89.08	100.00	100.00	99.56	81.57	64.57	69.05	100.00	98.15	100.00	100.00	42.79	99.95	99.14

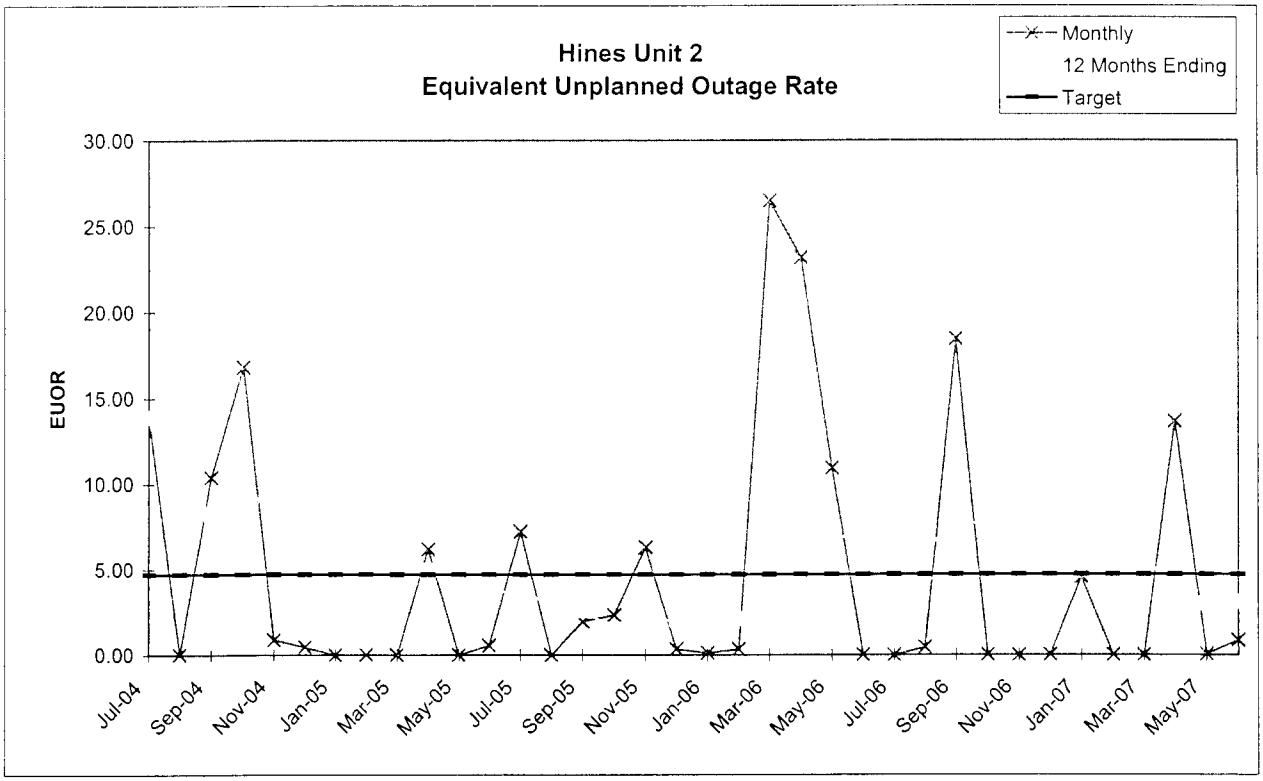
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.77	0.78	0.80	0.78	0.79	0.79	0.03	0.03	0.39	0.39	0.42	0.45	0.69	0.65	0.64	0.66	0.65	0.65
MOR	0.00	0.00	0.00	0.75	1.88	1.88	1.86	1.86	2.98	2.97	3.15	3.41	3.49	3.29	3.21	2.52	1.26	1.26
PFOR	0.23	0.25	0.25	0.46	0.46	0.46	0.46	0.50	0.68	0.68	0.69	0.71	0.72	0.67	0.65	0.43	0.43	0.46
PMOR	1.05	1.07	3.32	3.90	3.94	3.89	3.86	3.84	3.89	3.77	3.35	3.63	3.73	3.51	1.06	0.69	0.68	0.75
EUOR	2.04	2.10	4.34	5.80	6.92	6.87	6.12	6.14	7.77	7.64	7.43	8.00	8.40	7.92	5.45	4.23	2.99	3.08
EUOF	1.70	1.70	3.46	4.79	5.72	5.68	5.06	5.10	6.45	6.36	5.84	5.81	5.97	5.96	4.21	3.13	2.21	2.28
POF	8.95	8.95	8.95	4.48	4.48	4.48	4.48	4.48	4.48	3.01	5.56	5.56	5.56	5.56	5.56	9.76	9.76	9.76
EAF	89.36	89.35	87.60	90.72	89.80	89.84	90.46	90.42	89.06	90.63	88.60	88.63	88.48	88.48	90.24	87.10	88.03	87.96

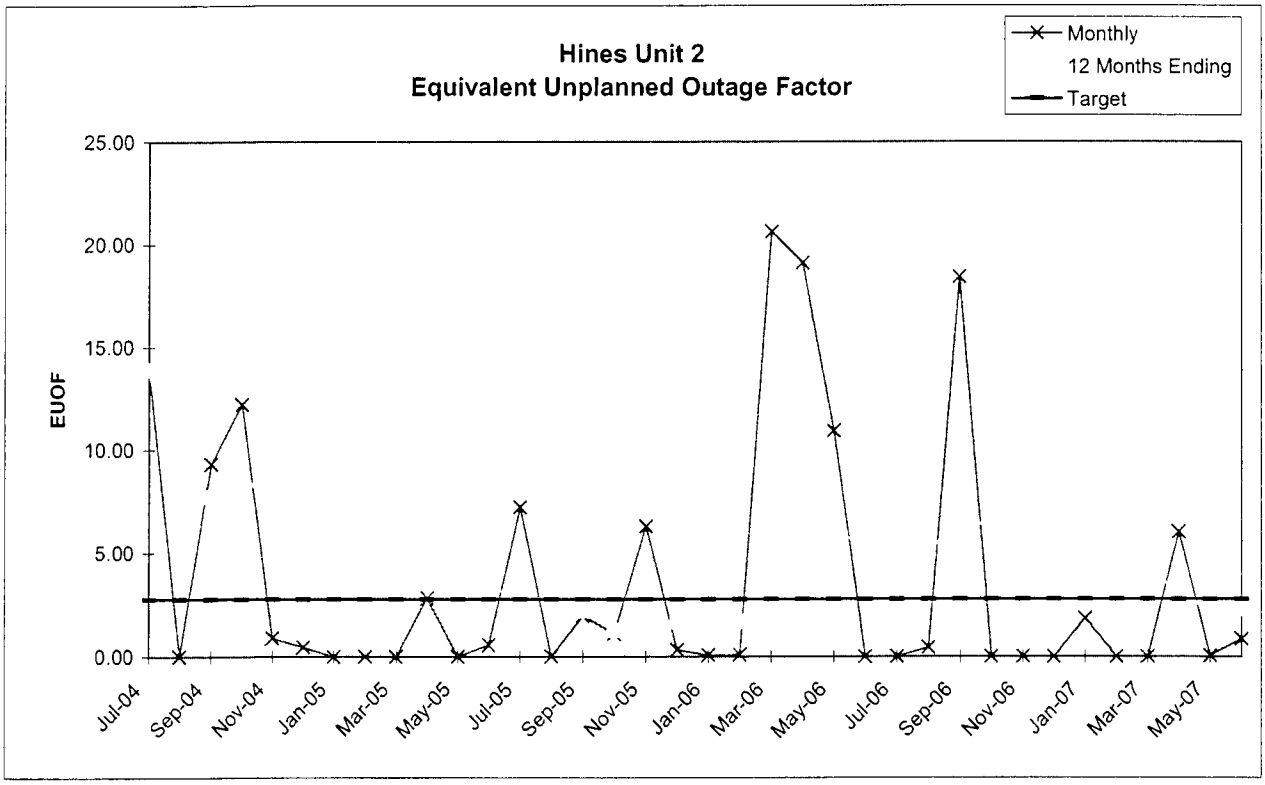

Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Hines Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Tiger Bay

	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	460.83	618.33	662.18	285.35	117.02	85.25	154.77	79.67	90.13	739.55	720.00	744.00	744.00	720.00	542.23	78.14	0.00
RSH	0.00	0.00	95.12	0.00	434.65	626.98	429.65	517.23	664.33	628.87	0.00	0.00	0.00	0.00	0.00	26.00	641.86	744.00
UH	0.00	283.17	6.55	82.82	0.00	0.00	229.10	0.00	0.00	0.00	4.45	0.00	0.00	0.00	0.00	176.77	0.00	0.00
POH	0.00	0.00	0.00	82.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	176.77	0.00	0.00
FOH	0.00	283.17	6.55	0.00	0.00	0.00	229.10	0.00	0.00	0.00	4.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	192.61	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

MONTHLY	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.00	38.06	1.05	0.00	0.00	0.00	72.88	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	38.06	1.05	0.00	0.00	0.00	72.88	0.00	0.00	0.00	0.60	0.03	0.00	0.00	0.00	0.00	0.00	0.00
EUOF	0.00	38.06	0.91	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.60	0.03	0.00	0.00	0.00	0.00	0.00	0.00
POF	0.00	0.00	0.00	11.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.73	0.00	0.00
EAF	100.00	61.94	99.09	88.88	100.00	100.00	69.21	100.00	100.00	100.00	99.40	99.97	100.00	100.00	100.00	76.27	100.00	100.00

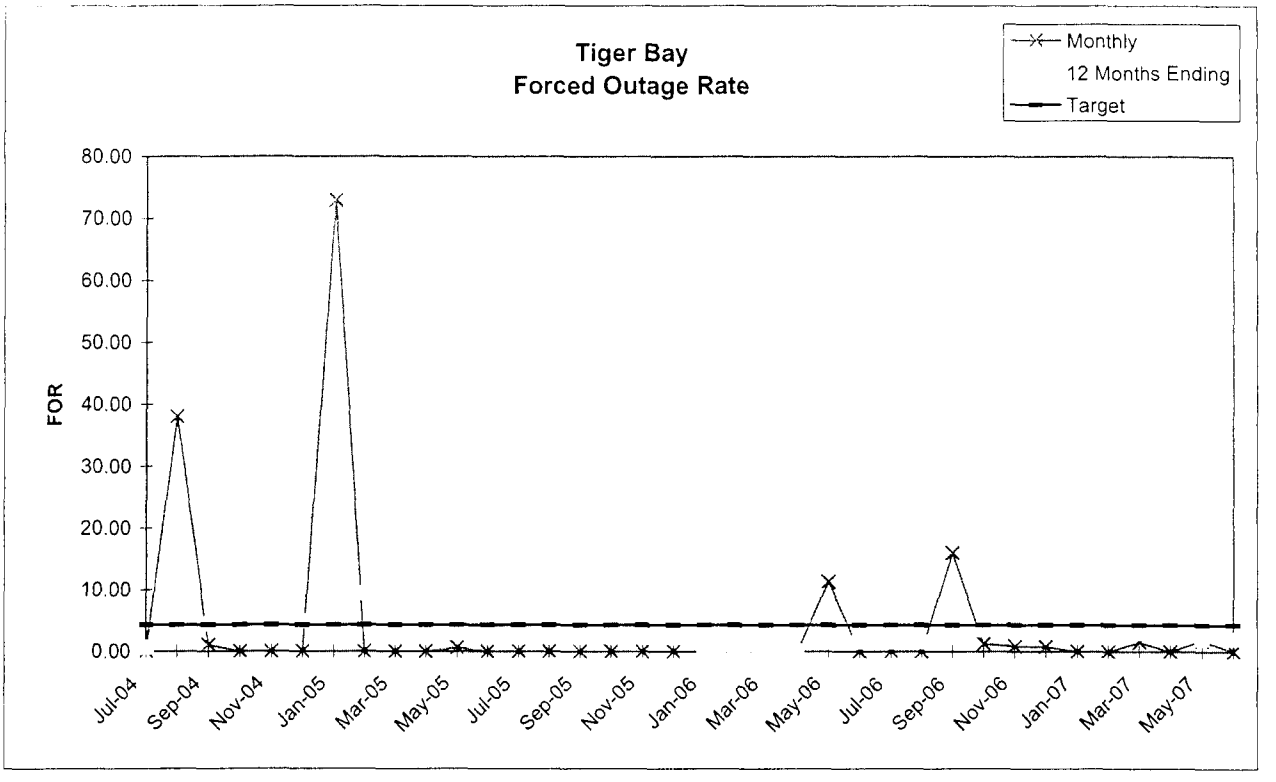
12 MONTHS	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
FOR	0.61	4.77	4.46	4.52	4.70	4.87	8.85	9.42	9.41	10.13	10.10	9.91	9.91	4.55	4.34	4.44	4.63	4.74
MOR	6.52	6.79	2.07	2.10	2.21	0.68	0.75	0.82	0.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	7.06	10.95	6.36	6.43	6.71	5.49	9.47	10.09	10.07	10.13	10.10	9.91	9.91	4.55	4.35	4.45	4.63	4.74
EUOF	5.85	9.07	5.20	5.20	5.16	4.02	6.63	6.52	6.52	6.04	6.09	5.98	5.98	2.74	2.67	2.67	2.67	2.67
POF	5.73	5.73	5.73	6.67	6.67	6.67	6.67	6.14	0.95	0.95	0.95	0.95	0.95	0.95	0.95	2.02	2.02	2.02
EAF	88.43	85.20	89.08	88.13	88.17	89.31	86.70	87.34	92.54	93.02	92.97	93.08	93.08	96.31	96.39	95.31	95.31	95.31

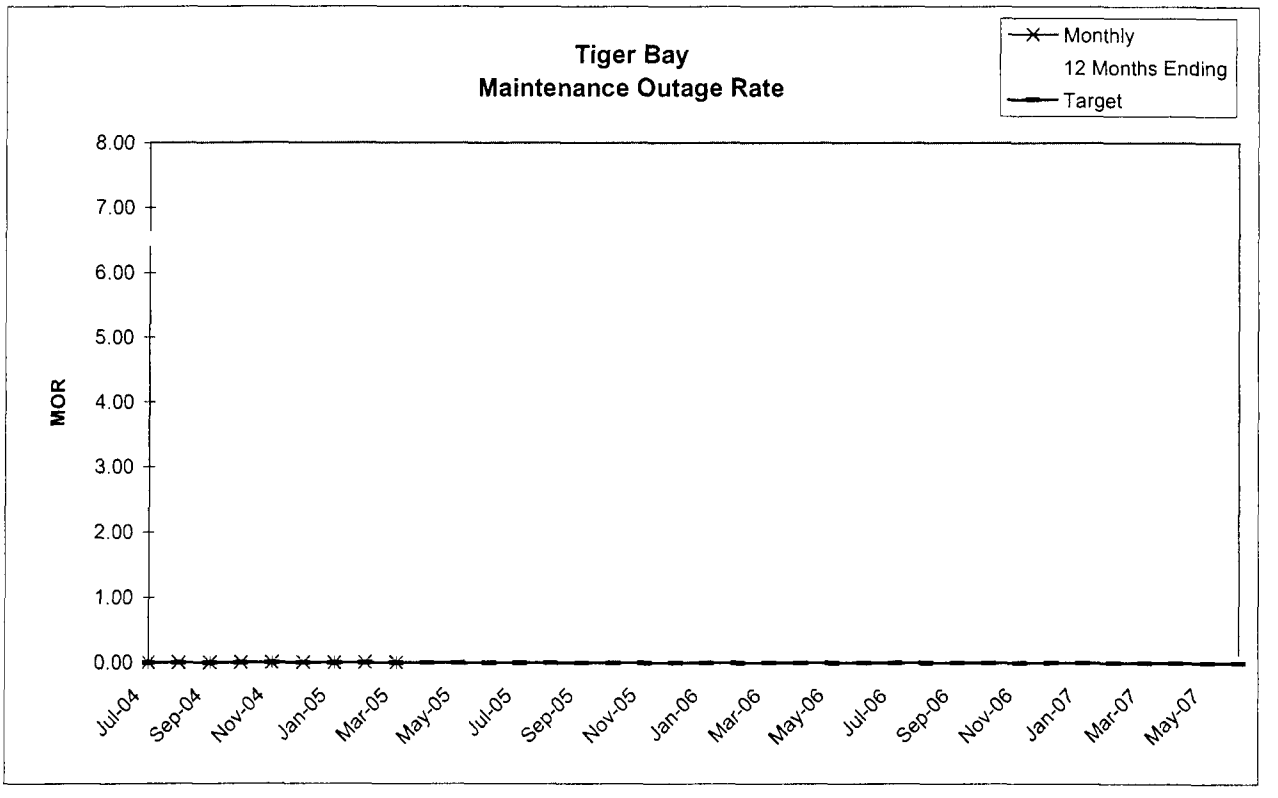
Tiger Bay

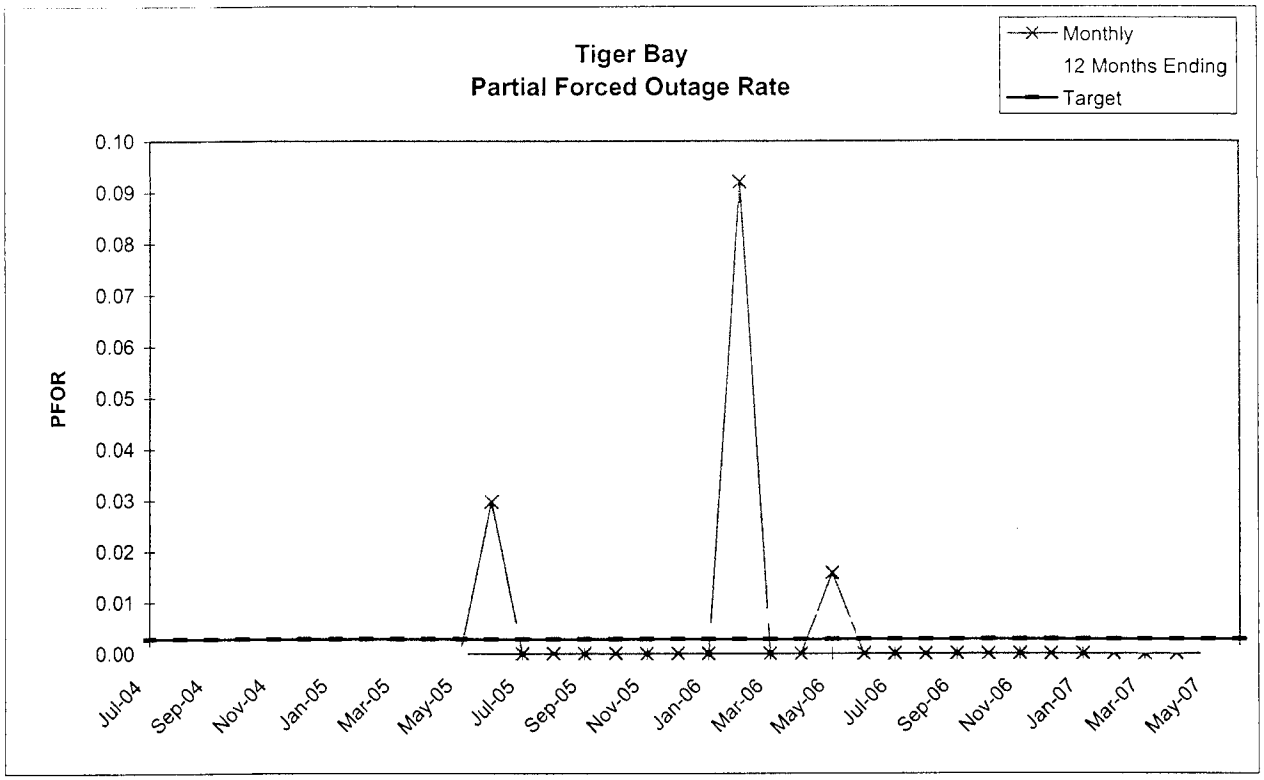
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	212.18	165.08	223.67	433.04	652.34	720.00	744.00	744.00	514.75	735.63	714.38	237.85	242.25	346.83	731.80	392.98	612.62	720.00
RSH	531.82	506.92	520.33	285.96	8.35	0.00	0.00	0.00	0.00	0.00	0.00	504.33	501.75	325.17	0.00	0.00	120.38	0.00
UH	0.00	0.00	0.00	0.00	83.32	0.00	0.00	0.00	205.25	9.37	5.62	1.82	0.00	0.00	11.20	327.02	11.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.25	0.00	0.00	0.00	0.00	0.00	0.00	327.02	0.00	0.00
FOH	0.00	0.00	0.00	0.00	83.32	0.00	0.00	0.00	98.00	9.37	5.62	1.82	0.00	0.00	11.20	0.00	11.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.20	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	157.30	0.00	0.00	164.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.15	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

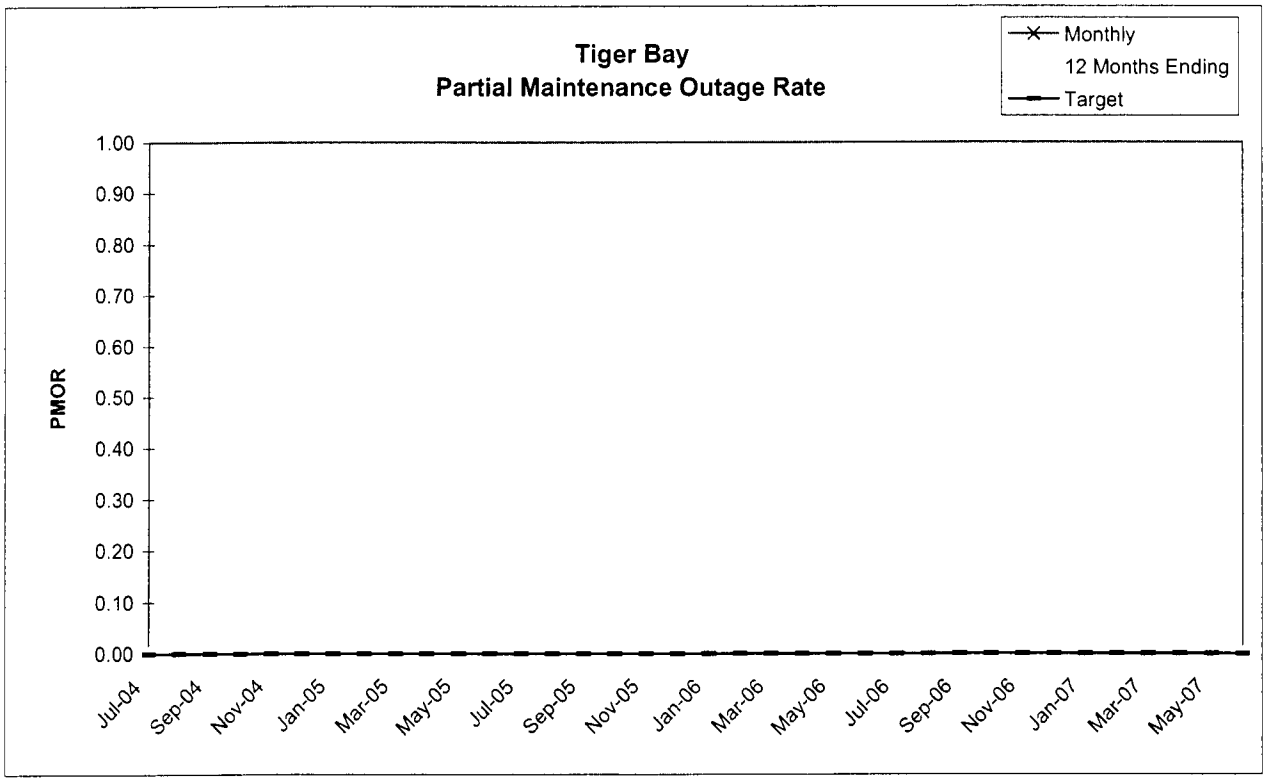
MONTHLY	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.00	0.00	0.00	0.00	11.33	0.00	0.00	0.00	15.99	1.26	0.78	0.76	0.00	0.00	1.51	0.00	1.76	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.09	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	0.09	0.00	0.00	11.34	0.00	0.00	0.00	15.99	1.26	0.78	0.76	0.00	0.00	1.51	0.00	1.76	0.00
EUOF	0.00	0.02	0.00	0.00	11.21	0.00	0.00	0.00	13.61	1.26	0.78	0.24	0.00	0.00	1.51	0.00	1.48	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.90	0.00	0.00	0.00	0.00	0.00	0.00	45.42	0.00	0.00
EAF	100.00	99.98	100.00	100.00	88.79	100.00	100.00	100.00	71.49	98.74	99.22	99.76	100.00	100.00	98.49	54.58	98.52	100.00

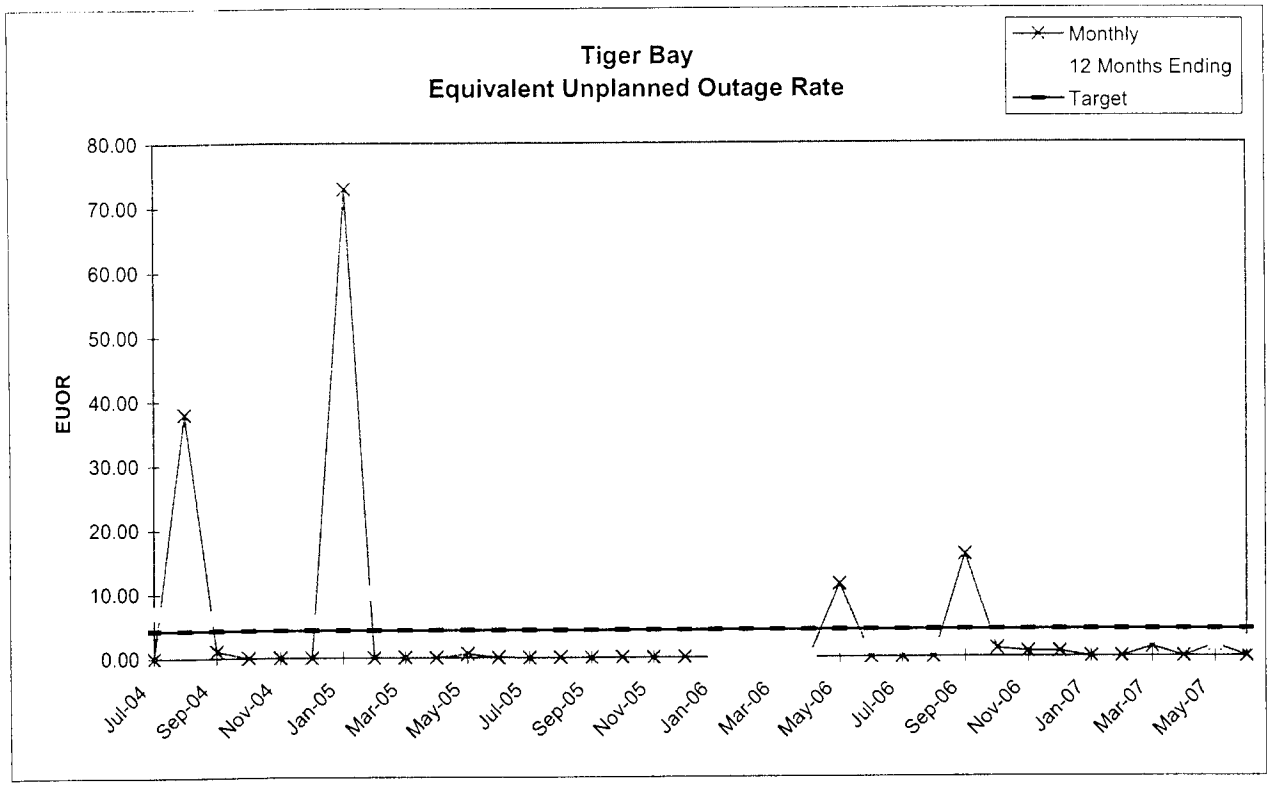
12 MONTHS	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FOR	0.09	0.09	0.09	0.08	1.57	1.57	1.57	1.57	3.48	3.52	3.24	3.15	3.13	3.04	2.98	3.00	1.99	1.99
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.10	0.10	0.10	0.09	1.58	1.57	1.57	1.57	3.48	3.53	3.25	3.15	3.14	3.05	2.98	3.00	1.99	1.99
EUOF	0.05	0.05	0.05	0.05	0.96	0.95	0.95	0.95	2.07	2.18	2.24	2.26	2.26	2.26	2.39	2.39	1.56	1.56
POF	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	3.24	1.22	1.22	1.22	1.22	1.22	1.22	4.96	4.96	4.96
EAF	97.93	97.93	97.93	97.93	97.03	97.03	97.03	97.03	94.68	96.60	96.53	96.51	96.51	96.51	96.38	92.65	93.48	93.48

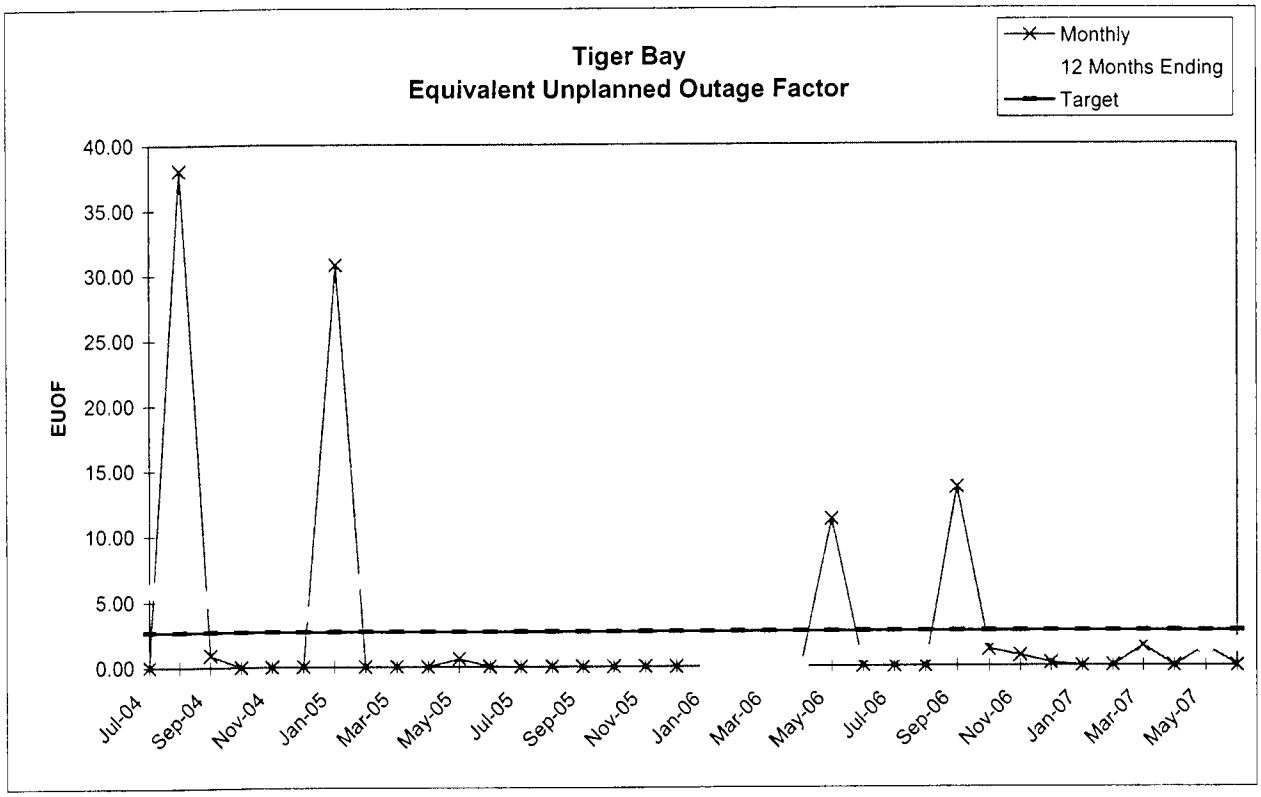

Tiger Bay
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Tiger Bay
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Tiger Bay
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Tiger Bay
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Tiger Bay
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07


Tiger Bay
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	TOTAL YEAR 2006	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						$ (416,637,197)
13						
14						
15		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 13
COMPANY Florida Power & Light Co.
WITNESS G. Yupp (GJY-1)
DATE 11-06-07

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	TOTAL YEAR 2006	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						$ (52,001,140)
13						
14		AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
15		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	TOTAL YEAR 2006	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12					$ -	$ -
13						
14		AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL	[redacted]			
15		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				
16						
17						
18						

19 Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	January-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	January-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	January-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	February-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

GJY-1
Docket No. 070001-EI
FPL Witness: Gerard Yupp
Page 7 of 39
April 2, 2007

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	February-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				ELECTRICITY		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	February-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	March-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	March-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	March-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	April-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	April-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

GJY-1
Docket No. 070001-EI
FPL Witness: Gerard Yupp
Page 14 of 39
April 2, 2007

CONFIDENTIAL

	A	B	C	D	E	F
1				ELECTRICITY		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	April-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	May-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	May-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	May-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						

17 Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	June-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	June-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	June-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	July-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	July-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	July-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						

17 Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	August-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	August-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				ELECTRICITY		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	August-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						

17 Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	September-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	September-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				ELECTRICITY		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	September-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	October-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	October-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				ELECTRICITY		
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	October-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	November-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	November-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	November-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	December-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
4	December-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						

CONFIDENTIAL

	A	B	C	D	E	F
1					ELECTRICITY	
2				VOLUME		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
4	December-06	FIXED PRICE TRANSACTIONS	[redacted]			
5		STORAGE				
6		PHYSICAL POWER OPTION PREMIUMS				
7		PHYSICAL POWER (EXERCISED OPTIONS)				
8		SWAPS				
9		SWING SWAPS				
10		OVER-THE-COUNTER OPTIONS				
11		BROKER FEES				
12						
13						
14						
15						
16						
17	Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.					

APPENDIX I

FUEL COST RECOVERY

GJY-2

DOCKET NO. 070001-EI

EXHIBIT_____

PAGES 1-6

SEPTEMBER 4, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 14
COMPANY Florida Power & Light Co.
WITNESS G. Yupp (GJY-2)
DATE 11-06-07

APPENDIX I

FUEL COST RECOVERY

TABLE OF CONTENTS

PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs	G. Yupp
3	Projected Availability of Natural Gas	G. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. Yupp
5, 6	2008 Risk Management Plan	G. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2008

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	62.01	62.53	62.53	61.27	61.35	61.81	62.62	62.62	62.62	62.44	62.62	62.98
1.0% Sulfur Grade ($/mmBtu)	9.69	9.77	9.77	9.57	9.59	9.66	9.78	9.78	9.78	9.76	9.78	9.84

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	94.44	94.61	93.66	91.77	89.99	88.98	89.13	89.78	90.57	91.44	92.32	93.18
0.05% Sulfur Grade ($/mmBtu)	16.20	16.23	16.07	15.74	15.44	15.26	15.29	15.40	15.54	15.68	15.83	15.98

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	750,000	750,000	750,000	839,000	874,000	874,000	874,000	874,000	874,000	839,000	750,000	750,000
Firm Gulfstream (mmBtu/Day)	350,000	350,000	350,000	350,000	350,000	350,000	535,000	535,000	535,000	535,000	535,000	535,000
Non-Firm FGT (mmBtu/Day)	140,000	140,000	140,000	110,000	75,000	75,000	75,000	75,000	75,000	110,000	140,000	140,000
Non-Firm Gulfstream (mmBtu/Day)	465,000	465,000	325,000	265,000	265,000	265,000	80,000	80,000	80,000	80,000	280,000	280,000
Total Projected Daily Availability (mmBtu/Day)	1,705,000	1,705,000	1,565,000	1,564,000	1,564,000	1,564,000	1,564,000	1,564,000	1,564,000	1,564,000	1,705,000	1,705,000

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	9.06	9.08	8.93	8.40	8.37	8.36	8.46	8.54	8.59	8.72	9.11	9.61
Firm Gulfstream ($/mmBtu)	8.81	8.83	8.68	8.17	8.14	8.13	8.23	8.30	8.36	8.48	8.86	9.35
Non-Firm FGT ($/mmBtu)	9.28	9.30	9.15	8.67	8.79	8.90	9.00	9.08	9.01	8.99	9.33	9.83
Non-Firm Gulfstream ($/mmBtu)	9.41	9.43	9.28	8.77	8.73	8.72	8.82	8.90	8.95	9.08	9.46	9.95

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.12	2.13	2.13	2.13	2.14	2.14	2.15	2.15	2.15	2.16	2.16	2.16
SJRPP ($/mmBtu)	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 1	1.7	6.2	18.0	02/02/08 - 04/04/08				
Cape Canaveral 2	2.0	7.3	8.2	11/15/08 - 12/12/08				
Cutler 5	0.4	0.5	0.0	NONE				
Cutler 6	0.9	1.3	0.0	NONE				
Lauderdale 4	1.6	0.3	2.7	03/15/08 - 03/23/08				
Lauderdale 5	1.6	0.5	4.1	11/01/08 - 11/14/08				
Lauderdale GTs	1.0	7.2	0.0	NONE				
Fort Myers 2 CC	1.5	2.5	4.7	02/09/08 - 03/05/08 *	01/12/08 - 02/06/08 *			
Ft. Myers 3	1.2	2.0	0.0	NONE				
Ft. Myers GTs	0.3	1.3	1.8	09/27/08 - 10/01/08 *	10/11/08 - 11/09/08 *	10/18/08 - 11/28/08 *		
Manatee 1	1.0	4.0	8.2	11/15/08 - 12/12/08				
Manatee 2	1.1	4.0	0.0	NONE				
Manatee 3	1.3	2.5	3.8	05/03/08 - 05/16/08				
Martin 1	0.9	4.0	16.1	10/04/08 - 11/28/08				
Martin 2	1.1	4.0	0.0	NONE				
Martin 3	1.4	1.7	1.0	05/17/08 - 05/23/08 *				
Martin 4	1.6	2.1	13.4	03/01/08 - 04/18/08 *				
Martin 8 CC	1.3	2.5	2.9	03/15/08 - 03/28/08 *	05/24/08 - 06/06/08 *	06/07/08 - 06/20/08 *		
Port Everglades 1	2.2	1.9	17.2	04/26/08 - 06/24/08				
Port Everglades 2	2.9	1.7	0.0	NONE				
Port Everglades 3	3.0	5.2	0.0	NONE				
Port Everglades 4	2.7	6.1	6.3	11/29/08 - 12/19/08				
Port Everglades GTs	1.9	9.7	0.0	NONE				
Putnam 1	0.5	2.5	7.2	03/01/08 - 04/14/08 *	11/08/08 - 11/17/08			
Putnam 2	0.6	2.5	0.0	NONE *				
Riviera 3	4.2	2.9	0.0	NONE				
Riviera 4	3.5	7.0	18.0	04/05/08 - 06/06/08				
Sanford 3	1.0	2.5	18.6	09/27/08 - 11/30/08				
Sanford 4 CC	1.6	2.5	1.9	02/02/08 - 02/29/08 *				
Sanford 5 CC	1.5	2.5	6.2	02/09/08 - 02/15/08 *	03/22/08 - 04/04/08	03/22/08 - 04/11/08 *	07/07/08 - 07/13/08 *	09/06/08 - 09/19/08 *
Turkey Point 1	2.8	3.5	8.5	10/18/08 - 11/14/08				
Turkey Point 2	3.2	3.5	0.0	NONE				
Turkey Point 3	1.3	1.3	0.0	NONE				
Turkey Point 4	1.1	1.1	9.6	03/30/08 - 05/04/08				
Turkey Point 5	1.5	2.5	1.9	03/01/08 - 03/07/08				
St. Lucie 1	1.1	1.1	11.2	10/20/08 - 11/30/08				
St. Lucie 2	1.3	1.3	0.0	NONE				
Saint Johns River Power Park 1	1.7	1.0	0.0	NONE				
Saint Johns River Power Park 2	1.9	1.0	16.1	03/01/08 - 04/28/08				
Scherer 4	1.7	1.0	10.4	03/18/08 - 04/23/08				

* Partial Planned Outage

2008 Risk Management Plan

1. Identify overall quantitative and qualitative risk management objectives.
   A. FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to achieve the goals of fuel price stability (volatility minimization), to potentially achieve fuel cost minimization, and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers. FPL plans to hedge a percentage of its residual fuel oil and natural gas purchases with a combination of fixed price transactions and options.

3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.
   A. The potential risks that FPL encounters with its fuel procurement are supplier credit, fuel supply and transportation availability, product quality, delivery timing, weather, environmental and supplier failure to deliver. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee for review and approval. Approval is given to remain within specified VaR limits. These VaR limits are specified in FPL's policies and procedures that were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI. FPL's policies and procedures are updated as necessary.

4. Describe the utility's oversight of its fuel procurement activities.
   A. The utility has a separate and independent middle office risk management department that provides oversight of fuel procurement activities at the deal level. In addition, an executive-level, Exposure Management Committee meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.
   A. Please see response to No. 4.

6. Describe the utility's corporate risk policy regarding fuel procurement activities.
   A. The utility has a written policy and procedures that define VaR and duration limits for all forward activity by portfolio. FPL's policies and procedures were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI. FPL's policies and procedures are updated as necessary. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities.
   A. Please see response to No. 6.

8. Describe the utility's strategy to fulfill its risk management objectives.
   A. Please see response to No. 1.

9. Verify that the utility has sufficient policies and procedures to implement its strategy.
   A. Please see response to No. 6.

13. Describe the utility's reporting system for fuel procurement activities.
   A. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities.
   A. Please see response to No. 13.

15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.
   A. FPL does not believe that there are any such limitations currently.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 15 Withdrawn
COMPANY _____
WITNESS _____
DATE _____

APPENDIX I

FUEL COST RECOVERY

TRUE UP CALCULATION

KMD-1
DOCKET NO. 070001-EI
FPL WITNESS: K.M. DUBIN
PAGES 1 - 6
EXHIBIT _____
March 1, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 16
COMPANY Florida Power & Light Co
WITNESS K. M. Dubin (KMD-1)
DATE 11-06-07

APPENDIX I

FUEL COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4-5	CALCULATION OF FINAL TRUE-UP AMOUNT
6	CALCULATION OF FINAL TRUE-UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2006

1	End of Period True-up for the period January through December 2006 (from page 4, lines D7 & D8)		$ 162,686,084
2	Less - Estimated/Actual True-up for the same period	*	$ 216,430,642
3	Net Final True-up for the period January through December 2006		$ (53,744,558)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

	LINE NO.			(1) JAN	(2) FEB	(3) MAR	(4) APR	(5) MAY	(6) JUN
A			**Fuel Costs & Net Power Transactions**						
	1	a	Fuel Cost of System Net Generation	$ 315,112,787	$ 296,130,097	$ 362,988,224	$ 427,175,559	$ 465,395,518	$ 498,860,024
		b	Incremental Hedging Costs	56,883	35,541	22,233	98,579	27,955	38,796
		c	Nuclear Fuel Disposal Costs	1,960,611	1,856,367	1,711,034	1,731,522	1,472,295	1,751,906
		d	Scherer Coal Cars Depreciation & Return	300,687	298,824	296,962	295,099	293,237	291,374
		e	Gas Pipelines Depreciation & Return	0	0	0	0	0	0
		f	DOE D&D Fund Payment	0	0	0	0	0	0
	2	a	Fuel Cost of Power Sold (Per A6)	(11,797,386)	(11,663,894)	(10,895,956)	(3,517,465)	(4,158,008)	(3,554,605)
		b	Gains from Off-System Sales	(3,248,253)	(3,480,746)	(2,438,709)	(727,924)	(777,282)	(486,429)
	3	a	Fuel Cost of Purchased Power (Per A7)	19,228,529	16,922,824	22,823,782	24,788,396	27,451,007	29,479,518
		b	Energy Payments to Qualifying Facilities (Per A8)	13,591,316	11,810,443	10,591,302	11,664,026	14,221,903	15,217,211
		c	Okeelanta Settlement Amortization including interest	811,625	809,550	807,449	805,614	803,013	800,474
	4		Energy Cost of Economy Purchases (Per A9)	8,081,737	3,796,966	7,374,033	9,586,158	20,151,662	6,224,615
	5		Total Fuel Costs & Net Power Transactions	$ 344,098,536	$ 316,515,971	$ 393,280,354	$ 471,899,564	$ 524,881,300	$ 548,622,884
	6		**Adjustments to Fuel Cost**						
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(4,658,460)	(3,907,152)	(3,724,406)	(4,711,300)	(5,149,414)	(5,650,335)
		b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	3,136	(35,018)	(99,944)	(52,487)	(69,190)	(9,916)
		c	Inventory Adjustments	29,862	(54,040)	387,944	(140,609)	9,950	(1,069,540)
		d	Non Recoverable Oil/Tank Bottoms	0	0	0	(27,966)	(25,592)	0
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 339,473,073	$ 312,519,762	$ 389,843,947	$ 466,967,201	$ 519,647,054	$ 541,893,093
B			**kWh Sales**						
	1		Jurisdictional kWh Sales	8,025,135,582	7,283,681,362	7,191,005,176	7,616,707,944	8,445,324,075	9,560,737,906
	2		Sale for Resale (excluding FKEC & CKW)	48,619,701	38,867,924	35,275,521	47,211,219	46,778,639	51,572,882
	3		Sub-Total Sales (excluding FKEC & CKW)	8,073,755,283	7,322,549,286	7,226,280,697	7,663,919,163	8,492,102,714	9,612,310,788
	6		**Jurisdictional % of Total Sales (B1/B3)**	99.39781%	99.46920%	99.51184%	99.38398%	99.44915%	99.46347%
C			**True-up Calculation**						
	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 472,878,512	$ 445,267,979	$ 439,184,910	$ 466,888,616	$ 520,556,663	$ 593,092,512
	2		**Fuel Adjustment Revenues Not Applicable to Period**						
		a	Prior Period True-up (Collected)/Refunded This Period	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)
		b	GPIF, Net of Revenue Taxes	(900,747)	(900,747)	(900,747)	(900,747)	(900,747)	(900,747)
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 410,049,421	$ 382,438,888	$ 376,355,819	$ 404,059,525	$ 457,727,572	$ 530,263,421
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 339,473,073	$ 312,519,762	$ 389,843,947	$ 466,967,201	$ 519,647,054	$ 541,893,093
		b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
		c	RTP Incremental Fuel -100% Retail	0	0	0	0	0	0
		d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	339,473,073	312,519,762	389,843,947	466,967,201	519,647,054	541,893,093
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.39781 %	99.46920 %	99.51184 %	99.38398 %	99.44915 %	99.46347 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 337,648,129	$ 311,062,967	$ 388,193,047	$ 464,392,249	$ 517,120,488	$ 539,336,015
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 72,401,292	$ 71,375,921	$ (11,837,228)	$ (60,332,724)	$ (59,392,916)	$ (9,072,594)
	8		Interest Provision for the Month (Line D10)	(3,609,912)	(3,213,771)	(2,966,509)	(3,010,630)	(3,085,699)	(3,082,214)
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(743,140,130)	(612,420,406)	(482,329,912)	(435,205,305)	(436,620,315)	(437,170,586)
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)
	10		Prior Period True-up Collected/(Refunded) This Period	61,928,344	61,928,344	61,928,344	61,928,344	61,928,344	61,928,344
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (919,858,006)	$ (789,767,512)	$ (742,642,905)	$ (744,057,915)	$ (744,608,186)	$ (694,834,650)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

LINE NO.				(7) JUL	(8) AUG	(9) SEP	(10) OCT	(11) NOV	(12) DEC	(13) TOTAL PERIOD
A			**Fuel Costs & Net Power Transactions**							
	1	a	Fuel Cost of System Net Generation	$ 496,788,362	$ 559,200,863	$ 468,260,158	$ 431,401,223	$ 362,858,371	$ 327,310,888	$ 5,011,482,074
		b	Incremental Hedging Costs	39,718	22,017	52,566	51,172	35,215	42,332	523,005
		c	Nuclear Fuel Disposal Costs	1,968,400	2,047,419	2,033,269	1,976,709	1,575,846	1,786,525	21,871,904
		d	Scherer Coal Cars Depreciation & Return	289,512	287,087	284,337	282,478	279,969	278,440	3,478,005
		e	Gas Pipelines Depreciation & Return	0	0	0	0	0	0	0
		f	DOE D&D Fund Payment	0	0	0	0	6,776,723	0	6,776,723
	2	a	Fuel Cost of Power Sold (Per A6)	(4,049,245)	(15,584,830)	(3,210,390)	(3,668,041)	(4,682,315)	(6,788,042)	(83,570,177)
		b	Gains from Off-System Sales	(619,665)	(3,384,834)	(458,576)	(700,694)	(1,036,124)	(2,018,573)	(19,377,809)
	3	a	Fuel Cost of Purchased Power (Per A7)	28,666,676	42,306,950	25,510,687	27,148,320	21,917,467	21,313,065	307,557,221
		b	Energy Payments to Qualifying Facilities (Per A8)	14,834,881	18,217,165	12,438,119	8,652,647	11,755,684	14,051,867	157,046,564
		c	Okeelanta Settlement Amortization including interest	797,756	794,271	790,709	787,292	783,870	780,457	9,572,079
	4		Energy Cost of Economy Purchases (Per A9)	5,074,148	6,457,450	6,582,909	6,678,496	11,247,480	7,802,151	99,057,805
	5		Total Fuel Costs & Net Power Transactions	$ 543,790,543	$ 610,363,558	$ 512,283,788	$ 472,609,601	$ 411,512,187	$ 364,559,110	$ 5,514,417,393
	6		**Adjustments to Fuel Cost**							
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(5,465,123)	(6,587,690)	(6,274,702)	(5,141,704)	(5,242,726)	(3,985,352)	(60,498,365)
		b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(64,705)	61,206	(67,222)	(28,951)	(75,865)	(98,799)	(537,756)
		c	Inventory Adjustments	20,430	57,082	55,664	(10,604)	21,729	(107,007)	(799,140)
		d	Non Recoverable Oil/Tank Bottoms	0	149,662	(12,161)	(50,702)	0	44,774	78,015
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 538,281,145	$ 604,043,817	$ 505,985,366	$ 467,377,639	$ 406,215,324	$ 360,412,724	$ 5,452,660,147
B			**kWh Sales**							
	1		Jurisdictional kWh Sales	10,009,127,890	10,084,115,688	9,957,139,728	9,383,354,467	8,180,636,882	7,921,599,004	103,658,565,704
	2		Sale for Resale (excluding FKEC & CKW)	47,151,365	50,879,047	53,033,027	46,691,237	48,159,079	44,171,749	558,411,390
	3		Sub-Total Sales (excluding FKEC & CKW)	10,056,279,255	10,134,994,735	10,010,172,755	9,430,045,704	8,228,795,961	7,965,770,753	104,216,977,094
	6		**Jurisdictional % of Total Sales (B1/B3)**	99.53113%	99.49799%	99.47021%	99.50487%	99.41475%	99.44548%	99.46418%
C			**True-up Calculation**							
	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 622,084,993	$ 627,611,415	$ 618,779,135	$ 580,731,886	$ 502,792,961	$ 484,804,745	$ 6,374,674,325
	2		**Fuel Adjustment Revenues Not Applicable to Period**							
		a	Prior Period True-up (Collected)/Refunded This Period	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)	(61,928,344)	(743,140,130)
		b	GPIF, Net of Revenue Taxes	(900,747)	(900,747)	(900,747)	(900,747)	(900,747)	(900,747)	(10,808,960)
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 559,255,902	$ 564,782,324	$ 555,950,044	$ 517,902,795	$ 439,963,870	$ 421,975,654	$ 5,620,725,235
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 538,281,145	$ 604,043,817	$ 505,985,366	$ 467,377,639	$ 406,215,324	$ 360,412,724	$ 5,452,660,147
		b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0
		c	RTP Incremental Fuel -100% Retail	0	0	0	0	0	0	0
		d	D&D Fund Payments -100% Retail	0	0	0	0	6,776,723	0	6,776,723
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	538,281,145	604,043,817	505,985,366	467,377,639	399,438,601	360,412,724	5,445,883,424
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.53113 %	99.49799 %	99.47021 %	99.50487 %	99.41475 %	99.44548 %	99.46418 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 536,105,548	$ 601,402,114	$ 503,631,855	$ 465,365,804	$ 404,135,725	$ 358,647,133	$ 5,427,041,074
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 23,150,354	$ (36,619,790)	$ 52,318,189	$ 52,536,991	$ 35,828,145	$ 63,328,521	$ 193,684,160
	8		Interest Provision for the Month (Line D10)	(2,894,560)	(2,657,503)	(2,337,994)	(1,846,516)	(1,387,726)	(905,041)	(30,998,076)
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(387,397,050)	(305,212,912)	(282,561,861)	(170,653,322)	(58,034,503)	38,334,260	(743,140,130)
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)	(307,437,600)
	10		Prior Period True-up Collected/(Refunded) This Period	61,928,344	61,928,344	61,928,344	61,928,344	61,928,344	61,928,344	743,140,130
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (612,650,512)	$ (589,999,461)	$ (478,090,922)	$ (365,472,103)	$ (269,103,340)	$ (144,751,516)	$ (144,751,516)

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs ESTIMATED/ACTUAL
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

LINE NO.				(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A			**Fuel Costs & Net Power Transactions**				
	1	a	Fuel Cost of System Net Generation	$ 5,011,482,074	$ 5,017,024,754	$ (5,542,680)	(0.1) %
		b	Incremental Hedging Costs	523,005	530,120	(7,115)	(1.3) %
		c	Nuclear Fuel Disposal Costs	21,871,904	21,977,573	(105,669)	(0.5) %
		d	Coal Cars Depreciation & Return	3,478,005	3,547,505	(69,500)	(2.0) %
		e	Gas Pipelines Depreciation & Return	0	0	0	N/A
		f	DOE D&D Fund Payment	6,776,723	7,076,000	(299,277)	(4.2) %
	2	a	Fuel Cost of Power Sold (Per A6)	(83,570,177)	(101,780,900)	18,210,723	(17.9) %
		b	Gains from Off-System Sales	(19,377,809)	(22,355,072)	2,977,263	(13.3) %
	3	a	Fuel Cost of Purchased Power (Per A7)	307,557,221	294,944,884	12,612,337	4.3 %
		b	Energy Payments to Qualifying Facilities (Per A8)	157,046,564	160,074,366	(3,027,802)	(1.9) %
		c	Okeelanta Settlement Amortization including interest	9,572,079	9,556,710	15,369	0.2 %
	4		Energy Cost of Economy Purchases (Per A9)	99,057,805	112,273,612	(13,215,807)	(11.8) %
	5		Total Fuel Costs & Net Power Transactions	$ 5,514,417,393	$ 5,502,869,552	$ 11,547,842	0.2 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (60,498,365)	$ (63,777,571)	$ 3,279,206	(5.1) %
		b	Reactive and Voltage Control Fuel Revenue	(537,756)	(334,141)	(203,615)	60.9 %
		c	Inventory Adjustments	(799,140)	(703,257)	(95,883)	13.6 %
		d	Non Recoverable Oil/Tank Bottoms	78,015	83,944	(5,929)	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 5,452,660,147	$ 5,438,138,526	$ 14,521,621	0.3 %
B			**Jurisdictional kWh Sales**				
	1		Jurisdictional kWh Sales	103,658,565,704	104,207,333,618	(548,767,914)	(0.5) %
	2		Sale for Resale (excluding FKEC & CKW)	558,411,390	554,617,680	3,793,710	0.7 %
	3		Sub-Total Sales (excluding FKEC & CKW)	104,216,977,094	104,761,951,298	(544,974,204)	(0.5) %
	4		**Jurisdictional % of Total Sales (B1/B3)**	N/A	N/A	N/A	N/A
			True-up Calculation				
C	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 6,374,674,325	$ 6,413,849,493	$ (39,175,169)	(0.6) %
	2		**Fuel Adjustment Revenues Not Applicable to Period**				
		a 1	Prior Period True-up (Collected)/Refunded This Period	(743,140,130)	(743,140,130)	0	0.0 %
		b	GPIF, Net of Revenue Taxes (b)	(10,808,960)	(10,808,960)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes	0	0	0	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 5,620,725,235	$ 5,659,900,403	$ (39,175,169)	(0.7) %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 5,452,660,147	$ 5,438,138,526	$ 14,521,621	0.3 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	0	0	0	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 f)	6,776,723	7,076,000	(299,277)	(4.2) %
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	5,445,883,424	5,431,062,526	14,820,898	0.3 %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 5,427,041,074	$ 5,412,868,109	$ 14,172,965	0.3 %
	7		True-up Provision for the Period Over/(Under) Recovery (Line C3 - Line C6)	$ 193,684,160	$ 247,032,294	$ (53,348,134)	(21.6) %
	8		Interest Provision for the Period	(30,998,076)	(30,601,652)	(396,424)	1.3 %
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(743,140,130)	(743,140,130)	0	0.0 %
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(307,437,600)	(307,437,600)	0	0.0 %
	10		Prior Period True-up Collected/(Refunded) This Period	743,140,130	743,140,130	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through D10)	$ (144,751,516)	$ (91,006,958)	$ (53,744,558)	59.1 %

NOTES

(a) **Per filing made October 24, 2006 - Approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006**

(b) **Generation Performance Incentive Factor is (($10,816,748) x 99.9280%) - See Order No. PSC-05-1252-FOF-EI.**

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO. 070001-EI
FPL WITNESS: K.M. DUBIN
PAGES 1 - 8
EXHIBIT _____
March 1, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 17
COMPANY Florida Power & Light Co.
WITNESS K. M. Dubin (KMD-2
DATE 11-06-07

APPENDIX II

CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE (S)	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4 - 5	CALCULATION OF FINAL TRUE-UP AMOUNT
6	CALCULATION OF FINAL TRUE-UP VARIANCES
7 - 8	SCHEDULE A12

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2006

1.	End of Period True-up for the period January through December 2006 (from page 6, lines 17 & 18)	$ (22,245,729)
2.	Less - Estimated/Actual True-up for the same period *	(18,215,446)
3.	Net True-up for the period January through December 2006	$ (4,030,283)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

LINE NO.		(1) JAN 2006	(2) FEB 2006	(3) MAR 2006	(4) APR 2006	(5) MAY 2006	(6) JUN 2006
1.	Payments to Non-cogenerators (UPS & SJRPP)	$ 16,328,586	$ 17,039,174	$ 16,424,843	$ 17,022,006	$ 16,137,875	$ 16,258,337
2.	Short Term Capacity Purchases CCR	5,567,800	5,760,442	3,714,452	3,604,238	6,904,812	13,741,290
3.	QF Capacity Charges	25,941,162	25,351,277	25,824,354	25,694,198	26,100,635	25,963,653
4a.	SJRPP Suspension Accrual	354,568	354,568	354,568	354,568	354,568	354,568
4b.	Return on SJRPP Suspension Liability	(370,319)	(373,599)	(376,878)	(380,157)	(383,436)	(386,715)
5.	Okeelanta Settlement (Capacity)	3,053,254	3,045,448	3,037,545	3,030,642	3,020,858	3,011,307
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,947,315	2,278,720	1,710,423	2,413,005	2,137,310	2,208,967
7.	Transmission of Electricity by Others	637,042	684,247	589,986	569,737	982,560	919,270
8.	Transmission Revenues from Capacity Sales	(612,573)	(510,704)	(448,830)	(147,753)	(152,625)	(149,806)
9.	Total (Lines 1 through 8)	$ 53,846,834	$ 53,629,573	$ 50,830,463	$ 52,160,484	$ 55,102,557	$ 61,920,870
10.	Jurisdictional Separation Factor (a)	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%
11.	Jurisdictional Capacity Charges	53,104,953.55	52,890,686.42	50,130,141.54	51,441,837.50	54,343,375.72	61,067,749.35
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 48,359,488	$ 48,145,220	$ 45,384,676	$ 46,696,372	$ 49,597,910	$ 56,322,283
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 45,391,676	$ 41,857,250	$ 41,260,600	$ 43,401,265	$ 47,773,199	$ 53,178,080
15.	Prior Period True-up Provision	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 44,798,528	$ 41,264,102	$ 40,667,452	$ 42,808,117	$ 47,180,051	$ 52,584,932
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(3,560,960)	(6,881,118)	(4,717,223)	(3,888,255)	(2,417,859)	(3,737,351)
18.	Interest Provision for Month	(19,441)	(37,453)	(58,912)	(76,927)	(89,697)	(103,714)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(7,117,775)	(10,105,027)	(16,430,451)	(20,613,438)	(23,985,472)	(25,899,880)
20.	Deferred True-up - Over/(Under) Recovery	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	593,148	593,148	593,148	593,148	593,148	593,148
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (6,799,339)	$ (13,124,763)	$ (17,307,750)	$ (20,679,784)	$ (22,594,192)	$ (25,842,108)

Notes: **(a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 9, 2005**
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

NOTE: Columns and rows may not add due to rounding.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

LINE NO.		(7) JUL 2006	(8) AUG 2006	(9) SEP 2006	(10) OCT 2006	(11) NOV 2006	(12) DEC 2006	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$ 16,684,681	$ 15,003,469	$ 16,649,279	$ 15,832,458	$ 15,108,177	$ 18,269,474	$ 196,758,360	1.
2.	Short Term Capacity Purchases CCR	13,796,520	13,796,520	7,819,940	3,428,305	3,742,625	5,875,105	87,752,049	2.
3.	QF Capacity Charges	26,187,808	25,949,913	26,791,939	26,013,632	26,072,000	26,134,780	312,025,350	3.
4a.	SJRPP Suspension Accrual	354,568	354,568	354,568	354,568	354,568	354,568	4,254,816	4a.
4b.	Return on SJRPP Suspension Liability	(389,994)	(393,273)	(396,552)	(399,831)	(403,110)	(406,389)	(4,660,252)	4b.
5.	Okeelanta Settlement (Capacity)	3,001,083	2,987,974	2,974,571	2,961,717	2,948,845	2,936,004	36,009,248	6b.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,172,622	1,583,563	1,859,331	1,368,610	2,144,982	2,219,185	25,044,033	6c.
7.	Transmission of Electricity by Others	942,138	818,051	941,745	543,384	577,666	681,047	8,886,872	7.
8.	Transmission Revenues from Capacity Sales	(158,354)	(509,398)	(132,051)	(176,908)	(152,245)	(321,679)	(3,472,927)	8.
9.	Total (Lines 1 through 8)	$ 62,591,074	$ 59,591,387	$ 56,862,770	$ 49,925,936	$ 50,393,508	$ 55,742,094	$ 662,597,548	9.
10.	Jurisdictional Separation Factor (a)	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	N/A	10.
11.	Jurisdictional Capacity Charges	61,728,718.78	58,770,360.24	56,079,337.31	49,238,076.23	49,699,206.48	54,974,101.24	653,468,544.35	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 56,983,253	$ 54,024,894	$ 51,333,871	$ 44,492,610	$ 44,953,740	$ 50,228,635	$ 596,522,952	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 55,273,079	$ 56,250,502	$ 55,355,377	$ 52,358,005	$ 46,155,734	$ 44,070,843	$ 582,325,610	14.
15.	Prior Period True-up Provision	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)	(593,144)	(7,117,772)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 54,679,931	$ 55,657,354	$ 54,762,229	$ 51,764,857	$ 45,562,586	$ 43,477,699	$ 575,207,838	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(2,303,322)	1,632,460	3,428,358	7,272,246	608,845	(6,750,936)	(21,315,114)	17.
18.	Interest Provision for Month	(118,469)	(117,630)	(103,334)	(77,711)	(58,105)	(69,221)	(930,614)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(29,147,796)	(30,976,439)	(28,868,461)	(24,950,290)	(17,162,606)	(16,018,718)	(7,117,775)	19.
20.	Deferred True-up - Over/(Under) Recovery	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	593,148	593,148	593,148	593,148	593,148	593,144	7,117,772	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (27,670,751)	$ (25,562,773)	$ (21,644,602)	$ (13,856,918)	$ (12,713,030)	$ (18,940,044)	$ (18,940,044)	22.

Notes: **(a) Per K. M. Dubin's Testimony Appendix III Page 3, filed**
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 9
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2006

Line No.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	Payments to Non-cogenerators (UPS & SJRPP)	$ 196,758,360	$ 196,133,840	$ 624,520	0.3 %
2	Short Term Capacity Payments	$ 87,752,049	87,579,598	172,451	0.2 %
3	Payments to Cogenerators (QF's)	312,025,350	309,472,210	2,553,140	0.8 %
4a	SJRPP Suspension Accrual	4,254,816	4,254,816	0	0.0 %
4b	Return Requirements on SJRPP Suspension Liability	(4,660,252)	(4,940,692)	280,440	(5.7) %
5	Okeelanta Settlement (Capacity)	36,009,248	36,000,942	8,306	0.0 %
6	Incremental Plant Security Costs-Order No. PSC-02-1761	25,044,033	26,861,570	(1,817,537)	(6.8) %
7	Transmission of Electricity by Others	8,886,872	8,936,181	(49,309)	(0.6) %
8	Transmission Revenues from Capacity Sales	(3,472,927)	(3,688,689)	215,762	(5.8) %
9	Total (Lines 1 through 8)	$ 662,597,548	$ 660,609,776	$ 1,987,772	0.3 %
10	Jurisdictional Separation Factor	98.62224%	98.62224%	0	0.0 %
11	Jurisdictional Capacity Charges	$ 653,468,544	$ 651,508,159	$ 1,960,386	0.3 %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 596,522,952	$ 594,562,567	$ 1,960,386	0.3 %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 582,325,610	$ 584,394,648	$ (2,069,038)	(0.4) %
15	Prior Period True-up Provision	(7,117,772)	(7,117,772)	0	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 575,207,838	$ 577,276,876	$ (2,069,038)	(0.4) %
17	True-up Provision for Period - Over/(Under) Recovery (Line 16 - Line 13)	$ (21,315,114)	$ (17,285,690)	$ (4,029,424)	N/A
18	Interest Provision for Period	(930,614)	(929,756)	(858)	0.1 %
19	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	(7,117,775)	(7,117,775)	0	N/A
20	Deferred True-up - Over/(Under) Recovery	3,305,688	3,305,688	0	N/A
21	Prior Period True-up Provision - Collected/(Refunded) this Period	7,117,772	7,117,775	3	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (18,940,044)	$ (14,909,759)	$ (4,030,283)	27.0 %

Notes:
(a) Per K. M. Dubin's Testimony Appendix II, Page 3, Docket No. 060001-EI, filed September 1, 2006.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

Columns and rows may not add due to rounding.

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 1 of 2

For the Month of Dec-06

Contract	Capacity MW	Term Start	End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Palm Beach Solid Waste Authority	47.5	4/1/1992	3/31/2010	QF
Broward North - 1987 Agreement	45	4/1/1992	12/31/2010	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1987 Agreement	50.6	4/1/1991	8/1/2009	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
Southern Co. - UPS	930	7/20/1988	5/31/2010	UPS
JEA - SJRPP	381	4/2/1982	9/30/2021	JEA

QF = Qualifying Facility
UPS= Unit Power Sales Agreement with Southern Company
JEA = SJRPP Purchased Power Agreements

2006 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	9,675,450	9,207,993	9,649,610	9,378,727	9,445,028	9,365,000	9,365,000	9,365,000	9,365,000	9,365,000	9,365,000	9,365,000	112,911,808
ICL	10,368,585	10,533,109	10,567,206	10,704,828	10,759,814	10,703,754	10,638,527	10,644,212	11,524,762	10,767,202	10,834,079	10,816,470	128,862,548
SWAPBC	1,888,244	1,792,650	1,792,650	1,792,650	1,889,550	1,889,550	1,889,550	1,886,923	1,847,016	1,827,146	1,810,004	1,889,550	22,195,483
BN-SOC	1,744,875	1,656,450	1,656,450	1,656,450	1,746,000	1,746,000	1,746,000	1,746,000	1,746,000	1,746,000	1,746,000	1,746,000	20,682,225
BN-NEG	214,077	210,409	207,772	210,879	209,035	208,141	497,524	256,569	257,953	259,011	268,255	269,710	3,069,336
BS-SOC	1,961,799	1,862,535	1,862,535	1,862,535	1,963,078	1,963,078	1,963,078	1,963,078	1,963,078	1,963,078	1,963,078	1,963,078	23,254,026
BS-NEG	88,130	88,130	88,130	88,130	88,130	88,130	88,130	88,130	88,130	86,196	85,584	84,972	1,049,922
SoCo	10,465,193	11,096,170	10,138,189	10,342,317	9,830,799	10,273,701	10,593,895	8,993,463	10,203,852	10,330,404	10,087,743	13,702,038	126,057,764
SJRPP	5,863,393	5,943,004	6,286,654	6,679,689	6,307,076	5,984,636	6,090,786	6,010,006	6,445,427	5,502,054	5,020,434	4,567,436	70,700,596
Total	42,269,747	42,390,450	42,249,197	42,716,205	42,238,510	42,221,990	42,872,490	40,953,382	43,441,218	41,846,090	41,180,177	44,404,253	508,783,709

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 2 of 2

CONFIDENTIAL

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Desoto County Generating Company, LLC - Progress Energy Ventures	Other Entity	June 1, 2002	May 31, 2007
2	Reliant Energy Services	Other Entity	April 1, 2002	February 28, 2007
3	Oleander Power Project L.P.	Other Entity	June 1, 2002	May 31, 2012
4	Reliant Energy Services - Indian River	Other Entity	January 1, 2006	December 31, 2009
5	Calpine Energy Services - True Up	Other Entity	August 9, 2005	December 31, 2005
6	Williams Power Company, Inc.	Other Entity	March 3, 2006	December 31, 2009
7	Progress Ventures, Inc.	Other Entity	May 1, 2006	April 30, 2009

2006 Capacity in MW

A	B	C	D	E	F	G	H	I	J	K	L	M
Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	372	372	372	320	320	320	320	320	320	320	372	372
2	467	467	467	467	467	469	469	469	469	469	469	469
3	156	156	156	156	156	155	155	155	155	155	155	155
4	562	569	569	569	569	569	569	569	569	566	566	566
5	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	n/a	n/a	56	56	56	56	56	56	56	56	56	56
7	n/a	n/a	n/a	n/a	55	28	28	28	13	13	13	55
Total	1,557	1,564	1,620	1,568	1,623	1,597	1,597	1,597	1,582	1,579	1,631	1,673

2006 Capacity in Dollars

A	B	C	D	E	F	G	H	I	J	K	L	M
Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	[redacted]											
2												
3												
4												
5												
6												
7												
Total	$ 5,567,800	$ 5,760,442	$ 3,714,452	$ 3,604,238	$ 6,849,582	$ 13,796,520	$ 13,796,520	$ 13,796,520	$ 7,819,940	$ 3,428,305	$ 3,742,625	$ 5,875,105

Year-to-date Short Term Capacity Payments	$ 87,752,049

APPENDIX I

FUEL COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

AND

REVISED E-SCHEDULES

KMD-3
DOCKET NO. 070001-EI
FPL WITNESS: K.M. DUBIN
August 6, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 18
COMPANY Florida Power & Light Co.
WITNESS K.M. Dubin (KMD-3)
DATE 11-06-07

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER
2007

LINE NO.		(1) Actual January	(2) Actual February	(3) Actual March	(4) Actual April	(5) Actual May	(6) Actual June
A	**Fuel Costs & Net Power Transactions**						
1	a Fuel Cost of System Net Generation	344,860,541	333,895,916	336,299,910	459,797,479	$ 514,498,368	$ 528,202,921
	b Incremental Hedging Costs	53,226	39,493	23,534	30,791	24,115	37,136
	c Nuclear Fuel Disposal Costs	2,080,232	1,838,048	2,068,516	1,527,611	1,426,405	1,772,838
	d Coal Car Investment	276,584	274,727	272,871	271,014	269,158	266,915
	e Gas Pipelines Depreciation & Return	-	-	-	-	-	-
	f DOE D&D Fund Payment	-	-	-	-	-	-
2	a Fuel Cost of Power Sold (Per A6)	(6,942,952)	(13,948,405)	(8,140,711)	(9,714,574)	(5,956,867)	(3,424,938)
	b Gains from Off-System Sales	(2,083,070)	(5,499,558)	(2,229,624)	(1,844,553)	(1,169,825)	(563,318)
3	a Fuel Cost of Purchased Power (Per A7)	21,506,997	22,969,094	17,804,660	21,444,941	23,110,057	24,916,606
	b Energy Payments to Qualifying Facilities (Per A8)	14,369,588	14,062,127	14,320,595	7,235,184	14,106,491	15,289,372
		-	-	-		-	-
4	Energy Cost of Economy Purchases (Per A9)	5,725,484	2,528,336	2,649,522	5,722,004	7,237,907	5,509,560
5	Total Fuel Costs & Net Power Transactions	379,846,630	356,159,778	363,069,273	484,469,897	553,545,809	572,007,092
6	**Adjustments to Fuel Cost**						
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(4,265,087)	(4,514,513)	(4,274,683)	(4,521,659)	$ (5,446,650)	(6,025,887)
	b Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(46,608)	(141,687)	(37,683)	(85,101)	10,120	(117,212)
	c Inventory Adjustments	(65,740)	(23,322)	151,823	165,860	44,370	45,870
	d Non Recoverable Oil/Tank Bottoms	226,102	53,484	-	(18,211)	(76,294)	-
7	Adjusted Total Fuel Costs & Net Power Transactions	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
B	**kWh Sales**						
1	Jurisdictional kWh Sales	8,555,173,173	7,458,110,394	7,381,834,925	7,481,240,405	8,249,438,274	9,086,669,337
2	Sale for Resale (excluding FKEC & CKW)	42,430,619	44,452,806	44,688,200	48,430,962	49,191,597	48,011,520
3	Sub-Total Sales (excluding FKEC & CKW)	8,597,603,792	7,502,563,200	7,426,523,125	7,529,671,367	8,298,629,871	9,134,680,857
4	**Jurisdictional % of Total Sales (B1/B3)**	99.50648%	99.40750%	99.39826%	99.35680%	99.40723%	99.47440%
C	**True-up Calculation**						
1	Juris Fuel Revenues (Net of Revenue Taxes)	495,538,005	424,858,917	420,150,299	426,184,984	$ 462,649,668	512,234,106
2	**Fuel Adjustment Revenues Not Applicable to Period**						
	a Prior Period True-up (Collected)/Refunded This Period	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)
	b GPIF, Net of Revenue Taxes	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)
	c Other	-	-	-	-	-	-
3	Jurisdictional Fuel Revenues Applicable to Period	487,248,093	416,569,005	411,860,387	417,895,072	454,359,756	503,944,194
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
	b Nuclear Fuel Expense - 100% Retail	-	-	-	-	-	-
	c	-	-	-	-	-	-
	d D&D Fund Payments -100% Retail	-	-	-	-	-	-
	e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.50648%	99.40750%	99.39826%	99.35680%	99.40723%	99.47440%
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00054) +(Lines C4b,c,d)	374,043,040	349,639,606	356,941,677	477,180,895	545,122,724	563,239,426
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	113,205,053	66,929,399	54,918,710	(59,285,823)	(90,762,968)	(59,295,232)
8	Interest Provision for the Month	(370,119)	56,650	357,189	382,426	88,490	(207,150)
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(91,006,958)	29,411,889	103,981,851	166,841,663	115,522,179	32,431,614
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)
10	Prior Period True-up Collected/(Refunded) This Period	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	(24,332,669)	50,237,293	113,097,105	61,777,621	(21,312,944)	(73,231,413)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER
2007

LINE NO.		(7) Estimated July	(8) Estimated August	(9) Estimated September	(10) Estimated October	(11) Estimated November	(12) Estimated December-07	(13) Total Period
A	**Fuel Costs & Net Power Transactions**							
1	a Fuel Cost of System Net Generation	$605,214,881	$567,774,607	$542,667,734	$524,304,978	$395,882,639	$434,886,417	5,588,286,392
	b Incremental Hedging Costs	36,253	36,253	51,580	36,253	36,253	36,253	441,140
	c Nuclear Fuel Disposal Costs	1,985,276	1,985,276	1,468,214	1,502,983	1,495,010	1,655,567	20,805,976
	d Coal Car Investment	265,445	263,588	261,732	259,875	258,019	256,162	3,196,089
	e Gas Pipelines Depreciation & Return	-	-	-	-	-	-	
	f DOE D&D Fund Payment	-	-	-	-	-	-	
2	a Fuel Cost of Power Sold (Per A6)	(5,463,285)	(9,198,924)	(2,940,862)	(4,921,156)	(9,383,626)	(22,015,976)	(102,052,276)
	b Gains from Off-System Sales	(658,516)	(1,623,193)	(379,296)	(526,914)	(1,208,004)	(4,268,792)	(22,054,662)
3	a Fuel Cost of Purchased Power (Per A7)	24,881,481	24,806,768	24,087,957	24,683,677	21,653,045	22,277,344	274,142,627
	b Energy Payments to Qualifying Facilities (Per A8)	17,624,000	17,851,000	17,828,000	15,323,000	15,590,000	18,815,000	182,414,357
		-	-	-	-	-	-	
4	Energy Cost of Economy Purchases (Per A9)	7,959,929	6,698,749	10,882,073	11,118,854	13,170,507	8,877,386	88,080,310
5	Total Fuel Costs & Net Power Transactions	651,845,465	608,594,124	593,927,132	571,781,550	437,493,843	460,519,361	6,033,259,954
6	**Adjustments to Fuel Cost**							
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(5,781,531)	(6,013,680)	(6,126,625)	(5,883,116)	(5,418,624)	(4,834,992)	(63,107,047)
	b Reactive and Voltage Control / Energy Imbalance Fuel Revenues	-	-	-	-	-	-	(418,171)
	c Inventory Adjustments	-	-	-	-	-	-	318,861
	d Non Recoverable Oil/Tank Bottoms	-	-	-	-	-	-	185,081
7	Adjusted Total Fuel Costs & Net Power Transactions	646,063,934	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,970,238,678
B	**kWh Sales**							
1	Jurisdictional kWh Sales	10,271,989,000	10,333,103,000	10,270,876,000	9,645,174,000	8,610,646,000	8,680,135,000	106,024,389,508
2	Sale for Resale (excluding FKEC & CKW)	40,773,551	48,816,612	43,527,178	45,220,055	47,828,782	580,148	503,952,029
3	Sub-Total Sales (excluding FKEC & CKW)	10,312,762,551	10,381,919,612	10,314,403,178	9,690,394,055	8,658,474,782	8,680,715,148	106,528,341,537
4	**Jurisdictional % of Total Sales (B1/B3)**	99.60463%	99.52979%	99.57800%	99.53335%	99.44761%	99.99332%	N/A
C	**True-up Calculation**							
1	Juris Fuel Revenues (Net of Revenue Taxes)	578,717,763	582,160,889	578,655,057	543,403,378	485,118,684	489,033,653	5,998,705,404
2	**Fuel Adjustment Revenues Not Applicable to Period**							
	a Prior Period True-up (Collected)/Refunded This Period	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(91,006,958)
	b GPIF, Net of Revenue Taxes	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(8,471,988)
	c Other		-					
3	Jurisdictional Fuel Revenues Applicable to Period	570,427,851	573,870,977	570,365,145	535,113,466	476,828,772	480,743,741	5,899,226,458
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	646,063,934	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,970,238,678
	b Nuclear Fuel Expense - 100% Retail	-	-	-	-	-	-	
	c	-	-	-	-	-	-	
	d D&D Fund Payments -100% Retail	-	-	-	-	-	-	
	e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	646,063,934	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,970,238,678
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.60463%	99.52979%	99.57800%	99.53335%	99.44761%	99.99332%	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00054) +(Lines C4b,c,d)	643,857,086	600,070,914	585,636,061	563,561,829	429,920,510	455,899,982	5,945,113,750
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	(73,429,235)	(26,199,937)	(15,270,916)	(28,448,363)	46,908,262	24,843,759	(45,887,292)
8	Interest Provision for the Month	(466,197)	(653,709)	(714,337)	(780,169)	(709,754)	(522,008)	(3,538,687)
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(19,486,855)	(85,798,374)	(105,068,106)	(113,469,446)	(135,114,065)	(81,331,644)	(91,006,958)
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)
10	Prior Period True-up Collected/(Refunded) This Period	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	91,006,958
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	(139,542,932)	(158,812,664)	(167,214,004)	(188,858,623)	(135,076,202)	(103,170,537)	(103,170,537)

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ESTIMATED/ACTUAL vs ORIGINAL PROJECTIONS
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	**Fuel Costs & Net Power Transactions**				
1	a Fuel Cost of System Net Generation	$ 5,588,286,392	$ 5,684,639,014	$ (96,352,622)	(1.7) %
	b Incremental Hedging Costs	441,140	570,098	(128,958)	(22.6) %
	c Nuclear Fuel Disposal Costs	20,805,976	20,914,580	(108,604)	(0.5) %
	d Coal Cars Depreciation & Return	3,196,089	3,265,273	(69,184)	(2.1) %
	e DOE D&D Fund Payment	0	0	0	N/A
2	a Fuel Cost of Power Sold (Per A6)	(102,052,276)	(147,352,443)	45,300,167	(30.7) %
	b Gains from Off-System Sales	(22,054,662)	(19,197,960)	(2,856,702)	14.9 %
3	a Fuel Cost of Purchased Power (Per A7)	274,142,627	246,819,107	27,323,520	11.1 %
	b Energy Payments to Qualifying Facilities (Per A8)	182,414,357	172,870,000	9,544,357	5.5 %
4	Energy Cost of Economy Purchases (Per A9)	88,080,310	133,340,912	(45,260,602)	(33.9) %
5	Total Fuel Costs & Net Power Transactions	$ 6,033,259,954	$ 6,095,868,581	$ (62,608,627)	(1.0) %
6	**Adjustments to Fuel Cost**				
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (63,107,047)	$ (63,348,749)	$ 241,702	(0.4) %
	b Reactive and Voltage Control Fuel Revenue	(418,171)		(418,171)	N/A
	c Inventory Adjustments	318,861		318,861	N/A
	d Non Recoverable Oil/Tank Bottoms	185,081		185,081	N/A
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 5,970,238,678	$ 6,032,519,832	$ (62,281,154)	(1.0) %
B	**Jurisdictional kWh Sales**				
1	Jurisdictional kWh Sales	106,024,389,508	107,697,622,000	(1,673,232,492)	(1.6) %
2	Sale for Resale (excluding FKEC & CKW)	503,952,029	495,373,000	8,579,029	1.7 %
3	Sub-Total Sales (excluding FKEC & CKW)	106,528,341,537	108,192,995,000	(1,664,653,463)	(1.5) %
4	**Jurisdictional % of Total Sales (B1/B3)**	N/A	N/A	N/A	N/A
	True-up Calculation				
C 1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 5,998,705,404	6,107,670,738	$ (108,965,334)	(1.8) %
2	**Fuel Adjustment Revenues Not Applicable to Period**				
a	1 Prior Period True-up (Collected)/Refunded This Period	(91,006,958)	(91,006,958)	0	0.0 %
	b GPIF, Net of Revenue Taxes (b)	(8,471,988)	(8,471,988)	0	0.0 %
3	Jurisdictional Fuel Revenues Applicable to Period	$ 5,899,226,458	$ 6,008,191,792	$ (108,965,334)	(1.8) %
4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 5,970,238,678	$ 6,032,519,832	$ (62,281,154)	(1.0) %
b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
c	RTP Incremental Fuel -100% Retail	0	0	0	N/A
d	D&D Fund Payments -100% Retail (Line A 1 e)	0	0	0	N/A
e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	5,970,238,678	6,032,519,832	(62,281,154)	(1.0) %
5	Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions	$ 5,945,113,750	$ 6,008,191,792	$ (63,078,042)	(1.0) %
7	True-up Provision for the Period Over/(Under) Recovery (Line C3 - Line C6)	$ (45,887,292)	0	$ (45,887,292)	N/M
8	Interest Provision for the Period	(3,538,687)	0	(3,538,687)	N/A
9 a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(91,006,958)	(91,006,958)	0	0.0 %
b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(53,744,558)	0	(53,744,558)	N/A
10	Prior Period True-up Collected/(Refunded) This Period	91,006,958	91,006,958	0	0.0 %
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through D10)	$ (103,170,537)	$ (0)	$ (103,170,537)	N/M

NOTES (a) **Generation Performance Incentive Factor is (($8,478,098) x 99.9280%) - See Order No. PSC-06-1057-FOF-EI.**
(b) **Per Projected Schedule E-2, revised October 24, 2006.**

Florida Power & Light Company
8/06/07

Generating System Comparative Data by Fuel Type

		Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$78,985,882	$67,099,182	$63,610,951	$51,494,065	$9,546,811	$12,439,946	$283,176,836
2	Light Oil	$0	$0	$234,000	$131,000	$0	$0	$365,000
3	Coal	$14,580,000	$14,511,000	$14,014,000	$14,409,000	$13,928,000	$14,218,000	$85,660,000
4	Gas	$503,377,999	$477,925,425	$458,424,783	$451,972,913	$365,600,828	$400,651,471	$2,657,953,421
5	Nuclear	$8,271,000	$8,239,000	$6,384,000	$6,298,000	$6,807,000	$7,577,000	$43,576,000
6	***Total***	$605,214,881	$567,774,607	$542,667,734	$524,304,978	$395,882,639	$434,886,417	$3,070,731,257
	System Net Generation (MWH)							
7	Heavy Oil	827,806	671,497	644,227	566,088	89,967	105,726	2,905,311
8	Light Oil	0	0	1,173	645	0	0	1,818
9	Coal	642,668	643,489	625,280	646,867	634,540	655,691	3,848,535
10	Gas	6,617,039	6,621,910	6,386,453	6,102,530	4,938,947	5,309,979	35,976,858
11	Nuclear	2,131,954	2,131,954	1,609,122	1,500,512	1,605,466	1,777,885	10,756,893
12	***Total***	10,219,467	10,068,850	9,266,255	8,816,642	7,268,920	7,849,281	53,489,415
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	1,278,657	1,038,517	994,768	861,714	141,865	171,649	4,487,170
14	Light Oil (BBLS)	0	0	2,576	1,429	0	0	4,005
15	Coal (TONS)	339,999	340,603	331,121	342,680	332,965	344,164	2,031,532
16	Gas (MCF)	52,670,564	52,902,343	50,841,364	48,798,014	37,773,480	40,456,392	283,442,157
17	Nuclear (MBTU)	23,769,566	23,769,566	17,857,894	16,792,872	17,985,710	19,891,630	120,067,238
	BTU Burned (MMBTU)							
18	Heavy Oil	8,183,404	6,646,508	6,366,516	5,514,973	907,936	1,098,553	28,717,890
19	Light Oil	0	0	15,017	8,329	0	0	23,346
20	Coal	6,465,458	6,473,723	6,290,130	6,507,210	6,327,259	6,538,172	38,601,952
21	Gas	52,670,564	52,902,343	50,841,364	48,798,014	37,773,480	40,456,392	283,442,157
22	Nuclear	23,769,566	23,769,566	17,857,894	16,792,872	17,985,710	19,891,630	120,067,238
23	***Total***	91,088,992	89,792,140	81,370,921	77,621,398	62,994,385	67,984,747	470,852,583

Florida Power & Light Company
8/06/07

Generating System Comparative Data by Fuel Type

		Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
	Generation Mix (%MWH)							
24	Heavy Oil	8.10%	6.67%	6.95%	6.42%	1.24%	1.35%	5.43%
25	Light Oil	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%
26	Coal	6.29%	6.39%	6.75%	7.34%	8.73%	8.35%	7.19%
27	Gas	64.75%	65.77%	68.92%	69.22%	67.95%	67.65%	67.26%
28	Nuclear	20.86%	21.17%	17.37%	17.02%	22.09%	22.65%	20.11%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	61.7725	64.6106	63.9455	59.7577	67.2950	72.4732	63.1081
31	Light Oil ($/BBL)	#DIV/0!	0.0000	90.8385	91.6725	0.0000	0.0000	91.1361
32	Coal ($/ton)	42.8825	42.6039	42.3229	42.0480	41.8302	41.3117	42.1652
33	Gas ($/MCF)	9.5571	9.0341	9.0168	9.2621	9.6788	9.9033	9.3774
34	Nuclear ($/MBTU)	0.3480	0.3466	0.3575	0.3750	0.3785	0.3809	0.3629
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	9.6520	10.0954	9.9915	9.3371	10.5148	11.3239	9.8606
36	Light Oil	0.0000	0.0000	15.5823	15.7282	0.0000	0.0000	15.6344
37	Coal	2.2551	2.2415	2.2279	2.2143	2.2013	2.1746	2.2191
38	Gas	9.5571	9.0341	9.0168	9.2621	9.6788	9.9033	9.3774
39	Nuclear	0.3480	0.3466	0.3575	0.3750	0.3785	0.3809	0.3629
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	9,886	9,898	9,882	9,742	10,092	10,391	9,885
41	Light Oil	0	0	12,802	12,913	0	0	12,842
42	Coal	10,060	10,060	10,060	10,060	9,971	9,971	10,030
43	Gas	7,960	7,989	7,961	7,996	7,648	7,619	7,878
44	Nuclear	11,149	11,149	11,098	11,191	11,203	11,188	11,162
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	9.5416	9.9925	9.8740	9.0965	10.6115	11.7662	9.7469
46	Light Oil	0.0000	0.0000	19.9488	20.3101	0.0000	0.0000	20.0770
47	Coal	2.2687	2.2551	2.2412	2.2275	2.1950	2.1684	2.2258
48	Gas	7.6073	7.2173	7.1781	7.4063	7.4024	7.5453	7.3880
49	Nuclear	0.3880	0.3865	0.3967	0.4197	0.4240	0.4262	0.4051
50	***Total***	5.9222	5.6389	5.8564	5.9468	5.4462	5.5405	5.7408

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	64,954	28.1	95.1	65.6	10,032	Heavy Oil BBLS ->	99,660	6,400,030	637,827	6,500,000	10.0071
2			14,175					Gas MCF ->	156,047	1,000,000	156,047	1,477,000	10.4199
4	TURKEY POINT 2	378	39,221	24.1	94.1	63.1	10,181	Heavy Oil BBLS ->	60,309	6,400,007	385,978	3,933,000	10.0278
5			28,543					Gas MCF ->	303,944	1,000,000	303,944	2,962,000	10.3773
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	1,739,000	0.3459
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	1,940,000	0.3859
11	TURKEY POINT 5	1,080	698,023	86.9	94.1	86.9	6,999	Gas MCF ->	4,885,838	1,000,000	4,885,838	43,872,000	6.2852
13	LAUDERDALE 4	432	260,480	81.0	97.6	81.0	8,123	Gas MCF ->	2,116,120	1,000,000	2,116,120	20,657,000	7.9304
15	LAUDERDALE 5	432	263,514	82.0	98.4	82.0	8,092	Gas MCF ->	2,132,445	1,000,000	2,132,445	21,221,000	8.0531
17	PT EVERGLADES 1	205	18,945	12.4	96.3	65.1	10,893	Gas MCF ->	206,373	1,000,000	206,373	2,057,000	10.8580
19	PT EVERGLADES 2	205	15,175	10.0	96.2	64.9	10,894	Gas MCF ->	165,330	1,000,000	165,330	1,648,000	10.8597
21	PT EVERGLADES 3	374	41,416	37.9	92.2	69.1	10,214	Heavy Oil BBLS ->	63,296	6,399,994	405,094	4,100,000	9.8996
22			64,079					Gas MCF ->	672,499	1,000,000	672,499	6,727,000	10.4980
24	PT EVERGLADES 4	374	32,412	33.9	93.0	68.8	10,241	Heavy Oil BBLS ->	49,562	6,400,065	317,200	3,210,000	9.9037
25			61,982					Gas MCF ->	649,513	1,000,000	649,513	6,509,000	10.5015
27	RIVIERA 3	273	16,111	7.9	94.0	92.2	10,612	Gas MCF ->	170,984	1,000,000	170,984	1,724,000	10.7007
29	RIVIERA 4	284	103,272	48.9	89.8	63.9	10,586	Gas MCF ->	1,093,293	1,000,000	1,093,293	10,878,000	10.5334

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,465,000	0.4050
33	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,127,000	0.4107
35	CAPE CANAVERAL 1	378	21,915	34.1	91.3	68.4	10,288	Heavy Oil BBLS ->	33,550	6,400,030	214,721	2,173,000	9.9156
36			73,950					Gas MCF ->	771,588	1,000,000	771,588	7,741,000	10.4678
38	CAPE CANAVERAL 2	378	15,732	29.6	90.4	66.9	10,347	Heavy Oil BBLS ->	24,138	6,400,116	154,486	1,563,000	9.9352
39			67,471					Gas MCF ->	706,468	1,000,000	706,468	7,076,000	10.4874
41	CUTLER 5	68	4,371	8.6	98.2	80.3	11,831	Gas MCF ->	51,712	1,000,000	51,712	477,000	10.9136
43	CUTLER 6	137	8,614	8.5	96.0	69.9	11,978	Gas MCF ->	103,178	1,000,000	103,178	969,000	11.2491
45	FORT MYERS 2	1,405	916,257	87.7	96.1	87.7	7,214	Gas MCF ->	6,610,360	1,000,000	6,610,360	63,322,000	6.9109
47	FORT MYERS 3A_B	158	53,852	22.9	96.3	99.4	10,999	Gas MCF ->	592,360	1,000,000	592,360	5,768,000	10.7108
49	SANFORD 3	138	5,443	5.3	95.1	37.6	12,332	Gas MCF ->	67,130	1,000,000	67,130	660,000	12.1248
51	SANFORD 4	936	612,242	87.9	96.3	87.9	7,204	Gas MCF ->	4,410,718	1,000,000	4,410,718	42,306,000	6.9100
53	SANFORD 5	936	613,899	88.2	96.5	88.2	7,201	Gas MCF ->	4,421,012	1,000,000	4,421,012	42,589,000	6.9375
55	PUTNAM 1	239	64,560	36.3	96.4	98.6	9,137	Gas MCF ->	589,900	1,000,000	589,900	5,740,000	8.8910
57	PUTNAM 2	239	59,554	33.5	96.1	98.5	9,148	Gas MCF ->	544,827	1,000,000	544,827	5,300,000	8.8994
59	MANATEE 1	793	86,473	56.4	94.4	56.4	10,379	Heavy Oil BBLS ->	135,231	6,399,990	865,477	8,742,000	10.1095
60			246,508					Gas MCF ->	2,590,561	1,000,000	2,590,561	25,624,000	10.3948

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	793	66,109	48.1	95.0	48.1	10,430	Heavy Oil	BBLS ->	103,764	6,400,004	664,090	6,707,000	10.1454
63			217,900					Gas	MCF ->	2,298,323	1,000,000	2,298,323	22,606,000	10.3745
64														
65	MANATEE 3	1,084	571,006	70.8	96.5	70.8	7,371	Gas	MCF ->	4,209,311	1,000,000	4,209,311	40,120,000	7.0262
66														
67	MARTIN 1	815	233,775	60.5	95.0	75.1	10,204	Heavy Oil	BBLS ->	360,614	6,400,001	2,307,930	21,387,000	9.1485
68			132,916					Gas	MCF ->	1,433,811	1,000,000	1,433,811	13,042,000	9.8122
69														
70	MARTIN 2	815	225,798	58.8	93.9	73.8	10,216	Heavy Oil	BBLS ->	348,531	6,400,007	2,230,601	20,671,000	9.1546
71			130,415					Gas	MCF ->	1,408,759	1,000,000	1,408,759	12,814,000	9.8255
72														
73	MARTIN 3	456	296,969	87.5		87.5	7,336	Gas	MCF ->	2,178,661	1,000,000	2,178,661	19,862,000	6.6882
74														
75	MARTIN 4	456	296,241	87.3	98.6	87.3	7,339	Gas	MCF ->	2,174,217	1,000,000	2,174,217	20,293,000	6.8502
76														
77	MARTIN 8	1,084	700,592	86.9	96.5	86.9	7,073	Gas	MCF ->	4,955,488	1,000,000	4,955,488	47,337,000	6.7567
78														
79	FORT MYERS 1-12	552		0.0	98.4		0							
80														
81	LAUDERDALE 1-24	684		0.0	91.7		0							
82														
83	EVERGLADES 1-12	342		0.0	88.3		0							
84														
85	ST JOHNS 1O	127	92,659	98.1	96.9	98.1	9,692	Coal	TONS ->	36,643	24,510,029	898,121	2,081,000	2.2459
86														
87	ST JOHNS 2O	127	92,517	97.9	97.0	97.9	9,773	Coal	TONS ->	36,893	24,509,799	904,240	2,096,000	2.2655
88														
89	SCHERER 4	634	457,491	97.0	97.2	97.0	10,192	Coal	TONS ->	266,463	17,499,979	4,663,097	10,403,000	2.2739
90														
91														
92														

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	TOTAL	21,128	10,219,484				8,913				91,089,197	605,215,000	5.9222

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	71,582	29.6	95.1	66.2	10,021	Heavy Oil BBLS ->	109,864	6,399,985	703,128	7,106,000	9.9271
2			11,735					Gas MCF ->	131,827	1,000,000	131,827	1,154,000	9.8342
3													
4	TURKEY POINT 2	378	54,295	25.8	94.1	64.8	10,092	Heavy Oil BBLS ->	83,412	6,400,038	533,840	5,395,000	9.9365
5			18,242					Gas MCF ->	198,222	1,000,000	198,222	1,789,000	9.8070
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	1,732,000	0.3445
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	1,933,000	0.3845
10													
11	TURKEY POINT 5	1,080	697,857	86.9	94.1	86.8	6,996	Gas MCF ->	4,882,352	1,000,000	4,882,352	41,038,000	5.8806
12													
13	LAUDERDALE 4	432	258,005	80.3	97.6	80.3	8,134	Gas MCF ->	2,098,789	1,000,000	2,098,789	19,464,000	7.5441
14													
15	LAUDERDALE 5	432	262,793	81.8	98.4	81.8	8,085	Gas MCF ->	2,124,729	1,000,000	2,124,729	20,044,000	7.6273
16													
17	PT EVERGLADES 1	205	23,175	15.2	96.3	65.7	10,886	Gas MCF ->	252,304	1,000,000	252,304	2,387,000	10.2998
18													
19	PT EVERGLADES 2	205	21,671	14.2	96.2	64.1	10,917	Gas MCF ->	236,590	1,000,000	236,590	2,236,000	10.3179
20													
21	PT EVERGLADES 3	374	61,858	31.7	92.2	67.5	10,091	Heavy Oil BBLS ->	94,747	6,399,970	606,378	6,119,000	9.8920
22			26,285					Gas MCF ->	283,147	1,000,000	283,147	2,594,000	9.8688
23													
24	PT EVERGLADES 4	374	56,956	31.6	93.0	68.1	10,115	Heavy Oil BBLS ->	87,208	6,399,998	558,131	5,632,000	9.8883
25			30,959					Gas MCF ->	331,149	1,000,000	331,149	3,070,000	9.9162
26													
27	RIVIERA 3	273	101,546	50.0	94.0	64.5	10,585	Gas MCF ->	1,074,944	1,000,000	1,074,944	10,106,000	9.9521
28													
29	RIVIERA 4	284	22,474	10.6	89.8	89.9	10,610	Gas MCF ->	238,464	1,000,000	238,464	2,285,000	10.1673
30													

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,455,000	0.4034
33	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,119,000	0.4091
35	CAPE CANAVERAL 1	378	50,043	31.7	91.3	66.7	10,165	Heavy Oil BBLS ->	76,774	6,400,005	491,354	4,961,000	9.9135
36			39,003					Gas MCF ->	413,802	1,000,000	413,802	3,870,000	9.9224
38	CAPE CANAVERAL 2	378	37,127	23.0	90.4	64.7	10,178	Heavy Oil BBLS ->	57,104	6,400,025	365,467	3,690,000	9.9389
39			27,478					Gas MCF ->	292,110	1,000,000	292,110	2,727,000	9.9244
41	CUTLER 5	68	11,117	22.0	98.2	78.6	11,925	Gas MCF ->	132,575	1,000,000	132,575	1,162,000	10.4525
43	CUTLER 6	137	36,690	36.0	96.0	74.4	11,939	Gas MCF ->	438,054	1,000,000	438,054	3,874,000	10.5586
45	FORT MYERS 2	1,405	908,750	86.9	96.1	86.9	7,221	Gas MCF ->	6,562,452	1,000,000	6,562,452	59,529,000	6.5506
47	FORT MYERS 3A_B	158	49,456	21.0	96.3	99.4	10,996	Gas MCF ->	543,837	1,000,000	543,837	5,010,000	10.1302
49	SANFORD 3	138	10,298	10.0	95.1	54.9	11,553	Gas MCF ->	118,983	1,000,000	118,983	1,118,000	10.8563
51	SANFORD 4	936	608,048	87.3	96.3	87.3	7,211	Gas MCF ->	4,384,917	1,000,000	4,384,917	39,824,000	6.5495
53	SANFORD 5	936	609,797	87.6	96.5	87.6	7,208	Gas MCF ->	4,395,755	1,000,000	4,395,755	40,089,000	6.5742
55	PUTNAM 1	239	56,549	31.8	96.4	98.6	9,143	Gas MCF ->	517,062	1,000,000	517,062	4,784,000	8.4600
57	PUTNAM 2	239	54,072	30.4	96.1	98.4	9,156	Gas MCF ->	495,087	1,000,000	495,087	4,558,000	8.4295
59	MANATEE 1	793	74,723	52.4	94.4	52.4	10,416	Heavy Oil BBLS ->	117,179	6,400,012	749,947	7,570,000	10.1307
60			234,424					Gas MCF ->	2,470,415	1,000,000	2,470,415	23,082,000	9.8462

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	793	62,417	46.6	95.0	46.6	10,466	Heavy Oil BBLS ->	98,280	6,400,000	628,992	6,349,000	10.1719
63			212,576					Gas MCF ->	2,249,302	1,000,000	2,249,302	20,866,000	9.8158
64													
65	MANATEE 3	1,084	572,571	71.0	96.5	71.0	7,365	Gas MCF ->	4,217,437	1,000,000	4,217,437	38,135,000	6.6603
66													
67	MARTIN 1	815	98,638	53.8	95.0	65.8	10,408	Heavy Oil BBLS ->	152,821	6,399,997	978,054	9,871,000	10.0073
68			227,617					Gas MCF ->	2,417,817	1,000,000	2,417,817	21,805,000	9.5797
69													
70	MARTIN 2	815	103,858	50.0	93.9	62.8	10,400	Heavy Oil BBLS ->	161,128	6,399,980	1,031,216	10,407,000	10.0204
71			199,243					Gas MCF ->	2,121,206	1,000,000	2,121,206	19,037,000	9.5547
72													
73	MARTIN 3	456	294,965	86.9	94.4	86.9	7,343	Gas MCF ->	2,166,208	1,000,000	2,166,208	18,537,000	6.2845
74													
75	MARTIN 4	456	294,049	86.7	98.6	86.7	7,347	Gas MCF ->	2,160,598	1,000,000	2,160,598	19,029,000	6.4714
76													
77	MARTIN 8	1,084	700,476	86.9	96.5	86.9	7,069	Gas MCF ->	4,952,319	1,000,000	4,952,319	44,720,000	6.3842
78													
79	FORT MYERS 1-12	552		0.0	98.4		0						
80													
81	LAUDERDALE 1-24	684		0.0	91.7		0						
82													
83	EVERGLADES 1-12	342		0.0	88.3		0						
84													
85	ST JOHNS 1O	127	92,603	98.0	96.9	98.0	9,693	Coal TONS ->	36,671	24,477,407	897,611	2,080,000	2.2461
86													
87	ST JOHNS 2O	127	92,350	97.7	97.0	97.7	9,774	Coal TONS ->	36,879	24,477,318	902,699	2,092,000	2.2653
88													
89	SCHERER 4	634	458,536	97.2	97.2	97.2	10,192	Coal TONS ->	267,052	17,500,011	4,673,413	10,339,000	2.2548
90													
91													
92													

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	TOTAL	21,128	10,068,859				8,918				89,792,247	567,773,000	5.6389

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	59,898	25.5	95.1	67.7	9,987	Heavy Oil BBLS ->	91,751	6,400,028	587,209	5,873,000	9.8050
2			9,490					Gas MCF ->	105,796	1,000,000	105,796	935,000	9.8521
4	TURKEY POINT 2	378	43,205	21.0	94.1	65.8	10,065	Heavy Oil BBLS ->	66,289	6,400,036	424,252	4,244,000	9.8229
5			13,979					Gas MCF ->	151,325	1,000,000	151,325	1,372,000	9.8150
7	TURKEY POINT 3	693	32,432	6.5	97.5	97.5	11,330	Nuclear Othr ->	367,491	1,000,000	367,491	111,000	0.3423
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	1,863,000	0.3829
11	TURKEY POINT 5	1,080	683,900	88.0	94.1	88.0	6,981	Gas MCF ->	4,774,918	1,000,000	4,774,918	40,512,000	5.9237
13	LAUDERDALE 4	432	255,669	82.2	97.6	82.2	8,084	Gas MCF ->	2,066,914	1,000,000	2,066,914	19,093,000	7.4679
15	LAUDERDALE 5	432	183,372	59.0	98.4	84.2	8,025	Gas MCF ->	1,471,579	1,000,000	1,471,579	13,893,000	7.5764
17	PT EVERGLADES 1	205	18,001	12.2		64.1	10,919	Gas MCF ->	196,552	1,000,000	196,552	1,853,000	10.2940
19	PT EVERGLADES 2	205	7,578	5.1	22.5	64.9	10,901	Gas MCF ->	82,612	1,000,000	82,612	779,000	10.2796
21	PT EVERGLADES 3	374	57,453	36.1	92.2	67.8	10,125	Heavy Oil BBLS ->	87,938	6,399,998	562,803	5,621,000	9.7836
22			39,651					Gas MCF ->	420,435	1,000,000	420,435	3,894,000	9.8208
24	PT EVERGLADES 4	374	48,894	26.3	93.0	68.7	10,082	Heavy Oil BBLS ->	74,797	6,400,003	478,701	4,781,000	9.7783
25			21,994					Gas MCF ->	235,996	1,000,000	235,996	2,169,000	9.8620
27	RIVIERA 3	273	19,375	9.9	94.0	88.7	10,650	Gas MCF ->	206,351	1,000,000	206,351	1,968,000	10.1574
29	RIVIERA 4	284	98,420	48.1	89.8	66.4	10,552	Gas MCF ->	1,038,589	1,000,000	1,038,589	9,767,000	9.9238

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	2,367,000	0.4019
33	ST LUCIE 2	714	501,219	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	2,042,000	0.4074
35	CAPE CANAVERAL 1	378	45,339	29.2	91.3	68.3	10,123	Heavy Oil BBLS ->	69,423	6,399,983	444,306	4,440,000	9.7929
36			34,201					Gas MCF ->	360,919	1,000,000	360,919	3,361,000	9.8271
38	CAPE CANAVERAL 2	378	30,475	20.1	90.4	64.6	10,193	Heavy Oil BBLS ->	46,875	6,399,957	299,998	2,998,000	9.8376
39			24,242					Gas MCF ->	257,779	1,000,000	257,779	2,392,000	9.8670
41	CUTLER 5	68	6,752	13.8	98.2	80.1	11,828	Gas MCF ->	79,869	1,000,000	79,869	698,000	10.3372
43	CUTLER 6	137	33,817	34.3	96.0	72.4	11,957	Gas MCF ->	404,365	1,000,000	404,365	3,550,000	10.4976
45	FORT MYERS 2	1,405	888,618	87.8	86.3	87.8	7,210	Gas MCF ->	6,407,484	1,000,000	6,407,484	57,822,000	6.5070
47	FORT MYERS 3A_B	158	46,159	20.3	19.3	99.4	11,005	Gas MCF ->	507,995	1,000,000	507,995	4,661,000	10.0977
49	SANFORD 3	138	8,327	8.4	95.1	56.9	11,517	Gas MCF ->	95,906	1,000,000	95,906	900,000	10.8083
51	SANFORD 4	936	595,029	88.3	96.3	88.3	7,198	Gas MCF ->	4,283,173	1,000,000	4,283,173	38,730,000	6.5089
53	SANFORD 5	936	597,491	88.7	96.5	88.7	7,193	Gas MCF ->	4,298,261	1,000,000	4,298,261	39,065,000	6.5382
55	PUTNAM 1	239	54,428	31.6	96.4	98.6	9,143	Gas MCF ->	497,678	1,000,000	497,678	4,573,000	8.4019
57	PUTNAM 2	239	51,669	30.0	96.1	98.3	9,158	Gas MCF ->	473,219	1,000,000	473,219	4,341,000	8.4016
59	MANATEE 1	793	86,356	57.9	94.4	57.9	10,374	Heavy Oil BBLS ->	134,994	6,399,973	863,958	8,631,000	9.9947
60			244,056					Gas MCF ->	2,563,759	1,000,000	2,563,759	23,905,000	9.7949

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	793	66,781	49.6	95.0	49.6	10,416	Heavy Oil BBLS ->	104,686	6,399,996	669,990	6,693,000	10.0223
63			216,422					Gas MCF ->	2,279,865	1,000,000	2,279,865	21,146,000	9.7707
64													
65	MANATEE 3	1,084	554,391	71.0	96.5	71.0	7,365	Gas MCF ->	4,083,222	1,000,000	4,083,222	36,706,000	6.6210
66													
67	MARTIN 1	815	102,841	55.1	95.0	70.7	10,391	Heavy Oil BBLS ->	158,791	6,399,985	1,016,260	10,151,000	9.8706
68			220,578					Gas MCF ->	2,344,703	1,000,000	2,344,703	21,188,000	9.6057
69													
70	MARTIN 2	815	102,984	50.7	93.9	68.0	10,393	Heavy Oil BBLS ->	159,225	6,400,000	1,019,040	10,179,000	9.8841
71			194,742					Gas MCF ->	2,075,343	1,000,000	2,075,343	18,698,000	9.6014
72													
73	MARTIN 3	456	288,881	88.0	94.4	88.0	7,328	Gas MCF ->	2,117,101	1,000,000	2,117,101	18,227,000	6.3095
74													
75	MARTIN 4	456	287,879	87.7	98.6	87.7	7,332	Gas MCF ->	2,110,905	1,000,000	2,110,905	18,541,000	6.4406
76													
77	MARTIN 8	1,084	687,341	88.1	96.5	88.1	7,054	Gas MCF ->	4,848,767	1,000,000	4,848,767	43,680,000	6.3549
78													
79	FORT MYERS 1-12	552	1,173	0.3	98.4	35.4	12,800	Light Oil BBLS ->	2,576	5,829,581	15,017	234,000	19.9488
80													
81	LAUDERDALE 1-24	684		0.0	91.7		0						
82													
83	EVERGLADES 1-12	342		0.0	88.3		0						
84													
85	ST JOHNS 1O	127	89,670	98.1	96.9	98.1	9,692	Coal TONS ->	35,556	24,444,538	869,150	2,014,000	2.2460
86													
87	ST JOHNS 2O	127	89,533	97.9	97.0	97.9	9,773	Coal TONS ->	35,799	24,444,007	875,071	2,028,000	2.2651
88													
89	SCHERER 4	634	446,077	97.8	97.2	97.8	10,190	Coal TONS ->	259,766	17,500,015	4,545,909	9,972,000	2.2355
90													
91													
92													

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	TOTAL	21,128	9,266,254				8,781				81,370,934	542,661,000	5.8563

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	107,845	39.6	95.1	82.5	9,766	Heavy Oil BBLS ->	162,820	6,400,000	1,042,048	9,739,000	9.0306
2			3,526					Gas MCF ->	45,669	1,000,000	45,669	421,000	11.9416
4	TURKEY POINT 2	378	69,510	36.1	94.1	80.3	9,924	Heavy Oil BBLS ->	105,074	6,399,985	672,472	6,285,000	9.0419
5			32,118					Gas MCF ->	336,158	1,000,000	336,158	3,209,000	9.9913
7	TURKEY POINT 3	693	389,192	75.5	97.5	97.5	11,330	Nuclear Othr ->	4,409,894	1,000,000	4,409,894	1,944,000	0.4995
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	1,917,000	0.3813
11	TURKEY POINT 5	1,080	765,362	95.3	94.1	95.3	6,903	Gas MCF ->	5,283,566	1,000,000	5,283,566	47,442,000	6.1986
13	LAUDERDALE 4	432	301,879	93.9	97.6	93.9	7,838	Gas MCF ->	2,366,222	1,000,000	2,366,222	22,162,000	7.3414
15	LAUDERDALE 5	432	274,348	85.4	54.0	94.5	7,826	Gas MCF ->	2,147,135	1,000,000	2,147,135	20,210,000	7.3666
17	PT EVERGLADES 1	205	32,192	21.1	96.3	79.3	10,704	Gas MCF ->	344,606	1,000,000	344,606	3,252,000	10.1019
19	PT EVERGLADES 2	205		0.0	0.0		0						
21	PT EVERGLADES 3	374	56,736	45.7	92.2	81.5	10,026	Heavy Oil BBLS ->	85,639	6,399,993	548,089	5,114,000	9.0137
22			70,385					Gas MCF ->	726,538	1,000,000	726,538	7,028,000	9.9851
24	PT EVERGLADES 4	374	37,815	44.5	93.0	83.1	10,083	Heavy Oil BBLS ->	57,040	6,400,053	365,059	3,406,000	9.0070
25			85,930					Gas MCF ->	882,730	1,000,000	882,730	8,578,000	9.9825
27	RIVIERA 3	273	90,720	44.7	94.0	80.3	10,372	Gas MCF ->	941,011	1,000,000	941,011	8,905,000	9.8159
29	RIVIERA 4	284	28,346	13.4	89.8	88.3	10,575	Gas MCF ->	299,772	1,000,000	299,772	2,855,000	10.0720

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,437,000	0.4004
33	ST LUCIE 2	714		0.0	0.0		0						
35	CAPE CANAVERAL 1	378	18,784	39.8	91.3	82.7	10,152	Heavy Oil BBLS ->	28,358	6,399,993	181,491	1,695,000	9.0236
36			93,191					Gas MCF ->	955,325	1,000,000	955,325	9,303,000	9.9827
38	CAPE CANAVERAL 2	378	12,452	29.3	90.4	80.5	10,190	Heavy Oil BBLS ->	18,837	6,399,851	120,554	1,126,000	9.0427
39			69,963					Gas MCF ->	719,327	1,000,000	719,327	6,985,000	9.9838
41	CUTLER 5	68		0.0	98.2		0						
43	CUTLER 6	137	46,821	45.9	40.2	88.8	11,647	Gas MCF ->	545,360	1,000,000	545,360	4,887,000	10.4377
45	FORT MYERS 2	1,405	731,266	70.0	66.6	95.2	7,196	Gas MCF ->	5,262,557	1,000,000	5,262,557	47,793,000	6.5357
47	FORT MYERS 3A_B	158	64,999	27.7	96.3	99.4	10,961	Gas MCF ->	712,466	1,000,000	712,466	6,626,000	10.1940
49	SANFORD 3	138	10,572	10.3	95.1	67.8	11,195	Gas MCF ->	118,359	1,000,000	118,359	1,111,000	10.5093
51	SANFORD 4	936	555,763	79.8	96.3	95.6	7,159	Gas MCF ->	3,979,125	1,000,000	3,979,125	36,729,000	6.6088
53	SANFORD 5	936	632,186	90.8	96.5	95.4	7,124	Gas MCF ->	4,504,303	1,000,000	4,504,303	41,997,000	6.6431
55	PUTNAM 1	239	76,105	42.8	96.4	98.6	9,102	Gas MCF ->	692,710	1,000,000	692,710	6,467,000	8.4975
57	PUTNAM 2	239	72,632	40.9	96.1	98.0	9,109	Gas MCF ->	661,663	1,000,000	661,663	6,165,000	8.4880
59	MANATEE 1	793	96,726	60.0	57.9	60.0	10,213	Heavy Oil BBLS ->	148,953	6,399,985	953,297	8,898,000	9.1992
60			257,462					Gas MCF ->	2,664,318	1,000,000	2,664,318	25,265,000	9.8131

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	793	14,769	9.2	95.0	56.8	10,215	Heavy Oil BBLS ->	22,746	6,400,114	145,577	1,359,000	9.2017
63			39,313					Gas MCF ->	406,890	1,000,000	406,890	3,916,000	9.9610
65	MANATEE 3	1,084	572,310	71.0	96.5	73.9	7,308	Gas MCF ->	4,182,640	1,000,000	4,182,640	38,639,000	6.7514
67	MARTIN 1	815	107,337	72.1	95.0	74.5	10,217	Heavy Oil BBLS ->	164,685	6,400,018	1,053,987	9,836,000	9.1637
68			329,588					Gas MCF ->	3,410,181	1,000,000	3,410,181	31,669,000	9.6087
70	MARTIN 2	815	44,115	27.9	15.1	73.8	10,187	Heavy Oil BBLS ->	67,562	6,400,047	432,400	4,035,000	9.1465
71			124,892					Gas MCF ->	1,289,349	1,000,000	1,289,349	12,099,000	9.6876
73	MARTIN 3	456	183,184	54.0	76.1	97.0	7,344	Gas MCF ->	1,345,305	1,000,000	1,345,305	11,911,000	6.5022
75	MARTIN 4	456	169,233	49.9	98.6	96.9	7,355	Gas MCF ->	1,244,800	1,000,000	1,244,800	11,021,000	6.5123
77	MARTIN 8	1,084	388,245	48.1	96.5	89.5	7,031	Gas MCF ->	2,729,938	1,000,000	2,729,938	25,325,000	6.5229
79	FORT MYERS 1-12	552	645	0.2	98.4	14.6	12,918	Light Oil BBLS ->	1,429	5,828,551	8,329	131,000	20.3101
81	LAUDERDALE 1-24	684		0.0	91.7		0						
83	EVERGLADES 1-12	342		0.0	88.3		0						
85	ST JOHNS 1O	127	92,659	98.1	96.9	98.1	9,692	Coal TONS ->	36,791	24,411,432	898,121	2,081,000	2.2459
87	ST JOHNS 2O	127	92,517	97.9	97.0	97.9	9,773	Coal TONS ->	37,041	24,411,868	904,240	2,096,000	2.2655
89	SCHERER 4	634	461,690	97.9	97.2	97.9	10,190	Coal TONS ->	268,848	17,500,030	4,704,848	10,232,000	2.2162

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	TOTAL	21,128	8,816,641				8,804				77,621,404	524,301,000	5.9467

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	39,465	16.7	95.1	67.7	9,976	Heavy Oil BBLS ->	59,902	6,400,020	383,374	4,032,000	10.2166
2			6,103					Gas MCF ->	71,250	1,000,000	71,250	694,000	11.3715
3													
4	TURKEY POINT 2	380	26,237	15.5	94.1	64.3	10,117	Heavy Oil BBLS ->	39,932	6,400,005	255,565	2,688,000	10.2451
5			16,256					Gas MCF ->	174,365	1,000,000	174,365	1,726,000	10.6174
6													
7	TURKEY POINT 3	717	503,332	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	2,506,000	0.4979
8													
9	TURKEY POINT 4	717	503,332	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	1,912,000	0.3799
10													
11	TURKEY POINT 5	1,103	713,374	89.8	94.1	89.8	6,903	Gas MCF ->	4,924,880	1,000,000	4,924,880	47,398,000	6.6442
12													
13	LAUDERDALE 4	443	271,639	85.2	97.6	85.2	7,942	Gas MCF ->	2,157,448	1,000,000	2,157,448	21,115,000	7.7732
14													
15	LAUDERDALE 5	443	277,212	86.9	98.4	86.9	7,900	Gas MCF ->	2,190,194	1,000,000	2,190,194	21,552,000	7.7746
16													
17	PT EVERGLADES 1	207	12,302	8.3	96.3	58.8	10,906	Gas MCF ->	134,177	1,000,000	134,177	1,327,000	10.7868
18													
19	PT EVERGLADES 2	207		0.0	44.9		0						
20													
21	PT EVERGLADES 3	370	2,172	25.8	92.2	66.7	10,414	Heavy Oil BBLS ->	3,312	6,400,966	21,200	223,000	10.2670
22			66,641					Gas MCF ->	695,463	1,000,000	695,463	6,978,000	10.4710
23													
24	PT EVERGLADES 4	376	74,748	27.6	93.0	63.7	10,431	Gas MCF ->	779,756	1,000,000	779,756	7,809,000	10.4471
25													
26	RIVIERA 3	275		0.0	94.0		0						
27													
28	RIVIERA 4	286	80,797	39.2	89.8	46.9	10,796	Gas MCF ->	872,331	1,000,000	872,331	8,589,000	10.6304
29													
30	ST LUCIE 1	853	598,803	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,579,119	1,000,000	6,579,119	2,389,000	0.3990
31													

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	726		0.0	0.0		0						
34	CAPE CANAVERAL 1	380	59,668	21.8	91.3	60.6	10,474	Gas MCF ->	625,009	1,000,000	625,009	6,255,000	10.4831
36	CAPE CANAVERAL 2	380	48,318	17.7	90.4	67.3	10,397	Gas MCF ->	502,362	1,000,000	502,362	5,030,000	10.4102
38	CUTLER 5	69		0.0	98.2		0						
40	CUTLER 6	138		0.0	0.0		0						
42	FORT MYERS 2	1,422	379,823	37.1	66.7	84.5	7,334	Gas MCF ->	2,785,880	1,000,000	2,785,880	26,685,000	7.0256
44	FORT MYERS 3A_B	164	37,465	15.9	96.3	97.2	10,977	Gas MCF ->	411,254	1,000,000	411,254	4,009,000	10.7008
46	SANFORD 3	140	4,348	4.3	95.1	41.4	11,980	Gas MCF ->	52,095	1,000,000	52,095	514,000	11.8204
48	SANFORD 4	955	588,838	85.6	90.7	90.9	7,122	Gas MCF ->	4,194,128	1,000,000	4,194,128	40,203,000	6.8275
50	SANFORD 5	945	493,161	72.5	96.5	92.9	7,164	Gas MCF ->	3,533,199	1,000,000	3,533,199	33,876,000	6.8692
52	PUTNAM 1	244	74,443	42.4	96.4	85.9	9,151	Gas MCF ->	681,272	1,000,000	681,272	6,650,000	8.9330
54	PUTNAM 2	244	64,258	36.6	96.1	86.6	9,148	Gas MCF ->	587,863	1,000,000	587,863	5,747,000	8.9437
56	MANATEE 1	805	13,540	8.7	44.1	57.9	10,465	Heavy Oil BBLS ->	23,211	6,400,026	148,551	1,561,000	11.5288
57			36,795					Gas MCF ->	378,215	1,000,000	378,215	3,761,000	10.2216
59	MANATEE 2	805	8,151	4.9	95.0	70.1	10,646	Heavy Oil BBLS ->	14,897	6,399,946	95,340	1,002,000	12.2930
60			20,077					Gas MCF ->	205,186	1,000,000	205,186	2,059,000	10.2558

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 3	1,104	479,787	60.4	96.5	70.1	7,315	Gas MCF ->	3,509,825	1,000,000	3,509,825	33,580,000	6.9989
64	MARTIN 1	820	401	13.8	95.0	55.9	10,625	Heavy Oil BBLS ->	610	6,401,639	3,905	41,000	10.2244
65			81,255					Gas MCF ->	863,687	1,000,000	863,687	8,514,000	10.4782
67	MARTIN 2	820		0.0	0.0		0						
69	MARTIN 3	470	162,500	48.0	94.4	92.4	7,354	Gas MCF ->	1,195,104	1,000,000	1,195,104	11,424,000	7.0301
71	MARTIN 4	470	164,557	48.6	98.6	94.6	7,343	Gas MCF ->	1,208,491	1,000,000	1,208,491	11,552,000	7.0201
73	MARTIN 8	1,104	724,583	91.2	96.5	91.2	6,955	Gas MCF ->	5,040,051	1,000,000	5,040,051	48,550,000	6.7004
75	FORT MYERS 1-12	627		0.0	98.4		0						
77	LAUDERDALE 1-24	766		0.0	91.7		0						
79	EVERGLADES 1-12	383		0.0	88.3		0						
81	ST JOHNS 1O	130	91,789	98.1	96.9	98.1	9,626	Coal TONS ->	36,244	24,379,152	883,598	2,048,000	2.2312
83	ST JOHNS 2O	130	91,648	97.9	97.0	97.9	9,707	Coal TONS ->	36,493	24,379,333	889,675	2,062,000	2.2499
85	SCHERER 4	640	451,103	97.9	97.2	97.9	10,095	Coal TONS ->	260,228	17,499,981	4,553,985	9,819,000	2.1767
89	TOTAL	21,638	7,268,919				8,666				62,994,388	395,880,000	5.4462

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	44,298	19.5	95.1	46.6	10,356	Heavy Oil BBLS ->	69,312	6,399,960	443,594	5,025,000	11.3436
2			10,770					Gas MCF ->	126,733	1,000,000	126,733	1,252,000	11.6253
4	TURKEY POINT 2	380	19,688	15.2	94.1	44.1	10,608	Heavy Oil BBLS ->	30,957	6,399,974	198,124	2,245,000	11.4029
5			23,245					Gas MCF ->	257,313	1,000,000	257,313	2,577,000	11.0864
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	2,580,000	0.4960
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	1,968,000	0.3784
11	TURKEY POINT 5	1,103	740,553	90.2	94.1	90.2	6,898	Gas MCF ->	5,108,990	1,000,000	5,108,990	50,387,000	6.8040
13	LAUDERDALE 4	443	275,700	83.7	97.6	83.6	7,969	Gas MCF ->	2,197,167	1,000,000	2,197,167	22,071,000	8.0054
15	LAUDERDALE 5	443	280,362	85.1	98.4	85.1	7,932	Gas MCF ->	2,223,859	1,000,000	2,223,859	22,490,000	8.0218
17	PT EVERGLADES 1	207	4,582	3.0	31.1	59.8	10,957	Gas MCF ->	50,213	1,000,000	50,213	511,000	11.1514
19	PT EVERGLADES 2	207	4,485	2.9	96.2	58.6	10,979	Gas MCF ->	49,248	1,000,000	49,248	498,000	11.1027
21	PT EVERGLADES 3	370	8,250	29.9	92.2	55.8	10,498	Heavy Oil BBLS ->	12,720	6,400,157	81,410	921,000	11.1636
22			73,984					Gas MCF ->	781,915	1,000,000	781,915	7,978,000	10.7834
24	PT EVERGLADES 4	376	2,745	27.0	93.0	53.5	10,559	Heavy Oil BBLS ->	4,243	6,399,481	27,153	307,000	11.1840
25			72,725					Gas MCF ->	769,783	1,000,000	769,783	7,851,000	10.7954
27	RIVIERA 3	275	39,828	19.5	94.0	33.2	11,410	Gas MCF ->	454,460	1,000,000	454,460	4,511,000	11.3262
29	RIVIERA 4	286	24,194	11.4	89.8	47.0	10,922	Gas MCF ->	264,253	1,000,000	264,253	2,677,000	11.0647

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	2,459,000	0.3974
33	ST LUCIE 2	726	118,903	22.0	22.0	97.5	10,987	Nuclear Othr ->	1,306,388	1,000,000	1,306,388	571,000	0.4802
35	CAPE CANAVERAL 1	380	3,981	24.2	91.3	48.0	10,677	Heavy Oil BBLS ->	6,203	6,399,968	39,699	449,000	11.2786
36			64,425					Gas MCF ->	690,733	1,000,000	690,733	7,018,000	10.8933
38	CAPE CANAVERAL 2	380	462	21.3	90.4	48.4	10,680	Heavy Oil BBLS ->	718	6,396,936	4,593	52,000	11.2554
39			59,719					Gas MCF ->	638,162	1,000,000	638,162	6,494,000	10.8742
41	CUTLER 5	69	275	0.5	98.2	99.7	12,518	Gas MCF ->	3,443	1,000,000	3,443	34,000	12.3636
43	CUTLER 6	138		0.0	27.9		0						
45	FORT MYERS 2	1,422	563,602	53.3	47.8	90.7	7,226	Gas MCF ->	4,073,106	1,000,000	4,073,106	39,862,000	7.0727
47	FORT MYERS 3A_B	164	4,563	1.9	96.3	99.4	11,016	Gas MCF ->	50,267	1,000,000	50,267	509,000	11.1547
49	SANFORD 3	140	2,193	2.1	95.1	43.5	12,030	Gas MCF ->	26,378	1,000,000	26,378	267,000	12.1773
51	SANFORD 4	955	542,731	76.4	80.0	91.8	7,150	Gas MCF ->	3,880,762	1,000,000	3,880,762	38,034,000	7.0079
53	SANFORD 5	945	436,361	62.1	96.5	94.0	7,189	Gas MCF ->	3,137,094	1,000,000	3,137,094	30,738,000	7.0442
55	PUTNAM 1	244	83,150	45.8	96.4	86.9	9,105	Gas MCF ->	757,148	1,000,000	757,148	7,605,000	9.1461
57	PUTNAM 2	244	72,175	39.8	96.1	71.8	9,597	Gas MCF ->	692,721	1,000,000	692,721	6,942,000	9.6183
59	MANATEE 1	805	10,849	7.2	94.4	49.7	10,728	Heavy Oil BBLS ->	19,900	6,400,101	127,362	1,441,000	13.2823
60			32,381					Gas MCF ->	336,455	1,000,000	336,455	3,415,000	10.5463

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	805	15,297	9.9	95.0	51.3	10,648	Heavy Oil BBLS ->	27,357	6,399,934	175,083	1,982,000	12.9568
63			43,777					Gas MCF ->	453,978	1,000,000	453,978	4,632,000	10.5810
64													
65	MANATEE 3	1,104	705,900	85.9	96.5	88.1	7,012	Gas MCF ->	4,949,823	1,000,000	4,949,823	48,470,000	6.8664
66													
67	MARTIN 1	820	156	14.8	95.0	47.8	10,855	Heavy Oil BBLS ->	240	6,400,000	1,536	17,000	10.8974
68			90,013					Gas MCF ->	977,272	1,000,000	977,272	9,826,000	10.9162
69													
70	MARTIN 2	820		0.0	51.5		0						
71													
72	MARTIN 3	470	139,775	40.0	94.4	76.3	7,490	Gas MCF ->	1,046,915	1,000,000	1,046,915	10,211,000	7.3053
73													
74	MARTIN 4	470	175,211	50.1	98.6	89.4	7,351	Gas MCF ->	1,288,052	1,000,000	1,288,052	12,563,000	7.1702
75													
76	MARTIN 8	1,104	743,299	90.5	96.5	91.5	6,955	Gas MCF ->	5,170,142	1,000,000	5,170,142	51,227,000	6.8918
77													
78	FORT MYERS 1-12	627		0.0	98.4		0						
79													
80	LAUDERDALE 1-24	766		0.0	91.7		0						
81													
82	EVERGLADES 1-12	383		0.0	88.3		0						
83													
84	ST JOHNS 1O	130	94,849	98.1	96.9	98.1	9,626	Coal TONS ->	37,502	24,346,755	913,052	2,116,000	2.2309
85													
86	ST JOHNS 2O	130	94,703	97.9	97.0	97.9	9,707	Coal TONS ->	37,760	24,346,690	919,331	2,131,000	2.2502
87													
88	SCHERER 4	640	466,140	97.9	97.2	97.9	10,095	Coal TONS ->	268,902	17,500,015	4,705,789	9,972,000	2.1393
89													
90													
91													

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	TOTAL	21,638	7,849,282				8,661				67,984,741	434,886,000	5.5405

Date: 8/6/2007

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	379	388,042	26.5	95.1	56.2	9,991	Heavy Oil BBLS ->	593,309	6,400,004	3,797,180	38,275,000	9.8636
2			55,798					Gas MCF ->	637,322	1,000,000	637,322	5,933,000	10.6330
3													
4	TURKEY POINT 2	379	252,156	23.0	76.0	64.5	10,120	Heavy Oil BBLS ->	385,973	6,400,010	2,470,231	24,790,000	9.8312
5			132,383					Gas MCF ->	1,421,326	1,000,000	1,421,326	13,635,000	10.2997
6													
7	TURKEY POINT 3	701	2,450,480	79.2	89.5	97.8	11,331	Nuclear Othr ->	27,766,380	1,000,000	27,766,380	10,612,000	0.4331
8													
9	TURKEY POINT 4	701	3,018,054	97.5	97.5	97.5	11,331	Nuclear Othr ->	34,197,533	1,000,000	34,197,533	11,533,000	0.3821
10													
11	TURKEY POINT 5	1,088	4,299,070	89.5	94.1	89.5	6,946	Gas MCF ->	29,860,543	1,000,000	29,860,543	270,649,000	6.2955
12													
13	LAUDERDALE 4	436	1,623,371	84.4	84.5	84.4	8,010	Gas MCF ->	13,002,659	1,000,000	13,002,659	124,562,000	7.6730
14													
15	LAUDERDALE 5	436	1,541,600	80.1	94.6	85.7	7,972	Gas MCF ->	12,289,941	1,000,000	12,289,941	119,410,000	7.7459
16													
17	PT EVERGLADES 1	206	109,197	12.0	90.7	67.5	10,845	Gas MCF ->	1,184,225	1,000,000	1,184,225	11,387,000	10.4279
18													
19	PT EVERGLADES 2	206	48,910	5.4	77.8	63.8	10,914	Gas MCF ->	533,780	1,000,000	533,780	5,161,000	10.5520
20			0						0		0	0	0.0000
21													
22	PT EVERGLADES 3	373	227,885	34.6	76.3	68.3	10,204	Heavy Oil BBLS ->	347,652	6,400,003	2,224,974	22,098,000	9.6970
23			341,025					Gas MCF ->	3,579,998	1,000,000	3,579,998	35,199,000	10.3215
24													
25	PT EVERGLADES 4	375	178,822	31.9	93.0	67.9	10,234	Heavy Oil BBLS ->	272,850	6,400,015	1,746,244	17,336,000	9.6946
26			348,338					Gas MCF ->	3,648,926	1,000,000	3,648,926	35,986,000	10.3308
27													
28	RIVIERA 3	274	267,580	22.1	81.4	62.2	10,643	Gas MCF ->	2,847,751	1,000,000	2,847,751	27,214,000	10.1704
29													
30													

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	RIVIERA 4	285	357,503	28.4	89.8	60.6	10,648	Gas MCF ->	3,806,702	1,000,000	3,806,702	37,051,000	10.3638
33	ST LUCIE 1	844	3,632,385	97.5	88.2	97.5	10,987	Nuclear Othr ->	39,909,168	1,000,000	39,909,168	14,572,000	0.4012
35	ST LUCIE 2	718	1,655,974	52.2	74.8	97.1	10,987	Nuclear Othr ->	18,194,160	1,000,000	18,194,160	6,859,000	0.4142
36			0						0		0	0	0.0000
38	CAPE CANAVERAL 1	379	140,062	30.2	84.3	65.8	10,285	Heavy Oil BBLS ->	214,308	6,399,999	1,371,571	13,718,000	9.7942
39			364,438					Gas MCF ->	3,817,375	1,000,000	3,817,375	37,548,000	10.3030
41	CAPE CANAVERAL 2	379	96,248	23.5	90.4	64.8	10,323	Heavy Oil BBLS ->	147,672	6,399,981	945,098	9,429,000	9.7966
42			297,192					Gas MCF ->	3,116,207	1,000,000	3,116,207	30,704,000	10.3314
44	CUTLER 5	68	22,515	7.5	98.2	79.2	11,885	Gas MCF ->	267,599	1,000,000	267,599	2,371,000	10.5308
45			0						0		0	0	0.0000
47	CUTLER 6	137	125,942	20.8	77.6	78.0	11,838	Gas MCF ->	1,490,958	1,000,000	1,490,958	13,280,000	10.5445
48			0						0		0	0	0.0000
50	FORT MYERS 2	1,411	4,388,316	70.4	84.4	88.7	7,224	Gas MCF ->	31,701,839	1,000,000	31,701,839	295,013,000	6.7227
52	FORT MYERS 3A_B	160	256,493	36.3	82.0	100.0	10,987	Gas MCF ->	2,818,178	1,000,000	2,818,178	26,583,000	10.3640
54	SANFORD 3	139	41,181	6.7	95.1	52.0	11,628	Gas MCF ->	478,851	1,000,000	478,851	4,570,000	11.0973
56	SANFORD 4	942	3,502,650	84.2	90.8	90.1	7,175	Gas MCF ->	25,132,822	1,000,000	25,132,822	235,826,000	6.7328
58	SANFORD 5	939	3,382,895	81.6	94.6	90.8	7,180	Gas MCF ->	24,289,623	1,000,000	24,289,623	228,354,000	6.7503
60	PUTNAM 1	241	409,234	38.5	96.4	93.7	9,129	Gas MCF ->	3,735,771	1,000,000	3,735,771	35,819,000	8.7527

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	PUTNAM 2	241	374,359	35.2	86.9	90.0	9,230	Gas MCF ->	3,455,380	1,000,000	3,455,380	33,053,000	8.8292
64	MANATEE 1	797	368,667	40.4	87.2	56.3	10,359	Heavy Oil BBLS ->	579,468	6,399,994	3,708,592	36,843,000	9.9936
65			1,051,626					Gas MCF ->	11,003,723	1,000,000	11,003,723	105,052,000	9.9895
67	MANATEE 2	797	233,524	27.9	95.0	49.0	10,444	Heavy Oil BBLS ->	371,730	6,400,000	2,379,072	24,092,000	10.3167
68			750,065					Gas MCF ->	7,893,545	1,000,000	7,893,545	75,225,000	10.0291
70	MANATEE 3	1,091	3,455,965	71.8	95.6	74.2	7,278	Gas MCF ->	25,152,257	1,000,000	25,152,257	235,650,000	6.8186
72	MARTIN 1	817	543,148	45.1	95.0	68.7	10,343	Heavy Oil BBLS ->	837,761	6,400,002	5,361,672	51,303,000	9.4455
73			1,081,967					Gas MCF ->	11,447,470	1,000,000	11,447,470	106,044,000	9.8010
75	MARTIN 2	817	476,755	31.2	75.9	68.9	10,309	Heavy Oil BBLS ->	736,446	6,400,004	4,713,257	45,292,000	9.5001
76			649,292					Gas MCF ->	6,894,656	1,000,000	6,894,656	62,648,000	9.6487
77			0						0		0	0	0.0000
79	MARTIN 3	461	1,366,274	67.2	92.8	87.6	7,355	Gas MCF ->	10,049,293	1,000,000	10,049,293	90,172,000	6.5998
81	MARTIN 4	461	1,387,169	68.2	98.6	89.1	7,344	Gas MCF ->	10,187,061	1,000,000	10,187,061	92,999,000	6.7042
83	MARTIN 8	1,091	3,944,537	81.9	95.6	89.0	7,022	Gas MCF ->	27,696,704	1,000,000	27,696,704	260,839,000	6.6127
85	FORT MYERS 1-12	577	1,818	0.1	95.4	22.5	12,842	Light Oil BBLS ->	4,005	5,829,213	23,346	365,000	20.0770
86			0						0		0	0	0.0000
88	LAUDERDALE 1-24	711	0	0.0	91.7	0.0	0		0		0	0	0.0000
90	EVERGLADES 1-12	356	0	0.0	88.3	0.0	0		0		0	0	0.0000

Date: 8/6/2007
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	ST JOHNS 1O	128	554,229	98.1	88.9	98.1	9,670	Coal TONS ->	219,407	24,427,903	5,359,653	12,420,000	2.2410
94	ST JOHNS 2O	128	553,268	97.9	97.0	97.9	9,752	Coal TONS ->	220,865	24,427,845	5,395,256	12,505,000	2.2602
96	SCHERER 4	636	2,741,037	97.6	97.2	97.6	10,159	Coal TONS ->	1,591,259	17,500,005	27,847,041	60,737,000	2.2158
100	TOTAL	21,298	53,489,438				8,803				470,852,911	3,070,716,000	5.7408

Schedule: E5

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2007 thru December 2007

			July 2007	August 2007	September 2007	October 2007	November 2007	December 2007	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	5,758,655	1,038,519	694,769	382,272	99,834	100,269	8,074,318
3	Unit Cost	($/BBLS)	58.5336	62.3012	61.9213	61.6995	62.0230	63.0105	59.5583
4	Amount	($)	337,075,000	64,701,000	43,021,000	23,586,000	6,192,000	6,318,000	480,893,000
5									
6	Burned:								
7	Units	(BBLS)	1,278,655	1,038,519	994,769	861,715	141,864	171,650	4,487,172
8	Unit Cost	($/BBLS)	61.7726	64.6114	63.9454	59.7565	67.2955	72.4727	63.1081
9	Amount	($)	78,985,882	67,100,182	63,610,951	51,493,065	9,546,811	12,439,946	283,176,836
10									
11	Ending Inventory:								
12	Units	(BBLS)	4,480,000	4,480,001	4,179,999	3,700,557	3,658,527	3,587,147	3,587,147
13	Unit Cost	($/BBLS)	58.9246	58.9245	58.7103	58.3301	58.2888	58.1964	58.1964
14	Amount	($)	263,982,000	263,982,000	245,409,000	215,854,000	213,251,000	208,759,000	208,759,000
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	756,762	0	2,576	1,429	0	0	760,767
21	Unit Cost	($/BBLS)	95.5981	0.0000	90.8385	91.6725	0.0000	0.0000	95.5746
22	Amount	($)	72,345,000	0	234,000	131,000	0	0	72,710,000
23									
24	Burned:								
25	Units	(BBLS)	0	0	2,576	1,429	0	0	4,005
26	Unit Cost	($/BBLS)	0.0000	0.0000	90.8385	91.6725	0.0000	0.0000	91.1361
27	Amount	($)	0	0	234,000	131,000	0	0	365,000
28									
29	Ending Inventory:								
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	95.5981	95.5981	95.5981	95.5981	95.5981	95.5981	95.5981
32	Amount	($)	72,345,000	72,345,000	72,345,000	72,345,000	72,345,000	72,345,000	72,345,000
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	131,035	73,550	71,354	73,831	72,739	75,264	497,773
39	Unit Cost	($/Tons)	56.8016	56.7233	56.6471	56.5752	56.4896	56.4148	56.6302
40	Amount	($)	7,443,000	4,172,000	4,042,000	4,177,000	4,109,000	4,246,000	28,189,000
41									
42	Burned:								
43	Units	(Tons)	73,535	73,550	71,354	73,831	72,739	75,264	440,273
44	Unit Cost	($/Tons)	56.8029	56.7233	56.6471	56.5752	56.4896	56.4148	56.6081
45	Amount	($)	4,177,000	4,172,000	4,042,000	4,177,000	4,109,000	4,246,000	24,923,000
46									
47	Ending Inventory:								
48	Units	(Tons)	57,499	57,499	57,499	57,499	57,501	57,502	57,502
49	Unit Cost	($/Tons)	56.8010	56.8010	56.8010	56.8010	56.7990	56.7980	56.7980
50	Amount	($)	3,266,000	3,266,000	3,266,000	3,266,000	3,266,000	3,266,000	3,266,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	9,292,518	4,673,410	4,545,905	4,704,840	4,553,990	4,705,785	32,476,448
57	Unit Cost	($/MBTU)	2.2309	2.2123	2.1934	2.1748	2.1561	2.1191	2.1882
58	Amount	($)	20,731,000	10,339,000	9,971,000	10,232,000	9,819,000	9,972,000	71,064,000
59									
60	Burned:								
61	Units	(MBTU)	4,663,103	4,673,410	4,545,905	4,704,840	4,553,990	4,705,785	27,847,033
62	Unit Cost	($/MBTU)	2.2309	2.2123	2.1934	2.1748	2.1561	2.1191	2.1811
63	Amount	($)	10,403,000	10,339,000	9,971,000	10,232,000	9,819,000	9,972,000	60,736,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	4,629,450	4,629,450	4,629,450	4,629,450	4,629,433	4,629,433	4,629,433
67	Unit Cost	($/MBTU)	2.2309	2.2309	2.2309	2.2309	2.2309	2.2309	2.2309
68	Amount	($)	10,328,000	10,328,000	10,328,000	10,328,000	10,328,000	10,328,000	10,328,000
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	52,670,563	52,902,354	50,841,379	48,798,021	37,773,485	40,456,380	283,442,182
75	Unit Cost	($/MCF)	9.5571	9.0341	9.0167	9.2621	9.6788	9.9033	9.3774
76	Amount	($)	503,376,999	477,926,425	458,423,783	451,972,913	365,600,828	400,651,471	2,657,952,421
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,769,566	23,769,566	17,857,893	16,792,871	17,985,713	19,891,632	120,067,241
83	Unit Cost	($/MBTU)	0.3480	0.3466	0.3574	0.3750	0.3785	0.3810	0.3629
84	Amount	($)	8,271,000	8,239,000	6,383,000	6,298,000	6,807,000	7,578,000	43,576,000

6-Aug-07
Company: Florida Power & Light

Schedule: E6

POWER SOLD

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	81,130		81,130	6.539	7.706	5,304,785	6,252,171	658,516
2007	St.Lucie Rel.		6,755		6,755	2.346	2.346	158,500	158,500	0
Total			87,885	0	87,885	6.216	7.294	5,463,285	6,410,671	658,516
August		OS	132,363		132,363	6.831	8.381	9,041,224	11,092,719	1,623,193
2007	St.Lucie Rel.		6,755		6,755	2.335	2.335	157,700	157,700	0
Total			139,118	0	139,118	6.612	8.087	9,198,924	11,250,419	1,623,193
September		OS	37,278		37,278	7.481	9.046	2,788,662	3,372,050	379,296
2007	St.Lucie Rel.		6,533		6,533	2.330	2.330	152,200	152,200	0
Total			43,811	0	43,811	6.713	8.044	2,940,862	3,524,250	379,296
October		OS	58,290		58,290	8.443	9.560	4,921,156	5,572,485	526,914
2007	St.Lucie Rel.		0		0	0.100	0.100	0	0	0
Total			58,290	0	58,290	8.443	9.560	4,921,156	5,572,485	526,914
November		OS	136,744		136,744	6.862	7.943	9,383,626	10,861,242	1,208,004
2007	St.Lucie Rel.		0		0	0.100	0.100	0	0	0
Total			136,744	0	136,744	6.862	7.943	9,383,626	10,861,242	1,208,004
December		OS	328,190		328,190	6.695	8.198	21,973,476	26,904,418	4,268,792
2007	St.Lucie Rel.		37,229		37,229	0.114	0.114	42,500	42,500	0
Total			365,419	0	365,419	6.025	7.374	22,015,976	26,946,918	4,268,792
Period		OS	773,995	0	773,995	6.901	8.276	53,412,929	64,055,085	8,664,714
	St.Lucie Rel.		57,272	0	57,272	0.892	0.892	510,900	510,900	0
Total			831,267	0	831,267	6.487	7.767	53,923,829	64,565,985	8,664,714

6-Aug-07
Company: Florida Power & Light

Schedule: E7

Purchased Power
(Exclusive of Economy Energy Purchases)
Estimated for the Period of : January 2007 thru December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2007 July	Sou. Co. (UPS + R)		690,409			690,409	2.182		15,064,000
	St. Lucie Rel.		38,577			38,577	0.411		158,500
	SJRPP		277,762			277,762	2.258		6,273,000
	PPAs		46,052			46,052	7.353		3,385,981
Total			1,052,800			1,052,800	2.363		24,881,481
2007 August	Sou. Co. (UPS + R)		689,643			689,643	2.182		15,048,000
	St. Lucie Rel.		38,577			38,577	0.409		157,700
	SJRPP		277,335			277,335	2.259		6,264,000
	PPAs		46,924			46,924	7.112		3,337,068
Total			1,052,479			1,052,479	2.357		24,806,768
2007 September	Sou. Co. (UPS + R)		669,595			669,595	2.182		14,610,000
	St. Lucie Rel.		37,333			37,333	0.408		152,200
	SJRPP		268,803			268,803	2.259		6,071,000
	PPAs		42,164			42,164	7.719		3,254,757
Total			1,017,895			1,017,895	2.366		24,087,957
2007 October	Sou. Co. (UPS + R)		691,915			691,915	2.182		15,097,000
	St. Lucie Rel.		74			74	0.000		0
	SJRPP		277,762			277,762	2.258		6,273,000
	PPAs		42,519			42,519	7.793		3,313,677
Total			1,012,270			1,012,270	2.438		24,683,677
2007 November	Sou. Co. (UPS + R)		669,595			669,595	2.182		14,610,000
	St. Lucie Rel.		74			74	0.000		0
	SJRPP		275,152			275,152	2.243		6,172,000
	PPAs		10,550			10,550	8.256		871,045
Total			955,371			955,371	2.266		21,653,045
2007 December	Sou. Co. (UPS + R)		691,865			691,865	2.182		15,096,000
	St. Lucie Rel.		8,856			8,856	0.480		42,500
	SJRPP		284,324			284,324	2.243		6,378,000
	PPAs		6,833			6,833	11.135		760,844
Total			991,878			991,878	2.246		22,277,344
Period Total	Sou. Co. (UPS + R)		4,103,022			4,103,022	2.182		89,525,000
	St. Lucie Rel.		123,492			123,492	0.414		510,900
	SJRPP		1,661,138			1,661,138	2.253		37,431,000
	PPAs		195,042			195,042	7.651		14,923,372
Total			6,082,694			6,082,694	2.341		142,390,272

6-Aug-07
Company: Florida Power & Light

Schedule: E8

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2007 thru December 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2007 July	Qual. Facilities		533,439			533,439	3.304	3.304	17,624,000
Total			533,439			533,439	3.304	3.304	17,624,000
2007 August	Qual. Facilities		535,518			535,518	3.333	3.333	17,851,000
Total			535,518			535,518	3.333	3.333	17,851,000
2007 September	Qual. Facilities		529,616			529,616	3.366	3.366	17,828,000
Total			529,616			529,616	3.366	3.366	17,828,000
2007 October	Qual. Facilities		439,710			439,710	3.485	3.485	15,323,000
Total			439,710			439,710	3.485	3.485	15,323,000
2007 November	Qual. Facilities		459,581			459,581	3.392	3.392	15,590,000
Total			459,581			459,581	3.392	3.392	15,590,000
2007 December	Qual. Facilities		544,949			544,949	3.453	3.453	18,815,000
Total			544,949			544,949	3.453	3.453	18,815,000
Period Total	Qual. Facilities		3,042,813			3,042,813	3.386	3.386	103,031,000
Total			3,042,813			3,042,813	3.386	3.386	103,031,000

6-Aug-07
Company: Florida Power & Light

Schedule: E9

Economy Energy Purchases

Estimated For the Period of : January 2007 Thru December 2007

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	OS	26,220	7.383	1,935,884	8.121	2,129,262	193,379
2	2007	Non-Florida	OS	85,361	7.057	6,024,046	7.982	6,813,197	789,151
3									
4	Total			111,581	7.134	7,959,929	8.014	8,942,459	982,530
5									
6									
7	August	Florida	OS	12,315	7.164	882,256	8.053	991,705	109,449
8	2007	Non-Florida	OS	82,187	7.077	5,816,493	7.978	6,556,983	740,491
9									
10	Total			94,502	7.088	6,698,749	7.988	7,548,689	849,940
11									
12									
13	September	Florida	OS	50,726	7.766	3,939,214	8.759	4,443,292	504,078
14	2007	Non-Florida	OS	98,443	7.053	6,942,859	8.369	8,239,106	1,296,247
15									
16	Total			149,169	7.295	10,882,073	8.502	12,682,397	1,800,324
17									
18									
19	October	Florida	OS	47,939	7.762	3,721,154	9.635	4,618,952	897,798
20	2007	Non-Florida	OS	108,790	6.800	7,397,700	9.322	10,140,910	2,743,210
21									
22	Total			156,729	7.094	11,118,854	9.417	14,759,863	3,641,009
23									
24									
25	November	Florida	OS	68,369	6.796	4,646,061	8.322	5,689,955	1,043,894
26	2007	Non-Florida	OS	128,855	6.616	8,524,446	8.307	10,703,412	2,178,966
27									
28	Total			197,224	6.678	13,170,507	8.312	16,393,367	3,222,860
29									
30									
31	December	Florida	OS	58,494	6.659	3,895,252	7.818	4,572,952	677,700
32	2007	Non-Florida	OS	77,196	6.454	4,982,134	7.808	6,027,730	1,045,597
33									
34	Total			135,690	6.542	8,877,386	7.812	10,600,682	1,723,297
35									
36									
37	Period	Florida	OS	264,063	7.203	19,019,821	8.500	22,446,118	3,426,298
38	Total	Non-Florida	OS	580,832	6.833	39,687,676	8.347	48,481,338	8,793,662
39									
40	Total			844,895	6.948	58,707,497	8.395	70,927,457	12,219,960
41									

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-4
DOCKET NO. 070001-EI
FPL WITNESS: K.M. DUBIN
August 6, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 19
COMPANY Florida Power & Light Co.
WITNESS K.M. Dubin (KMD-4)
DATE 11-06-07

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.		(1) ACTUAL JAN 2007	(2) ACTUAL FEB 2007	(3) ACTUAL MAR 2007	(4) ACTUAL APR 2007	(5) ACTUAL MAY 2007	(6) ACTUAL JUN 2007
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,383,756	$17,018,383	$17,030,951	$16,722,795	$13,815,314	$15,877,507
2.	Short Term Capacity Purchases CCR	$7,021,345	$7,021,345	$4,249,275	$4,152,555	$4,350,955	$4,475,730
3.	QF Capacity Charges	$26,843,422	$26,186,844	$26,596,356	$26,564,029	$26,849,668	$26,815,949
4.	SJRPP Suspension Accrual	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744
5	Return on SJRPP Suspension Liability	($409,392)	($412,118)	($414,843)	($417,569)	($420,295)	($423,021)
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	$2,433,624	$1,534,657	$1,346,516	$1,876,545	$1,594,392	$1,783,662
7.	Transmission of Electricity by Others	$421,249	$990,593	$291,996	$268,353	$502,666	$477,100
8.	Transmission Revenues from Capacity Sales	($332,908)	($584,810)	($359,555)	($303,874)	($271,113)	($258,391)
9.	Total (Lines 1 through 8)	$52,655,840	$52,049,638	$49,035,440	$49,157,578	$46,716,330	$49,043,281
10.	Jurisdictional Separation Factor (a)	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%
11.	Jurisdictional Capacity Charges	51,963,605	51,365,373	48,390,800	48,511,333	46,102,179	48,398,539
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	47,218,139	46,619,907	43,645,334	43,765,867	41,356,713	43,653,073
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	41,977,411	37,923,420	37,558,510	37,852,639	41,380,033	45,114,346
15.	Prior Period True-up Provision	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,480)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	40,734,931	36,680,940	36,316,030	36,610,159	40,137,553	43,871,866
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(6,483,208)	(9,938,967)	(7,329,304)	(7,155,708)	(1,219,159)	218,794
18.	Interest Provision for Month	(94,596)	(125,467)	(158,417)	(185,411)	(199,133)	(197,126)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(14,909,758)	(20,245,082)	(29,067,036)	(35,312,278)	(41,410,917)	(41,586,729)
20.	Deferred True-up - Over/(Under) Recovery	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,242,480	1,242,480	1,242,480	1,242,480	1,242,480	1,242,480
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	(24,275,365)	(33,097,319)	(39,342,561)	(45,441,200)	(45,617,012)	(44,352,865)

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 1, 2006
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.		(7) ESTIMATED JUL 2007	(8) ESTIMATED AUG 2007	(9) ESTIMATED SEP 2007	(10) ESTIMATED OCT 2007	(11) ESTIMATED NOV 2007	(12) ESTIMATED DEC 2007	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,463,785	$16,463,785	$16,463,785	$16,463,785	$16,463,785	$16,463,785	$195,631,414	1.
2.	Short Term Capacity Purchases CCR	$4,318,980	$4,318,980	$4,338,230	$3,377,820	$3,380,570	$3,828,930	$54,834,715	2.
3.	QF Capacity Charges	$26,277,828	$26,277,828	$26,277,828	$26,277,828	$26,277,828	$26,277,828	$317,523,238	3.
4.	SJRPP Suspension Accrual	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$3,536,928	4a.
5	Return on SJRPP Suspension Liability	($425,747)	($428,472)	($431,198)	($433,924)	($436,650)	($439,376)	($5,092,605)	4b.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	$2,952,370	$2,952,370	$2,952,370	$2,952,370	$2,952,370	$2,952,370	$28,283,614	6c.
7.	Transmission of Electricity by Others	$489,497	$488,717	$476,964	$249,937	$261,458	$275,943	$5,194,472	7.
8.	Transmission Revenues from Capacity Sales	($288,871)	($428,302)	($204,092)	($124,416)	($269,612)	($662,150)	($4,088,093)	8.
9.	Total (Lines 1 through 8)	$50,082,587	$49,939,649	$50,168,630	$49,058,144	$48,924,492	$48,992,075	$595,823,684	9.
10.	Jurisdictional Separation Factor (a)	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	N/A	10.
11.	Jurisdictional Capacity Charges	49,424,181	49,283,123	49,509,094	48,413,206	48,281,311	48,348,005	587,990,747	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	44,678,715	44,537,657	44,763,628	43,667,740	43,535,845	43,602,539	531,045,155	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	51,630,904	51,938,085	51,625,307	48,480,293	43,280,367	43,629,644	532,390,958	14.
15.	Prior Period True-up Provision	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,480)	(1,242,478)	(14,909,758)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	50,388,424	50,695,605	50,382,827	47,237,813	42,037,887	42,387,166	517,481,200	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	5,709,709	6,157,949	5,619,199	3,570,073	(1,497,959)	(1,215,373)	(13,563,955)	17.
18.	Interest Provision for Month	(179,858)	(149,073)	(118,353)	(93,190)	(83,575)	(84,445)	(1,668,644)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(40,322,582)	(33,550,251)	(26,298,896)	(19,555,569)	(14,836,206)	(15,175,259)	(14,909,758)	19.
20.	Deferred True-up - Over/(Under) Recovery	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	(4,030,283)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,242,480	1,242,480	1,242,480	1,242,480	1,242,480	1,242,478	14,909,758	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	(37,580,534)	(30,329,179)	(23,585,852)	(18,866,489)	(19,205,542)	(19,262,882)	(19,262,882)	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No.
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATE/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$ 195,631,414	$ 195,185,676	$ 445,738	0.2 %
2.	Short Term Capacity Payments	54,834,715	52,399,434	2,435,281	4.6 %
3.	Capacity Payments to Cogenerators (QF's)	317,523,238	316,149,792	1,373,446	0.4 %
4.	SJRPP Suspension Accrual	3,536,928	3,536,928	0	0.0 %
5.	Return Requirements on SJRPP Suspension Payments	(5,092,605)	(5,399,062)	306,457	(5.7) %
6.	Incremental Plant Security Costs	28,283,614	30,442,387	(2,158,773)	(7.1) %
7.	Transmission of Electricity by Others	5,194,472	2,679,339	2,515,133	93.9 %
8.	Transmission Revenues from Capacity Sales	(4,088,093)	(3,941,588)	(146,505)	3.7 %
9.	Total (Lines 1 through 8)	$ 595,823,684	$ 591,052,906	$ 4,770,778	0.8 %
10.	Jurisdictional Separation Factor	98.68536%	98.68536%	0	0.0 %
11.	Jurisdictional Capacity Charges	$ 587,990,747	$ 583,282,688	$ 4,708,059	0.8 %
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(56,945,592)	(56,945,592)	0	N/A
13.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 531,045,155	$ 526,337,096	$ 4,708,059	0.9 %
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 532,390,958	$ 541,246,854	$ (8,855,896)	(1.6) %
15.	Prior Period True-up Provision	(14,909,758)	(14,909,758)	0	N/A
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 517,481,200	$ 526,337,096	$ (8,855,896)	(1.7) %
17.	True-up Provision for Period - Over/(Under) Recovery (Line 15 - Line 12)	$ (13,563,955)	$0	$ (13,563,955)	N/A
18.	Interest Provision for Period	(1,668,644)	0	(1,668,644)	N/A
19.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	(14,909,758)	(14,909,758)	0	N/A
20.	Deferred True-up - Over/(Under) Recovery	(4,030,283)	0	(4,030,283)	N/A
21.	Prior Period True-up Provision - Collected/(Refunded) this Period	14,909,758	14,909,758	0	N/A
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	$ (19,262,882)	$0	$ (19,262,882)	N/A

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 1, 2006.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 070001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-71
SEPTEMBER 4, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 20
COMPANY Florida Power & Light Co.
WITNESS K.M. Dubin (KMD-5)
DATE 11-06-07

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2008 – December 2008

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
3	Schedule E1 Fuel & Purchased Power Cost Recovery Clause Calculation	K. M. Dubin
4	Schedule E1-A Calculation of Total True-up (Projected Period)	K. M. Dubin
4a-4b	Schedule E1-B REVISED 2007 Estimated/Actual True-up Calculation	K. M. Dubin
5	Schedule E1-C Calculation Generating Performance Incentive Factor and True-Up Factor	K. M. Dubin
6a-6b	Schedule E1-D Time of Use Rate Schedule	K. M. Dubin
7a-7b	Schedule E1-E Factors by Rate Group	K. M. Dubin
8a-8c	2006 Actual Energy Losses by Rate Class	K. M. Dubin
9-10	Schedule E2 Monthly Summary of Fuel & Purchased Power Cost Recovery Clause Calculation	K. M. Dubin/ G. Yupp/T. Jones
11-14	Schedule E3 Monthly Summary of Generating System Data	G. Yupp/T. Jones
15-57	Schedule E4 Monthly Generation and Fuel Cost by Unit	G. Yupp/T. Jones
58-59	Schedule E5 Monthly Fuel Inventory Data	G. Yupp/T. Jones
60-61	Schedule E6 Monthly Power Sold Data	G. Yupp/T. Jones
62-63	Schedule E7 Monthly Purchased Power Data	G. Yupp
64-65	Schedule E8 Energy Payment to Qualifying Facilities	G. Yupp
66-67	Schedule E9 Monthly Economy Energy Purchase Data	G. Yupp
68	Schedule E10 Residential Bill Comparison	K. M. Dubin
69	Schedule H1 Three Year Historical Comparison	K. M. Dubin
70-71	Cogeneration Tariff Sheets	K. M. Dubin

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$5,674,081,865		103,303,869	5.4926
2	Nuclear Fuel Disposal Costs (E2)	22,330,882		24,050,491	0.0929
3	Fuel Related Transactions (E2)	2,929,140		0	0.0000
4	Incremental Hedging Costs (E2)	597,125		0	
5	Fuel Cost of Sales to FKEC / CKW (E2)	(64,045,018)		(1,020,300)	6.2771
6	TOTAL COST OF GENERATED POWER	$5,635,893,994		102,283,569	5.5101
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	318,568,650		12,153,700	2.6212
8	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	28,723,111		401,992	7.1452
9	Energy Cost of Other Econ Purch (Non-Florida) (E9)	77,363,716		1,088,971	7.1043
10	Payments to Qualifying Facilities (E8)	188,840,506		5,929,307	3.1849
11	TOTAL COST OF PURCHASED POWER	$613,495,983		19,573,970	3.1342
12	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			121,857,539	
13	Fuel Cost of Economy Sales (E6)	(117,801,650)		(1,840,000)	6.4023
14	Gain on Economy Sales (E6A)	0		0	0.0000
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,807,900)		(66,877)	2.7033
16	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
17	Revenues from Off-System Sales	(19,100,675)		(1,906,877)	1.0017
18	TOTAL FUEL COST AND GAINS OF POWER SALES	($138,710,225)		(1,906,877)	7.2742
19	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 6 + 11 + 18)	$6,110,679,752		119,950,662	5.0943
21	Net Unbilled Sales	689,154	**	13,528	0.0006
22	Company Use	18,332,039	**	359,852	0.0164
23	T & D Losses	397,194,184	**	7,796,793	0.3553
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,110,679,752		111,780,489	5.4667
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$365,419		6,681	5.4667
26	Jurisdictional MWH Sales	$6,110,314,333		111,773,808	5.4667
27	Jurisdictional Loss Multiplier	-		-	1.00065
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,114,286,037		111,773,808	5.4702
29	FINAL TRUE-UP JAN 06 - DEC 06 $53,744,558 underrecovery / EST/ACT TRUE-UP JAN 07 - DEC 07 $25,577,700 underrecovery	79,322,258		111,773,808	0.0710
30	TOTAL JURISDICTIONAL FUEL COST	$6,193,608,295		111,773,808	5.5412
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes	6,198,067,693			5.5452
33	GPIF ***	$9,001,300		111,773,808	0.0081
34	Fuel Factor including GPIF (Line 32 + Line 33)	6,207,068,993		111,773,808	5.5533
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				5.553

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

1. Estimated/Actual over/(under) recovery (January 2007 - September 2007)	$ (25,577,700)
2. Final over/(under) recovery (January 2006 - December 2006)	$ (53,744,558)
3. Total over/(under) recovery to be included in the January 2008 - December 2008 projected period (Schedule E1, Line 29)	$ (79,322,258)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	111,773,808
5. True-Up Factor (Lines 3/4) c/kWh:	(0.0710)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.				(1) Actual January	(2) Actual February	(3) Actual March	(4) Actual April	(5) Actual May	(6) Actual June
A			**Fuel Costs & Net Power Transactions**						
	1	a	Fuel Cost of System Net Generation	344,860,541	333,895,916	336,299,910	459,797,479	$ 514,498,368	$ 528,202,921
		b	Incremental Hedging Costs	53,226	39,493	23,534	30,791	24,115	37,136
		c	Nuclear Fuel Disposal Costs	2,080,232	1,838,048	2,068,516	1,527,611	1,426,405	1,772,838
		d	Coal Car Investment	276,584	274,727	272,871	271,014	269,158	266,915
		e	Gas Pipelines Depreciation & Return	-	-	-	-	-	-
		f	DOE D&D Fund Payment	-	-	-	-	-	-
	2	a	Fuel Cost of Power Sold (Per A6)	(6,942,952)	(13,948,405)	(8,140,711)	(9,714,574)	(5,956,867)	(3,424,938)
		b	Gains from Off-System Sales	(2,083,070)	(5,499,558)	(2,229,624)	(1,844,553)	(1,169,825)	(563,318)
	3	a	Fuel Cost of Purchased Power (Per A7)	21,506,997	22,969,094	17,804,660	21,444,941	23,110,057	24,916,606
		b	Energy Payments to Qualifying Facilities (Per A8)	14,369,588	14,062,127	14,320,595	7,235,184	14,106,491	15,289,372
				-	-	-		-	-
	4		Energy Cost of Economy Purchases (Per A9)	5,725,484	2,528,336	2,649,522	5,722,004	7,237,907	5,509,560
	5		Total Fuel Costs & Net Power Transactions	379,846,630	356,159,778	363,069,273	484,469,897	553,545,809	572,007,092
	6		**Adjustments to Fuel Cost**						
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(4,265,087)	(4,514,513)	(4,274,683)	(4,521,659)	$ (5,446,650)	(6,025,887)
		b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(46,608)	(141,687)	(37,683)	(85,101)	10,120	(117,212)
		c	Inventory Adjustments	(65,740)	(23,322)	151,823	165,860	44,370	45,870
		d	Non Recoverable Oil/Tank Bottoms	226,102	53,484	-	(18,211)	(76,294)	-
	7		Adjusted Total Fuel Costs & Net Power Transactions	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
B			**kWh Sales**						
	1		Jurisdictional kWh Sales	8,555,173,173	7,458,110,394	7,381,834,925	7,481,240,405	8,249,438,274	9,086,669,337
	2		Sale for Resale (excluding FKEC & CKW)	42,430,619	44,452,806	44,688,200	48,430,962	49,191,597	48,011,520
	3		Sub-Total Sales (excluding FKEC & CKW)	8,597,603,792	7,502,563,200	7,426,523,125	7,529,671,367	8,298,629,871	9,134,680,857
	4		**Jurisdictional % of Total Sales (B1/B3)**	99.50648%	99.40750%	99.39826%	99.35680%	99.40723%	99.47440%
C			**True-up Calculation**						
	1		Juris Fuel Revenues (Net of Revenue Taxes)	495,538,005	424,858,917	420,150,299	426,184,984	$ 462,649,668	512,234,106
	2		**Fuel Adjustment Revenues Not Applicable to Period**						
		a	Prior Period True-up (Collected)/Refunded This Period	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)
		b	GPIF, Net of Revenue Taxes	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)
		c	Other	-	-	-	-	-	-
	3		Jurisdictional Fuel Revenues Applicable to Period	487,248,093	416,569,005	411,860,387	417,895,072	454,359,756	503,944,194
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
		b	Nuclear Fuel Expense - 100% Retail	-	-	-	-	-	-
		c		-	-	-	-	-	-
		d	D&D Fund Payments -100% Retail	-	-	-	-	-	-
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	375,695,297	351,533,740	358,908,730	480,010,786	548,077,355	565,909,863
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.50648%	99.40750%	99.39826%	99.35680%	99.40723%	99.47440%
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00054) +(Lines C4b,c,d)	374,043,040	349,639,606	356,941,677	477,180,895	545,122,724	563,239,426
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	113,205,053	66,929,399	54,918,710	(59,285,823)	(90,762,968)	(59,295,232)
	8		Interest Provision for the Month	(370,119)	56,650	357,189	382,426	88,490	(207,150)
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(91,006,958)	29,411,889	103,981,851	166,841,663	115,522,179	32,431,614
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)
	10		Prior Period True-up Collected/(Refunded) This Period	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	(24,332,669)	50,237,293	113,097,105	61,777,621	(21,312,944)	(73,231,413)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.			(7) Actual July	(8) Estimated August	(9) Estimated September	(10) Estimated October	(11) Estimated November	(12) Estimated December-07	(13) Total Period
A		**Fuel Costs & Net Power Transactions**							
	1	a Fuel Cost of System Net Generation	$578,361,756	$567,774,607	$542,667,734	$524,304,978	$395,882,639	$434,886,417	5,561,433,267
		b Incremental Hedging Costs	26,004	36,253	51,580	36,253	36,253	36,253	430,891
		c Nuclear Fuel Disposal Costs	1,872,419	1,985,276	1,468,214	1,502,983	1,495,010	1,655,567	20,693,119
		d Coal Car Investment	264,673	263,588	261,732	259,875	258,019	256,162	3,195,318
		e Gas Pipelines Depreciation & Return	-	-	-	-	-	-	
		f DOE D&D Fund Payment	-	-	-	-	-	-	
	2	a Fuel Cost of Power Sold (Per A6)	(4,562,581)	(9,198,924)	(2,940,862)	(4,921,156)	(9,383,626)	(22,015,976)	(101,151,572)
		b Gains from Off-System Sales	(838,551)	(1,623,193)	(379,296)	(526,914)	(1,208,004)	(4,268,792)	(22,234,697)
	3	a Fuel Cost of Purchased Power (Per A7)	28,862,020	24,806,768	24,087,957	24,683,677	21,653,045	22,277,344	278,123,166
		b Energy Payments to Qualifying Facilities (Per A8)	14,465,306	17,851,000	17,828,000	15,323,000	15,590,000	18,815,000	179,255,663
			-	-	-	-	-	-	
	4	Energy Cost of Economy Purchases (Per A9)	7,475,360	6,698,749	10,882,073	11,118,854	13,170,507	8,877,386	87,595,741
	5	Total Fuel Costs & Net Power Transactions	625,926,406	608,594,124	593,927,132	571,781,550	437,493,843	460,519,361	6,007,340,895
	6	**Adjustments to Fuel Cost**							
		a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(5,888,231)	(6,013,680)	(6,126,625)	(5,883,116)	(5,418,624)	(4,834,992)	(63,213,747)
		b Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(55,860)	-	-	-	-	-	(474,031)
		c Inventory Adjustments	22,507	-	-	-	-	-	341,368
		d Non Recoverable Oil/Tank Bottoms	-	-	-	-	-	-	185,081
	7	Adjusted Total Fuel Costs & Net Power Transactions	620,004,822	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,944,179,566
B		**kWh Sales**							
	1	Jurisdictional kWh Sales	10,150,866,208	10,333,103,000	10,270,876,000	9,645,174,000	8,610,646,000	8,680,135,000	105,903,266,716
	2	Sale for Resale (excluding FKEC & CKW)	43,849,746	48,816,612	43,527,178	45,220,055	47,828,782	580,148	507,028,224
	3	Sub-Total Sales (excluding FKEC & CKW)	10,194,715,954	10,381,919,612	10,314,403,178	9,690,394,055	8,658,474,782	8,680,715,148	106,410,294,940
	4	**Jurisdictional % of Total Sales (B1/B3)**	99.56988%	99.52979%	99.57800%	99.53335%	99.44761%	99.99332%	N/A
C		**True-up Calculation**							
	1	Juris Fuel Revenues (Net of Revenue Taxes)	575,795,562	582,160,889	578,655,057	543,403,378	485,118,684	489,033,653	5,995,783,203
	2	**Fuel Adjustment Revenues Not Applicable to Period**							
		a Prior Period True-up (Collected)/Refunded This Period	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(7,583,913)	(91,006,958)
		b GPIF, Net of Revenue Taxes	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(705,999)	(8,471,988)
		c Other		-					
	3	Jurisdictional Fuel Revenues Applicable to Period	567,505,650	573,870,977	570,365,145	535,113,466	476,828,772	480,743,741	5,896,304,257
	4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	620,004,822	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,944,179,566
		b Nuclear Fuel Expense - 100% Retail	-	-	-	-	-	-	
		c	-	-	-	-	-	-	
		d D&D Fund Payments -100% Retail	-	-	-	-	-	-	
		e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	620,004,822	602,580,444	587,800,507	565,898,434	432,075,219	455,684,369	5,944,179,566
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.56988%	99.52979%	99.57800%	99.53335%	99.44761%	99.99332%	N/A
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00054) +(Lines C4b,c,d)	617,671,420	600,070,914	585,636,061	563,561,829	429,920,510	455,899,982	5,918,928,084
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	(50,165,770)	(26,199,937)	(15,270,916)	(28,448,363)	46,908,262	24,843,759	(22,623,827)
	8	Interest Provision for the Month	(414,320)	(548,176)	(607,999)	(672,992)	(602,509)	(415,364)	(2,953,873)
	9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(19,486,855)	(62,483,032)	(81,647,232)	(89,942,233)	(111,479,675)	(57,590,009)	(91,006,958)
		b Deferred True-up Beginning of Period - Over/(Under) Recovery	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)	(53,744,558)
	10	Prior Period True-up Collected/(Refunded) This Period	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	7,583,913	91,006,958
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	(116,227,590)	(135,391,790)	(143,686,791)	(165,224,233)	(111,334,567)	(79,322,258)	(79,322,258)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

1. TOTAL AMOUNT OF ADJUSTMENTS:	88,323,558
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$9,001,300
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 79,322,258
2. TOTAL JURISDICTIONAL SALES (MWH)	111,773,808
3. ADJUSTMENT FACTORS c/kWh:	0.0791
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0081
B. TRUE-UP FACTOR	0.0710

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2008 - DECEMBER 2008

NET ENERGY FOR LOAD (%)

		FUEL COST (%)
ON PEAK	30.36	32.90
OFF PEAK	69.64	67.10
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,110,679,752	$2,010,413,638	$4,100,266,114
2	MWH SALES	111,780,489	33,936,556	77,843,933
3	COST PER KWH SOLD	5.4667	5.9240	5.2673
4	JURISDICTIONAL LOSS FACTOR	1.00065	1.00065	1.00065
5	JURISDICTIONAL FUEL FACTOR	5.4702	5.9279	5.2707
6	TRUE-UP	0.0710	0.0710	0.0710
7				
8	TOTAL	5.5412	5.9989	5.3417
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	5.5452	6.0032	5.3455
11	GPIF	0.0081	0.0081	0.0081
11A				
12	RECOVERY FACTOR including GPIF	5.5533	6.0113	5.3536
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	5.553	6.011	5.354

HOURS:	ON-PEAK	24.68 %
	OFF-PEAK	75.32 %

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2008 THROUGH SEPTEMBER 2008 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	23.51	25.61
OFF PEAK	76.49	74.39
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,110,679,752	$1,564,945,084	$4,545,734,668
2	MWH SALES	111,780,489	26,279,593	85,500,896
3	COST PER KWH SOLD	5.4667	5.9550	5.3166
4	JURISDICTIONAL LOSS FACTOR	1.00065	1.00065	1.00065
5	JURISDICTIONAL FUEL FACTOR	5.4702	5.9589	5.3200
6	TRUE-UP	0.0710	0.0710	0.0710
7				
8	TOTAL	5.5412	6.0299	5.3910
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	SDTR RECOVERY FACTOR	5.5452	6.0342	5.3949
11	GPIF	0.0081	0.0081	0.0081
12	SDTR RECOVERY FACTOR including GPIF	5.5533	6.0423	5.4030
13	SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	5.553	6.042	5.403

HOURS:		
	ON-PEAK	19.84 %
	OFF-PEAK	80.16 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2008 - DECEMBER 2008

(1) GROUP	(2) RATE SCHEDULE	(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh	5.553	1.00207	5.227
	all additional kWh	5.553	1.00207	6.227
A	GS-1, SL-2, GSCU-1	5.553	1.00207	5.565
A-1*	SL-1, OL-1, PL-1	5.459	1.00207	5.470
B	GSD-1	5.553	1.00201	5.564
C	GSLD-1 & CS-1	5.553	1.00091	5.558
D	GSLD-2, CS-2, OS-2 & MET	5.553	0.99379	5.519
E	GSLD-3 & CS-3	5.553	0.95688	5.314
A	RST-1, GST-1 ON-PEAK	6.011	1.00207	6.024
	OFF-PEAK	5.354	1.00207	5.365
B	GSDT-1, CILC-1(G), ON-PEAK	6.011	1.00201	6.023
	HLFT-1 (21-499 kW) OFF-PEAK	5.354	1.00201	5.364
C	GSLDT-1, CST-1, ON-PEAK	6.011	1.00103	6.017
	HLFT-2 (500-1,999 kW) OFF-PEAK	5.354	1.00103	5.359
D	GSLDT-2, CST-2, ON-PEAK	6.011	0.99551	5.984
	HLFT-3 (2,000+) OFF-PEAK	5.354	0.99551	5.330
E	GSLDT-3,CST-3, ON-PEAK	6.011	0.95688	5.752
	CILC -1(T) OFF-PEAK	5.354	0.95688	5.123
	& ISST-1(T)			
F	CILC -1(D) & ON-PEAK	6.011	0.99302	5.969
	ISST-1(D) OFF-PEAK	5.354	0.99302	5.316

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2008 THROUGH SEPTEMBER 2008 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1)	(2)		(3)	(4)	(5)
GROUP	OTHERWISE APPLICABLE RATE SCHEDULE		AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	6.042	1.00201	6.054
		OFF-PEAK	5.403	1.00201	5.414
C	GSLD(T)-1	ON-PEAK	6.042	1.00106	6.049
		OFF-PEAK	5.403	1.00106	5.409
D	GSLD(T)-2	ON-PEAK	6.042	0.99565	6.015
		OFF-PEAK	5.403	0.99565	5.379

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Florida Power & Light Company
2006 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1	S	54,531,749	1.07349429	58,539,522	0.931537	4,007,772	1.00207
2								
3	CILC-1D	P	1,178,825	1.04702619	1,234,261	0.955086	55,436	
4	CILC-1D	S	2,042,176	1.07349429	2,192,264	0.931537	150,088	
5	CILC-1D Total		3,221,001	1.06380747	3,426,525	0.940020	205,524	0.99302
6								
7	CILC-1G	P	0	1.04702619	0	0.000000	0	
8	CILC-1G	S	211,903	1.07349429	227,477	0.931537	15,574	
9	CILC-1G Total		211,903	1.07349429	227,477	0.931537	15,574	1.00207
10								
11	CILC-1T	T	1,554,701	1.02508821	1,593,705	0.975526	39,005	0.95688
12								
13	CS-1	P	48,622	1.04702619	50,908	0.955086	2,286	
14	CS-1	S	176,822	1.07349429	189,817	0.931537	12,995	
15	CS-1 Total		225,443	1.06778586	240,725	0.936517	15,282	0.99674
16								
17	CS-2	P	42,563	1.04702619	44,565	0.955086	2,002	
18	CS-2	S	81,373	1.07349429	87,353	0.931537	5,980	
19	CS-2 Total		123,936	1.06440441	131,918	0.939493	7,982	0.99358
20								
21	CS-3	T	20,985	1.02508821	21,512	0.975526	526	0.95688
22								
23	GS-1	S	6,138,415	1.07349429	6,589,553	0.931537	451,138	1.00207
24								
25	GSCU-1	S	22,504	1.07349429	24,158	0.931537	1,654	1.00207
26								
27	GSD-1	P	48,900	1.04702619	51,199	0.955086	2,300	
28	GSD-1	S	22,822,901	1.07349429	24,500,254	0.931537	1,677,353	
29	GSD-1 Total		22,871,801	1.07343770	24,551,454	0.931586	1,679,653	1.00201
30								
31	GSLD-1	P	241,520	1.04702619	252,878	0.955086	11,358	
32	GSLD-1	S	5,712,823	1.07349429	6,132,682	0.931537	419,860	
33	GSLD-1 Total		5,954,343	1.07242069	6,385,560	0.932470	431,218	1.00106
34								
35	GSLD-2	P	262,393	1.04702619	274,733	0.955086	12,339	
36	GSLD-2	S	747,546	1.07349429	802,486	0.931537	54,940	
37	GSLD-2 Total		1,009,939	1.06661759	1,077,219	0.937543	67,280	0.99565
38								
39	GSLD-3	T	218,817	1.02508821	224,307	0.975526	5,490	0.95688
40								
41	HLFT-1	P	8,234	1.04702619	8,622	0.955086	387	
42	HLFT-1	S	910,679	1.07349429	977,609	0.931537	66,930	
43	HLFT-1 Total		918,913	1.07325711	986,230	0.931743	67,317	1.00185
44								
45	HLFT-2	P	167,614	1.04702619	175,497	0.955086	7,882	
46	HLFT-2	S	4,514,089	1.07349429	4,845,849	0.931537	331,760	
47	HLFT-2 Total		4,681,704	1.07254668	5,021,346	0.932360	339,642	1.00118
48								
49	HLFT-3	P	218,370	1.04702619	228,639	0.955086	10,269	
50	HLFT-3	S	619,422	1.07349429	664,946	0.931537	45,524	

Florida Power & Light Company
2006 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
51	HLFT-3 Total		837,792	1.06659541	893,585	0.937563	55,793	0.99563
52								
53	MET	P	93,758	1.04702619	98,167	0.955086	4,409	0.97736
54								
55	OL-1	S	106,276	1.07349429	114,087	0.931537	7,811	1.00207
56								
57	OS-2	P	18,541	1.04702619	19,412	0.955086	872	
58	OS-2	S	-	1.07349429	-	0.000000	-	
59	OS-2 Total		18,541	1.04702619	19,412	0.955086	872	0.97736
60								
61	STDR-1A	P	1,145	1.04702619	1,199	0.955086	54	
62	STDR-1A	S	109,518	1.07349429	117,567	0.931537	8,049	
63	STDR-1A Total		110,663	1.07322032	118,766	0.931775	8,103	1.00181
64								
65	STDR-1B	P	0	1.04702619	0	0.000000	0	
66	STDR-1B	S	818	1.07349429	878	0.931537	60	
67	STDR-1B Total		818	1.07349429	878	0.931537	60	1.00207
68								
69	STDR-2A	P	19,356	1.04702619	20,266	0.955086	910	
70	STDR-2A	S	38,642	1.07349429	41,482	0.931537	2,840	
71	STDR-2A Total		57,998	1.06466107	61,748	0.939266	3,750	0.99382
72								
73	STDR-2B	P	12,098	1.04702619	12,667	0.955086	569	
74	STDR-2B	S	1,493	1.07349429	1,603	0.931537	110	
75	STDR-2B Total		13,591	1.04993385	14,270	0.952441	679	0.98007
76								
77	STDR-3A	P	5,347	1.04702619	5,598	0.955086	251	
78	STDR-3A	S	8,863	1.07349429	9,514	0.931537	651	
79	STDR-3A Total		14,210	1.06353474	15,113	0.940261	903	0.99277
80								
81	STDR-3B	P	26,197	1.04702619	27,429	0.955086	1,232	
82	STDR-3B	S	0	1.07349429	0	0.000000	0	
83	STDR-3B Total		26,197	1.04702619	27,429	0.955086	1,232	0.97736
84								
85	SL-1	S	451,283	1.07349429	484,450	0.931537	33,167	1.00207
86								
87	SL-2	S	56,762	1.07349429	60,934	0.931537	4,172	1.00207
88								
89	SST-1D	P	7,863	1.04702619	8,233	0.955086	370	
90	SST-1D	S	0	1.07349429	0	0.000000	0	
91	SST-1D Total		7,863	1.04702619	8,233	0.955086	370	0.97736
92								
93	SST-1T	T	151,007	1.02508821	154,796	0.975526	3,788	0.95688
94								
95	**Rate Class Groups -**							
96								
97	CILC-1D / CILC-1G		3,432,904	1.06440541	3,654,002	0.939492	221,098	0.99358
98								
99	GSDT-1 / HLFT-1		23,790,715	1.07343073	25,537,684	0.931592	1,746,969	1.00201
100								

Florida Power & Light Company
2006 Actual Energy Losses by Rate Class

Line No	Rate Class	Voltage Level (Note 1)	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
101	GSDT-1, CILC-1G & HLFT-1		24,002,618	1.07343129	25,765,161	0.931592	1,762,543	1.00201
102								
103	GSLD-1 / CS-1		6,179,786	1.07225161	6,626,285	0.932617	446,499	1.00091
104								
105	GSLDT-1, CST-1 & HLFT-2		10,861,490	1.07237880	11,647,631	0.932506	786,142	1.00103
106								
107	GSLD-2 / CS-2		1,133,875	1.06637568	1,209,137	0.937756	75,262	0.99542
108								
109	GSLDT-2, CST-2 & HLFT-3		1,971,667	1.06646905	2,102,722	0.937674	131,055	0.99551
110								
111	GSLD-2, CS-2, OS-2 & MET		1,246,174	1.06463201	1,326,716	0.939292	80,543	0.99379
112								
113	GSLD-3 / CS-3		239,802	1.02508821	245,818	0.975526	6,016	0.95688
114								
115	GSLDT-3, CST-3 & CILC-1T		1,794,503	1.02508821	1,839,524	0.975526	45,021	0.95688
116								
117	OL-1 / SL-1		557,560	1.07349429	598,537	0.931537	40,977	1.00207
118								
119	SL-2 / GSCU-1		79,266	1.07349429	85,091	0.931537	5,826	1.00207
120								
121	Total FPSC		103,652,914	1.07197254	111,113,078	0.932860	7,460,164	1.00065
122								
123	Total FERC Sales		1,560,007	1.02508821	1,599,145	0.975526	39,138	
124								
125	Total Company		105,212,921	1.07127738	112,712,222	0.933465	7,499,302	
126								
127	Company Use		130,169	1.07349429	139,736	0.931537	9,567	
128								
129	Total FPL		105,343,090	1.07128012	112,851,958	0.933463	7,508,868	1.00000
130								
131	**Summary of Sales by Voltage:**							
132								
133	Transmission		3,505,517	1.02508821	3,593,464	0.975526	87,947	
134								
135	Primary		2,401,346	1.04702619	2,514,272	0.955086	112,926	
136								
137	Secondary		99,306,058	1.07349429	106,604,486	0.931537	7,298,428	
138								
139	Total		105,212,921	1.07127738	112,712,222	0.933465	7,499,302	
140								
141								

142 **Note 1:**
143 *T = Transmission Voltage*
144 P = Primary Voltage
145 S = Secondary Voltage

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2008 - DECEMBER 2008

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$362,114,711	$333,929,194	$377,331,956	$456,038,095	$500,811,308	$547,658,370	$2,577,883,636	A1
1a	NUCLEAR FUEL DISPOSAL	2,029,287	1,898,366	1,998,131	1,463,957	1,934,349	1,915,663	11,239,753	1a
1b	COAL CAR INVESTMENT	254,306	252,449	250,593	248,736	246,880	245,023	1,497,987	1b
1c	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1c
1d	INCREMENTAL HEDGING COSTS	45,361	45,361	78,962	45,361	45,361	45,361	305,767	1d
2	FUEL COST OF POWER SOLD	(15,044,550)	(15,270,100)	(13,444,750)	(11,384,750)	(6,613,300)	(7,391,850)	(69,149,300)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(3,285,417)	(3,048,460)	(1,846,369)	(1,268,974)	(891,124)	(653,355)	(10,993,699)	2a
3	FUEL COST OF PURCHASED POWER	26,665,786	25,148,400	23,920,400	24,393,492	25,522,549	26,911,000	152,561,627	3
3a	QUALIFYING FACILITIES	16,349,455	16,076,340	16,824,686	9,441,000	15,695,539	16,654,538	91,041,558	3a
4	ENERGY COST OF ECONOMY PURCHASES	5,348,821	4,670,225	6,668,872	8,542,197	12,993,091	8,293,181	46,516,387	4
4a	FUEL COST OF SALES TO FKEC / CKW	(4,683,838)	(4,680,818)	(4,593,067)	(4,995,207)	(5,189,917)	(5,507,004)	(29,649,852)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$389,793,923	$359,020,957	$407,189,414	$482,523,907	$544,554,736	$588,170,927	$2,771,253,864	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,915,668	7,884,258	7,946,690	7,874,435	8,928,163	9,904,616	51,453,830	6
7	COST PER KWH SOLD (¢/KWH)	4.3720	4.5536	5.1240	6.1277	6.0993	5.9384	5.3859	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	4.3749	4.5566	5.1273	6.1317	6.1033	5.9422	5.3894	7b
9	TRUE-UP (¢/KWH)	0.0741	0.0838	0.0832	0.0840	0.0740	0.0667	0.0771	9
10	TOTAL	4.4490	4.6404	5.2105	6.2157	6.1773	6.0089	5.4665	10
11	REVENUE TAX FACTOR 0.00072	0.0032	0.0033	0.0038	0.0045	0.0044	0.0043	0.0039	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	4.4522	4.6437	5.2143	6.2202	6.1817	6.0132	5.4704	12
13	GPIF (¢/KWH)	0.0084	0.0095	0.0094	0.0095	0.0084	0.0076	0.0087	13
14	RECOVERY FACTOR including GPIF	4.4606	4.6532	5.2237	6.2297	6.1901	6.0208	5.4791	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.461	4.653	5.224	6.230	6.190	6.021	5.479	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2008 - DECEMBER 2008

SCHEDULE E2
Page 2 of 2

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$625,756,004	$618,772,815	$554,563,834	$512,754,484	$403,939,592	$380,411,498	$5,674,081,865	A1
1a	NUCLEAR FUEL DISPOSAL	1,979,519	1,979,519	1,915,663	1,760,770	1,426,371	2,029,287	$22,330,882	1a
1b	COAL CAR INVESTMENT	243,167	241,310	239,454	237,597	235,741	233,884	$2,929,140	1b
1c	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	$0 $0	1c
1d	INCREMENTAL HEDGING COSTS	45,361	45,361	64,553	45,361	45,361	45,361	$597,125	1d
2	FUEL COST OF POWER SOLD	(8,966,900)	(8,881,400)	(4,081,450)	(3,646,250)	(8,802,450)	(16,081,800)	($119,609,550)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(923,500)	(1,389,673)	(513,287)	(445,416)	(1,194,714)	(3,640,386)	($19,100,675)	2a
3	FUEL COST OF PURCHASED POWER	29,596,801	29,396,834	26,626,917	25,917,300	26,781,700	27,687,471	$318,568,650	3
3a	QUALIFYING FACILITIES	17,507,830	17,493,095	16,993,141	14,096,095	14,843,774	16,865,013	$188,840,506	3a
4	ENERGY COST OF ECONOMY PURCHASES	8,097,021	6,728,751	10,721,706	10,946,801	14,433,936	8,642,224	$106,086,825	4
4a	FUEL COST OF SALES TO FKEC / CKW	(5,837,067)	(6,068,265)	(6,180,620)	(5,938,244)	(5,475,976)	(4,894,993)	($64,045,018)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$667,498,236	$658,318,347	$600,349,911	$555,728,498	$446,233,335	$411,297,559	$6,110,679,750	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,722,695	11,178,413	10,768,843	10,114,363	8,954,144	8,588,202	111,780,490	6
7	COST PER KWH SOLD (¢/KWH)	6.2251	5.8892	5.5749	5.4944	4.9835	4.7891	5.4667	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	6.2291	5.8930	5.5785	5.4980	4.9868	4.7922	5.4702	7b
9	TRUE-UP (¢/KWH)	0.0616	0.0591	0.0614	0.0654	0.0738	0.0770	0.0710	9
10	TOTAL	6.2907	5.9521	5.6399	5.5634	5.0606	4.8692	5.5412	10
11	REVENUE TAX FACTOR 0.00072	0.0045	0.0043	0.0041	0.0040	0.0036	0.0035	0.0040	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	6.2952	5.9564	5.6440	5.5674	5.0642	4.8727	5.5452	12
13	GPIF (¢/KWH)	0.0070	0.0067	0.0070	0.0074	0.0084	0.0087	0.0081	13
14	RECOVERY FACTOR including GPIF	6.3022	5.9631	5.6510	5.5748	5.0726	4.8814	5.5533	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	6.302	5.963	5.651	5.575	5.073	4.881	5.553	15

Florida Power & Light Company
9/04/07

Generating System Comparative Data by Fuel Type

		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$21,351,163	$5,017,136	$5,793,683	$38,899,817	$54,996,920	$90,644,692
2	Light Oil	$66,000	$0	$0	$0	$0	$0
3	Coal	$14,872,000	$13,929,000	$7,936,000	$4,426,000	$14,522,000	$14,399,000
4	Gas	$316,327,548	$306,130,058	$354,299,273	$405,651,278	$421,235,388	$432,626,678
5	Nuclear	$9,498,000	$8,853,000	$9,303,000	$7,061,000	$10,057,000	$9,988,000
6	***Total***	$362,114,711	$333,929,194	$377,331,956	$456,038,095	$500,811,308	$547,658,370
	System Net Generation (MWH)						
7	Heavy Oil	230,132	60,061	82,891	424,770	593,463	966,129
8	Light Oil	328	0	0	0	0	0
9	Coal	654,060	611,863	349,870	184,668	631,106	624,452
10	Gas	4,304,277	4,166,430	4,829,092	5,701,253	5,782,361	5,974,638
11	Nuclear	2,185,554	2,044,551	2,151,999	1,576,690	2,083,305	2,063,180
12	***Total***	7,374,351	6,882,905	7,413,852	7,887,381	9,090,235	9,628,399
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	365,565	96,459	128,415	654,478	924,040	1,497,034
14	Light Oil (BBLS)	701	0	0	0	0	0
15	Coal (TONS)	345,358	322,877	185,425	90,656	337,357	331,928
16	Gas (MCF)	32,281,420	31,287,650	36,677,176	43,368,399	45,344,792	46,200,764
17	Nuclear (MBTU)	24,370,624	22,798,320	23,990,398	17,490,402	23,218,316	23,002,796
	BTU Burned (MMBTU)						
18	Heavy Oil	2,339,618	617,335	821,854	4,188,661	5,913,855	9,581,015
19	Light Oil	4,086	0	0	0	0	0
20	Coal	6,522,030	6,101,245	3,487,608	1,834,807	6,360,091	6,281,765
21	Gas	32,281,420	31,287,650	36,677,176	43,368,399	45,344,792	46,200,764
22	Nuclear	24,370,624	22,798,320	23,990,398	17,490,402	23,218,316	23,002,796
23	***Total***	65,517,778	60,804,550	64,977,036	66,882,269	80,837,054	85,066,340

Florida Power & Light Company
9/04/07

Generating System Comparative Data by Fuel Type

		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
	Generation Mix (%MWH)						
24	Heavy Oil	3.12%	0.87%	1.12%	5.39%	6.53%	10.03%
25	Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	Coal	8.87%	8.89%	4.72%	2.34%	6.94%	6.49%
27	Gas	58.37%	60.53%	65.14%	72.28%	63.61%	62.05%
28	Nuclear	29.64%	29.70%	29.03%	19.99%	22.92%	21.43%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	58.4059	52.0131	45.1169	59.4364	59.5179	60.5495
31	Light Oil ($/BBL)	94.1512	0.0000	0.0000	0.0000	0.0000	0.0000
32	Coal ($/ton)	43.0626	43.1403	42.7990	48.8219	43.0464	43.3799
33	Gas ($/MCF)	9.7991	9.7844	9.6599	9.3536	9.2896	9.3641
34	Nuclear ($/MBTU)	0.3897	0.3883	0.3878	0.4037	0.4331	0.4342
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	9.1259	8.1271	7.0495	9.2869	9.2997	9.4609
36	Light Oil	16.1527	0.0000	0.0000	0.0000	0.0000	0.0000
37	Coal	2.2803	2.2830	2.2755	2.4122	2.2833	2.2922
38	Gas	9.7991	9.7844	9.6599	9.3536	9.2896	9.3641
39	Nuclear	0.3897	0.3883	0.3878	0.4037	0.4331	0.4342
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,166	10,278	9,915	9,861	9,965	9,917
41	Light Oil	12,457	0	0	0	0	0
42	Coal	9,972	9,972	9,968	9,936	10,078	10,060
43	Gas	7,500	7,509	7,595	7,607	7,842	7,733
44	Nuclear	11,151	11,151	11,148	11,093	11,145	11,149
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	9.2778	8.3534	6.9895	9.1579	9.2671	9.3823
46	Light Oil	20.1220	0.0000	0.0000	0.0000	0.0000	0.0000
47	Coal	2.2738	2.2765	2.2683	2.3967	2.3010	2.3059
48	Gas	7.3491	7.3475	7.3368	7.1151	7.2848	7.2411
49	Nuclear	0.4346	0.4330	0.4323	0.4478	0.4827	0.4841
50	***Total***	4.9105	4.8516	5.0896	5.7819	5.5093	5.6879

Florida Power & Light Company
9/04/07

Generating System Comparative Data by Fuel Type

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$136,085,556	$126,970,556	$88,374,556	$66,705,536	$17,056,889	$22,632,718	$674,529,222
2	Light Oil	$0	$12,000	$0	$0	$0	$0	$78,000
3	Coal	$14,897,000	$14,915,000	$14,451,000	$14,950,000	$14,565,000	$15,068,000	$158,930,000
4	Gas	$464,488,448	$466,625,259	$441,854,278	$421,822,948	$364,423,703	$331,524,780	$4,727,009,643
5	Nuclear	$10,285,000	$10,250,000	$9,884,000	$9,276,000	$7,894,000	$11,186,000	$113,535,000
6	***Total***	$625,756,004	$618,772,815	$554,563,834	$512,754,484	$403,939,592	$380,411,498	$5,674,081,865
	System Net Generation (MWH)							
7	Heavy Oil	1,436,715	1,339,559	938,508	717,171	186,582	237,835	7,213,816
8	Light Oil	0	60	0	0	0	0	388
9	Coal	645,267	645,267	624,452	645,267	632,961	654,060	6,903,293
10	Gas	6,508,748	6,540,231	6,136,471	5,703,431	5,069,171	4,419,779	65,135,881
11	Nuclear	2,131,954	2,131,954	2,063,180	1,896,360	1,536,210	2,185,554	24,050,491
12	***Total***	10,722,684	10,657,071	9,762,611	8,962,229	7,424,924	7,497,228	103,303,869
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	2,214,499	2,069,060	1,452,813	1,096,243	290,345	373,724	11,162,675
14	Light Oil (BBLS)	0	137	0	0	0	0	838
15	Coal (TONS)	342,782	342,571	331,317	342,150	332,148	343,005	3,647,574
16	Gas (MCF)	50,089,712	50,127,193	47,221,904	44,277,408	37,153,784	32,662,462	496,692,663
17	Nuclear (MBTU)	23,769,566	23,769,566	23,002,796	21,181,082	17,224,656	24,370,624	268,189,146
	BTU Burned (MMBTU)							
18	Heavy Oil	14,172,794	13,241,982	9,298,004	7,015,953	1,858,206	2,391,832	71,441,109
19	Light Oil	0	798	0	0	0	0	4,884
20	Coal	6,491,157	6,491,157	6,281,765	6,491,157	6,311,638	6,522,031	69,176,451
21	Gas	50,089,712	50,127,193	47,221,904	44,277,408	37,153,784	32,662,462	496,692,663
22	Nuclear	23,769,566	23,769,566	23,002,796	21,181,082	17,224,656	24,370,624	268,189,146
23	***Total***	94,523,229	93,630,696	85,804,469	78,965,600	62,548,284	65,946,949	905,504,253

Florida Power & Light Company
9/04/07

Generating System Comparative Data by Fuel Type

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
	Generation Mix (%MWH)							
24	Heavy Oil	13.40%	12.57%	9.61%	8.00%	2.51%	3.17%	6.98%
25	Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	Coal	6.02%	6.05%	6.40%	7.20%	8.52%	8.72%	6.68%
27	Gas	60.70%	61.37%	62.86%	63.64%	68.27%	58.95%	63.05%
28	Nuclear	19.88%	20.01%	21.13%	21.16%	20.69%	29.15%	23.28%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	61.4521	61.3663	60.8300	60.8492	58.7470	60.5600	60.4272
31	Light Oil ($/BBL)	0.0000	87.5912	0.0000	0.0000	0.0000	0.0000	93.0788
32	Coal ($/ton)	43.4591	43.5384	43.6168	43.6943	43.8509	43.9294	43.5714
33	Gas ($/MCF)	9.2731	9.3088	9.3570	9.5268	9.8085	10.1500	9.5170
34	Nuclear ($/MBTU)	0.4327	0.4312	0.4297	0.4379	0.4583	0.4590	0.4233
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	9.6019	9.5885	9.5047	9.5077	9.1792	9.4625	9.4418
36	Light Oil	0.0000	15.0376	0.0000	0.0000	0.0000	0.0000	15.9705
37	Coal	2.2950	2.2977	2.3005	2.3031	2.3076	2.3103	2.2975
38	Gas	9.2731	9.3088	9.3570	9.5268	9.8085	10.1500	9.5170
39	Nuclear	0.4327	0.4312	0.4297	0.4379	0.4583	0.4590	0.4233
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	9,865	9,885	9,907	9,783	9,959	10,057	9,903
41	Light Oil	0	13,300	0	0	0	0	12,588
42	Coal	10,060	10,060	10,060	10,060	9,972	9,972	10,021
43	Gas	7,696	7,664	7,695	7,763	7,329	7,390	7,625
44	Nuclear	11,149	11,149	11,149	11,169	11,212	11,151	11,151
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	9.4720	9.4785	9.4165	9.3012	9.1418	9.5161	9.3505
46	Light Oil	0.0000	20.0000	0.0000	0.0000	0.0000	0.0000	20.1031
47	Coal	2.3087	2.3114	2.3142	2.3169	2.3011	2.3038	2.3022
48	Gas	7.1364	7.1347	7.2005	7.3960	7.1890	7.5009	7.2572
49	Nuclear	0.4824	0.4808	0.4791	0.4891	0.5139	0.5118	0.4721
50	***Total***	5.8358	5.8062	5.6805	5.7213	5.4403	5.0740	5.4926

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 1

Estimated For The Period of : Jan-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	21,897	8.9	93.2	51.6	10,307	Heavy Oil BBLS ->	34,066	6,400,047	218,024	1,991,962	9.0970
2			3,374					Gas MCF ->	42,472	1,000,000	42,472	412,786	12.2329
3													
4	TURKEY POINT 2	380	15,970	7.6	93.3	50.6	10,379	Heavy Oil BBLS ->	24,850	6,400,000	159,040	1,453,065	9.0987
5			5,547					Gas MCF ->	64,303	1,000,000	64,303	627,717	11.3155
6													
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	2,559,500	0.4921
8													
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	1,956,000	0.3761
10													
11	TURKEY POINT 5	1,104	674,212	82.1	96.0	82.1	6,990	Gas MCF ->	4,713,180	1,000,000	4,713,180	46,194,872	6.8517
12													
13	LAUDERDALE 4	443	229,577	69.7	98.1	69.7	8,301	Gas MCF ->	1,905,915	1,000,000	1,905,915	18,948,965	8.2539
14													
15	LAUDERDALE 5	443	237,584	72.1	97.8	72.1	8,214	Gas MCF ->	1,951,574	1,000,000	1,951,574	19,479,332	8.1989
16													
17	PT EVERGLADES 1	207	1,752	1.3	95.2	66.3	10,556	Heavy Oil BBLS ->	2,802	6,399,358	17,931	163,515	9.3330
18			308					Gas MCF ->	3,812	1,000,000	3,812	37,045	12.0237
19													
20	PT EVERGLADES 2	207	1,750	1.3	95.4	66.3	10,501	Heavy Oil BBLS ->	2,785	6,398,923	17,821	162,578	9.2902
21			308					Gas MCF ->	3,792	1,000,000	3,792	36,827	11.9607
22													
23	PT EVERGLADES 3	376	22,598	14.5	91.8	43.4	10,697	Heavy Oil BBLS ->	35,960	6,399,917	230,141	2,099,180	9.2892
24			17,851					Gas MCF ->	202,584	1,000,000	202,584	1,979,095	11.0867
25													
26	PT EVERGLADES 4	376	19,898	12.6	90.6	46.6	10,553	Heavy Oil BBLS ->	31,335	6,399,968	200,543	1,829,192	9.1928
27			15,340					Gas MCF ->	171,335	1,000,000	171,335	1,679,852	10.9509
28													
29	RIVIERA 3	275	10,199	6.7	93.0	55.9	10,550	Heavy Oil BBLS ->	16,083	6,400,174	102,934	939,033	9.2071
30			3,483					Gas MCF ->	41,405	1,000,000	41,405	402,122	11.5469
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 2

Estimated For The Period of : Jan-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIVIERA 4	286	13,020	24.6	87.1	28.6	11,422	Heavy Oil BBLS ->	22,143	6,399,991	141,715	1,292,806	9.9294
33			39,381					Gas MCF ->	456,821	1,000,000	456,821	4,444,375	11.2856
34													
35	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	2,453,600	0.3965
36													
37	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,528,800	0.4802
38													
39	CAPE CANAVERAL 1	380	21,997	12.0	90.4	49.2	10,423	Heavy Oil BBLS ->	34,400	6,400,087	220,163	2,009,447	9.1351
40			12,022					Gas MCF ->	134,439	1,000,000	134,439	1,315,407	10.9420
41													
42	CAPE CANAVERAL 2	380	21,213	9.7	89.9	53.9	10,280	Heavy Oil BBLS ->	32,834	6,399,951	210,136	1,917,943	9.0414
43			6,250					Gas MCF ->	72,208	1,000,000	72,208	705,061	11.2808
44													
45	CUTLER 5	69	227	0.4	99.2	82.2	12,806	Gas MCF ->	2,905	1,000,000	2,905	28,225	12.4449
46													
47	CUTLER 6	138		0.0	97.7		0						
48													
49	FORT MYERS 2	1,422	498,692	47.1	75.2	78.6	7,360	Gas MCF ->	3,670,628	1,000,000	3,670,628	35,724,414	7.1636
50													
51	FORT MYERS 3A_B	328	1,304	0.5	96.8	99.4	11,016	Gas MCF ->	14,366	1,000,000	14,366	146,085	11.2020
52													
53	SANFORD 3	140	997	1.0	95.6	54.8	11,871	Gas MCF ->	11,840	1,000,000	11,840	120,301	12.0615
54													
55	SANFORD 4	955	470,753	66.3	95.9	85.9	7,237	Gas MCF ->	3,406,951	1,000,000	3,406,951	33,189,502	7.0503
56													
57	SANFORD 5	955	383,868	54.0	95.8	84.8	7,296	Gas MCF ->	2,801,019	1,000,000	2,801,019	27,349,761	7.1248
58													
59	PUTNAM 1	244	44,987	24.8	96.8	74.0	9,517	Gas MCF ->	428,152	1,000,000	428,152	4,268,464	9.4882
60													
61	PUTNAM 2	244	55,993	30.8	96.9	72.6	9,556	Gas MCF ->	535,112	1,000,000	535,112	5,326,733	9.5132
62													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 3

Estimated For The Period of : Jan-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 1	805	11,597	2.3	94.6	57.5	10,574	Heavy Oil BBLS ->	19,220	6,399,948	123,007	1,122,332	9.6778
64			2,287					Gas MCF ->	23,816	1,000,000	23,816	231,425	10.1178
65													
66	MANATEE 2	805	26,230	5.3	94.9	54.2	10,650	Heavy Oil BBLS ->	43,841	6,399,968	280,581	2,560,030	9.7599
67			5,612					Gas MCF ->	58,536	1,000,000	58,536	568,805	10.1361
68													
69	MANATEE 3	1,104	608,265	74.1	96.0	80.3	7,128	Gas MCF ->	4,335,814	1,000,000	4,335,814	42,310,909	6.9560
70													
71	MARTIN 1	820	18,890	5.4	94.1	47.6	10,731	Heavy Oil BBLS ->	29,264	6,400,082	187,292	1,708,618	9.0451
72			14,308					Gas MCF ->	168,959	1,000,000	168,959	1,640,705	11.4670
73													
74	MARTIN 2	820	23,120	7.2	94.9	45.7	10,743	Heavy Oil BBLS ->	35,983	6,399,967	230,290	2,100,895	9.0869
75			20,724					Gas MCF ->	240,751	1,000,000	240,751	2,340,890	11.2954
76													
77	MARTIN 3	470	123,234	35.2	96.9	80.4	7,507	Gas MCF ->	925,187	1,000,000	925,187	8,989,184	7.2944
78													
79	MARTIN 4	470	138,336	39.6	95.8	80.9	7,484	Gas MCF ->	1,035,345	1,000,000	1,035,345	10,059,645	7.2719
80													
81	MARTIN 8	1,104	689,337	83.9	96.1	83.9	7,044	Gas MCF ->	4,856,268	1,000,000	4,856,268	47,749,796	6.9269
82													
83	FORT MYERS 1-12	627	328	0.1	98.4	26.1	12,462	Light Oil BBLS ->	694	5,829,971	4,046	65,300	19.9085
84													
85	LAUDERDALE 1-24	766	115	0.0	91.8	15.1	16,769	Gas MCF ->	1,936	1,000,000	1,936	18,749	16.2470
86													
87	EVERGLADES 1-12	383		0.0	88.4		0						
88													
89	ST JOHNS 1O	130	94,715	97.9	97.3	97.9	9,626	Coal TONS ->	38,447	23,715,192	911,778	2,448,400	2.5850
90													
91	ST JOHNS 2O	130	94,067	97.3	96.5	97.3	9,707	Coal TONS ->	38,505	23,715,180	913,153	2,452,100	2.6068
92													

Date: 9/04/2007

Company: Florida Power & Light

Schedule E4
Page: 4

Estimated For The Period of : Jan-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	SCHERER 4	640	465,279	97.7	97.0	97.7	10,095	Coal TONS ->	268,406	17,499,978	4,697,099	9,971,500	2.1431
94													
95	TOTAL	21,819	7,374,352				8,885				65,517,744	362,112,845	4.9104

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 5

Estimated For The Period of : Feb-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	12,903	6.9	93.2	45.8	10,435	Heavy Oil BBLS ->	20,149	6,399,921	128,952	1,049,184	8.1313
2			5,206					Gas MCF ->	60,027	1,000,000	60,027	588,150	11.2984
3													
4	TURKEY POINT 2	380	9,323	7.7	93.3	44.2	10,560	Heavy Oil BBLS ->	14,602	6,400,082	93,454	760,313	8.1552
5			11,022					Gas MCF ->	121,405	1,000,000	121,405	1,199,363	10.8818
6													
7	TURKEY POINT 3	717	486,554	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,513,183	1,000,000	5,513,183	2,385,600	0.4903
8													
9	TURKEY POINT 4	717	486,554	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,513,183	1,000,000	5,513,183	1,822,700	0.3746
10													
11	TURKEY POINT 5	1,104	663,114	86.3	96.0	86.3	6,939	Gas MCF ->	4,601,670	1,000,000	4,601,670	45,105,099	6.8020
12													
13	LAUDERDALE 4	443	224,858	72.9	98.1	72.9	8,223	Gas MCF ->	1,849,171	1,000,000	1,849,171	18,324,171	8.1492
14													
15	LAUDERDALE 5	443	230,378	74.7	97.8	74.7	8,166	Gas MCF ->	1,881,322	1,000,000	1,881,322	18,676,589	8.1069
16													
17	PT EVERGLADES 1	207		0.0	95.2		0						
18													
19	PT EVERGLADES 2	207		0.0	95.4		0						
20													
21	PT EVERGLADES 3	376	4,502	14.9	91.8	41.1	11,033	Heavy Oil BBLS ->	7,183	6,399,972	45,971	373,303	8.2919
22			34,448					Gas MCF ->	383,767	1,000,000	383,767	3,813,246	11.0697
23													
24	PT EVERGLADES 4	376	3,576	13.0	90.6	43.5	10,863	Heavy Oil BBLS ->	5,640	6,399,468	36,093	293,090	8.1960
25			30,465					Gas MCF ->	333,697	1,000,000	333,697	3,328,080	10.9243
26													
27	RIVIERA 3	275	11,999	26.2	93.0	31.3	11,408	Heavy Oil BBLS ->	20,308	6,399,892	129,969	1,055,707	8.7983
28			38,057					Gas MCF ->	441,087	1,000,000	441,087	4,295,461	11.2870
29													
30	RIVIERA 4	286	2,296	1.2	87.1	44.6	11,072	Gas MCF ->	25,424	1,000,000	25,424	254,418	11.0800
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 6

Estimated For The Period of : Feb-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	853	578,843	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,359,814	1,000,000	6,359,814	2,286,400	0.3950
34	ST LUCIE 2	726	492,599	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,412,140	1,000,000	5,412,140	2,358,600	0.4788
36	CAPE CANAVERAL 1	380		0.0	0.0		0						
38	CAPE CANAVERAL 2	380	3,225	8.8	89.9	40.2	10,917	Heavy Oil BBLS ->	5,126	6,399,727	32,805	266,611	8.2670
39			20,127					Gas MCF ->	222,141	1,000,000	222,141	2,208,006	10.9702
41	CUTLER 5	69		0.0	99.2		0						
43	CUTLER 6	138		0.0	97.7		0						
45	FORT MYERS 2	1,422	452,278	45.7	66.1	79.9	7,359	Gas MCF ->	3,328,649	1,000,000	3,328,649	32,315,229	7.1450
47	FORT MYERS 3A_B	328		0.0	96.8		0						
49	SANFORD 3	140		0.0	95.6		0						
51	SANFORD 4	955	348,208	52.4	72.7	76.1	7,444	Gas MCF ->	2,592,240	1,000,000	2,592,240	25,162,070	7.2262
53	SANFORD 5	955	354,524	53.3	90.0	88.6	7,282	Gas MCF ->	2,581,738	1,000,000	2,581,738	25,081,416	7.0747
55	PUTNAM 1	244	57,057	33.6	96.8	78.5	9,321	Gas MCF ->	531,846	1,000,000	531,846	5,276,705	9.2482
57	PUTNAM 2	244	61,509	36.2	96.9	81.3	9,231	Gas MCF ->	567,802	1,000,000	567,802	5,629,402	9.1521
59	MANATEE 1	805	4,940	1.8	94.6	48.3	10,570	Heavy Oil BBLS ->	8,283	6,400,338	53,014	430,691	8.7184
60			5,164					Gas MCF ->	53,796	1,000,000	53,796	537,677	10.4116

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 7

Estimated For The Period of : Feb-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	805	3,600	0.8	94.9	68.0	10,636	Heavy Oil BBLS ->	6,045	6,400,331	38,690	314,308	8.7308
63			778					Gas MCF ->	7,870	1,000,000	7,870	79,985	10.2835
65	MANATEE 3	1,104	642,100	83.6	96.0	84.5	7,057	Gas MCF ->	4,531,441	1,000,000	4,531,441	44,098,056	6.8678
67	MARTIN 1	820	2,992	0.8	94.1	65.1	10,696	Heavy Oil BBLS ->	4,495	6,400,445	28,770	233,664	7.8096
68			1,282					Gas MCF ->	16,946	1,000,000	16,946	164,109	12.8000
70	MARTIN 2	820	3,001	7.8	94.9	48.5	10,776	Heavy Oil BBLS ->	4,628	6,399,741	29,618	240,566	8.0162
71			41,570					Gas MCF ->	450,719	1,000,000	450,719	4,455,465	10.7179
73	MARTIN 3	470	129,393	39.6	96.9	89.4	7,406	Gas MCF ->	958,294	1,000,000	958,294	9,290,245	7.1799
75	MARTIN 4	470	139,672	42.7	95.8	88.2	7,415	Gas MCF ->	1,035,700	1,000,000	1,035,700	10,040,678	7.1888
77	MARTIN 8	1,104	672,925	87.6	96.1	87.6	7,000	Gas MCF ->	4,710,898	1,000,000	4,710,898	46,207,665	6.8667
79	FORT MYERS 1-12	627		0.0	98.4		0						
81	LAUDERDALE 1-24	766		0.0	91.8		0						
83	EVERGLADES 1-12	383		0.0	88.4		0						
85	ST JOHNS 1O	130	88,604	97.9	97.3	97.9	9,626	Coal TONS ->	35,867	23,780,996	852,953	2,290,400	2.5850
87	ST JOHNS 2O	130	87,998	97.3	96.5	97.3	9,707	Coal TONS ->	35,921	23,781,075	854,240	2,293,900	2.6068
89	SCHERER 4	640	435,261	97.7	97.0	97.7	10,095	Coal TONS ->	251,089	17,499,978	4,394,052	9,344,800	2.1469
91	TOTAL	13,949	3,556,209				7,838				27,874,222	225,961,648	6.3540

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 8

Estimated For The Period of : Mar-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	31,946	16.9	93.2	58.0	10,253	Heavy Oil BBLS ->	48,865	6,399,939	312,733	2,206,089	6.9057
2			15,886					Gas MCF ->	177,695	1,000,000	177,695	1,742,331	10.9676
3													
4	TURKEY POINT 2	380	22,146	15.6	93.3	58.7	10,306	Heavy Oil BBLS ->	33,762	6,400,065	216,079	1,524,231	6.8826
5			21,813					Gas MCF ->	236,978	1,000,000	236,978	2,338,384	10.7200
6													
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	2,540,600	0.4885
8													
9	TURKEY POINT 4	717	486,554	91.2	94.4	97.5	11,331	Nuclear Othr ->	5,513,183	1,000,000	5,513,183	1,815,500	0.3731
10													
11	TURKEY POINT 5	1,104	551,311	67.1	74.3	87.8	6,933	Gas MCF ->	3,822,403	1,000,000	3,822,403	36,885,452	6.6905
12													
13	LAUDERDALE 4	443	173,631	52.7	66.4	77.8	8,129	Gas MCF ->	1,411,574	1,000,000	1,411,574	13,785,447	7.9395
14													
15	LAUDERDALE 5	443	261,450	79.3	97.8	79.3	8,089	Gas MCF ->	2,114,869	1,000,000	2,114,869	20,699,925	7.9174
16													
17	PT EVERGLADES 1	207	1,434	0.9	95.2	86.6	10,851	Gas MCF ->	15,560	1,000,000	15,560	157,201	10.9632
18													
19	PT EVERGLADES 2	207	1,488	1.0	95.4	89.8	10,768	Gas MCF ->	16,023	1,000,000	16,023	162,099	10.8945
20													
21	PT EVERGLADES 3	376	5,853	29.3	91.8	71.2	10,421	Heavy Oil BBLS ->	8,867	6,400,023	56,749	399,430	6.8244
22			76,021					Gas MCF ->	796,482	1,000,000	796,482	7,959,030	10.4695
23													
24	PT EVERGLADES 4	376	5,098	27.1	90.6	63.7	10,449	Heavy Oil BBLS ->	7,762	6,400,412	49,680	349,734	6.8602
25			70,824					Gas MCF ->	743,631	1,000,000	743,631	7,404,815	10.4552
26													
27	RIVIERA 3	275	5,908	4.8	93.0	63.0	10,396	Heavy Oil BBLS ->	9,201	6,400,065	58,887	414,591	7.0175
28			3,969					Gas MCF ->	43,786	1,000,000	43,786	430,809	10.8557
29													
30	RIVIERA 4	286	68,687	32.3	87.1	38.9	11,030	Gas MCF ->	757,669	1,000,000	757,669	7,401,904	10.7764
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 9

Estimated For The Period of : Mar-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	2,433,800	0.3933
33													
34	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,513,200	0.4773
35													
36	CAPE CANAVERAL 1	380		0.0	0.0		0						
37													
38	CAPE CANAVERAL 2	380	64,511	22.8	89.9	57.9	10,540	Gas MCF ->	679,954	1,000,000	679,954	6,761,276	10.4808
39													
40	CUTLER 5	69		0.0	99.2		0						
41													
42	CUTLER 6	138		0.0	97.7		0						
43													
44	FORT MYERS 2	1,422	818,201	77.3	90.7	88.7	7,206	Gas MCF ->	5,896,191	1,000,000	5,896,191	56,467,099	6.9014
45													
46	FORT MYERS 3A_B	328		0.0	96.8		0						
47													
48	SANFORD 3	140		0.0	95.6		0						
49													
50	SANFORD 4	955	574,260	80.8	95.9	90.3	7,149	Gas MCF ->	4,105,522	1,000,000	4,105,522	39,291,176	6.8421
51													
52	SANFORD 5	955	343,333	48.3	62.3	91.7	7,174	Gas MCF ->	2,463,104	1,000,000	2,463,104	23,617,825	6.8790
53													
54	PUTNAM 1	244	38,333	21.1	53.5	53.1	10,744	Gas MCF ->	411,874	1,000,000	411,874	4,022,806	10.4944
55													
56	PUTNAM 2	244	81,211	44.7	96.9	91.7	9,126	Gas MCF ->	741,158	1,000,000	741,158	7,237,385	8.9118
57													
58	MANATEE 1	805	3,716	1.0	94.6	85.5	10,534	Heavy Oil BBLS ->	6,254	6,399,584	40,023	281,905	7.5862
59			2,477					Gas MCF ->	25,216	1,000,000	25,216	255,716	10.3224
60													
61	MANATEE 2	805	7,065	2.0	94.9	81.3	10,562	Heavy Oil BBLS ->	11,946	6,399,883	76,453	538,423	7.6210
62			4,710					Gas MCF ->	47,917	1,000,000	47,917	485,866	10.3156
63													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 10

Estimated For The Period of : Mar-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MANATEE 3	1,104	704,821	85.8	96.0	85.8	7,042	Gas MCF ->	4,963,946	1,000,000	4,963,946	47,543,150	6.7454
66	MARTIN 1	820	36,288	6.0	94.1	56.0	10,993	Gas MCF ->	398,917	1,000,000	398,917	3,926,348	10.8200
68	MARTIN 2	820	1,161	12.3	94.9	60.2	10,810	Heavy Oil BBLS ->	1,758	6,399,317	11,250	79,179	6.8199
69			73,819					Gas MCF ->	799,336	1,000,000	799,336	7,859,889	10.6476
71	MARTIN 3	470	187,644	53.7	96.9	94.8	7,336	Gas MCF ->	1,376,660	1,000,000	1,376,660	13,135,680	7.0003
73	MARTIN 4	470		0.0	0.0		0						
75	MARTIN 8	1,104	652,980	79.5	85.2	80.4	7,091	Gas MCF ->	4,630,793	1,000,000	4,630,793	44,730,139	6.8502
77	FORT MYERS 1-12	627		0.0	98.4		0						
79	LAUDERDALE 1-24	766		0.0	91.8		0						
81	EVERGLADES 1-12	383		0.0	88.4		0						
83	ST JOHNS 1O	130	94,715	97.9	97.3	97.9	9,626	Coal TONS ->	38,234	23,847,309	911,778	2,448,400	2.5850
85	ST JOHNS 2O	130		0.0	0.0		0						
87	SCHERER 4	640	255,156	53.6	53.2	97.7	10,095	Coal TONS ->	147,190	17,500,027	2,575,829	5,487,800	2.1508
89	TOTAL	14,329	3,944,400				7,645				30,155,923	264,170,062	6.6973

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 11

Estimated For The Period of : Apr-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	93,373	37.1	93.2	78.4	9,906	Heavy Oil BBLS ->	140,620	6,400,021	899,971	8,365,829	8.9596
2			7,621					Gas MCF ->	100,532	1,000,000	100,532	959,957	12.5960
3													
4	TURKEY POINT 2	378	52,282	30.1	93.3	71.1	10,135	Heavy Oil BBLS ->	79,124	6,399,980	506,392	4,707,226	9.0035
5			29,632					Gas MCF ->	323,855	1,000,000	323,855	3,122,176	10.5365
6													
7	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,368,100	0.4868
8													
9	TURKEY POINT 4	693		0.0	0.0		0						
10													
11	TURKEY POINT 5	1,080	704,560	90.6	96.0	90.6	6,948	Gas MCF ->	4,895,603	1,000,000	4,895,603	45,047,397	6.3937
12													
13	LAUDERDALE 4	432	267,937	86.1	98.1	86.1	7,973	Gas MCF ->	2,136,430	1,000,000	2,136,430	20,408,342	7.6168
14													
15	LAUDERDALE 5	432	272,605	87.6	97.8	87.6	7,933	Gas MCF ->	2,162,773	1,000,000	2,162,773	20,862,222	7.6529
16													
17	PT EVERGLADES 1	205	1,584	1.1	79.3	96.6	10,726	Gas MCF ->	16,987	1,000,000	16,987	166,385	10.5068
18													
19	PT EVERGLADES 2	205	1,583	1.1	95.4	96.5	10,783	Gas MCF ->	17,065	1,000,000	17,065	167,167	10.5635
20													
21	PT EVERGLADES 3	374	52,524	48.6	91.8	79.7	10,121	Heavy Oil BBLS ->	79,334	6,399,967	507,735	4,712,132	8.9714
22			78,341					Gas MCF ->	816,770	1,000,000	816,770	7,952,958	10.1517
23													
24	PT EVERGLADES 4	374	46,191	45.6	90.6	82.4	10,125	Heavy Oil BBLS ->	69,534	6,399,963	445,015	4,130,022	8.9412
25			76,530					Gas MCF ->	797,569	1,000,000	797,569	7,777,455	10.1626
26													
27	RIVIERA 3	273	58,941	52.0	93.0	60.6	10,322	Heavy Oil BBLS ->	92,504	6,400,015	592,027	5,495,218	9.3233
28			43,189					Gas MCF ->	462,250	1,000,000	462,250	4,383,377	10.1493
29													
30	RIVIERA 4	284	1,511	0.7	11.6	66.5	10,867	Gas MCF ->	16,424	1,000,000	16,424	157,996	10.4536
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 12

Estimated For The Period of : Apr-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	2,308,300	0.3919
34	ST LUCIE 2	714	501,219	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	2,385,000	0.4758
36	CAPE CANAVERAL 1	378	32,956	30.5	72.3	77.0	10,164	Heavy Oil BBLS ->	49,727	6,400,004	318,253	2,955,488	8.9680
37			49,965					Gas MCF ->	524,629	1,000,000	524,629	5,113,787	10.2348
39	CAPE CANAVERAL 2	378	11,271	23.4	89.9	73.7	10,360	Heavy Oil BBLS ->	16,999	6,400,082	108,795	1,010,301	8.9637
40			52,507					Gas MCF ->	551,975	1,000,000	551,975	5,391,619	10.2684
42	CUTLER 5	68		0.0	99.2		0						
44	CUTLER 6	137	539	0.6	97.7	98.3	12,493	Gas MCF ->	6,728	1,000,000	6,728	61,644	11.4452
46	FORT MYERS 2	1,405	877,669	86.8	95.8	89.9	7,194	Gas MCF ->	6,314,108	1,000,000	6,314,108	58,069,671	6.6164
48	FORT MYERS 3A_B	316	2,984	1.3	96.8	99.4	11,078	Gas MCF ->	33,058	1,000,000	33,058	315,711	10.5805
50	SANFORD 3	138	856	0.9	95.6	77.6	11,463	Gas MCF ->	9,816	1,000,000	9,816	95,877	11.1980
52	SANFORD 4	936	608,626	90.3	95.9	90.3	7,169	Gas MCF ->	4,363,776	1,000,000	4,363,776	40,280,074	6.6182
54	SANFORD 5	936	500,280	74.2	80.1	90.7	7,182	Gas MCF ->	3,593,238	1,000,000	3,593,238	33,372,321	6.6707
56	PUTNAM 1	239	64,734	37.6	73.7	74.0	9,719	Gas MCF ->	629,207	1,000,000	629,207	5,988,480	9.2510
58	PUTNAM 2	239	104,636	60.8	96.9	94.0	9,063	Gas MCF ->	948,377	1,000,000	948,377	8,997,750	8.5991
60	MANATEE 1	793	32,123	9.5	94.6	65.6	10,685	Heavy Oil BBLS ->	55,178	6,400,051	353,142	3,278,459	10.2060
61			21,950					Gas MCF ->	224,671	1,000,000	224,671	2,194,630	9.9985

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 13

Estimated For The Period of : Apr-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	793	13,614	4.0	94.9	69.8	10,788	Heavy Oil BBLS ->	23,785	6,400,000	152,224	1,413,168	10.3803
64			9,076					Gas MCF ->	92,557	1,000,000	92,557	908,507	10.0101
65													
66	MANATEE 3	1,084	698,400	89.5	96.0	89.5	7,057	Gas MCF ->	4,928,791	1,000,000	4,928,791	45,667,043	6.5388
67													
68	MARTIN 1	815	9,924	13.4	94.1	70.7	10,918	Heavy Oil BBLS ->	15,010	6,400,200	96,067	891,733	8.9856
69			68,490					Gas MCF ->	760,120	1,000,000	760,120	7,243,145	10.5755
70													
71	MARTIN 2	815	21,571	22.8	94.9	74.8	10,726	Heavy Oil BBLS ->	32,663	6,399,933	209,041	1,940,309	8.9950
72			111,941					Gas MCF ->	1,223,016	1,000,000	1,223,016	11,640,799	10.3991
73													
74	MARTIN 3	456	250,040	76.2	96.9	92.9	7,310	Gas MCF ->	1,827,937	1,000,000	1,827,937	16,729,450	6.6907
75													
76	MARTIN 4	456	81,474	24.8	38.3	95.0	7,331	Gas MCF ->	597,364	1,000,000	597,364	5,466,540	6.7095
77													
78	MARTIN 8	1,084	711,998	91.2	96.1	91.2	7,012	Gas MCF ->	4,992,804	1,000,000	4,992,804	47,109,765	6.6166
79													
80	FORT MYERS 1-12	552		0.0	98.4		0						
81													
82	LAUDERDALE 1-24	684		0.0	91.8		0						
83													
84	EVERGLADES 1-12	342		0.0	88.4		0						
85													
86	ST JOHNS 1O	127	89,544	97.9	97.3	97.9	9,692	Coal TONS ->	36,294	23,913,870	867,930	2,330,700	2.6029
87													
88	ST JOHNS 2O	127	5,929	6.5	6.4	97.3	9,773	Coal TONS ->	2,423	23,914,569	57,945	155,600	2.6244
89													
90	SCHERER 4	634	89,195	19.6	19.4	97.7	10,190	Coal TONS ->	51,939	17,499,990	908,932	1,939,900	2.1749
91													
92	TOTAL	13,554	4,439,370				7,625				33,851,618	302,493,196	6.8139

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 14

Estimated For The Period of : May-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	28,872	13.3	93.2	65.7	10,070	Heavy Oil BBLS ->	44,277	6,400,050	283,375	2,638,661	9.1392
2			8,403					Gas MCF ->	91,998	1,000,000	91,998	863,569	10.2768
3													
4	TURKEY POINT 2	378	18,446	10.8	93.3	62.1	10,204	Heavy Oil BBLS ->	28,427	6,399,972	181,932	1,694,058	9.1839
5			11,841					Gas MCF ->	127,123	1,000,000	127,123	1,208,629	10.2075
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,437,400	0.4849
8													
9	TURKEY POINT 4	693	454,058	88.1	84.9	97.5	11,330	Nuclear Othr ->	5,144,894	1,000,000	5,144,894	2,787,000	0.6138
10													
11	TURKEY POINT 5	1,080	669,728	83.4	96.0	83.3	7,054	Gas MCF ->	4,724,391	1,000,000	4,724,391	42,401,389	6.3311
12													
13	LAUDERDALE 4	432	248,823	77.4	98.1	77.4	8,222	Gas MCF ->	2,045,921	1,000,000	2,045,921	19,474,004	7.8265
14													
15	LAUDERDALE 5	432	250,736	78.0	97.8	78.0	8,200	Gas MCF ->	2,056,263	1,000,000	2,056,263	19,701,480	7.8575
16													
17	PT EVERGLADES 1	205		0.0	0.0		0						
18													
19	PT EVERGLADES 2	205	6,600	4.3	95.4	63.1	10,428	Heavy Oil BBLS ->	10,754	6,400,409	68,830	638,222	9.6700
20													
21	PT EVERGLADES 3	374	41,090	22.3	91.8	64.4	10,155	Heavy Oil BBLS ->	63,114	6,400,022	403,931	3,755,245	9.1391
22			20,839					Gas MCF ->	224,998	1,000,000	224,998	2,131,065	10.2262
23													
24	PT EVERGLADES 4	374	40,751	23.5	90.6	64.4	10,147	Heavy Oil BBLS ->	62,562	6,399,955	400,394	3,722,366	9.1344
25			24,506					Gas MCF ->	261,823	1,000,000	261,823	2,493,180	10.1737
26													
27	RIVIERA 3	273	5,588	4.0	93.0	92.3	10,275	Heavy Oil BBLS ->	8,516	6,399,601	54,499	506,761	9.0687
28			2,472					Gas MCF ->	28,319	1,000,000	28,319	273,834	11.0761
29													
30	RIVIERA 4	284		0.0	0.0		0						
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 15

Estimated For The Period of : May-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,375,800	0.3904
34	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,456,600	0.4743
36	CAPE CANAVERAL 1	378	16,915	21.9	90.4	62.8	10,357	Heavy Oil BBLS ->	26,042	6,400,046	166,670	1,550,466	9.1662
37			44,609					Gas MCF ->	470,536	1,000,000	470,536	4,535,435	10.1671
39	CAPE CANAVERAL 2	378	16,795	7.0	89.9	62.3	10,073	Heavy Oil BBLS ->	25,891	6,399,907	165,700	1,541,446	9.1780
40			2,761					Gas MCF ->	31,297	1,000,000	31,297	284,708	10.3136
42	CUTLER 5	68	773	1.5	99.2	71.0	12,027	Gas MCF ->	9,296	1,000,000	9,296	84,997	10.9972
44	CUTLER 6	137	1,302	1.3	97.7	59.4	12,243	Gas MCF ->	15,944	1,000,000	15,944	147,960	11.3606
46	FORT MYERS 2	1,405	897,097	85.8	95.8	85.8	7,235	Gas MCF ->	6,491,090	1,000,000	6,491,090	59,867,051	6.6734
48	FORT MYERS 3A_B	316	5,183	2.2	96.8	99.4	11,119	Gas MCF ->	57,626	1,000,000	57,626	561,488	10.8341
50	SANFORD 3	138	1,807	1.8	95.6	50.4	11,706	Gas MCF ->	21,158	1,000,000	21,158	203,141	11.2394
52	SANFORD 4	936	601,823	86.4	95.9	86.4	7,224	Gas MCF ->	4,347,708	1,000,000	4,347,708	40,131,939	6.6684
54	SANFORD 5	936	599,692	86.1	95.8	86.1	7,228	Gas MCF ->	4,334,957	1,000,000	4,334,957	40,113,776	6.6891
56	PUTNAM 1	239	37,659	21.2	96.8	98.5	9,170	Gas MCF ->	345,354	1,000,000	345,354	3,309,509	8.7880
58	PUTNAM 2	239	42,267	23.8	96.9	98.3	9,167	Gas MCF ->	387,506	1,000,000	387,506	3,698,522	8.7503
60	MANATEE 1	793	141,234	51.2	94.6	51.2	10,313	Heavy Oil BBLS ->	221,687	6,400,010	1,418,799	13,194,551	9.3423
61			160,891					Gas MCF ->	1,697,082	1,000,000	1,697,082	16,081,497	9.9953

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 16

Estimated For The Period of : May-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	793	120,726	45.6	94.9	45.6	10,363	Heavy Oil BBLS ->	190,252	6,399,985	1,217,610	11,323,554	9.3795
64			148,319					Gas MCF ->	1,570,709	1,000,000	1,570,709	14,823,242	9.9941
65													
66	MANATEE 3	1,084	366,470	45.4	52.7	82.9	7,163	Gas MCF ->	2,625,211	1,000,000	2,625,211	24,553,905	6.7001
67													
68	MARTIN 1	815	76,225	46.5	94.1	60.7	10,477	Heavy Oil BBLS ->	118,275	6,400,017	756,962	7,038,389	9.2337
69			205,797					Gas MCF ->	2,197,889	1,000,000	2,197,889	20,658,181	10.0381
70													
71	MARTIN 2	815	80,222	51.7	94.9	64.9	10,446	Heavy Oil BBLS ->	124,243	6,399,974	795,152	7,393,460	9.2162
72			233,258					Gas MCF ->	2,479,622	1,000,000	2,479,622	23,343,515	10.0076
73													
74	MARTIN 3	456	266,363	78.5	85.9	78.5	7,425	Gas MCF ->	1,977,754	1,000,000	1,977,754	18,015,736	6.7636
75													
76	MARTIN 4	456	288,584	85.1	95.8	85.1	7,366	Gas MCF ->	2,125,731	1,000,000	2,125,731	19,413,893	6.7273
77													
78	MARTIN 8	1,084	640,378	79.4	89.9	79.4	7,179	Gas MCF ->	4,597,695	1,000,000	4,597,695	42,860,000	6.6929
79													
80	FORT MYERS 1-12	552		0.0	98.4		0						
81													
82	LAUDERDALE 1-24	684		0.0	91.8		0						
83													
84	EVERGLADES 1-12	342		0.0	88.4		0						
85													
86	ST JOHNS 1O	127	87,077	92.2	97.3	92.2	9,730	Coal TONS ->	35,332	23,981,122	847,301	2,275,300	2.6130
87													
88	ST JOHNS 2O	127	85,687	90.7	96.5	90.7	9,817	Coal TONS ->	35,080	23,980,929	841,251	2,259,000	2.6363
89													
90	SCHERER 4	634	458,341	97.2	97.0	97.2	10,192	Coal TONS ->	266,945	17,500,006	4,671,539	9,988,200	2.1792
91													
92	TOTAL	13,554	5,566,731				8,268				46,027,943	383,166,960	6.8832

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 17

Estimated For The Period of : Jun-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	82,346	34.9	93.2	65.6	10,003	Heavy Oil BBLS ->	126,411	6,399,981	809,028	7,663,033	9.3059
2			12,693					Gas MCF ->	141,747	1,000,000	141,747	1,310,896	10.3275
3													
4	TURKEY POINT 2	378	56,986	31.7	93.3	63.1	10,143	Heavy Oil BBLS ->	87,721	6,400,030	561,417	5,317,704	9.3316
5			29,144					Gas MCF ->	312,286	1,000,000	312,286	2,985,014	10.2422
6													
7	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,350,500	0.4832
8													
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,977,200	0.6120
10													
11	TURKEY POINT 5	1,080	672,482	86.5	96.0	86.5	6,999	Gas MCF ->	4,707,327	1,000,000	4,707,327	42,753,806	6.3576
12													
13	LAUDERDALE 4	432	247,054	79.4	98.1	79.4	8,156	Gas MCF ->	2,015,073	1,000,000	2,015,073	19,528,069	7.9044
14													
15	LAUDERDALE 5	432	250,964	80.7	97.8	80.7	8,113	Gas MCF ->	2,036,260	1,000,000	2,036,260	19,793,435	7.8870
16													
17	PT EVERGLADES 1	205	2,023	1.4	9.5	89.7	10,207	Heavy Oil BBLS ->	3,226	6,401,116	20,650	194,466	9.6128
18													
19	PT EVERGLADES 2	205	7,290	4.9	95.4	64.7	10,395	Heavy Oil BBLS ->	11,841	6,400,135	75,784	715,028	9.8083
20													
21	PT EVERGLADES 3	374	84,053	35.9	91.8	67.9	9,984	Heavy Oil BBLS ->	128,700	6,400,000	823,680	7,789,499	9.2674
22			12,504					Gas MCF ->	140,355	1,000,000	140,355	1,287,740	10.2990
23													
24	PT EVERGLADES 4	374	73,052	31.8	90.6	66.0	10,024	Heavy Oil BBLS ->	112,043	6,399,998	717,075	6,781,342	9.2829
25			12,605					Gas MCF ->	141,611	1,000,000	141,611	1,306,954	10.3689
26													
27	RIVIERA 3	273	15,530	11.3	93.0	92.7	10,268	Heavy Oil BBLS ->	23,659	6,400,017	151,418	1,432,186	9.2221
28			6,733					Gas MCF ->	77,183	1,000,000	77,183	753,648	11.1928
29													
30	RIVIERA 4	284	21,067	10.3	61.0	91.6	10,583	Gas MCF ->	222,953	1,000,000	222,953	2,197,854	10.4328
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 18

Estimated For The Period of : Jun-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	2,290,100	0.3888
34	ST LUCIE 2	714	501,219	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	2,370,200	0.4729
36	CAPE CANAVERAL 1	378	82,789	38.3	90.4	66.2	10,037	Heavy Oil BBLS ->	127,081	6,400,013	813,320	7,696,273	9.2963
37			21,528					Gas MCF ->	233,759	1,000,000	233,759	2,195,559	10.1989
39	CAPE CANAVERAL 2	378	49,283	22.4	89.9	63.6	10,081	Heavy Oil BBLS ->	75,884	6,399,992	485,657	4,595,671	9.3251
40			11,571					Gas MCF ->	127,828	1,000,000	127,828	1,195,633	10.3328
42	CUTLER 5	68		0.0	99.2		0						
44	CUTLER 6	137		0.0	97.7		0						
46	FORT MYERS 2	1,405	874,102	86.4	95.8	86.4	7,226	Gas MCF ->	6,316,925	1,000,000	6,316,925	58,393,566	6.6804
48	FORT MYERS 3A_B	316	9,894	4.4	96.8	99.4	11,093	Gas MCF ->	109,759	1,000,000	109,759	1,070,330	10.8179
50	SANFORD 3	138	1,610	1.6	95.6	50.7	11,741	Gas MCF ->	18,906	1,000,000	18,906	184,080	11.4321
52	SANFORD 4	936	586,567	87.0	95.9	87.0	7,214	Gas MCF ->	4,231,741	1,000,000	4,231,741	39,323,747	6.7041
54	SANFORD 5	936	584,756	86.8	95.8	86.8	7,218	Gas MCF ->	4,220,974	1,000,000	4,220,974	39,340,783	6.7277
56	PUTNAM 1	239	50,134	29.1	96.8	98.5	9,164	Gas MCF ->	459,440	1,000,000	459,440	4,479,467	8.9350
58	PUTNAM 2	239	53,218	30.9	96.9	98.5	9,158	Gas MCF ->	487,405	1,000,000	487,405	4,752,323	8.9299
60	MANATEE 1	793	151,131	50.7	94.6	50.7	10,282	Heavy Oil BBLS ->	237,135	6,399,992	1,517,662	14,356,964	9.4997
61			138,578					Gas MCF ->	1,461,186	1,000,000	1,461,186	13,922,593	10.0467

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 19

Estimated For The Period of : Jun-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	793	120,243	45.6	94.9	45.6	10,355	Heavy Oil BBLS ->	189,451	6,399,998	1,212,486	11,470,060	9.5391
64			140,357					Gas MCF ->	1,486,072	1,000,000	1,486,072	14,136,228	10.0716
66	MANATEE 3	1,084	659,655	84.5	96.0	84.5	7,128	Gas MCF ->	4,702,433	1,000,000	4,702,433	44,216,985	6.7030
68	MARTIN 1	815	131,877	46.7	94.1	62.6	10,366	Heavy Oil BBLS ->	204,407	6,400,006	1,308,206	12,373,497	9.3826
69			142,260					Gas MCF ->	1,533,762	1,000,000	1,533,762	14,324,222	10.0691
71	MARTIN 2	815	109,525	51.9	94.9	66.4	10,404	Heavy Oil BBLS ->	169,474	6,399,991	1,084,632	10,258,857	9.3667
72			194,980					Gas MCF ->	2,083,443	1,000,000	2,083,443	19,704,598	10.1059
74	MARTIN 3	456	284,051	86.5	96.9	86.5	7,351	Gas MCF ->	2,088,234	1,000,000	2,088,234	19,154,711	6.7434
76	MARTIN 4	456	281,690	85.8	95.8	85.8	7,354	Gas MCF ->	2,071,563	1,000,000	2,071,563	19,001,869	6.7457
78	MARTIN 8	1,084	674,453	86.4	80.1	86.4	7,076	Gas MCF ->	4,772,685	1,000,000	4,772,685	45,313,783	6.7186
80	FORT MYERS 1-12	552		0.0	98.4		0						
82	LAUDERDALE 1-24	684		0.0	91.8		0						
84	EVERGLADES 1-12	342		0.0	88.4		0						
86	ST JOHNS 1O	127	89,544	97.9	97.3	97.9	9,692	Coal TONS ->	36,091	24,048,378	867,930	2,330,700	2.6029
88	ST JOHNS 2O	127	88,930	97.3	96.5	97.3	9,773	Coal TONS ->	36,143	24,048,474	869,184	2,334,000	2.6245
90	SCHERER 4	634	445,978	97.7	97.0	97.7	10,190	Coal TONS ->	259,694	17,500,023	4,544,651	9,734,200	2.1827
92	TOTAL	13,554	5,874,388				8,182				48,062,764	405,968,867	6.9108

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 20

Estimated For The Period of : Jul-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	104,243	43.3	93.2	72.6	9,941	Heavy Oil BBLS ->	158,859	6,400,015	1,016,700	9,774,004	9.3762
2			17,579					Gas MCF ->	194,428	1,000,000	194,428	1,835,673	10.4424
3													
4	TURKEY POINT 2	378	84,839	40.5	93.3	73.2	9,989	Heavy Oil BBLS ->	129,208	6,399,998	826,931	7,949,687	9.3703
5			28,911					Gas MCF ->	309,385	1,000,000	309,385	2,982,706	10.3169
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,419,700	0.4813
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,066,800	0.6101
10													
11	TURKEY POINT 5	1,080	726,253	90.4	96.0	90.4	6,951	Gas MCF ->	5,048,282	1,000,000	5,048,282	45,201,812	6.2240
12													
13	LAUDERDALE 4	432	282,879	88.0	98.1	88.0	7,933	Gas MCF ->	2,244,259	1,000,000	2,244,259	21,262,660	7.5165
14													
15	LAUDERDALE 5	432	285,166	88.7	97.8	88.7	7,912	Gas MCF ->	2,256,451	1,000,000	2,256,451	21,729,662	7.6200
16													
17	PT EVERGLADES 1	205	27,728	18.2	95.2	70.1	10,242	Heavy Oil BBLS ->	44,376	6,399,901	284,002	2,721,046	9.8134
18													
19	PT EVERGLADES 2	205	27,853	18.3	95.4	69.0	10,327	Heavy Oil BBLS ->	44,946	6,399,969	287,653	2,755,369	9.8925
20													
21	PT EVERGLADES 3	374	123,784	48.8	91.8	73.8	9,899	Heavy Oil BBLS ->	188,322	6,399,990	1,205,259	11,568,845	9.3460
22			12,056					Gas MCF ->	139,456	1,000,000	139,456	1,278,955	10.6086
23													
24	PT EVERGLADES 4	374	116,460	46.5	90.6	73.3	9,907	Heavy Oil BBLS ->	177,255	6,400,011	1,134,434	10,888,976	9.3500
25			12,914					Gas MCF ->	147,383	1,000,000	147,383	1,363,118	10.5558
26													
27	RIVIERA 3	273	17,996	12.2	93.0	94.7	10,235	Heavy Oil BBLS ->	27,386	6,399,949	175,269	1,682,605	9.3499
28			6,826					Gas MCF ->	78,805	1,000,000	78,805	774,861	11.3513
29													
30	RIVIERA 4	284	6,219	15.8	87.1	92.0	10,493	Heavy Oil BBLS ->	9,463	6,400,190	60,565	581,471	9.3499
31			27,239					Gas MCF ->	290,533	1,000,000	290,533	2,876,929	10.5618
32													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 21

Estimated For The Period of : Jul-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,357,100	0.3873
34													
35	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,441,800	0.4715
36													
37	CAPE CANAVERAL 1	378	105,498	45.1	90.4	71.7	9,968	Heavy Oil BBLS ->	160,975	6,400,000	1,030,240	9,894,894	9.3792
38			21,386					Gas MCF ->	234,585	1,000,000	234,585	2,228,919	10.4223
39													
40	CAPE CANAVERAL 2	378	88,888	35.3	89.9	70.7	9,950	Heavy Oil BBLS ->	135,864	6,400,025	869,533	8,351,389	9.3954
41			10,242					Gas MCF ->	116,898	1,000,000	116,898	1,070,208	10.4492
42													
43	CUTLER 5	68	6,538	12.9	99.2	83.6	11,852	Gas MCF ->	77,498	1,000,000	77,498	713,131	10.9071
44													
45	CUTLER 6	137	12,536	12.3	97.7	74.4	11,956	Gas MCF ->	149,884	1,000,000	149,884	1,393,362	11.1153
46													
47	FORT MYERS 2	1,405	938,288	89.8	95.8	89.8	7,185	Gas MCF ->	6,742,499	1,000,000	6,742,499	63,210,970	6.7368
48													
49	FORT MYERS 3A_B	316	35,179	15.0	96.8	99.4	11,049	Gas MCF ->	388,699	1,000,000	388,699	3,681,184	10.4642
50													
51	SANFORD 3	138	759	14.6	95.6	57.1	11,417	Heavy Oil BBLS ->	1,261	6,402,062	8,073	79,703	10.5011
52			14,211					Gas MCF ->	162,848	1,000,000	162,848	1,591,549	11.1993
53													
54	SANFORD 4	936	630,556	90.6	95.9	90.5	7,165	Gas MCF ->	4,518,199	1,000,000	4,518,199	42,332,312	6.7135
55													
56	SANFORD 5	936	603,932	86.7	90.4	86.7	7,213	Gas MCF ->	4,356,436	1,000,000	4,356,436	41,224,767	6.8261
57													
58	PUTNAM 1	239	68,493	38.5	96.8	98.5	9,131	Gas MCF ->	625,425	1,000,000	625,425	5,922,383	8.6467
59													
60	PUTNAM 2	239	75,118	42.2	96.9	98.5	9,111	Gas MCF ->	684,419	1,000,000	684,419	6,481,591	8.6286
61													
62	MANATEE 1	793	209,169	58.0	94.6	58.0	10,162	Heavy Oil BBLS ->	325,819	6,400,001	2,085,242	20,021,496	9.5719
63			133,080					Gas MCF ->	1,393,033	1,000,000	1,393,033	13,355,993	10.0360
64													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 22

Estimated For The Period of : Jul-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MANATEE 2	793	168,498	50.4	94.9	50.4	10,210	Heavy Oil BBLS ->	263,117	6,399,997	1,683,948	16,168,496	9.5957
66			128,944					Gas MCF ->	1,353,074	1,000,000	1,353,074	12,864,845	9.9771
68	MANATEE 3	1,084	721,565	89.5	96.0	89.5	7,056	Gas MCF ->	5,091,976	1,000,000	5,091,976	45,625,157	6.3231
70	MARTIN 1	815	184,755	58.0	94.1	69.8	10,253	Heavy Oil BBLS ->	285,283	6,400,010	1,825,814	17,527,794	9.4870
71			167,034					Gas MCF ->	1,781,223	1,000,000	1,781,223	16,630,261	9.9562
73	MARTIN 2	815	170,025	60.8	94.9	72.3	10,272	Heavy Oil BBLS ->	262,364	6,400,009	1,679,132	16,119,589	9.4807
74			198,699					Gas MCF ->	2,108,422	1,000,000	2,108,422	19,840,987	9.9855
76	MARTIN 3	456	306,470	90.3	96.9	90.3	7,296	Gas MCF ->	2,236,115	1,000,000	2,236,115	20,478,876	6.6822
78	MARTIN 4	456	302,871	89.3	95.8	89.3	7,303	Gas MCF ->	2,211,997	1,000,000	2,211,997	20,447,043	6.7511
80	MARTIN 8	1,084	733,816	91.0	96.1	91.0	7,015	Gas MCF ->	5,147,824	1,000,000	5,147,824	46,093,067	6.2813
82	FORT MYERS 1-12	552		0.0	98.4		0						
84	LAUDERDALE 1-24	684		0.0	91.8		0						
86	EVERGLADES 1-12	342		0.0	88.4		0						
88	ST JOHNS 1O	127	92,529	97.9	97.3	97.9	9,692	Coal TONS ->	37,189	24,116,271	896,860	2,408,300	2.6028
90	ST JOHNS 2O	127	91,895	97.3	96.5	97.3	9,773	Coal TONS ->	37,242	24,116,804	898,158	2,411,800	2.6245
92	SCHERER 4	634	460,844	97.7	97.0	97.7	10,190	Coal TONS ->	268,351	17,499,987	4,696,139	10,076,500	2.1865
94	TOTAL	21,286	10,722,713				8,815				94,523,553	625,760,345	5.8358

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 23

Estimated For The Period of : Aug-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	93,608	38.1	93.2	70.6	9,951	Heavy Oil BBLS ->	142,931	6,400,011	914,760	8,782,112	9.3818
2			13,409					Gas MCF ->	150,184	1,000,000	150,184	1,404,405	10.4738
3													
4	TURKEY POINT 2	378	79,598	34.7	93.3	70.8	9,980	Heavy Oil BBLS ->	121,512	6,400,018	777,679	7,466,108	9.3798
5			18,025					Gas MCF ->	196,603	1,000,000	196,603	1,870,760	10.3790
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,410,600	0.4795
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,057,700	0.6082
10													
11	TURKEY POINT 5	1,080	733,224	91.3	96.0	91.3	6,940	Gas MCF ->	5,088,791	1,000,000	5,088,791	45,772,126	6.2426
12													
13	LAUDERDALE 4	432	286,147	89.0	98.1	89.0	7,902	Gas MCF ->	2,261,216	1,000,000	2,261,216	21,541,006	7.5279
14													
15	LAUDERDALE 5	432	287,479	89.4	97.8	89.4	7,889	Gas MCF ->	2,268,062	1,000,000	2,268,062	21,954,138	7.6368
16													
17	PT EVERGLADES 1	205	34,783	22.8	95.2	67.6	10,292	Heavy Oil BBLS ->	55,939	6,400,061	358,013	3,424,770	9.8461
18													
19	PT EVERGLADES 2	205	31,339	20.6	95.4	67.3	10,349	Heavy Oil BBLS ->	50,679	6,399,968	324,344	3,102,850	9.9009
20													
21	PT EVERGLADES 3	374	108,126	43.9	91.8	71.7	9,944	Heavy Oil BBLS ->	164,824	6,399,996	1,054,873	10,111,613	9.3517
22			14,135					Gas MCF ->	160,999	1,000,000	160,999	1,494,443	10.5726
23													
24	PT EVERGLADES 4	374	104,146	43.0	90.6	70.4	9,949	Heavy Oil BBLS ->	158,917	6,399,982	1,017,066	9,749,214	9.3611
25			15,396					Gas MCF ->	172,274	1,000,000	172,274	1,611,831	10.4693
26													
27	RIVIERA 3	273	25,446	17.4	93.0	94.5	10,236	Heavy Oil BBLS ->	38,725	6,400,052	247,842	2,376,028	9.3375
28			9,908					Gas MCF ->	114,080	1,000,000	114,080	1,127,699	11.3814
29													
30	RIVIERA 4	284	5,443	19.3	87.1	91.9	10,511	Heavy Oil BBLS ->	8,283	6,400,217	53,013	508,282	9.3383
31			35,259					Gas MCF ->	374,840	1,000,000	374,840	3,734,455	10.5915
32													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 24

Estimated For The Period of : Aug-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUCIE 1	839	608,613	97.5	97.5	97.5	10,986	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	2,347,700	0.3857
35	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,433,800	0.4699
37	CAPE CANAVERAL 1	378	92,381	42.1	90.4	70.4	9,998	Heavy Oil BBLS ->	141,130	6,399,986	903,230	8,663,299	9.3778
38			26,083					Gas MCF ->	281,272	1,000,000	281,272	2,712,730	10.4003
40	CAPE CANAVERAL 2	378	74,621	30.7	89.9	69.7	9,969	Heavy Oil BBLS ->	114,139	6,400,004	730,490	7,006,471	9.3894
41			11,591					Gas MCF ->	129,035	1,000,000	129,035	1,210,206	10.4412
43	CUTLER 5	68	7,368	14.6	99.2	78.5	11,852	Gas MCF ->	87,326	1,000,000	87,326	806,785	10.9501
45	CUTLER 6	137	16,231	15.9	97.7	69.3	11,966	Gas MCF ->	194,214	1,000,000	194,214	1,809,509	11.1486
47	FORT MYERS 2	1,405	942,462	90.2	95.8	90.2	7,178	Gas MCF ->	6,765,084	1,000,000	6,765,084	63,669,460	6.7557
49	FORT MYERS 3A_B	316	31,724	13.5	96.8	99.4	11,049	Gas MCF ->	350,548	1,000,000	350,548	3,334,665	10.5115
51	SANFORD 3	138	519	15.9	95.6	55.6	11,478	Heavy Oil BBLS ->	865	6,402,312	5,538	54,601	10.5204
52			15,838					Gas MCF ->	182,213	1,000,000	182,213	1,786,907	11.2825
54	SANFORD 4	936	634,478	91.1	95.9	91.1	7,157	Gas MCF ->	4,540,971	1,000,000	4,540,971	42,768,645	6.7408
56	SANFORD 5	936	632,274	90.8	95.8	90.8	7,160	Gas MCF ->	4,527,688	1,000,000	4,527,688	42,890,481	6.7835
58	PUTNAM 1	239	62,373	35.1	96.8	98.5	9,137	Gas MCF ->	569,930	1,000,000	569,930	5,420,927	8.6911
60	PUTNAM 2	239	66,405	37.3	96.9	98.5	9,123	Gas MCF ->	605,833	1,000,000	605,833	5,762,637	8.6781
62	MANATEE 1	793	206,293	56.3	94.6	56.3	10,175	Heavy Oil BBLS ->	321,895	6,400,009	2,060,131	19,753,670	9.5755
63			125,726					Gas MCF ->	1,318,336	1,000,000	1,318,336	12,639,083	10.0529

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 25

Estimated For The Period of : Aug-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MANATEE 2	793	150,828	48.9	94.9	48.9	10,258	Heavy Oil BBLS ->	236,118	6,399,991	1,511,153	14,489,787	9.6068
66			137,736					Gas MCF ->	1,448,983	1,000,000	1,448,983	13,885,675	10.0813
67													
68	MANATEE 3	1,084	729,408	90.4	96.0	90.4	7,043	Gas MCF ->	5,137,571	1,000,000	5,137,571	46,281,701	6.3451
69													
70	MARTIN 1	815	162,647	52.6	94.1	68.1	10,298	Heavy Oil BBLS ->	251,111	6,400,010	1,607,113	15,407,349	9.4729
71			156,308					Gas MCF ->	1,677,706	1,000,000	1,677,706	15,731,924	10.0647
72													
73	MARTIN 2	815	169,780	56.1	94.9	71.0	10,287	Heavy Oil BBLS ->	261,990	6,400,004	1,676,737	16,074,835	9.4680
74			170,606					Gas MCF ->	1,825,140	1,000,000	1,825,140	17,132,525	10.0422
75													
76	MARTIN 3	456	309,777	91.3	96.9	91.3	7,280	Gas MCF ->	2,255,409	1,000,000	2,255,409	20,743,895	6.6964
77													
78	MARTIN 4	456	306,114	90.2	95.8	90.2	7,287	Gas MCF ->	2,230,849	1,000,000	2,230,849	20,647,840	6.7452
79													
80	MARTIN 8	1,084	744,749	92.3	96.1	92.3	6,998	Gas MCF ->	5,212,039	1,000,000	5,212,039	46,880,740	6.2948
81													
82	FORT MYERS 1-12	552	60	0.0	98.4	10.8	13,404	Light Oil BBLS ->	130	5,830,769	758	11,600	19.3333
83													
84	LAUDERDALE 1-24	684		0.0	91.8		0						
85													
86	EVERGLADES 1-12	342		0.0	88.4		0						
87													
88	ST JOHNS 1O	127	92,529	97.9	97.3	97.9	9,692	Coal TONS ->	37,084	24,184,554	896,860	2,408,300	2.6028
89													
90	ST JOHNS 2O	127	91,895	97.3	96.5	97.3	9,773	Coal TONS ->	37,137	24,184,991	898,158	2,411,800	2.6245
91													
92	SCHERER 4	634	460,844	97.7	97.0	97.7	10,190	Coal TONS ->	268,351	17,499,987	4,696,139	10,094,400	2.1904
93													
94	TOTAL	21,286	10,657,071				8,786				93,630,659	618,774,087	5.8062

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 26

Estimated For The Period of : Sep-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	50,450	23.9	93.2	67.1	10,036	Heavy Oil BBLS ->	77,267	6,399,977	494,507	4,705,852	9.3278
2			14,694					Gas MCF ->	159,325	1,000,000	159,325	1,526,664	10.3900
3													
4	TURKEY POINT 2	378	46,797	23.5	93.3	68.2	10,040	Heavy Oil BBLS ->	71,632	6,400,017	458,446	4,362,743	9.3227
5			17,135					Gas MCF ->	183,458	1,000,000	183,458	1,768,753	10.3226
6													
7	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,324,000	0.4777
8													
9	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	2,949,700	0.6063
10													
11	TURKEY POINT 5	1,080	695,707	89.5	96.0	89.5	6,961	Gas MCF ->	4,842,830	1,000,000	4,842,830	43,843,061	6.3019
12													
13	LAUDERDALE 4	432	265,912	85.5	98.1	85.5	7,989	Gas MCF ->	2,124,400	1,000,000	2,124,400	20,313,733	7.6393
14													
15	LAUDERDALE 5	432	269,315	86.6	97.8	86.6	7,956	Gas MCF ->	2,142,804	1,000,000	2,142,804	20,639,877	7.6638
16													
17	PT EVERGLADES 1	205	7,993	5.4	95.2	67.2	10,292	Heavy Oil BBLS ->	12,855	6,400,078	82,273	780,249	9.7617
18													
19	PT EVERGLADES 2	205	7,722	5.2	95.4	66.1	10,367	Heavy Oil BBLS ->	12,509	6,400,032	80,058	759,175	9.8313
20													
21	PT EVERGLADES 3	374	81,010	34.7	91.8	69.5	9,968	Heavy Oil BBLS ->	123,765	6,400,000	792,096	7,526,054	9.2903
22			12,520					Gas MCF ->	140,234	1,000,000	140,234	1,314,942	10.5027
23													
24	PT EVERGLADES 4	374	71,029	30.2	90.6	68.7	9,965	Heavy Oil BBLS ->	108,564	6,399,985	694,808	6,601,647	9.2943
25			10,187					Gas MCF ->	114,539	1,000,000	114,539	1,069,212	10.4954
26													
27	RIVIERA 3	273	10,136	7.4	93.0	94.7	10,247	Heavy Oil BBLS ->	15,424	6,400,091	98,715	938,103	9.2552
28			4,344					Gas MCF ->	49,672	1,000,000	49,672	491,165	11.3070
29													
30	RIVIERA 4	284	2,570	8.4	87.1	91.3	10,505	Heavy Oil BBLS ->	3,912	6,399,796	25,036	237,925	9.2578
31			14,545					Gas MCF ->	154,765	1,000,000	154,765	1,540,567	10.5918
32													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 27

Estimated For The Period of : Sep-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUCIE 1	839	588,980	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	2,262,300	0.3841
34													
35	ST LUCIE 2	714	501,219	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	2,348,100	0.4685
36													
37	CAPE CANAVERAL 1	378	63,046	31.2	90.4	68.0	10,040	Heavy Oil BBLS ->	96,516	6,399,975	617,700	5,872,638	9.3148
38			21,790					Gas MCF ->	234,065	1,000,000	234,065	2,259,040	10.3675
39													
40	CAPE CANAVERAL 2	378	45,385	20.0	89.9	65.8	10,039	Heavy Oil BBLS ->	69,675	6,399,957	445,917	4,239,484	9.3412
41			9,051					Gas MCF ->	100,579	1,000,000	100,579	950,351	10.4995
42													
43	CUTLER 5	68	2,740	5.6	99.2	79.0	11,775	Gas MCF ->	32,265	1,000,000	32,265	299,707	10.9378
44													
45	CUTLER 6	137	4,002	4.1	97.7	69.5	11,923	Gas MCF ->	47,717	1,000,000	47,717	447,940	11.1943
46													
47	FORT MYERS 2	1,405	895,161	88.5	95.8	88.5	7,200	Gas MCF ->	6,445,431	1,000,000	6,445,431	61,032,805	6.8181
48													
49	FORT MYERS 3A_B	316	8,167	3.6	96.8	99.4	11,104	Gas MCF ->	90,684	1,000,000	90,684	867,896	10.6274
50													
51	SANFORD 3	138	4,455	4.5	82.9	58.7	11,422	Gas MCF ->	50,888	1,000,000	50,888	502,166	11.2710
52													
53	SANFORD 4	936	603,183	89.5	95.9	89.5	7,179	Gas MCF ->	4,330,568	1,000,000	4,330,568	40,974,874	6.7931
54													
55	SANFORD 5	936	551,142	81.8	84.6	81.8	7,282	Gas MCF ->	4,013,882	1,000,000	4,013,882	38,321,185	6.9531
56													
57	PUTNAM 1	239	46,603	27.1	96.8	98.5	9,151	Gas MCF ->	426,501	1,000,000	426,501	4,081,745	8.7585
58													
59	PUTNAM 2	239	51,570	30.0	96.9	98.5	9,147	Gas MCF ->	471,726	1,000,000	471,726	4,514,728	8.7546
60													
61	MANATEE 1	793	172,961	55.1	94.6	55.1	10,239	Heavy Oil BBLS ->	270,632	6,399,993	1,732,043	16,461,925	9.5177
62			141,787					Gas MCF ->	1,490,853	1,000,000	1,490,853	14,309,382	10.0922
63													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 28

Estimated For The Period of : Sep-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MANATEE 2	793	138,273	47.9	94.9	47.9	10,297	Heavy Oil BBLS ->	217,106	6,400,007	1,389,480	13,206,033	9.5507
65			135,291					Gas MCF ->	1,427,485	1,000,000	1,427,485	13,610,015	10.0598
66													
67	MANATEE 3	1,084	690,478	88.5	96.0	88.5	7,069	Gas MCF ->	4,881,292	1,000,000	4,881,292	44,204,678	6.4020
68													
69	MARTIN 1	815	125,127	51.2	94.1	65.4	10,354	Heavy Oil BBLS ->	193,663	6,400,004	1,239,444	11,778,133	9.4129
70			175,025					Gas MCF ->	1,868,387	1,000,000	1,868,387	17,720,856	10.1248
71													
72	MARTIN 2	815	116,008	55.1	94.9	68.6	10,369	Heavy Oil BBLS ->	179,294	6,400,013	1,147,484	10,904,321	9.3996
73			207,178					Gas MCF ->	2,203,743	1,000,000	2,203,743	20,958,451	10.1162
74													
75	MARTIN 3	456	292,209	89.0	96.9	89.0	7,314	Gas MCF ->	2,137,341	1,000,000	2,137,341	19,795,890	6.7746
76													
77	MARTIN 4	456	289,036	88.0	95.8	88.0	7,320	Gas MCF ->	2,115,829	1,000,000	2,115,829	19,766,684	6.8388
78													
79	MARTIN 8	1,084	703,249	90.1	96.1	90.1	7,025	Gas MCF ->	4,940,646	1,000,000	4,940,646	44,728,689	6.3603
80													
81	FORT MYERS 1-12	552		0.0	97.3		0						
82													
83	LAUDERDALE 1-24	684		0.0	91.8		0						
84													
85	EVERGLADES 1-12	342		0.0	88.4		0						
86													
87	ST JOHNS 1O	127	89,544	97.9	97.3	97.9	9,692	Coal TONS ->	35,785	24,254,017	867,930	2,330,700	2.6029
88													
89	ST JOHNS 2O	127	88,930	97.3	96.5	97.3	9,773	Coal TONS ->	35,837	24,253,816	869,184	2,334,000	2.6245
90													
91	SCHERER 4	634	445,978	97.7	97.0	97.7	10,190	Coal TONS ->	259,694	17,500,023	4,544,651	9,786,000	2.1943
92													
93	TOTAL	21,286	9,762,612				8,789				85,804,474	554,564,138	5.6805

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 29

Estimated For The Period of : Oct-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	53,680	20.5	51.1	84.2	9,754	Heavy Oil BBLS ->	80,756	6,400,020	516,840	4,919,488	9.1645
2			3,928					Gas MCF ->	45,106	1,000,000	45,106	438,437	11.1630
3													
4	TURKEY POINT 2	378	46,354	24.8	93.3	81.0	9,923	Heavy Oil BBLS ->	69,952	6,399,989	447,692	4,261,289	9.1929
5			23,451					Gas MCF ->	245,015	1,000,000	245,015	2,406,600	10.2622
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	2,391,800	0.4758
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,330	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,038,300	0.6044
10													
11	TURKEY POINT 5	1,080	772,054	96.1	96.0	96.1	6,895	Gas MCF ->	5,323,904	1,000,000	5,323,904	49,164,667	6.3680
12													
13	LAUDERDALE 4	432	306,591	95.4	98.1	95.4	7,809	Gas MCF ->	2,394,452	1,000,000	2,394,452	23,061,134	7.5218
14													
15	LAUDERDALE 5	432	306,715	95.4	97.8	95.4	7,807	Gas MCF ->	2,394,678	1,000,000	2,394,678	23,229,870	7.5738
16													
17	PT EVERGLADES 1	205	8,278	5.4	95.2	77.7	10,659	Gas MCF ->	88,247	1,000,000	88,247	860,024	10.3889
18													
19	PT EVERGLADES 2	205	4,287	2.8	95.4	80.4	10,684	Gas MCF ->	45,808	1,000,000	45,808	446,768	10.4210
20													
21	PT EVERGLADES 3	374	45,001	38.6	91.8	83.7	10,012	Heavy Oil BBLS ->	67,783	6,400,041	433,814	4,122,702	9.1614
22			62,318					Gas MCF ->	640,696	1,000,000	640,696	6,382,418	10.2418
23													
24	PT EVERGLADES 4	374	28,973	36.8	90.6	84.9	10,059	Heavy Oil BBLS ->	43,580	6,400,000	278,912	2,650,607	9.1485
25			73,325					Gas MCF ->	750,177	1,000,000	750,177	7,495,684	10.2226
26													
27	RIVIERA 3	273	8,591	6.0	93.0	93.7	10,255	Heavy Oil BBLS ->	13,079	6,399,801	83,703	795,615	9.2610
28			3,682					Gas MCF ->	42,166	1,000,000	42,166	410,171	11.1402
29													
30	RIVIERA 4	284	18,763	8.9	87.1	91.8	10,586	Gas MCF ->	198,630	1,000,000	198,630	1,936,532	10.3208
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 30

Estimated For The Period of : Oct-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	373,019	59.8	59.8	97.5	10,986	Nuclear Othr ->	4,098,349	1,000,000	4,098,349	1,427,000	0.3826
34	ST LUCIE 2	714	517,926	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,418,400	0.4669
36	CAPE CANAVERAL 1	378	18,491	33.8	90.4	83.0	10,126	Heavy Oil BBLS ->	27,861	6,400,093	178,313	1,695,669	9.1702
37			76,611					Gas MCF ->	784,739	1,000,000	784,739	7,797,125	10.1776
39	CAPE CANAVERAL 2	378	4,357	20.0	89.9	78.3	10,233	Heavy Oil BBLS ->	6,587	6,399,727	42,155	400,831	9.1997
40			51,905					Gas MCF ->	533,589	1,000,000	533,589	5,329,927	10.2686
42	CUTLER 5	68		0.0	99.2		0						
44	CUTLER 6	137		0.0	97.7		0						
46	FORT MYERS 2	1,405	564,445	54.0	95.8	97.3	7,226	Gas MCF ->	4,079,105	1,000,000	4,079,105	39,271,089	6.9575
48	FORT MYERS 3A_B	316	3,298	1.4	96.8	99.4	11,113	Gas MCF ->	36,653	1,000,000	36,653	350,622	10.6314
50	SANFORD 3	138		0.0	0.0		0						
52	SANFORD 4	936	514,969	74.0	95.9	96.2	7,182	Gas MCF ->	3,698,607	1,000,000	3,698,607	35,720,107	6.9364
54	SANFORD 5	936	416,245	59.8	95.8	96.7	7,233	Gas MCF ->	3,010,898	1,000,000	3,010,898	29,117,064	6.9952
56	PUTNAM 1	239	36,749	20.7	96.8	97.9	9,156	Gas MCF ->	336,479	1,000,000	336,479	3,220,080	8.7623
58	PUTNAM 2	239	41,240	23.2	96.9	98.0	9,152	Gas MCF ->	377,471	1,000,000	377,471	3,610,527	8.7549
60	MANATEE 1	793	219,001	66.1	94.6	66.1	10,054	Heavy Oil BBLS ->	336,666	6,399,999	2,154,662	20,483,055	9.3530
61			171,105					Gas MCF ->	1,767,608	1,000,000	1,767,608	17,227,862	10.0686

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 31

Estimated For The Period of : Oct-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	793	185,124	57.0	94.9	57.0	10,077	Heavy Oil BBLS ->	285,098	6,400,003	1,824,628	17,345,687	9.3698
64			151,055					Gas MCF ->	1,563,285	1,000,000	1,563,285	15,167,192	10.0408
65													
66	MANATEE 3	1,084	728,448	90.3	96.0	95.7	7,000	Gas MCF ->	5,099,562	1,000,000	5,099,562	47,273,323	6.4896
67													
68	MARTIN 1	815	4,545	6.0	9.1	62.4	10,250	Heavy Oil BBLS ->	6,974	6,399,914	44,633	424,203	9.3334
69			32,083					Gas MCF ->	330,831	1,000,000	330,831	3,185,691	9.9295
70													
71	MARTIN 2	815	103,055	72.4	94.9	74.6	10,199	Heavy Oil BBLS ->	157,907	6,399,989	1,010,603	9,605,616	9.3209
72			336,049					Gas MCF ->	3,468,209	1,000,000	3,468,209	33,513,047	9.9727
73													
74	MARTIN 3	456	122,236	36.0	96.9	97.5	7,382	Gas MCF ->	902,445	1,000,000	902,445	8,522,770	6.9724
75													
76	MARTIN 4	456	93,176	27.5	95.8	97.3	7,414	Gas MCF ->	690,874	1,000,000	690,874	6,555,743	7.0358
77													
78	MARTIN 8	1,084	780,437	96.8	96.1	96.8	6,955	Gas MCF ->	5,428,334	1,000,000	5,428,334	50,129,067	6.4232
79													
80	FORT MYERS 1-12	552		0.0	88.9		0						
81													
82	LAUDERDALE 1-24	684		0.0	91.8		0						
83													
84	EVERGLADES 1-12	342		0.0	88.4		0						
85													
86	ST JOHNS 1O	127	92,529	97.9	97.3	97.9	9,692	Coal TONS ->	36,873	24,322,946	896,860	2,408,300	2.6028
87													
88	ST JOHNS 2O	127	91,895	97.3	96.5	97.3	9,773	Coal TONS ->	36,926	24,323,187	898,158	2,411,800	2.6245
89													
90	SCHERER 4	634	460,844	97.7	97.0	97.7	10,190	Coal TONS ->	268,351	17,499,987	4,696,139	10,130,000	2.1981
91													
92	TOTAL	13,554	5,204,791				8,241				42,891,787	361,403,603	6.9437

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 32

Estimated For The Period of : Nov-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	4,902	3.9	40.4	38.1	10,948	Heavy Oil BBLS ->	7,851	6,399,949	50,246	461,790	9.4204
2			5,801					Gas MCF ->	66,938	1,000,000	66,938	658,479	11.3503
3													
4	TURKEY POINT 2	380	18,471	11.1	93.3	52.5	10,327	Heavy Oil BBLS ->	28,479	6,400,084	182,268	1,675,062	9.0686
5			11,835					Gas MCF ->	130,721	1,000,000	130,721	1,301,235	10.9953
6													
7	TURKEY POINT 3	717	503,332	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	2,386,300	0.4741
8													
9	TURKEY POINT 4	717	503,332	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	3,033,000	0.6026
10													
11	TURKEY POINT 5	1,103	712,323	89.7	96.0	89.7	6,905	Gas MCF ->	4,919,276	1,000,000	4,919,276	47,237,858	6.6315
12													
13	LAUDERDALE 4	443	262,688	82.4	98.1	82.4	7,993	Gas MCF ->	2,099,778	1,000,000	2,099,778	20,951,584	7.9758
14													
15	LAUDERDALE 5	443	130,519	40.9	48.9	81.8	7,997	Gas MCF ->	1,043,859	1,000,000	1,043,859	10,457,009	8.0119
16													
17	PT EVERGLADES 1	207	1,544	1.0	95.2	93.2	10,247	Heavy Oil BBLS ->	2,394	6,400,585	15,323	140,565	9.1040
18			0					Gas MCF ->	500	1,000,000	500	4,863	
19													
20	PT EVERGLADES 2	207	1,829	1.5	95.4	52.5	10,673	Heavy Oil BBLS ->	2,959	6,399,797	18,937	173,764	9.5005
21			454					Gas MCF ->	5,438	1,000,000	5,438	53,235	11.7180
22													
23	PT EVERGLADES 3	376	31,332	26.0	91.8	51.9	10,483	Heavy Oil BBLS ->	48,718	6,399,955	311,793	2,860,856	9.1308
24			38,960					Gas MCF ->	425,082	1,000,000	425,082	4,228,383	10.8532
25													
26	PT EVERGLADES 4	376	27,274	20.8	84.6	49.6	10,498	Heavy Oil BBLS ->	42,488	6,399,972	271,922	2,495,045	9.1481
27			28,890					Gas MCF ->	317,734	1,000,000	317,734	3,162,290	10.9459
28													
29	RIVIERA 3	275	5,886	3.3	93.0	94.7	10,092	Heavy Oil BBLS ->	8,922	6,399,910	57,100	524,015	8.9027
30			625					Gas MCF ->	8,617	1,000,000	8,617	85,978	13.7543
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 33

Estimated For The Period of : Nov-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIVIERA 4	286	4,552	3.0	87.1	80.8	10,230	Heavy Oil BBLS ->	6,926	6,399,653	44,324	406,798	8.9367
33			1,689					Gas MCF ->	19,521	1,000,000	19,521	195,474	11.5727
35	ST LUCIE 1	853	19,960	3.3	3.2	97.5	10,986	Nuclear Othr ->	219,303	1,000,000	219,303	102,400	0.5130
37	ST LUCIE 2	726	509,586	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,598,761	1,000,000	5,598,761	2,372,200	0.4655
39	CAPE CANAVERAL 1	380	22,049	16.9	90.4	50.5	10,487	Heavy Oil BBLS ->	34,230	6,400,058	219,074	2,011,340	9.1221
40			24,239					Gas MCF ->	266,375	1,000,000	266,375	2,651,737	10.9399
42	CAPE CANAVERAL 2	380	14,248	9.5	41.9	56.7	10,291	Heavy Oil BBLS ->	21,877	6,400,101	140,015	1,285,503	9.0223
43			11,800					Gas MCF ->	128,048	1,000,000	128,048	1,276,560	10.8187
45	CUTLER 5	69		0.0	99.2		0						
47	CUTLER 6	138	453	0.5	97.7	82.1	12,741	Gas MCF ->	5,777	1,000,000	5,777	56,549	12.4832
49	FORT MYERS 2	1,422	757,151	74.0	95.8	90.6	7,201	Gas MCF ->	5,452,433	1,000,000	5,452,433	54,159,507	7.1531
51	FORT MYERS 3A_B	328	1,304	0.6	96.8	99.4	11,016	Gas MCF ->	14,366	1,000,000	14,366	144,101	11.0498
53	SANFORD 3	140		0.0	0.0		0						
55	SANFORD 4	955	603,229	87.7	95.9	90.9	7,116	Gas MCF ->	4,293,066	1,000,000	4,293,066	42,823,249	7.0990
57	SANFORD 5	955	518,286	75.4	95.8	92.6	7,154	Gas MCF ->	3,708,141	1,000,000	3,708,141	37,057,168	7.1499
59	PUTNAM 1	244	55,185	31.4	79.0	74.9	9,596	Gas MCF ->	529,604	1,000,000	529,604	5,261,360	9.5341
61	PUTNAM 2	244	77,349	44.0	96.9	89.3	9,114	Gas MCF ->	705,004	1,000,000	705,004	6,997,863	9.0472

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 34

Estimated For The Period of : Nov-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 1	805	9,830	2.4	44.1	63.3	10,206	Heavy Oil BBLS ->	15,641	6,399,910	100,101	918,818	9.3471
64			3,920					Gas MCF ->	40,239	1,000,000	40,239	402,057	10.2558
65													
66	MANATEE 2	805	22,589	4.4	94.9	72.2	10,259	Heavy Oil BBLS ->	36,230	6,399,972	231,871	2,128,245	9.4216
67			3,001					Gas MCF ->	30,673	1,000,000	30,673	306,501	10.2130
68													
69	MANATEE 3	1,104	705,773	88.8	96.0	88.8	6,998	Gas MCF ->	4,939,374	1,000,000	4,939,374	47,451,166	6.7233
70													
71	MARTIN 1	820		0.0	0.0		0						
72													
73	MARTIN 2	820	22,074	8.6	94.9	55.1	10,499	Heavy Oil BBLS ->	33,630	6,400,030	215,233	1,975,180	8.9480
74			28,507					Gas MCF ->	315,855	1,000,000	315,855	3,119,851	10.9443
75													
76	MARTIN 3	470	174,538	51.6	96.9	95.7	7,332	Gas MCF ->	1,279,865	1,000,000	1,279,865	12,552,027	7.1916
77													
78	MARTIN 4	470	189,121	55.9	95.8	95.4	7,320	Gas MCF ->	1,384,458	1,000,000	1,384,458	13,594,369	7.1882
79													
80	MARTIN 8	1,104	721,548	90.8	96.1	90.8	6,961	Gas MCF ->	5,023,225	1,000,000	5,023,225	48,236,004	6.6851
81													
82	FORT MYERS 1-12	627		0.0	87.2		0						
83													
84	LAUDERDALE 1-24	766		0.0	91.8		0						
85													
86	EVERGLADES 1-12	383		0.0	88.4		0						
87													
88	ST JOHNS 1O	130	91,659	97.9	97.3	97.9	9,626	Coal TONS ->	36,173	24,392,945	882,366	2,369,400	2.5850
89													
90	ST JOHNS 2O	130	91,032	97.3	96.5	97.3	9,707	Coal TONS ->	36,228	24,392,624	883,696	2,373,000	2.6068
91													
92	SCHERER 4	640	450,270	97.7	97.0	97.7	10,095	Coal TONS ->	259,747	17,500,013	4,545,576	9,822,500	2.1815
93													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 35

Estimated For The Period of : Nov-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	TOTAL	21,818	7,424,936				8,424				62,548,465	403,942,238	5.4403

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 36

Estimated For The Period of : Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	33,411	14.0	93.2	44.4	10,329	Heavy Oil BBLS ->	52,448	6,400,053	335,670	3,179,505	9.5163
2			6,241					Gas MCF ->	73,927	1,000,000	73,927	751,420	12.0410
3													
4	TURKEY POINT 2	380	25,939	12.2	93.3	39.9	10,526	Heavy Oil BBLS ->	41,199	6,399,961	263,672	2,497,587	9.6287
5			8,673					Gas MCF ->	100,676	1,000,000	100,676	1,018,412	11.7422
6													
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	2,455,800	0.4722
8													
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	3,124,100	0.6007
10													
11	TURKEY POINT 5	1,103	711,870	86.8	96.0	86.7	6,935	Gas MCF ->	4,937,473	1,000,000	4,937,473	49,281,865	6.9229
12													
13	LAUDERDALE 4	443	250,695	76.1	98.1	76.1	8,136	Gas MCF ->	2,039,722	1,000,000	2,039,722	20,991,659	8.3734
14													
15	LAUDERDALE 5	443	258,363	78.4	97.8	78.4	8,065	Gas MCF ->	2,083,952	1,000,000	2,083,952	21,522,688	8.3304
16													
17	PT EVERGLADES 1	207	2,005	1.6	95.2	47.4	10,748	Heavy Oil BBLS ->	3,273	6,399,328	20,945	198,076	9.8791
18			450					Gas MCF ->	5,441	1,000,000	5,441	55,432	12.3100
19													
20	PT EVERGLADES 2	207	1,826	1.5	95.4	43.9	10,870	Heavy Oil BBLS ->	3,009	6,399,801	19,257	182,123	9.9739
21			446					Gas MCF ->	5,438	1,000,000	5,438	55,229	12.3749
22													
23	PT EVERGLADES 3	376	38,556	19.3	91.8	46.4	10,527	Heavy Oil BBLS ->	60,748	6,399,980	388,786	3,676,856	9.5364
24			15,511					Gas MCF ->	180,429	1,000,000	180,429	1,834,778	11.8288
25													
26	PT EVERGLADES 4	376	350	1.6	29.2	23.3	12,206	Heavy Oil BBLS ->	617	6,398,703	3,948	37,288	10.6537
27			4,032					Gas MCF ->	49,542	1,000,000	49,542	503,857	12.4958
28													
29	RIVIERA 3	275	10,013	5.9	93.0	58.0	10,305	Heavy Oil BBLS ->	15,697	6,399,885	100,459	950,214	9.4898
30			2,104					Gas MCF ->	24,411	1,000,000	24,411	248,785	11.8244
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 37

Estimated For The Period of : Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIVIERA 4	286	10,121	6.2	87.1	45.1	10,540	Heavy Oil BBLS ->	16,123	6,399,864	103,185	975,970	9.6430
33			3,025					Gas MCF ->	35,385	1,000,000	35,385	360,825	11.9269
34													
35	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	3,162,600	0.5111
36													
37	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,986	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,443,200	0.4640
38													
39	CAPE CANAVERAL 1	380	34,257	15.6	90.4	46.7	10,396	Heavy Oil BBLS ->	53,633	6,399,996	343,251	3,248,201	9.4819
40			9,790					Gas MCF ->	114,702	1,000,000	114,702	1,167,437	11.9244
41													
42	CAPE CANAVERAL 2	380	8,412	4.5	49.3	42.3	10,571	Heavy Oil BBLS ->	13,390	6,400,000	85,696	810,970	9.6406
43			4,277					Gas MCF ->	48,451	1,000,000	48,451	493,368	11.5359
44													
45	CUTLER 5	69		0.0	99.2		0						
46													
47	CUTLER 6	138	208	0.2	97.7	37.7	15,037	Gas MCF ->	3,133	1,000,000	3,133	31,952	15.3615
48													
49	FORT MYERS 2	1,422	537,100	50.8	95.8	87.6	7,274	Gas MCF ->	3,906,871	1,000,000	3,906,871	40,273,438	7.4983
50													
51	FORT MYERS 3A_B	328	1,304	0.5	96.8	99.4	11,016	Gas MCF ->	14,366	1,000,000	14,366	147,903	11.3414
52													
53	SANFORD 3	140	1,364	1.3	86.4	39.0	12,153	Gas MCF ->	16,580	1,000,000	16,580	171,806	12.5976
54													
55	SANFORD 4	955	459,497	64.7	95.9	91.0	7,203	Gas MCF ->	3,309,956	1,000,000	3,309,956	34,174,991	7.4375
56													
57	SANFORD 5	955	382,207	53.8	95.8	91.0	7,245	Gas MCF ->	2,769,304	1,000,000	2,769,304	28,352,175	7.4180
58													
59	PUTNAM 1	244	57,949	31.9	96.8	81.1	9,251	Gas MCF ->	536,123	1,000,000	536,123	5,516,425	9.5194
60													
61	PUTNAM 2	244	55,751	30.7	96.9	82.2	9,228	Gas MCF ->	514,485	1,000,000	514,485	5,296,999	9.5012
62													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 38

Estimated For The Period of : Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 1	805	8,979	1.7	51.9	51.9	10,305	Heavy Oil BBLS ->	14,449	6,399,958	92,473	874,874	9.7436
64			1,465					Gas MCF ->	15,156	1,000,000	15,156	154,646	10.5560
65													
66	MANATEE 2	805		0.0	94.9		0						
67													
68	MANATEE 3	1,104	632,697	77.0	96.0	86.6	7,051	Gas MCF ->	4,461,285	1,000,000	4,461,285	44,551,963	7.0416
69													
70	MARTIN 1	820	26,901	8.1	91.1	43.9	10,695	Heavy Oil BBLS ->	41,959	6,399,986	268,537	2,540,023	9.4421
71			22,431					Gas MCF ->	259,105	1,000,000	259,105	2,635,167	11.7480
72													
73	MARTIN 2	820	37,065	10.1	94.9	48.5	10,459	Heavy Oil BBLS ->	57,180	6,400,017	365,953	3,461,403	9.3387
74			24,230					Gas MCF ->	275,187	1,000,000	275,187	2,801,367	11.5616
75													
76	MARTIN 3	470	133,568	38.2	96.9	87.7	7,423	Gas MCF ->	991,601	1,000,000	991,601	10,110,658	7.5697
77													
78	MARTIN 4	470	131,507	37.6	95.8	89.4	7,398	Gas MCF ->	972,933	1,000,000	972,933	9,940,151	7.5586
79													
80	MARTIN 8	1,104	703,032	85.6	96.1	88.7	6,993	Gas MCF ->	4,916,911	1,000,000	4,916,911	49,080,315	6.9812
81													
82	FORT MYERS 1-12	627		0.0	98.4		0						
83													
84	LAUDERDALE 1-24	766		0.0	91.8		0						
85													
86	EVERGLADES 1-12	383		0.0	88.4		0						
87													
88	ST JOHNS 1O	130	94,715	97.9	97.3	97.9	9,626	Coal TONS ->	37,272	24,462,841	911,779	2,448,400	2.5850
89													
90	ST JOHNS 2O	130	94,067	97.3	96.5	97.3	9,707	Coal TONS ->	37,328	24,462,950	913,153	2,452,100	2.6068
91													
92	SCHERER 4	640	465,279	97.7	97.0	97.7	10,095	Coal TONS ->	268,406	17,499,978	4,697,099	10,167,800	2.1853
93													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 39

Estimated For The Period of : Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	TOTAL	21,818	7,497,239				8,796				65,947,032	380,412,801	5.0740

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 40

Estimated For The Period of : Jan-08 Thru Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	379	611,631	21.8	85.3	65.8	10,028	Heavy Oil BBLS ->	934,500	6,400,006	5,980,806	55,737,509	9.1129
2			114,835					Gas MCF ->	1,304,379	1,000,000	1,304,379	12,492,767	10.8789
3													
4	TURKEY POINT 2	379	477,151	20.9	93.3	64.1	10,122	Heavy Oil BBLS ->	730,468	6,400,009	4,675,002	43,669,073	9.1520
5			217,028					Gas MCF ->	2,351,808	1,000,000	2,351,808	22,829,749	10.5192
6													
7	TURKEY POINT 3	703	6,020,517	97.5	97.5	97.5	11,331	Nuclear Othr ->	68,218,468	1,000,000	68,218,468	29,029,900	0.4822
8													
9	TURKEY POINT 4	703	5,451,821	88.3	88.2	97.6	11,331	Nuclear Othr ->	61,774,597	1,000,000	61,774,597	29,628,000	0.5435
10													
11													
12	TURKEY POINT 5	1,090	8,286,836	86.6	94.1	88.3	6,954	Gas MCF ->	57,625,129	1,000,000	57,625,129	538,889,404	6.5030
13													
14	LAUDERDALE 4	437	3,046,792	79.4	95.4	81.7	8,050	Gas MCF ->	24,527,910	1,000,000	24,527,910	238,590,774	7.8309
15													
16	LAUDERDALE 5	437	3,041,275	79.3	93.8	82.7	8,021	Gas MCF ->	24,392,869	1,000,000	24,392,869	238,746,227	7.8502
17													
18	PT EVERGLADES 1	206	77,828	5.0	78.8	69.4	10,343	Heavy Oil BBLS ->	124,865	6,400,008	799,137	7,622,687	9.7943
19			12,054					Gas MCF ->	130,547	1,000,000	130,547	1,280,950	10.6266
20			0						0		0	0	0.0000
21													
22	PT EVERGLADES 2	206	86,209	5.2	95.4	66.7	10,406	Heavy Oil BBLS ->	139,482	6,399,994	892,684	8,489,109	9.8471
23			8,566					Gas MCF ->	93,563	1,000,000	93,563	921,325	10.7555
24													
25													
26	PT EVERGLADES 3	375	638,429	31.4	91.8	65.6	10,162	Heavy Oil BBLS ->	977,318	6,399,993	6,254,828	58,995,715	9.2408
27			395,503					Gas MCF ->	4,251,851	1,000,000	4,251,851	41,657,053	10.5327
28													
29	PT EVERGLADES 4	375	536,798	27.7	84.9	66.5	10,146	Heavy Oil BBLS ->	820,297	6,399,987	5,249,890	49,528,523	9.2267
30			375,014					Gas MCF ->	4,001,314	1,000,000	4,001,314	39,196,328	10.4520
31													

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 41

Estimated For The Period of : Jan-08 Thru Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIVIERA 3	274	186,233	13.0	93.0	59.8	10,476	Heavy Oil BBLS ->	289,504	6,399,988	1,852,822	17,110,076	9.1875
33			125,392					Gas MCF ->	1,411,781	1,000,000	1,411,781	13,677,910	10.9081
35	RIVIERA 4	285	41,925	11.0	71.4	50.4	10,824	Heavy Oil BBLS ->	66,850	6,399,970	427,838	4,003,252	9.5486
36			233,463					Gas MCF ->	2,552,963	1,000,000	2,552,963	25,101,329	10.7518
39	ST LUCIE 1	845	6,420,890	86.5	86.6	97.4	10,987	Nuclear Othr ->	70,546,615	1,000,000	70,546,615	25,807,100	0.4019
41	ST LUCIE 2	719	6,157,262	97.5	97.5	97.5	10,987	Nuclear Othr ->	67,649,473	1,000,000	67,649,473	29,069,900	0.4721
43	CAPE CANAVERAL 1	379	490,379	24.0	74.1	66.3	10,132	Heavy Oil BBLS ->	751,595	6,400,008	4,810,214	45,597,715	9.2985
44			308,022					Gas MCF ->	3,279,101	1,000,000	3,279,101	31,977,176	10.3815
45			0						0		0	0	0.0000
47	CAPE CANAVERAL 2	379	337,698	17.9	82.5	64.0	10,195	Heavy Oil BBLS ->	518,266	6,399,993	3,316,899	31,426,620	9.3061
48			256,592					Gas MCF ->	2,742,003	1,000,000	2,742,003	26,876,923	10.4746
50	CUTLER 5	68	17,646	2.9	99.2	79.6	11,861	Gas MCF ->	209,290	1,000,000	209,290	1,932,845	10.9536
51			0						0		0	0	0.0000
53	CUTLER 6	137	35,270	2.9	97.7	70.5	12,005	Gas MCF ->	423,397	1,000,000	423,397	3,948,916	11.1963
54			0						0		0	0	0.0000
56	FORT MYERS 2	1,412	9,052,644	73.0	91.3	87.9	7,225	Gas MCF ->	65,409,013	1,000,000	65,409,013	622,454,299	6.8759
58	FORT MYERS 3A_B	321	100,340	7.1	96.8	100.0	11,064	Gas MCF ->	1,110,125	1,000,000	1,110,125	10,619,985	10.5840
59			0						0		0	0	0.0000
61	SANFORD 3	139	41,140	3.5	77.9	55.2	11,501	Gas MCF ->	474,249	1,000,000	474,249	4,655,827	11.3172
62			1,278					Heavy Oil BBLS ->	2,126	6,402,164	13,611	134,304	10.5089
63			0						0		0	0	0.0000

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 42

Estimated For The Period of : Jan-08 Thru Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	SANFORD 4	944	6,636,148	80.0	94.0	88.9	7,194	Gas MCF ->	47,739,304	1,000,000	47,739,304	456,172,686	6.8741
67	SANFORD 5	944	5,870,537	70.8	89.8	88.4	7,219	Gas MCF ->	42,381,379	1,000,000	42,381,379	405,838,722	6.9131
69	PUTNAM 1	241	620,256	29.3	89.8	83.3	9,399	Gas MCF ->	5,829,935	1,000,000	5,829,935	56,768,351	9.1524
71	PUTNAM 2	241	766,267	36.2	96.9	91.1	9,170	Gas MCF ->	7,026,297	1,000,000	7,026,297	68,306,460	8.9142
73	MANATEE 1	798	1,170,974	29.7	86.8	56.2	10,215	Heavy Oil BBLS ->	1,832,859	6,400,001	11,730,299	111,178,740	9.4946
74			908,431					Gas MCF ->	9,510,991	1,000,000	9,510,991	91,312,561	10.0517
76	MANATEE 2	798	956,790	26.0	94.9	49.6	10,269	Heavy Oil BBLS ->	1,502,989	6,399,996	9,619,124	90,957,791	9.5066
77			864,879					Gas MCF ->	9,087,161	1,000,000	9,087,161	86,836,861	10.0403
80	MANATEE 3	1,092	7,888,079	82.2	92.4	87.4	7,061	Gas MCF ->	55,698,693	1,000,000	55,698,693	523,778,036	6.6401
82	MARTIN 1	817	743,883	24.6	79.0	63.9	10,399	Heavy Oil BBLS ->	1,150,441	6,400,014	7,362,838	69,923,403	9.3998
83			1,021,306					Gas MCF ->	10,993,846	1,000,000	10,993,846	103,860,609	10.1694
86	MARTIN 2	817	856,607	34.8	94.9	67.4	10,379	Heavy Oil BBLS ->	1,321,114	6,399,997	8,455,125	80,154,210	9.3572
87			1,641,560					Gas MCF ->	17,473,443	1,000,000	17,473,443	166,711,384	10.1557
89	MARTIN 3	462	2,579,522	63.6	95.9	88.6	7,349	Gas MCF ->	18,956,843	1,000,000	18,956,843	177,519,122	6.8819
91	MARTIN 4	462	2,241,581	55.3	83.0	88.2	7,349	Gas MCF ->	16,472,643	1,000,000	16,472,643	154,934,455	6.9118
94	MARTIN 8	1,092	8,428,903	87.8	93.3	88.2	7,027	Gas MCF ->	59,230,120	1,000,000	59,230,120	559,119,030	6.6334

Date: 9/04/2007
Company: Florida Power & Light

Schedule E4
Page: 43

Estimated For The Period of : Jan-08 Thru Dec-08

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FORT MYERS 1-12	583	388	0.0	96.6	22.2	12,381	Light Oil BBLS ->	824	5,830,097	4,804	76,900	19.8196
97			0						0		0	0	0.0000
98													
99	LAUDERDALE 1-24	718	115	0.0	91.8	16.1	16,775	Gas MCF ->	1,936	1,000,000	1,936	18,749	16.2470
100			0						0		0	0	0.0000
101													
102	EVERGLADES 1-12	359	0	0.0	88.4	0.0	0		0		0	0	0.0000
103													
104	ST JOHNS 1O	128	1,097,704	97.4	97.3	97.4	9,668	Coal TONS ->	440,641	24,083,835	10,612,325	28,497,300	2.5961
105													
106	ST JOHNS 2O	128	912,325	81.0	80.9	96.5	9,751	Coal TONS ->	368,770	24,124,197	8,896,280	23,889,100	2.6185
107													
108													
109	SCHERER 4	636	4,893,269	87.5	87.0	97.7	10,150	Coal TONS ->	2,838,163	17,499,997	49,667,845	106,543,600	2.1774
110													
111	TOTAL	21,508	103,303,984				8,765				905,505,407	5,674,097,340	5.4926

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2008 thru June 2008

			January 2008	February 2008	March 2008	April 2008	May 2008	June 2008
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	375,564	136,460	398,414	899,478	1,351,040	1,897,033
3	Unit Cost	($/BBLS)	62.0880	63.0734	62.6534	61.3445	61.4319	61.8292
4	Amount	($)	23,318,000	8,607,000	24,962,000	55,178,000	82,997,000	117,292,000
5								
6	Burned:							
7	Units	(BBLS)	365,564	96,460	128,414	654,478	924,040	1,497,033
8	Unit Cost	($/BBLS)	58.4061	52.0230	45.1094	59.4379	59.5190	60.5502
9	Amount	($)	21,351,163	5,018,136	5,792,683	38,900,817	54,997,920	90,645,692
10								
11	Ending Inventory:							
12	Units	(BBLS)	3,120,000	3,160,000	3,430,000	3,675,000	4,102,000	4,501,999
13	Unit Cost	($/BBLS)	63.0022	63.0187	62.9921	62.8879	62.7506	62.6679
14	Amount	($)	196,567,000	199,139,000	216,063,000	231,113,000	257,403,000	282,131,000
15								
16	Light Oil							
17	----------							
18								
19	Purchases:							
20	Units	(BBLS)	701	0	0	0	0	0
21	Unit Cost	($/BBLS)	94.1512	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	66,000	0	0	0	0	0
23								
24	Burned:							
25	Units	(BBLS)	701	0	0	0	0	0
26	Unit Cost	($/BBLS)	94.1512	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	66,000	0	0	0	0	0
28								
29	Ending Inventory:							
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	92.3646	92.3646	92.3646	92.3646	92.3646	92.3646
32	Amount	($)	69,898,000	69,898,000	69,898,000	69,898,000	69,898,000	69,898,000
33								
34	Coal - SJRPP							
35	----------							
36								
37	Purchases:							
38	Units	(Tons)	76,954	71,790	38,234	38,717	70,411	72,233
39	Unit Cost	($/Tons)	63.6874	63.8529	64.0268	64.2095	64.3933	64.5827
40	Amount	($)	4,901,000	4,584,000	2,448,000	2,486,000	4,534,000	4,665,000
41								
42	Burned:							
43	Units	(Tons)	76,954	71,790	38,234	38,717	70,411	72,233
44	Unit Cost	($/Tons)	63.6874	63.8529	64.0268	64.2095	64.3933	64.5827
45	Amount	($)	4,901,000	4,584,000	2,448,000	2,486,000	4,534,000	4,665,000
46								
47	Ending Inventory:							
48	Units	(Tons)	57,502	57,502	57,500	57,500	57,499	57,499
49	Unit Cost	($/Tons)	56.4154	56.4154	56.4174	56.4174	56.4184	56.4184
50	Amount	($)	3,244,000	3,244,000	3,244,000	3,244,000	3,244,000	3,244,000
51								
52	Coal - SCHERER							
53	----------							
54								
55	Purchases:							
56	Units	(MBTU)	4,697,105	4,394,058	2,575,825	908,933	4,671,538	4,544,645
57	Unit Cost	($/MBTU)	2.1228	2.1267	2.1306	2.1344	2.1381	2.1419
58	Amount	($)	9,971,000	9,345,000	5,488,000	1,940,000	9,988,000	9,734,000
59								
60	Burned:							
61	Units	(MBTU)	4,697,105	4,394,058	2,575,825	908,933	4,671,538	4,544,645
62	Unit Cost	($/MBTU)	2.1228	2.1267	2.1306	2.1344	2.1381	2.1419
63	Amount	($)	9,971,000	9,345,000	5,488,000	1,940,000	9,988,000	9,734,000
64								
65	Ending Inventory:							
66	Units	(MBTU)	4,629,415	4,629,415	4,629,415	4,629,433	4,629,415	4,629,415
67	Unit Cost	($/MBTU)	2.1191	2.1191	2.1191	2.1191	2.1191	2.1191
68	Amount	($)	9,810,000	9,810,000	9,810,000	9,810,000	9,810,000	9,810,000
69								
70	Gas							
71	----------							
72								
73	Burned:							
74	Units	(MCF)	32,281,426	31,287,649	36,677,166	43,368,397	45,345,802	46,202,269
75	Unit Cost	($/MCF)	9.7991	9.7844	9.6599	9.3536	9.2896	9.3640
76	Amount	($)	316,327,548	306,131,058	354,299,273	405,650,278	421,244,388	432,639,678
77								
78	Nuclear							
79	----------							
80								
81	Burned:							
82	Units	(MBTU)	24,370,626	22,798,320	23,990,399	17,490,402	23,218,316	23,002,796
83	Unit Cost	($/MBTU)	0.3898	0.3884	0.3878	0.4037	0.4331	0.4342
84	Amount	($)	9,499,000	8,854,000	9,303,000	7,061,000	10,057,000	9,987,000

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2008 thru December 2008

		July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	Total
Heavy Oil								
Purchases:								
Units	(BBLS)	2,213,236	2,068,190	1,152,811	683,830	84,760	229,617	11,490,433
Unit Cost	($/BBLS)	62.6422	62.6422	62.6417	62.4775	62.6711	63.0267	62.2495
Amount	($)	138,642,000	129,556,000	72,214,000	42,724,000	5,312,000	14,472,000	715,274,000
Burned:								
Units	(BBLS)	2,214,497	2,069,055	1,452,811	1,096,238	290,346	373,723	11,162,659
Unit Cost	($/BBLS)	61.4566	61.3732	60.8321	60.8495	58.7502	60.5601	60.4301
Amount	($)	136,095,556	126,984,556	88,377,556	66,705,536	17,057,889	22,632,718	674,560,222
Ending Inventory:								
Units	(BBLS)	4,500,739	4,499,871	4,199,871	3,787,460	3,581,880	3,437,774	3,437,774
Unit Cost	($/BBLS)	62.6673	62.6671	62.6695	62.6929	62.6961	62.6836	62.6836
Amount	($)	282,049,000	281,994,000	263,204,000	237,447,000	224,570,000	215,492,000	215,492,000
Light Oil								
Purchases:								
Units	(BBLS)	0	137	0	0	0	0	838
Unit Cost	($/BBLS)	0.0000	87.5912	0.0000	0.0000	0.0000	0.0000	93.0788
Amount	($)	0	12,000	0	0	0	0	78,000
Burned:								
Units	(BBLS)	0	137	0	0	0	0	838
Unit Cost	($/BBLS)	0.0000	87.5912	0.0000	0.0000	0.0000	0.0000	93.0788
Amount	($)	0	12,000	0	0	0	0	78,000
Ending Inventory:								
Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762	756,762
Unit Cost	($/BBLS)	92.3646	92.3646	92.3646	92.3646	92.3646	92.3646	92.3646
Amount	($)	69,898,000	69,898,000	69,898,000	69,898,000	69,898,000	69,898,000	69,898,000
Coal - SJRPP								
Purchases:								
Units	(Tons)	74,430	74,219	71,621	73,798	72,403	74,601	809,411
Unit Cost	($/Tons)	64.7588	64.9429	65.1345	65.3134	65.5083	65.6962	64.7224
Amount	($)	4,820,000	4,820,000	4,665,000	4,820,000	4,743,000	4,901,000	52,387,000
Burned:								
Units	(Tons)	74,430	74,219	71,621	73,798	72,403	74,601	809,411
Unit Cost	($/Tons)	64.7588	64.9429	65.1345	65.3134	65.5083	65.6962	64.7224
Amount	($)	4,820,000	4,820,000	4,665,000	4,820,000	4,743,000	4,901,000	52,387,000
Ending Inventory:								
Units	(Tons)	57,499	57,499	57,499	57,499	57,502	57,502	57,502
Unit Cost	($/Tons)	56.4184	56.4184	56.4184	56.4184	56.4154	56.4154	56.4154
Amount	($)	3,244,000	3,244,000	3,244,000	3,244,000	3,244,000	3,244,000	3,244,000
Coal - SCHERER								
Purchases:								
Units	(MBTU)	4,696,143	4,696,143	4,544,645	4,696,143	4,545,573	4,697,105	49,667,853
Unit Cost	($/MBTU)	2.1458	2.1494	2.1533	2.1571	2.1610	2.1647	2.1451
Amount	($)	10,077,000	10,094,000	9,786,000	10,130,000	9,823,000	10,168,000	106,544,000
Burned:								
Units	(MBTU)	4,696,143	4,696,143	4,544,645	4,696,143	4,545,573	4,697,105	49,667,853
Unit Cost	($/MBTU)	2.1458	2.1494	2.1533	2.1571	2.1610	2.1647	2.1451
Amount	($)	10,077,000	10,094,000	9,786,000	10,130,000	9,823,000	10,168,000	106,544,000
Ending Inventory:								
Units	(MBTU)	4,629,415	4,629,415	4,629,415	4,629,415	4,629,415	4,629,415	4,629,415
Unit Cost	($/MBTU)	2.1191	2.1191	2.1191	2.1191	2.1191	2.1191	2.1191
Amount	($)	9,810,000	9,810,000	9,810,000	9,810,000	9,810,000	9,810,000	9,810,000
Gas								
Burned:								
Units	(MCF)	50,096,214	50,135,695	47,223,909	44,277,405	37,153,788	32,662,468	496,712,187
Unit Cost	($/MCF)	9.2730	9.3086	9.3569	9.5268	9.8085	10.1501	9.5169
Amount	($)	464,541,448	466,694,259	441,870,278	421,821,848	364,423,703	331,525,780	4,727,169,643
Nuclear								
Burned:								
Units	(MBTU)	23,769,566	23,769,566	23,002,796	21,181,082	17,224,658	24,370,626	268,189,153
Unit Cost	($/MBTU)	0.4327	0.4313	0.4297	0.4379	0.4582	0.4590	0.4233
Amount	($)	10,286,000	10,251,000	9,884,000	9,275,000	7,893,000	11,186,000	113,536,000

Date:9/04/2007
Company: Florida Power & Light

Schedule: E6
Page : 1 of 2

POWER SOLD

Estimated for the Period of : January 2008 thru December 2008

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	280,000		280,000	5.306	6.675	14,856,250	18,688,652	3,285,417
2008	St.Lucie Rel.		6,864		6,864	2.743	2.743	188,300	188,300	0
Total			286,864	0	286,864	5.244	6.580	15,044,550	18,876,952	3,285,417
February		OS	275,000		275,000	5.489	6.796	15,094,300	18,687,719	3,048,460
2008	St.Lucie Rel.		6,421		6,421	2.738	2.738	175,800	175,800	0
Total			281,421	0	281,421	5.426	6.703	15,270,100	18,863,519	3,048,460
March		OS	210,000		210,000	6.313	7.385	13,257,750	15,508,164	1,846,369
2008	St.Lucie Rel.		6,864		6,864	2.724	2.724	187,000	187,000	0
Total			216,864	0	216,864	6.200	7.237	13,444,750	15,695,164	1,846,369
April		OS	150,000		150,000	7.471	8.516	11,207,150	12,773,439	1,268,974
2008	St.Lucie Rel.		6,533		6,533	2.719	2.719	177,600	177,600	0
Total			156,533	0	156,533	7.273	8.274	11,384,750	12,951,039	1,268,974
May		OS	90,000		90,000	7.145	8.348	6,430,200	7,513,198	891,124
2008	St.Lucie Rel.		6,755		6,755	2.711	2.711	183,100	183,100	0
Total			96,755	0	96,755	6.835	7.954	6,613,300	7,696,298	891,124
June		OS	100,000		100,000	7.215	8.103	7,215,450	8,102,593	653,355
2008	St.Lucie Rel.		6,533		6,533	2.700	2.700	176,400	176,400	0
Total			106,533	0	106,533	6.939	7.771	7,391,850	8,278,993	653,355

Date:9/04/2007
Company: Florida Power & Light

Schedule: E6
Page : 2 of 2

POWER SOLD

Estimated for the Period of : January 2008 thru December 2008

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	110,000		110,000	7.986	9.041	8,785,100	9,945,263	923,500
2008	St.Lucie Rel.		6,755		6,755	2.691	2.691	181,800	181,800	0
Total			116,755	0	116,755	7.680	8.674	8,966,900	10,127,063	923,500
August		OS	110,000		110,000	7.909	9.409	8,700,000	10,349,468	1,389,673
2008	St.Lucie Rel.		6,755		6,755	2.685	2.685	181,400	181,400	0
Total			116,755	0	116,755	7.607	9.020	8,881,400	10,530,868	1,389,673
September		OS	50,000		50,000	7.814	9.068	3,906,750	4,533,921	513,287
2008	St.Lucie Rel.		6,533		6,533	2.674	2.674	174,700	174,700	0
Total			56,533	0	56,533	7.220	8.329	4,081,450	4,708,621	513,287
October		OS	50,000		50,000	7.292	8.392	3,646,250	4,196,045	445,416
2008	St.Lucie Rel.		0		0	0.100	0.100	0	0	0
Total			50,000	0	50,000	7.292	8.392	3,646,250	4,196,045	445,416
November		OS	135,000		135,000	6.520	7.603	8,802,450	10,264,164	1,194,714
2008	St.Lucie Rel.		0		0	0.100	0.100	0	0	0
Total			135,000	0	135,000	6.520	7.603	8,802,450	10,264,164	1,194,714
December		OS	280,000		280,000	5.679	7.179	15,900,000	20,100,456	3,640,386
2008	St.Lucie Rel.		6,864		6,864	2.649	2.649	181,800	181,800	0
Total			286,864	0	286,864	5.606	7.070	16,081,800	20,282,256	3,640,386
Period		OS	1,840,000	0	1,840,000	6.402	7.645	117,801,650	140,663,083	19,100,677
	St.Lucie Rel.		66,877	0	66,877	2.703	2.703	1,807,900	1,807,900	0
Total			1,906,877	0	1,906,877	6.273	7.471	119,609,550	142,470,983	19,100,677

Date: 9/04/2007
Company: Florida Power & Light

Schedule: E7
Page : 1 of 2

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2008 thru December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2008	Sou. Co. (UPS + R)		687,934			687,934	2.391		16,448,000
January	St. Lucie Rel.		39,221			39,221	0.480		188,300
	SJRPP		283,171			283,171	2.596		7,350,000
	PPAs		31,648			31,648	8.467		2,679,486
Total			1,041,974			1,041,974	2.559		26,665,786
2008	Sou. Co. (UPS + R)		647,275			647,275	2.391		15,476,000
February	St. Lucie Rel.		36,691			36,691	0.479		175,800
	SJRPP		264,901			264,901	2.595		6,875,000
	PPAs		33,761			33,761	7.765		2,621,600
Total			982,628			982,628	2.559		25,148,400
2008	Sou. Co. (UPS + R)		688,217			688,217	2.391		16,455,000
March	St. Lucie Rel.		39,221			39,221	0.477		187,000
	SJRPP		142,072			142,072	2.585		3,672,000
	PPAs		47,266			47,266	7.630		3,606,400
Total			916,776			916,776	2.609		23,920,400
2008	Sou. Co. (UPS + R)		669,595			669,595	2.391		16,010,000
April	St. Lucie Rel.		37,333			37,333	0.476		177,600
	SJRPP		143,210			143,210	2.603		3,728,000
	PPAs		59,149			59,149	7.571		4,477,892
Total			909,287			909,287	2.683		24,393,492
2008	Sou. Co. (UPS + R)		667,599			667,599	2.391		15,962,000
May	St. Lucie Rel.		38,577			38,577	0.475		183,100
	SJRPP		259,224			259,224	2.624		6,802,000
	PPAs		34,941			34,941	7.371		2,575,449
Total			1,000,341			1,000,341	2.551		25,522,549
2008	Sou. Co. (UPS + R)		668,425			668,425	2.391		15,982,000
June	St. Lucie Rel.		37,333			37,333	0.473		176,400
	SJRPP		267,712			267,712	2.613		6,996,000
	PPAs		50,396			50,396	7.454		3,756,600
Total			1,023,866			1,023,866	2.628		26,911,000
	Sou. Co. (UPS + R)		4,029,045			4,029,045	2.391		96,333,000
Period	St. Lucie Rel.		228,376			228,376	0.476		1,088,200
Total	SJRPP		1,360,290			1,360,290	2.604		35,423,000
	PPAs		257,161			257,161	7.667		19,717,427
Total			5,874,872			5,874,872	2.597		152,561,627

Date: 9/04/2007
Company: Florida Power & Light

Schedule: E7
Page : 2 of 2

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2008 thru December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2008	Sou. Co. (UPS + R)		691,915			691,915	2.391		16,543,000
July	St. Lucie Rel.		38,577			38,577	0.471		181,800
	SJRPP		276,637			276,637	2.613		7,229,000
	PPAs		68,091			68,091	8.287		5,643,001
Total			1,075,220			1,075,220	2.753		29,596,801
2008	Sou. Co. (UPS + R)		691,915			691,915	2.391		16,543,000
August	St. Lucie Rel.		38,577			38,577	0.470		181,400
	SJRPP		276,637			276,637	2.613		7,229,000
	PPAs		64,824			64,824	8.397		5,443,434
Total			1,071,953			1,071,953	2.742		29,396,834
2008	Sou. Co. (UPS + R)		669,329			669,329	2.391		16,003,000
September	St. Lucie Rel.		37,333			37,333	0.468		174,700
	SJRPP		267,712			267,712	2.613		6,996,000
	PPAs		42,942			42,942	8.042		3,453,217
Total			1,017,316			1,017,316	2.617		26,626,917
2008	Sou. Co. (UPS + R)		691,915			691,915	2.391		16,543,000
October	St. Lucie Rel.		38,577			38,577	0.467		180,100
	SJRPP		276,637			276,637	2.613		7,229,000
	PPAs		26,593			26,593	7.390		1,965,200
Total			1,033,722			1,033,722	2.507		25,917,300
2008	Sou. Co. (UPS + R)		669,584			669,584	2.391		16,009,000
November	St. Lucie Rel.		37,956			37,956	0.466		176,800
	SJRPP		274,037			274,037	2.596		7,113,000
	PPAs		44,202			44,202	7.880		3,482,900
Total			1,025,779			1,025,779	2.611		26,781,700
2008	Sou. Co. (UPS + R)		690,736			690,736	2.391		16,515,000
December	St. Lucie Rel.		39,221			39,221	0.464		181,800
	SJRPP		283,171			283,171	2.596		7,350,000
	PPAs		41,710			41,710	8.729		3,640,671
Total			1,054,838			1,054,838	2.625		27,687,471
	Sou. Co. (UPS + R)		8,134,439			8,134,439	2.391		194,489,000
Period	St. Lucie Rel.		458,617			458,617	0.472		2,164,800
Total	SJRPP		3,015,121			3,015,121	2.606		78,569,000
	PPAs		545,523			545,523	7.946		43,345,850
Total			12,153,700			12,153,700	2.621		318,568,650

Date: 9/04/2007
Company: Florida Power & Light

Schedule: E8
Page : 1 of 2

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2008 thru December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2008 January	Qual. Facilities		535,830			535,830	3.051	3.051	16,349,455
Total			535,830			535,830	3.051	3.051	16,349,455
2008 February	Qual. Facilities		520,438			520,438	3.089	3.089	16,076,340
Total			520,438			520,438	3.089	3.089	16,076,340
2008 March	Qual. Facilities		537,100			537,100	3.133	3.133	16,824,686
Total			537,100			537,100	3.133	3.133	16,824,686
2008 April	Qual. Facilities		259,921			259,921	3.632	3.632	9,441,000
Total			259,921			259,921	3.632	3.632	9,441,000
2008 May	Qual. Facilities		499,307			499,307	3.143	3.143	15,695,539
Total			499,307			499,307	3.143	3.143	15,695,539
2008 June	Qual. Facilities		524,723			524,723	3.174	3.174	16,654,538
Total			524,723			524,723	3.174	3.174	16,654,538
Period Total	Qual. Facilities		2,877,319			2,877,319	3.164	3.164	91,041,559
Total			2,877,319			2,877,319	3.164	3.164	91,041,559

Date: 9/04/2007
Company: Florida Power & Light

Schedule: E8
Page : 2 of 2

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2008 thru December 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2008 July	Qual. Facilities		545,570			545,570	3.209	3.209	17,507,830
Total			545,570			545,570	3.209	3.209	17,507,830
2008 August	Qual. Facilities		546,183			546,183	3.203	3.203	17,493,095
Total			546,183			546,183	3.203	3.203	17,493,095
2008 September	Qual. Facilities		531,345			531,345	3.198	3.198	16,993,141
Total			531,345			531,345	3.198	3.198	16,993,141
2008 October	Qual. Facilities		432,075			432,075	3.262	3.262	14,096,095
Total			432,075			432,075	3.262	3.262	14,096,095
2008 November	Qual. Facilities		453,462			453,462	3.273	3.273	14,843,774
Total			453,462			453,462	3.273	3.273	14,843,774
2008 December	Qual. Facilities		543,353			543,353	3.104	3.104	16,865,013
Total			543,353			543,353	3.104	3.104	16,865,013
Period Total	Qual. Facilities		5,929,307			5,929,307	3.185	3.185	188,840,508
Total			5,929,307			5,929,307	3.185	3.185	188,840,508

Date:9/04/2007
Company: Florida Power & Light

Schedule: E9
Page : 1 of 2

Economy Energy Purchases

Estimated For the Period of : January 2008 Thru December 2008

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	January	Florida	OS	23,216	5.496	1,275,901	6.650	1,543,940	268,039
2	2008	Non-Florida	OS	70,673	5.763	4,072,921	6.671	4,714,639	641,718
3									
4	Total			93,889	5.697	5,348,821	6.666	6,258,578	909,757
5									
6									
7	February	Florida	OS	12,456	5.910	736,146	7.202	897,060	160,914
8	2008	Non-Florida	OS	61,110	6.438	3,934,079	7.265	4,439,646	505,567
9									
10	Total			73,566	6.348	4,670,225	7.254	5,336,706	666,481
11									
12									
13	March	Florida	OS	18,109	7.004	1,268,321	8.086	1,464,233	195,912
14	2008	Non-Florida	OS	76,962	7.017	5,400,551	8.101	6,234,903	834,352
15									
16	Total			95,071	7.015	6,668,872	8.098	7,699,137	1,030,264
17									
18									
19	April	Florida	OS	19,993	7.246	1,448,573	8.586	1,716,516	267,944
20	2008	Non-Florida	OS	102,925	6.892	7,093,625	8.497	8,745,625	1,652,001
21									
22	Total			122,918	6.950	8,542,197	8.512	10,462,142	1,919,945
23									
24									
25	May	Florida	OS	30,654	7.549	2,314,059	8.315	2,548,953	234,895
26	2008	Non-Florida	OS	147,424	7.244	10,679,033	8.319	12,263,922	1,584,889
27									
28	Total			178,077	7.296	12,993,091	8.318	14,812,875	1,819,784
29									
30									
31	June	Florida	OS	33,502	7.723	2,587,200	8.276	2,772,600	185,400
32	2008	Non-Florida	OS	77,137	7.397	5,705,981	8.278	6,385,471	679,489
33									
34	Total			110,639	7.496	8,293,181	8.277	9,158,070	864,889
35									
36									
37	Period	Florida	OS	137,929	6.982	9,630,199	7.934	10,943,303	1,313,104
38	Total	Non-Florida	OS	536,231	6.879	36,886,189	7.979	42,784,205	5,898,016
39									
40	Total			674,159	6.900	46,516,388	7.970	53,727,508	7,211,120
41									

Date:9/04/2007
Company: Florida Power & Light

Schedule: E9
Page : 2 of 2

Economy Energy Purchases

Estimated For the Period of : January 2008 Thru December 2008

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	OS	26,220	7.670	2,011,020	8.818	2,312,028	301,008
2	2008	Non-Florida	OS	78,641	7.739	6,086,001	8.954	7,041,393	955,392
3									
4	Total			104,861	7.722	8,097,021	8.920	9,353,421	1,256,400
5									
6									
7	August	Florida	OS	12,315	7.515	925,530	8.610	1,060,280	134,750
8	2008	Non-Florida	OS	75,526	7.684	5,803,221	8.812	6,654,994	851,773
9									
10	Total			87,841	7.660	6,728,751	8.783	7,715,274	986,523
11									
12									
13	September	Florida	OS	50,726	7.660	3,885,392	8.748	4,437,394	552,002
14	2008	Non-Florida	OS	89,377	7.649	6,836,314	8.748	7,818,481	982,167
15									
16	Total			140,103	7.653	10,721,706	8.748	12,255,876	1,534,169
17									
18									
19	October	Florida	OS	47,939	7.558	3,623,286	9.539	4,573,129	949,843
20	2008	Non-Florida	OS	99,239	7.380	7,323,515	9.396	9,324,097	2,000,582
21									
22	Total			147,178	7.438	10,946,801	9.442	13,897,226	2,950,425
23									
24									
25	November	Florida	OS	68,369	7.274	4,973,135	8.263	5,649,503	676,368
26	2008	Non-Florida	OS	130,740	7.236	9,460,801	8.194	10,713,287	1,252,486
27									
28	Total			199,109	7.249	14,433,936	8.218	16,362,790	1,928,855
29									
30									
31	December	Florida	OS	58,494	6.282	3,674,550	7.419	4,339,752	665,203
32	2008	Non-Florida	OS	79,218	6.271	4,967,674	7.323	5,801,301	833,627
33									
34	Total			137,712	6.276	8,642,224	7.364	10,141,053	1,498,830
35									
36									
37	Period	Florida	OS	401,992	7.145	28,723,111	8.288	33,315,390	4,592,279
38	Total	Non-Florida	OS	1,088,971	7.104	77,363,716	8.277	90,137,759	12,774,043
39									
40	Total			1,490,963	7.115	106,086,827	8.280	123,453,148	17,366,322
41									

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	MAY 23, 2007 - DEC 2007	JAN 2008 - DEC 2008	DIFFERENCE $	DIFFERENCE %
BASE	$39.37	$39.37	$0.00	0.00%
FUEL	$52.95	$52.27	-$0.68	-1.28%
CONSERVATION	$1.69	$1.45	($0.24)	-14.20%
CAPACITY PAYMENT	$5.57	$5.46	($0.11)	-1.97%
ENVIRONMENTAL	$0.24	$0.40	$0.16	66.67%
STORM RESTORATION SURCHARGE	$1.02	$0.98	($0.04)	-3.92%
SUBTOTAL	$100.84	$99.93	($0.91)	-0.90%
GROSS RECEIPTS TAX	$2.59	$2.56	-$0.03	-1.16%
TOTAL	**$103.43**	**$102.49**	**-$0.94**	**-0.91%**

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC 2005 - 2005 (COLUMN 1)	JAN - DEC 2006 - 2006 (COLUMN 2)	JAN - DEC 2007 - 2007 (COLUMN 3)	JAN - DEC 2008 - 2008 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	1,189,534,130	792,923,918	717,220,025	674,529,222	(33.3)	(9.6)	(6.0)
2	LIGHT OIL	21,649,472	3,022,019	1,887,752	78,000	(86.0)	(37.5)	(95.9)
3	COAL	101,261,934	130,156,710	156,980,213	158,930,000	28.5	20.6	1.2
4	GAS	3,104,658,880	3,988,536,281	4,595,482,132	4,727,009,643	28.5	15.2	2.9
5	NUCLEAR	75,683,285	96,843,144	89,863,159	113,535,000	28.0	(7.2)	26.3
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	4,492,787,701	5,011,482,072	5,561,433,281	5,674,081,865	11.6	11.0	2.0
	SYSTEM NET GENERATION							
8	HEAVY OIL	19,069,057	9,585,826	7,483,157	7,213,816	(49.7)	(21.9)	(3.6)
9	LIGHT OIL	186,425	25,951	9,121	388	(86.1)	(64.9)	(95.8)
10	COAL	5,765,059	6,168,129	7,149,755	6,903,293	7.0	15.9	(3.5)
11	GAS	47,113,904	56,985,272	61,095,973	65,135,881	21.0	7.2	6.6
12	NUCLEAR	21,405,553	23,532,578	22,187,420	24,050,491	9.9	(5.7)	8.4
13	OTHER	0		0	0	0.0	0.0	0.0
14	TOTAL (MWH)	93,539,998	96,297,756	97,925,426	103,303,869	3.0	1.7	5.5
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	30,217,452	15,296,754	11,970,501	11,162,675	(49.4)	(21.7)	(6.8)
16	LIGHT OIL (Bbl)	344,163	39,600	23,285	838	(88.5)	(41.2)	(96.4)
17	COAL (TON)	695,245	749,567	833,181	3,647,574	7.8	11.2	337.8
18	GAS (MCF)	345,850,962	437,700,179	470,102,070	496,692,663	26.6	7.4	5.7
19	NUCLEAR (MMBTU)	235,447,135	257,691,698	244,797,746	268,189,146	9.5	(5.0)	9.6
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	192,970,149	97,243,909	76,246,450	71,441,109	(49.6)	(21.6)	(6.3)
22	LIGHT OIL	1,790,210	217,781	118,282	4,884	(87.8)	(45.7)	(95.9)
23	COAL	58,749,974	64,086,288	72,686,121	69,176,451	9.1	13.4	(4.8)
24	GAS	363,861,486	452,949,944	477,709,622	496,692,663	24.5	5.5	4.0
25	NUCLEAR	235,447,135	257,691,698	244,797,746	268,189,146	9.5	(5.0)	9.6
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	852,818,954	872,189,620	871,558,221	905,504,253	2.3	(0.1)	3.9
	GENERATION MIX (%MWH)							
28	HEAVY OIL	20.39	9.95	7.64	6.98	-	-	-
29	LIGHT OIL	0.20	0.03	0.01	0.00	-	-	-
30	COAL	6.16	6.41	7.30	6.68			
31	GAS	50.37	59.18	62.39	63.05	-	-	-
32	NUCLEAR	22.88	24.44	22.66	23.28	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	39.3658	51.8361	59.9156	60.4272	31.7	15.6	0.9
36	LIGHT OIL ($/Bbl)	62.9047	76.3139	81.0716	93.0788	21.3	6.2	14.8
37	COAL ($/TON)	44.4710	47.8288	54.0756	43.5714	7.6	13.1	(19.4)
38	GAS ($/MCF)	8.9769	9.1125	9.7755	9.5170	1.5	7.3	(2.6)
39	NUCLEAR ($/MMBTU)	0.3214	0.3758	0.3671	0.4233	16.9	(2.3)	15.3
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	6.1643	8.1540	9.4066	9.4418	32.3	15.4	0.4
42	LIGHT OIL	12.0933	13.8764	15.9598	15.9705	14.7	15.0	0.1
43	COAL	1.7236	2.0310	2.1597	2.2975	17.8	6.3	6.4
44	GAS	8.5325	8.8057	9.6198	9.5170	3.2	9.3	(1.1)
45	NUCLEAR	0.3214	0.3758	0.3671	0.4233	16.9	(2.3)	15.3
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	5.2682	5.7459	6.3810	6.2662	9.1	11.1	(1.8)
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,120	10,145	10,189	9,903	0.3	0.4	(2.8)
49	LIGHT OIL	9,603	8,392	12,968	12,588	(12.6)	54.5	(2.9)
50	COAL	10,191	10,390	10,166	10,021	2.0	(2.2)	(1.4)
51	GAS	7,723	7,949	7,819	7,625	2.9	(1.6)	(2.5)
52	NUCLEAR	10,999	10,950	11,033	11,151	(0.5)	0.8	1.1
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	9,117	9,057	8,900	8,765	(0.7)	(1.7)	(1.5)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	6.2380	8.2718	9.5845	9.3505	32.6	15.9	(2.4)
56	LIGHT OIL	11.6130	11.6453	20.6968	20.1031	0.3	77.7	(2.9)
57	COAL	1.7565	2.1101	2.1956	2.3022	20.1	4.1	4.9
58	GAS	6.5897	6.9992	7.5217	7.2572	6.2	7.5	(3.5)
59	NUCLEAR	0.3536	0.4115	0.4050	0.4721	16.4	(1.6)	16.6
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	4.8031	5.2042	5.6793	5.4926	8.4	9.1	(3.3)

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next four periods are as follows. In addition, As-Available Energy cost payments will include .0012¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2007 – March 31, 2008	7.87	6.74	7.08
April 1, 2008 – September 30, 2008	8.16	7.60	7.77
October 1, 2008 – March 31, 2009	8.41	7.10	7.50
April 1, 2009 – September 30, 2009	8.76	7.88	8.15

A MW block size ranging from 58 MW to 65 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0214
Secondary Voltage Delivery	1.0472

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2008	20	6	54	6	14	.42	9.74	8.55	2.29
2009	19	5	57	6	13	.63	8.21	7.14	1.82
2010	17	6	60	5	11	.71	8.71	6.64	1.79
2011	18	6	61	6	9	.77	8.41	6.04	1.83
2012	19	2	64	5	9	.79	8.29	6.32	1.87
2013	19	2	65	5	9	.81	8.21	6.50	1.91
2014	19	3	64	5	9	.84	8.52	7.01	2.16
2015	19	2	67	5	8	.84	8.52	7.01	2.16
2016	18	2	72	5	3	.85	9.16	7.44	2.20
2017	18	2	73	5	3	.87	9.76	7.98	2.24

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revisions. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.51	CST-1	104.04
GST-1	11.64	GSLD-2	160.77
GSD-1	33.10	GSLDT-2	160.77
GSDT-1	39.24	CS-2	160.77
RS-1	5.34	CST-2	160.77
RST-1	8.47	GSLD-3	378.28
GSLD-1	38.78	CS-3	378.28
GSLDT-1	38.78	CST-3	378.28
CS-1	104.04	GSLDT-3	378.28

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.193%
Distribution Equipment	0.262%
Transmission Equipment	0.123%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 070001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-7
SEPTEMBER 4, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 21
COMPANY Florida Power & Light Co.
WITNESS K.M. Dubin (KMD-6)
DATE 11-06-07

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
3	Projected Capacity Payments	K. M. Dubin
3a-3b	REVISED – 2007 Capacity Estimated/actual True-up Calculation	K. M. Dubin
4	Calculation of Energy & Demand Allocation % By Rate Class	K. M. Dubin
5	Calculation of Capacity Recovery Factor	K. M. Dubin
6-7	Capacity Costs – 2008 Projections	G. J. Yupp

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2008 THROUGH DECEMBER 2008

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$17,130,068	$205,560,816
2. SHORT TERM CAPACITY PAYMENTS	$4,077,250	$4,077,250	$3,619,804	$3,619,804	$3,619,804	$4,579,180	$4,579,180	$4,579,180	$4,579,180	$3,619,804	$3,619,804	$4,077,250	$48,647,490
3. CAPACITY PAYMENTS TO COGENERATORS	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$26,968,428	$323,621,136
4. SJRPP SUSPENSION ACCRUAL	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$251,668	$3,020,012
5. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($441,902)	($444,230)	($446,557)	($448,885)	($451,212)	($453,540)	($455,867)	($458,194)	($460,522)	($462,849)	($465,177)	($467,504)	($5,456,439)
6. INCREMENTAL PLANT SECURITY COSTS	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$2,774,818	$33,297,815
7. TRANSMISSION OF ELECTRICITY BY OTHERS	$514,233	$531,030	$518,280	$509,781	$501,368	$503,591	$487,788	$487,692	$484,465	$491,034	$495,328	$509,531	$6,034,121
8. TRANSMISSION REVENUES FROM CAPACITY SALES	($546,986)	($544,959)	($404,045)	($297,315)	($191,874)	($233,788)	($236,664)	($259,795)	($113,884)	($104,378)	($267,000)	($560,070)	($3,760,758)
9. SYSTEM TOTAL	$50,727,577	$50,744,073	$50,412,464	$50,508,367	$50,603,068	$51,520,425	$51,499,419	$51,473,865	$51,614,221	$50,868,593	$50,507,937	$50,684,189	$610,964,193
10. JURISDICTIONAL % *													98.76048%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$603,391,170
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. FINAL TRUE-UP – overrecovery/(underrecovery) JANUARY 2006 - DECEMBER 2006 ($4,030,283)			EST \ ACT TRUE-UP – overrecovery/(underrecovery) JANUARY 2007 - DECEMBER 2007 ($15,561,009)										($19,591,292)
14. TOTAL (Lines 10+11+12)													$566,036,870
15. REVENUE TAX MULTIPLIER													1.00072
16. TOTAL RECOVERABLE CAPACITY PAYMENTS													$566,444,416

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	18,625	98.76048%
FERC	234	1.23952%
TOTAL	18,859	100.00000%

* BASED ON 2006 ACTUAL DATA

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.		(1) ACTUAL JAN 2007	(2) ACTUAL FEB 2007	(3) ACTUAL MAR 2007	(4) ACTUAL APR 2007	(5) ACTUAL MAY 2007	(6) ACTUAL JUN 2007
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,383,755.80	$17,018,383.02	$17,030,951.30	$16,722,795.02	$13,815,313.68	$15,877,507.40
2.	Short Term Capacity Purchases CCR	7,021,345.00	7,021,345.00	4,249,275.00	4,152,555.00	4,350,955.00	4,475,730.00
3.	QF Capacity Charges	26,843,421.96	26,186,843.62	26,596,355.75	26,564,028.95	26,849,667.90	26,815,949.19
4a.	SJRPP Suspension Accrual	294,744.00	294,744.00	294,744.00	294,744.00	294,744.00	294,744.00
4b.	Return on SJRPP Suspension Liability	(409,391.73)	(412,117.54)	(414,843.36)	(417,569.17)	(420,295.01)	(423,020.82)
5.	Okeelanta Settlement (Capacity)	0.00	0.00	0.00	0.00	0.00	0.00
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,433,623.62	1,534,657.13	1,346,516.33	1,876,545.08	1,594,391.85	1,783,662.27
7.	Transmission of Electricity by Others	421,248.94	990,592.74	291,995.92	268,353.39	502,665.81	477,099.83
8.	Transmission Revenues from Capacity Sales	(332,907.65)	(584,809.76)	(359,555.43)	(303,874.29)	(271,113.11)	(258,390.77)
9.	Total (Lines 1 through 8)	$ 52,655,839.94	$ 52,049,638.21	$ 49,035,439.51	$ 49,157,577.98	$ 46,716,330.12	$ 49,043,281.10
10.	Jurisdictional Separation Factor (a)	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%
11.	Jurisdictional Capacity Charges	51,963,605.21	51,365,372.85	48,390,800.01	48,511,332.80	46,102,178.56	48,398,538.51
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)
13.	Jurisdictional Capacity Charges Authorized	$ 47,218,139.21	$ 46,619,906.85	$ 43,645,334.01	$ 43,765,866.80	$ 41,356,712.56	$ 43,653,072.51
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 41,977,411.05	$ 37,923,419.72	$ 37,558,509.62	$ 37,852,638.71	$ 41,380,033.07	$ 45,114,346.14
15.	Prior Period True-up Provision	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 40,734,931.05	$ 36,680,939.72	$ 36,316,029.62	$ 36,610,158.71	$ 40,137,553.07	$ 43,871,866.14
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(6,483,208.16)	(9,938,967.12)	(7,329,304.39)	(7,155,708.08)	(1,219,159.49)	218,793.63
18.	Interest Provision for Month	(94,596.28)	(125,466.82)	(158,416.87)	(185,411.38)	(199,132.82)	(197,126.00)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(14,909,758.00)	(20,245,082.44)	(29,067,036.38)	(35,312,277.64)	(41,410,917.11)	(41,586,729.41)
20.	Deferred True-up - Over/(Under) Recovery	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,242,480.00	1,242,480.00	1,242,480.00	1,242,480.00	1,242,480.00	1,242,480.00
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (24,275,365.44)	$ (33,097,319.38)	$ (39,342,560.64)	$ (45,441,200.11)	$ (45,617,012.41)	$ (44,352,864.78)

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 1, 2006
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2007

LINE NO.		(7) ACTUAL JUL 2007	(8) ESTIMATED AUG 2007	(9) ESTIMATED SEP 2007	(10) ESTIMATED OCT 2007	(11) ESTIMATED NOV 2007	(12) ESTIMATED DEC 2007	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$15,880,348.98	$16,463,784.67	$16,463,784.67	$16,463,784.67	$16,463,784.67	$16,463,784.67	$195,047,978.53	1.
2.	Short Term Capacity Purchases CCR	4,318,980.00	4,318,980.00	4,338,230.00	3,377,820.00	3,380,570.00	3,828,930.00	54,834,715.00	2.
3.	QF Capacity Charges	26,844,696.10	26,277,828.50	26,277,828.50	26,277,828.50	26,277,828.50	26,277,828.50	318,090,105.96	3.
4a.	SJRPP Suspension Accrual	294,744.00	294,744.00	294,744.00	294,744.00	294,744.00	294,744.00	3,536,928.00	4a.
4b.	Return on SJRPP Suspension Liability	(425,746.64)	(428,472.45)	(431,198.27)	(433,924.08)	(436,649.91)	(439,375.72)	(5,092,604.70)	4b.
5.	Okeelanta Settlement (Capacity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6b.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	1,888,267.19	2,952,369.66	2,952,369.66	2,952,369.66	2,952,369.66	2,952,369.66	27,219,511.78	6c.
7.	Transmission of Electricity by Others	441,724.07	488,717.04	476,963.53	249,936.75	261,457.90	275,943.28	5,146,699.20	7.
8.	Transmission Revenues from Capacity Sales	(321,199.04)	(428,302.16)	(204,091.65)	(124,415.88)	(269,612.50)	(662,149.53)	(4,120,421.77)	8.
9.	Total (Lines 1 through 8)	$ 48,921,814.66	$ 49,939,649.26	$ 50,168,630.44	$ 49,058,143.61	$ 48,924,492.32	$ 48,992,074.85	$594,662,912.00	9.
10.	Jurisdictional Separation Factor (a)	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	N/A	10.
11.	Jurisdictional Capacity Charges	48,278,668.92	49,283,122.66	49,509,093.55	48,413,205.63	48,281,311.38	48,348,005.44	586,845,235.49	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(56,945,592.00)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 43,533,202.92	$ 44,537,656.66	$ 44,763,627.55	$ 43,667,739.63	$ 43,535,845.38	$ 43,602,539.44	$529,899,643.49	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 50,160,132.37	$ 51,938,085.31	$ 51,625,306.94	$ 48,480,293.01	$ 43,280,366.68	$ 43,629,644.27	530,920,186.88	14.
15.	Prior Period True-up Provision	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,480.00)	(1,242,478.00)	(14,909,758.00)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 48,917,652.37	$ 50,695,605.31	$ 50,382,826.94	$ 47,237,813.01	$ 42,037,886.68	$ 42,387,166.27	$516,010,428.88	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	5,384,449.46	6,157,948.65	5,619,199.38	3,570,073.38	(1,497,958.70)	(1,215,373.16)	(13,889,214.61)	17.
18.	Interest Provision for Month	(179,889.37)	(149,364.50)	(118,877.79)	(93,908.15)	(84,368.60)	(85,235.62)	(1,671,794.19)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(40,322,581.78)	(33,875,541.70)	(26,624,477.55)	(19,881,675.95)	(15,163,030.72)	(15,502,878.02)	(14,909,758.00)	19.
20.	Deferred True-up - Over/(Under) Recovery	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	(4,030,283.00)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	1,242,480.00	1,242,480.00	1,242,480.00	1,242,480.00	1,242,480.00	1,242,478.00	14,909,758.00	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (37,905,824.70)	$ (30,654,760.55)	$ (23,911,958.95)	$ (19,193,313.72)	$ (19,533,161.02)	$ (19,591,291.81)	$ (19,591,291.81)	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed Sep
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2008 THROUGH DECEMBER 2008

Rate Schedule	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1/RST1	64.061%	58,804,147,081	10,478,766	1.09370109	1.07349429	63,125,916,120	11,460,638	52.68401%	57.06444%
GS1/GST1	65.694%	6,619,341,251	1,150,231	1.09370109	1.07349429	7,105,825,036	1,258,009	5.93042%	6.26384%
GSD1/GSDT1/HLFT1 (21-499 kW)	74.508%	25,774,860,665	3,949,020	1.09361402	1.07343073	27,667,527,500	4,318,704	23.09093%	21.50355%
OS2	57.663%	19,993,143	3,958	1.05919630	1.04702619	20,933,344	4,192	0.01747%	0.02087%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	77.165%	11,789,652,172	1,744,121	1.09222289	1.07237880	12,642,973,049	1,904,969	10.55165%	9.48516%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	90.280%	2,169,713,444	274,351	1.08471538	1.06646905	2,313,932,235	297,593	1.93118%	1.48177%
GSLD3/GSLDT3/CS3/CST3	89.044%	258,589,835	33,151	1.03077723	1.02508821	265,077,391	34,171	0.22123%	0.17014%
ISST1D	84.918%	0	0	1.05919630	1.04702619	0	0	0.00000%	0.00000%
ISST1T	131.296%	0	0	1.03077723	1.02508821	0	0	0.00000%	0.00000%
SST1T	131.296%	162,838,087	14,158	1.03077723	1.02508821	166,923,403	14,594	0.13931%	0.07267%
SST1D1/SST1D2/SST1D3	84.918%	8,479,038	1,140	1.05919630	1.04702619	8,877,775	1,207	0.00741%	0.00601%
CILC D/CILC G	89.894%	3,701,861,702	470,095	1.08178491	1.06440541	3,940,281,623	508,542	3.28850%	2.53212%
CILC T	90.295%	1,676,506,768	211,952	1.03077723	1.02508821	1,718,567,321	218,475	1.43429%	1.08782%
MET	66.435%	101,103,804	17,373	1.05919630	1.04702619	105,858,331	18,401	0.08835%	0.09162%
OL1/SL1/PL1	210.146%	601,242,889	32,661	1.09370109	1.07349429	645,430,808	35,721	0.53867%	0.17786%
SL2, GSCU1	126.155%	85,476,122	7,735	1.09370109	1.07349429	91,758,129	8,460	0.07658%	0.04212%
TOTAL		111,773,806,000	18,388,712			119,819,882,065	20,083,676	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2008 through December 2008.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2006 demand losses.
(5) Based on 2006 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2008 THROUGH DECEMBER 2008

Rate Schedule	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1/RST1	52.68401%	57.06444%	$22,955,817	$298,373,866	$321,329,683	58,804,147,081	-	-	-	0.00546
GS1/GST1	5.93042%	6.26384%	$2,584,042	$32,751,842	$35,335,884	6,619,341,251	-	-	-	0.00534
GSD1/GSDT1/HLFT1 (21-499 kW)	23.09093%	21.50355%	$10,061,330	$112,436,010	$122,497,340	25,774,860,665	46.94990%	75,203,628	1.63	-
OS2	0.01747%	0.02087%	$7,612	$109,137	$116,749	19,993,143	-	-	-	0.00584
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10.55165%	9.48516%	$4,597,633	$49,595,229	$54,192,862	11,789,652,172	61.11976%	26,423,874	2.05	-
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	1.93118%	1.48177%	$841,464	$7,747,734	$8,589,198	2,169,713,444	68.57238%	4,334,413	1.98	-
GSLD3/GSLDT3/CS3/CST3	0.22123%	0.17014%	$96,396	$889,631	$986,027	258,589,835	66.95647%	529,049	1.86	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	63.96565%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	19.18899%	0	**	-
SST1T	0.13931%	0.07267%	$60,702	$379,950	$440,652	162,838,087	19.18899%	1,162,468	**	-
SST1D1/SST1D2/SST1D3	0.00741%	0.00601%	$3,228	$31,424	$34,652	8,479,038	63.96565%	18,158	**	-
CILC D/CILC G	3.28850%	2.53212%	$1,432,888	$13,239,720	$14,672,608	3,701,861,702	74.34374%	6,821,077	2.15	-
CILC T	1.43429%	1.08782%	$624,959	$5,687,923	$6,312,882	1,676,506,768	74.83860%	3,068,717	2.06	-
MET	0.08835%	0.09162%	$38,496	$479,064	$517,560	101,103,804	58.38177%	237,229	2.18	-
OL1/SL1/PL1	0.53867%	0.17786%	$234,712	$929,984	$1,164,696	601,242,889	-	-	-	0.00194
SL2/GSCU1	0.07658%	0.04212%	$33,368	$220,253	$253,621	85,476,122	-	-	-	0.00297
TOTAL			$43,572,647	$522,871,768	$566,444,416	111,773,806,000		117,798,613		

Note:There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2008 through December 2008
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730)
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

	CAPACITY RECOVERY FACTOR	
	RDC	SDD
	** ($/kw)	** ($/kw)
ISST1D	$0.25	$0.12
ISST1T	$0.24	$0.12
SST1T	$0.24	$0.12
SST1D1/SST1D2/SST1D3	$0.25	$0.12

Florida Power & Light Company
Schedule E12 - Capacity Costs
Page 1 of 2

Projected 2008

Contract	Capacity MW	Term Start	End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Palm Beach Solid Waste Authority	47.5	4/1/1992	3/31/2010	QF
Broward North - 1987 Agreement	45	4/1/1992	12/31/2010	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1987 Agreement	50.6	4/1/1991	8/1/2009	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
Southern Co. - UPS	931	7/20/1988	5/31/2010	UPS
JEA - SJRPP	375	4/2/1982	9/30/2021	JEA

QF = Qualifying Facility
UPS= Unit Power Sales Agreement with Southern Company
JEA = SJRPP Purchased Power Agreements

6

2007 Capacity In Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	10,042,500	120,510,000
ICL	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	10,407,630	124,891,556
SWAPBC	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	2,072,188	24,866,250
BN-SOC	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	1,914,638	22,975,650
BN-NEG	287,210	287,210	287,210	287,210	287,210	287,210	287,210	287,210	287,210	287,210	287,210	287,210	3,446,520
BS-SOC	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	2,152,878	25,834,538
BS-NEG	91,385	91,385	91,385	91,385	91,385	91,385	91,385	91,385	91,385	91,385	91,385	91,385	1,096,620
SoCo	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	11,097,447	133,169,369
SJRPP	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	6,032,621	72,391,448
Total	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	44,098,496	529,181,951

Florida Power & Light Company
Docket No. 070001-EI
Schedule E12
Page 2 of 2

CONFIDENTIAL

Contract	Counterparty	Identification	Contract End Date
1	Southern Power Company (Oleander)	Other Entity	May 31, 2012
2	Reliant Energy Services (Indian River)	Other Entity	December 31, 2009
3	Williams Power Company	Other Entity	December 31, 2009
4	Constellation Energy Commodities Group, Inc.	Other Entity	April 30, 2009

Capacity in MW

Contract	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
1	158	158	158	158	158	158	158	158	158	158	158	158
2	576	576	576	576	576	576	576	576	576	576	576	576
3	106	106	106	106	106	106	106	106	106	106	106	106
4	93	93	48	48	48	48	48	48	48	48	48	93
Total	933	933	888	888	888	888	888	888	888	888	888	933

Capacity in Dollars

Contract	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
1	[redacted]											
2												
3												
4												
Total	4,077,250	4,077,250	3,619,804	3,619,804	3,619,804	4,579,180	4,579,180	4,579,180	4,579,180	3,619,804	3,619,804	4,077,250

Total Short Term Capacity Payments for 2007	48,647,490	(1)

(1) September 4, 2007 Projection Filing, Appendix III, page 3, line 2

7

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2006

PS-1
DOCKET NO. 070001-EI
FPL Witness: Pamela Sonnelitter
Exhibit No.: _____
Pages 1 - 21
April 2, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 22
COMPANY Florida Power & Light Co
WITNESS Pamela Sonnelitter (PS-1)
DATE 11-06-07

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2006

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	6.203.001	Index of Manual Pages
	6.203.002	GPIF Reward/(Penalty) Table (Actual)
	6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
	6.203.004	Derivation of System Actual GPIF Points
	6.203.005	Actual Equivalent Availability and Adjustments Summary
	6.203.006	EAF Adjustment Documentation
	6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
	6.203.008 - 6.203.020	GPIF Units Points Tables
	6.203.021	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2006

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+ 10		159,518.1		28,512.7
+ 9		143,566.3		25,661.5
+ 8		127,614.5		22,810.2
+ 7		111,662.7		19,958.9
+ 6		95,710.9		17,107.6
+ 5		79,759.1		14,256.4
+ 4		63,807.2		11,405.1
+ 3	<---------- 3.16	47,855.4	9,001.3 ---------->	8,553.8
+ 2		31,903.6		5,702.5
+ 1		15,951.8		2,851.3
0		0.0		0.0
- 1		(15,951.8)		(2,851.3)
- 2		(31,903.6)		(5,702.5)
- 3		(47,855.4)		(8,553.8)
- 4		(63,807.2)		(11,405.1)
- 5		(79,759.1)		(14,256.4)
- 6		(95,710.9)		(17,107.6)
- 7		(111,662.7)		(19,958.9)
- 8		(127,614.5)		(22,810.2)
- 9		(143,566.3)		(25,661.5)
- 10		(159,518.1)		(28,512.7)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2006

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 6,736,887,430
LINE 2	MONTH OF January	2006	$ 6,781,218,339
LINE 3	MONTH OF February	2006	$ 6,814,949,601
LINE 4	MONTH OF March	2006	$ 6,859,197,570
LINE 5	MONTH OF April	2006	$ 6,912,501,792
LINE 6	MONTH OF May	2006	$ 6,986,198,078
LINE 7	MONTH OF June	2006	$ 7,041,526,575
LINE 8	MONTH OF July	2006	$ 7,137,927,980
LINE 9	MONTH OF August	2006	$ 7,259,570,270
LINE 10	MONTH OF September	2006	$ 7,369,298,910
LINE 11	MONTH OF October	2006	$ 7,448,422,300
LINE 12	MONTH OF November	2006	$ 7,497,921,630
LINE 13	MONTH OF December	2006	$ 7,539,303,120
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 7,106,532,584
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		61.3808%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 28,944,457
LINE 18	JURISDICTIONAL SALES		103,658,565,540 KWH
LINE 19	TOTAL SALES		105,228,047,611 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.51%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 28,512,748

JANUARY THROUGH DECEMBER, 2006

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Ft. Myers 2	EAF	2.24	-2.80	-.0626
Ft. Myers 2	ANOHR	12.36	0.00	.0000
Lauderdale 4	EAF	0.36	10.00	.0363
Lauderdale 4	ANOHR	5.87	-3.57	-.2094
Lauderdale 5	EAF	0.37	10.00	.0366
Lauderdale 5	ANOHR	4.62	0.00	.0000
Martin 1	EAF	0.36	10.00	.0357
Martin 1	ANOHR	3.06	0.00	.0000
Martin 2	EAF	0.27	2.00	.0054
Martin 2	ANOHR	5.02	0.00	.0000
Martin 3	EAF	0.36	10.00	.0357
Martin 3	ANOHR	1.32	0.00	.0000
Martin 4	EAF	0.55	10.00	.0549
Martin 4	ANOHR	4.19	0.00	.0000
Sanford 5	EAF	1.99	-10.00	-.1995
Sanford 5	ANOHR	7.07	-1.17	-.0826
Scherer 4	EAF	3.48	10.00	.3481
Scherer 4	ANOHR	1.03	-3.23	-.0333
St. Lucie 1	EAF	9.82	10.00	.9824
St. Lucie 1	ANOHR	1.55	0.00	.0000
St. Lucie 2	EAF	7.02	10.00	.7020
St. Lucie 2	ANOHR	1.11	2.13	.0236
Turkey Point 3	EAF	7.62	10.00	.7616
Turkey Point 3	ANOHR	5.15	0.00	.0000
Turkey Point 4	EAF	7.47	9.67	.7219
Turkey Point 4	ANOHR	5.75	0.00	.0000
GPIF System Total:		100.00		3.16

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2006

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO	ADJUSTED ACTUAL	TARGET	POINTS FROM	ORIGINAL PLANNED	ACTUAL	ACTUAL FUEL SAVINGS/ (LOSS)
UNIT	FOF	MOF	POF	EAF	EAF [1]	EAF	EAF	TABLES	DATES	DATES	($000)
Ft. Myers 2	2.5	5.0	0.0	92.4	0.0	92.4	93.1	-2.80	NONE	NONE	(998.9)
Lauderdale 4	0.9	0.3	4.6	94.2	1.9	96.1	93.3	10.00	02/11/06 - 02/20/06	02/17/2006 - 03/04/2006	578.5
Lauderdale 5	0.5	0.5	0.0	99.0	-2.7	96.3	92.9	10.00	09/23/06 - 10/02/06	NONE	583.6
Martin 1	0.2	5.7	0.0	94.2	0.0	94.2	90.8	10.00	NONE	NONE	569.6
Martin 2	0.3	5.0	11.0	83.7	1.3	85.0	84.5	2.00	01/29/06 - 03/04/06	02/24/2006 - 04/06/2006	85.3
Martin 3	0.6	1.7	15.9	81.8	-4.1	77.7	73.0	10.00	04/08/06 - 04/14/06	5/12/06-5/19/06, 10/23/06-12/18/06	570.0
Martin 4	0.5	2.0	3.1	94.4	0.5	94.9	90.8	10.00	09/09/06 - 09/20/06	09/23/2006 - 10/05/2006	875.8
Sanford 5	10.4	5.4	1.3	82.9	0.8	83.7	91.3	-10.00	11/11/06 - 11/16/06	02/07/2006 - 02/14/2006	(3,181.8)
Scherer 4	0.1	1.5	10.1	88.3	0.0	88.3	85.9	10.00	04/22/06 - 05/28/06	04/22/2006 - 05/29/2006	5,553.2
St. Lucie 1	0.1	0.0	0.2	99.6	0.3	99.9	93.6	10.00	NONE	3/1-3/2/06, 4/6-4/13/06, 5/30-5/31/06, 9/18-9/19/06	15,671.3
St. Lucie 2	2.8	0.0	14.0	83.2	-2.3	80.9	75.8	10.00	04/24/06 - 06/23/06	04/22/2006 - 06/13/2006	11,198.7
Turkey Point 3	1.9	0.0	8.8	89.4	1.9	91.3	86.0	10.00	03/05/06 - 03/30/06	03/05/2006 - 04/05/2006	12,149.7
Turkey Point 4	3.4	0.0	10.4	86.3	3.4	89.7	86.8	9.67	10/29/06 - 11/23/06	10/28/2006 - 12/04/2006	11,516.2
											55,171.4

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGETED DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2006

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Ft. Myers 2	8760	222.5	439.9	0.0	0.0	0.0	92.4
Lauderdale 4	8760	78.0	24.5	405.6	2.7	236.5	96.1
Lauderdale 5	8760	43.3	48.0	0.0	2.7	236.5	96.3
Martin 1	8760	13.5	498.6	0.0	0.0	0.0	94.2
Martin 2	8760	27.6	442.3	959.7	9.6	841.0	85.0
Martin 3	8760	55.5	147.3	1390.1	20.1	1760.8	77.7
Martin 4	8760	45.8	171.9	271.6	2.6	227.8	94.9
Sanford 5	8760	908.2	468.9	118.1	0.4	35.0	83.7
Scherer 4	8760	7.8	131.5	888.8	10.1	884.8	88.3
St. Lucie 1	8760	12.2	0.0	19.0	0.0	0.0	99.9
St. Lucie 2	8760	247.0	0.0	1228.4	16.4	1436.6	80.9
Turkey Point 3	8760	162.6	0.0	770.2	6.8	595.7	91.3
Turkey Point 4	8760	294.6	0.0	909.8	6.8	595.7	89.7

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2006

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET [2]	ADJUST.[3]		ADJUST.[5]	GPIF[6]	ACTUAL
UNIT	HEAT RATE [1] FORMULA	NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET [4] ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	POINTS FROM TABLE	FUEL SAV./(LOSS) $000
Ft. Myers 2	ANOHR= -10.42 x NOF + 7724	80.9	6843	6881	-38	6801	6763	0.00	0.0
Lauderdale 4	ANOHR= -11.99 x NOF + 8644	79.4	7848	7692	156	7690	7846	-3.57	(3341.0)
Lauderdale 5	ANOHR= -12.74 x NOF + 8662	81.4	7661	7625	36	7644	7680	0.00	0.0
Martin 1	ANOHR= -3.66 x NOF + 10243	50.4	10092	10058	34	10011	10045	0.00	0.0
Martin 2	ANOHR= -1.40 x NOF + 10023	51.2	9970	9951	19	9942	9961	0.00	0.0
Martin 3	ANOHR= -2.56 x NOF + 7232	82.5	7074	7021	53	7008	7061	0.00	0.0
Martin 4	ANOHR= -3.31 x NOF + 7246	85.2	6953	6964	-11	6950	6939	0.00	0.0
Sanford 5	ANOHR= -3.40 x NOF + 7174	71.4	7015	6931	84	6879	6963	-1.17	(1318.1)
Scherer 4	ANOHR= -12.56 x NOF + 11248	87.8	10260	10146	114	9998	10112	-3.23	(530.4)
St. Lucie 1	ANOHR= -54.23 x NOF + 16293	101.5	10770	10788	-18	10870	10852	0.00	0.0
St. Lucie 2	ANOHR= -76.43 x NOF + 18584	97.1	11076	11162	-86	10931	10845	2.13	377.0
Turkey Point 3	ANOHR= -37.44 x NOF + 14816	102.0	10982	10997	-15	11078	11063	0.00	0.0
Turkey Point 4	ANOHR= -27.88 x NOF + 13856	101.4	10990	11030	-40	11072	11032	0.00	0.0

(4812.5)

1) THESE FORMULAS ARE AS APPROVED BY THE COMMSION IN THE PROJECTED DATA AND ARE BASED ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM THE GPIF POINT TABLES USING THE COMMISION APPROVED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Ft. Myers 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,567.49	95.6		+10	19718.83	6637	
+9	3,210.74	95.4		+9	17746.95	6646	
+8	2,853.99	95.1		+8	15775.07	6654	
+7	2,497.24	94.9		+7	13803.18	6663	
+6	2,140.49	94.6		+6	11831.30	6672	
+5	1,783.74	94.4		+5	9859.42	6681	
+4	1,426.99	94.1		+4	7887.53	6690	
+3	1,070.25	93.9		+3	5915.65	6699	
+2	713.50	93.6		+2	3943.77	6708	
+1	356.75	93.4		+1	1971.88	6717	
					0.00	6726	<- Adj. Act. HR=6763
0	0.00	93.1		0	0.00	6801	
					(0.00)	6876	
-1	(-356.75)	92.9		-1	(-1971.88)	6885	
-2	(-713.50)	92.6		-2	(-3943.77)	6893	
-3	(-1,070.25)	92.4	<- Adj. Act. EAF= 92.4	-3	(-5915.65)	6902	
-4	(-1,426.99)	92.1		-4	(-7887.53)	6911	
-5	(-1,783.74)	91.9		-5	(-9859.42)	6920	
-6	(-2,140.49)	91.6		-6	(-11831.30)	6929	
-7	(-2,497.24)	91.4		-7	(-13803.18)	6938	
-8	(-2,853.99)	91.1		-8	(-15775.07)	6947	
-9	(-3,210.74)	90.9		-9	(-17746.95)	6956	
-10	(-3,567.49)	90.6		-10	(-19718.83)	6965	
	WEIGHTING FACTOR =	2.24			WEIGHTING FACTOR =	12.36	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Lauderdale 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	578.52	95.3	<- Adj. Act. EAF= 96.1	+10	9362.85	7388	
+9	520.67	95.1		+9	8426.56	7411	
+8	462.82	94.9		+8	7490.28	7433	
+7	404.97	94.7		+7	6553.99	7456	
+6	347.11	94.5		+6	5617.71	7479	
+5	289.26	94.3		+5	4681.42	7501	
+4	231.41	94.1		+4	3745.14	7524	
+3	173.56	93.9		+3	2808.85	7547	
+2	115.70	93.7		+2	1872.57	7569	
+1	57.85	93.5		+1	936.28	7592	
					0.00	7615	
0	0.00	93.3		0	0.00	7690	
					(0.00)	7765	
-1	(-57.85)	93.1		-1	(-936.28)	7788	
-2	(-115.70)	92.9		-2	(-1872.57)	7810	
-3	(-173.56)	92.7		-3	(-2808.85)	7833	<- Adj. Act. HR=7846
-4	(-231.41)	92.5		-4	(-3745.14)	7856	
-5	(-289.26)	92.3		-5	(-4681.42)	7878	
-6	(-347.11)	92.1		-6	(-5617.71)	7901	
-7	(-404.97)	91.9		-7	(-6553.99)	7924	
-8	(-462.82)	91.7		-8	(-7490.28)	7946	
-9	(-520.67)	91.5		-9	(-8426.56)	7969	
-10	(-578.52)	91.3		-10	(-9362.85)	7992	
	WEIGHTING FACTOR =	0.36			WEIGHTING FACTOR =	5.87	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Lauderdale 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	583.57	94.9	<- Adj. Act. EAF= 96.3	+10	7,376.52	7,411	
+9	525.22	94.7		+9	6638.87	7,427	
+8	466.86	94.5		+8	5901.22	7,443	
+7	408.50	94.3		+7	5163.57	7,459	
+6	350.14	94.1		+6	4425.91	7,475	
+5	291.79	93.9		+5	3688.26	7,490	
+4	233.43	93.7		+4	2950.61	7,506	
+3	175.07	93.5		+3	2212.96	7,522	
+2	116.71	93.3		+2	1475.30	7,538	
+1	58.36	93.1		+1	737.65	7,554	
					0.00	7,569	
0	0.00	92.9		0	0.00	7,644	<- Adj. Act. HR=7680
					(0.00)	7,719	
-1	(-58.36)	92.7		-1	(-737.65)	7,735	
-2	(-116.71)	92.5		-2	(-1475.30)	7,751	
-3	(-175.07)	92.3		-3	(-2212.96)	7,767	
-4	(-233.43)	92.1		-4	(-2950.61)	7,783	
-5	(-291.79)	91.9		-5	(-3688.26)	7,798	
-6	(-350.14)	91.7		-6	(-4425.91)	7,814	
-7	(-408.50)	91.5		-7	(-5163.57)	7,830	
-8	(-466.86)	91.3		-8	(-5901.22)	7,846	
-9	(-525.22)	91.1		-9	(-6638.87)	7,862	
-10	(-583.57)	90.9		-10	(-7,376.52)	7,877	
	WEIGHTING FACTOR =	0.37			WEIGHTING FACTOR =	4.62	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Martin 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	569.63	93.8	<- Adj. Act. EAF= 94.2	+10	4877.76	9818	
+9	512.67	93.5		+9	4389.99	9830	
+8	455.71	93.2		+8	3902.21	9842	
+7	398.74	92.9		+7	3414.44	9853	
+6	341.78	92.6		+6	2926.66	9865	
+5	284.82	92.3		+5	2438.88	9877	
+4	227.85	92.0		+4	1951.11	9889	
+3	170.89	91.7		+3	1463.33	9901	
+2	113.93	91.4		+2	975.55	9913	
+1	56.96	91.1		+1	487.78	9925	
					0.00	9936	
0	0.00	90.8		0	0.00	10011	<- Adj. Act. HR=10045
					(0.00)	10086	
-1	(-56.96)	90.5		-1	(-487.78)	10098	
-2	(-113.93)	90.2		-2	(-975.55)	10110	
-3	(-170.89)	89.9		-3	(-1463.33)	10122	
-4	(-227.85)	89.6		-4	(-1951.11)	10134	
-5	(-284.82)	89.3		-5	(-2438.88)	10146	
-6	(-341.78)	89.0		-6	(-2926.66)	10158	
-7	(-398.74)	88.7		-7	(-3414.44)	10170	
-8	(-455.71)	88.4		-8	(-3902.21)	10181	
-9	(-512.67)	88.1		-9	(-4389.99)	10193	
-10	(-569.63)	87.8		-10	(-4877.76)	10205	
	WEIGHTING FACTOR =	0.36			WEIGHTING FACTOR =	3.06	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Martin 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	426.72	87.0		+10	8011.49	9598	
+9	384.05	86.8		+9	7210.34	9625	
+8	341.37	86.5		+8	6409.19	9652	
+7	298.70	86.3		+7	5608.04	9679	
+6	256.03	86.0		+6	4806.89	9706	
+5	213.36	85.8		+5	4005.74	9732	
+4	170.69	85.5		+4	3204.60	9759	
+3	128.02	85.3		+3	2403.45	9786	
+2	85.34	85.0	<- Adj. Act. EAF= 85.0	+2	1602.30	9813	
+1	42.67	84.8		+1	801.15	9840	
					0.00	9867	
0	0.00	84.5		0	0.00	9942	<- Adj. Act. HR=9961
					(0.00)	10017	
-1	(-42.67)	84.3		-1	(-801.15)	10043	
-2	(-85.34)	84.0		-2	(-1602.30)	10070	
-3	(-128.02)	83.8		-3	(-2403.45)	10097	
-4	(-170.69)	83.5		-4	(-3204.60)	10124	
-5	(-213.36)	83.3		-5	(-4005.74)	10151	
-6	(-256.03)	83.0		-6	(-4806.89)	10177	
-7	(-298.70)	82.8		-7	(-5608.04)	10204	
-8	(-341.37)	82.5		-8	(-6409.19)	10231	
-9	(-384.05)	82.3		-9	(-7210.34)	10258	
-10	(-426.72)	82.0		-10	(-8011.49)	10285	
	WEIGHTING FACTOR =	0.27			WEIGHTING FACTOR =	5.02	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Martin 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	570.04	75.5	<- Adj. Act. EAF= 77.7	+10	2098.49	6933	
+9	513.03	75.3		+9	1888.64	6933	
+8	456.03	75.0		+8	1678.79	6933	
+7	399.03	74.8		+7	1468.94	6933	
+6	342.02	74.5		+6	1259.09	6933	
+5	285.02	74.3		+5	1049.25	6933	
+4	228.01	74.0		+4	839.40	6933	
+3	171.01	73.8		+3	629.55	6933	
+2	114.01	73.5		+2	419.70	6933	
+1	57.00	73.3		+1	209.85	6933	
					0.00	6933	
0	0.00	73.0		0	0.00	7008	<- Adj. Act. HR=7061
					(0.00)	7083	
-1	(-57.00)	72.8		-1	(-209.85)	7083	
-2	(-114.01)	72.5		-2	(-419.70)	7083	
-3	(-171.01)	72.3		-3	(-629.55)	7083	
-4	(-228.01)	72.0		-4	(-839.40)	7083	
-5	(-285.02)	71.8		-5	(-1049.25)	7083	
-6	(-342.02)	71.5		-6	(-1259.09)	7083	
-7	(-399.03)	71.3		-7	(-1468.94)	7083	
-8	(-456.03)	71.0		-8	(-1678.79)	7083	
-9	(-513.03)	70.8		-9	(-1888.64)	7083	
-10	(-570.04)	70.5		-10	(-2098.49)	7083	
	WEIGHTING FACTOR =	0.36			WEIGHTING FACTOR =	1.32	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Martin 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	875.84	93.3	<- Adj. Act. EAF= 94.9	+10	6683.15	6760	
+9	788.26	93.1		+9	6014.83	6772	
+8	700.67	92.8		+8	5346.52	6783	
+7	613.09	92.6		+7	4678.20	6795	
+6	525.51	92.3		+6	4009.89	6806	
+5	437.92	92.1		+5	3341.57	6818	
+4	350.34	91.8		+4	2673.26	6829	
+3	262.75	91.6		+3	2004.94	6841	
+2	175.17	91.3		+2	1336.63	6852	
+1	87.58	91.1		+1	668.31	6864	
					0.00	6875	<- Adj. Act. HR=6939
0	0.00	90.8		0	0.00	6950	
					(0.00)	7025	
-1	(-87.58)	90.6		-1	(-668.31)	7036	
-2	(-175.17)	90.3		-2	(-1336.63)	7048	
-3	(-262.75)	90.1		-3	(-2004.94)	7059	
-4	(-350.34)	89.8		-4	(-2673.26)	7071	
-5	(-437.92)	89.6		-5	(-3341.57)	7082	
-6	(-525.51)	89.3		-6	(-4009.89)	7094	
-7	(-613.09)	89.1		-7	(-4678.20)	7105	
-8	(-700.67)	88.8		-8	(-5346.52)	7117	
-9	(-788.26)	88.6		-9	(-6014.83)	7128	
-10	(-875.84)	88.3		-10	(-6683.15)	7140	
	WEIGHTING FACTOR =	0.55			WEIGHTING FACTOR =	4.19	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Sanford 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,181.78	94.3		+10	11275.05	6727	
+9	2,863.60	94.0		+9	10147.54	6734	
+8	2,545.42	93.7		+8	9020.04	6742	
+7	2,227.25	93.4		+7	7892.53	6750	
+6	1,909.07	93.1		+6	6765.03	6757	
+5	1,590.89	92.8		+5	5637.52	6765	
+4	1,272.71	92.5		+4	4510.02	6773	
+3	954.53	92.2		+3	3382.51	6780	
+2	636.36	91.9		+2	2255.01	6788	
+1	318.18	91.6		+1	1127.50	6796	
					0.00	6804	
0	0.00	91.3		0	0.00	6879	
					(0.00)	6954	
-1	(-318.18)	91.0		-1	(-1127.50)	6961	<- Adj. Act. HR=6963
-2	(-636.36)	90.7		-2	(-2255.01)	6969	
-3	(-954.53)	90.4		-3	(-3382.51)	6977	
-4	(-1,272.71)	90.1		-4	(-4510.02)	6984	
-5	(-1,590.89)	89.8		-5	(-5637.52)	6992	
-6	(-1,909.07)	89.5		-6	(-6765.03)	7000	
-7	(-2,227.25)	89.2		-7	(-7892.53)	7007	
-8	(-2,545.42)	88.9		-8	(-9020.04)	7015	
-9	(-2,863.60)	88.6		-9	(-10147.54)	7023	
-10	(-3,181.78)	88.3	<- Adj. Act. EAF= 83.7	-10	(-11275.05)	7031	
	WEIGHTING FACTOR =	1.99			WEIGHTING FACTOR =	7.07	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,553.21	87.9	<- Adj. Act. EAF= 88.3	+10	1642.29	9802	
+9	4,997.89	87.7		+9	1478.06	9815	
+8	4,442.57	87.5		+8	1313.83	9827	
+7	3,887.25	87.3		+7	1149.60	9839	
+6	3,331.93	87.1		+6	985.37	9851	
+5	2,776.61	86.9		+5	821.14	9863	
+4	2,221.28	86.7		+4	656.91	9875	
+3	1,665.96	86.5		+3	492.69	9887	
+2	1,110.64	86.3		+2	328.46	9899	
+1	555.32	86.1		+1	164.23	9911	
					0.00	9923	
0	0.00	85.9		0	0.00	9998	
					(0.00)	10073	
-1	(-555.32)	85.7		-1	(-164.23)	10085	
-2	(-1,110.64)	85.5		-2	(-328.46)	10097	
-3	(-1,665.96)	85.3		-3	(-492.69)	10109	<- Adj. Act. HR=10112
-4	(-2,221.28)	85.1		-4	(-656.91)	10122	
-5	(-2,776.61)	84.9		-5	(-821.14)	10134	
-6	(-3,331.93)	84.7		-6	(-985.37)	10146	
-7	(-3,887.25)	84.5		-7	(-1149.60)	10158	
-8	(-4,442.57)	84.3		-8	(-1313.83)	10170	
-9	(-4,997.89)	84.1		-9	(-1478.06)	10182	
-10	(-5,553.21)	83.9		-10	(-1642.29)	10194	
	WEIGHTING FACTOR =	3.48			WEIGHTING FACTOR =	1.03	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	15,671.33	96.6	<- Adj. Act. EAF= 99.9	+10	2472.31	10818	
+9	14,104.20	96.3		+9	2225.08	10816	
+8	12,537.07	96.0		+8	1977.85	10813	
+7	10,969.93	95.7		+7	1730.62	10811	
+6	9,402.80	95.4		+6	1483.39	10809	
+5	7,835.67	95.1		+5	1236.16	10806	
+4	6,268.53	94.8		+4	988.92	10804	
+3	4,701.40	94.5		+3	741.69	10802	
+2	3,134.27	94.2		+2	494.46	10799	
+1	1,567.13	93.9		+1	247.23	10797	
					0.00	10795	<- Adj. Act. HR=10852
0	0.00	93.6		0	0.00	10870	
					(0.00)	10945	
-1	(-1,567.13)	93.3		-1	(-247.23)	10942	
-2	(-3,134.27)	93.0		-2	(-494.46)	10940	
-3	(-4,701.40)	92.7		-3	(-741.69)	10938	
-4	(-6,268.53)	92.4		-4	(-988.92)	10935	
-5	(-7,835.67)	92.1		-5	(-1236.16)	10933	
-6	(-9,402.80)	91.8		-6	(-1483.39)	10931	
-7	(-10,969.93)	91.5		-7	(-1730.62)	10929	
-8	(-12,537.07)	91.2		-8	(-1977.85)	10926	
-9	(-14,104.20)	90.9		-9	(-2225.08)	10924	
-10	(-15,671.33)	90.6		-10	(-2472.31)	10922	
	WEIGHTING FACTOR =	9.82			WEIGHTING FACTOR =	1.55	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	11,198.73	78.8	<- Adj. Act. EAF= 80.9	+10	1769.28	10879	
+9	10,078.85	78.5		+9	1592.36	10877	
+8	8,958.98	78.2		+8	1415.43	10874	
+7	7,839.11	77.9		+7	1238.50	10872	
+6	6,719.24	77.6		+6	1061.57	10870	
+5	5,599.36	77.3		+5	884.64	10867	
+4	4,479.49	77.0		+4	707.71	10865	
+3	3,359.62	76.7		+3	530.79	10863	
+2	2,239.75	76.4		+2	353.86	10860	
+1	1,119.87	76.1		+1	176.93	10858	
					0.00	10856	<- Adj. Act. HR=10845
0	0.00	75.8		0	0.00	10931	
					(0.00)	11006	
-1	(-1,119.87)	75.5		-1	(-176.93)	11003	
-2	(-2,239.75)	75.2		-2	(-353.86)	11001	
-3	(-3,359.62)	74.9		-3	(-530.79)	10999	
-4	(-4,479.49)	74.6		-4	(-707.71)	10996	
-5	(-5,599.36)	74.3		-5	(-884.64)	10994	
-6	(-6,719.24)	74.0		-6	(-1061.57)	10992	
-7	(-7,839.11)	73.7		-7	(-1238.50)	10989	
-8	(-8,958.98)	73.4		-8	(-1415.43)	10987	
-9	(-10,078.85)	73.1		-9	(-1592.36)	10985	
-10	(-11,198.73)	72.8		-10	(-1769.28)	10982	
	WEIGHTING FACTOR =	7.02			WEIGHTING FACTOR =	1.11	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	12,149.68	89.0	<- Adj. Act. EAF= 91.3	+10	8213.95	10848	
+9	10,934.71	88.7		+9	7392.56	10864	
+8	9,719.74	88.4		+8	6571.16	10879	
+7	8,504.77	88.1		+7	5749.77	10895	
+6	7,289.81	87.8		+6	4928.37	10910	
+5	6,074.84	87.5		+5	4106.98	10926	
+4	4,859.87	87.2		+4	3285.58	10941	
+3	3,644.90	86.9		+3	2464.19	10956	
+2	2,429.94	86.6		+2	1642.79	10972	
+1	1,214.97	86.3		+1	821.40	10987	
					0.00	11003	<- Adj. Act. HR=11063
0	0.00	86.0		0	0.00	11078	
					(0.00)	11153	
-1	(-1,214.97)	85.7		-1	(-821.40)	11168	
-2	(-2,429.94)	85.4		-2	(-1642.79)	11184	
-3	(-3,644.90)	85.1		-3	(-2464.19)	11199	
-4	(-4,859.87)	84.8		-4	(-3285.58)	11215	
-5	(-6,074.84)	84.5		-5	(-4106.98)	11230	
-6	(-7,289.81)	84.2		-6	(-4928.37)	11246	
-7	(-8,504.77)	83.9		-7	(-5749.77)	11261	
-8	(-9,719.74)	83.6		-8	(-6571.16)	11276	
-9	(-10,934.71)	83.3		-9	(-7392.56)	11292	
-10	(-12,149.68)	83.0		-10	(-8213.95)	11307	
	WEIGHTING FACTOR =	7.62			WEIGHTING FACTOR =	5.15	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2006

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	11,913.27	89.8		+10	9176.30	10811	
+9	10,721.94	89.5	<- Adj. Act. EAF= 89.7	+9	8258.67	10829	
+8	9,530.62	89.2		+8	7341.04	10848	
+7	8,339.29	88.9		+7	6423.41	10867	
+6	7,147.96	88.6		+6	5505.78	10885	
+5	5,956.64	88.3		+5	4588.15	10904	
+4	4,765.31	88.0		+4	3670.52	10923	
+3	3,573.98	87.7		+3	2752.89	10941	
+2	2,382.65	87.4		+2	1835.26	10960	
+1	1,191.33	87.1		+1	917.63	10979	
					0.00	10997	<- Adj. Act. HR=11032
0	0.00	86.8		0	0.00	11072	
					(0.00)	11147	
-1	(-1,191.33)	86.5		-1	(-917.63)	11166	
-2	(-2,382.65)	86.2		-2	(-1835.26)	11185	
-3	(-3,573.98)	85.9		-3	(-2752.89)	11203	
-4	(-4,765.31)	85.6		-4	(-3670.52)	11222	
-5	(-5,956.64)	85.3		-5	(-4588.15)	11241	
-6	(-7,147.96)	85.0		-6	(-5505.78)	11259	
-7	(-8,339.29)	84.7		-7	(-6423.41)	11278	
-8	(-9,530.62)	84.4		-8	(-7341.04)	11297	
-9	(-10,721.94)	84.1		-9	(-8258.67)	11315	
-10	(-11,913.27)	83.8		-10	(-9176.30)	11334	
	WEIGHTING FACTOR =	7.47			WEIGHTING FACTOR =	5.75	

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2006

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Ft. Myers 2	NONE	
Lauderdale 4	02/17/2006 - 03/04/2006	4A CT, 4B CT, and steam turbine overhaul
Lauderdale 5	NONE	
Martin 1	NONE	
Martin 2	02/24/2006 - 04/06/2006	Major overhaul
Martin 3	5/12/06-5/19/06, 10/23/06-12/18/06	3A CT combustor inspection, and 3A CT, 3B CT & steam turbine overhaul
Martin 4	09/23/2006 - 10/05/2006	4A CT combustor inspection, 4B CT hot gas path
Sanford 5	02/07/2006 - 02/14/2006	Steam turbine inspection outage
Scherer 4	04/22/2006 - 05/29/2006	Boiler and steam turbine overhaul
St. Lucie 1	3/1-3/2/06, 4/6-4/13/06, 5/30-5/31/06, 9/18-9/19/06	Partial power reductions for turbine valve tests and HDP motor repair
St. Lucie 2	04/22/2006 - 06/13/2006	Refueling outage
Turkey Point 3	03/05/2006 - 04/05/2006	Refueling outage
Turkey Point 4	10/28/2006 - 12/04/2006	Refueling outage

DOCUMENT NO. 1

WITNESS: FRANK IRIZARRY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2008

FI-2
DOCKET NO. 070001-EI
FPL Witness: Frank Irizarry
Exhibit No.: _____
Pages 1 - 24
September 4, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 23
COMPANY Florida Power & Light Co
WITNESS Frank Irizarry (FI-2)
DATE 11-06-07

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2008

DOCUMENT	PAGE NUMBER	TITLE
1	7.201.001	Index
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 - 7.201.023	Unit MOF and FOF vs Time Graphs
	7.201.024	Planned Outages Schedule (Estimated)

Table 2.0
POWRSYM Projected System Generation
January Through December, 2008

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
FT. MYERS 2	1,412	7,292	9,052,636	87.9%	8.8	8.8	558,880
MARTIN 8	1,092	8,750	8,428,896	88.2%	8.2	16.9	502,154
TURKEY POINT 5	1,090	8,609	8,286,828	88.3%	8.0	24.9	483,396
MANATEE 3	1,092	8,258	7,888,074	87.4%	7.6	32.6	470,284
SANFORD 4	944	7,907	6,636,144	88.9%	6.4	39.0	409,953
ST. LUCIE 1	845	7,800	6,420,882	97.4%	6.2	45.2	25,802
ST. LUCIE 2	719	8,784	6,157,258	97.5%	6.0	51.2	29,065
TURKEY POINT 3	703	8,784	6,020,510	97.5%	5.8	57.0	29,024
SANFORD 5	944	7,032	5,870,531	88.4%	5.7	62.7	364,600
TURKEY POINT 4	703	7,944	5,451,815	97.6%	5.3	68.0	29,623
SCHERER 4	637	7,872	4,893,259	97.7%	4.7	72.7	106,537
LAUDERDALE 4	437	8,544	3,046,785	81.7%	2.9	75.7	214,892
LAUDERDALE 5	437	8,424	3,041,271	82.7%	2.9	78.6	215,216
MARTIN 3	462	6,304	2,579,515	88.6%	2.5	81.1	158,981
MARTIN 2	817	4,536	2,498,162	67.4%	2.4	83.5	231,468
MARTIN 4	462	5,506	2,241,574	88.2%	2.2	85.7	138,775
MANATEE 1	798	4,637	2,079,398	56.2%	2.0	87.7	195,814
MANATEE 2	798	4,600	1,821,665	49.6%	1.8	89.5	171,227
MARTIN 1	817	3,380	1,765,183	63.9%	1.7	91.2	164,487
ST JOHNS 1O	128	8,784	1,097,698	97.4%	1.1	92.2	28,492
PT EVERGLADES 3	375	4,203	1,033,927	65.6%	1.0	93.2	98,443
ST JOHNS 2O	128	7,368	912,318	96.5%	0.9	94.1	23,884
PT EVERGLADES 4	375	3,657	911,807	66.5%	0.9	95.0	86,364
CAPE CANAVERAL 1	379	3,178	798,396	66.3%	0.8	95.8	75,535
PUTNAM 2	241	3,490	766,261	91.1%	0.7	96.5	61,547
TURKEY POINT 1	379	2,916	726,461	65.8%	0.7	97.2	69,448
TURKEY POINT 2	379	2,857	694,174	64.1%	0.7	97.9	66,081
PUTNAM 1	241	3,088	620,249	83.3%	0.6	98.5	51,157
CAPE CANAVERAL 2	379	2,452	594,285	64.0%	0.6	99.1	56,555
RIVIERA 3	274	1,903	311,617	59.8%	0.3	99.4	30,272
RIVIERA 4	285	1,917	275,382	50.4%	0.3	99.6	26,855
FORT MYERS 3A_B	321	319	100,337	98.0%	0.1	99.7	9,498
PT EVERGLADES 2	206	690	94,770	66.7%	0.1	99.8	9,534
PT EVERGLADES 1	206	629	89,875	69.4%	0.1	99.9	8,958
SANFORD 3	139	553	42,415	55.2%	0.0	99.9	4,316
CUTLER 6	137	364	35,267	70.5%	0.0	100.0	3,521
CUTLER 5	68	324	17,642	79.6%	0.0	100.0	1,720
FORT MYERS 1-12	583	3	386	0.0%	0.0	100.0	77
LAUDERDALE 1-24	718	1	115	0.0%	0.0	100.0	17
EVERGLADES 1-12	359	0	0	0.0%	0.0	100.0	0
Total	21,508		103,303,768		100.0	100.0	5,212,452

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2008

Ft. Myers 2

Lauderdale 4

Lauderdale 5

Martin 2

Martin 3

Martin 4

Sanford 4

Sanford 5

Scherer 4

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2008

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	149,700	29,718
+ 9	134,730	26,746
+ 8	119,760	23,774
+ 7	104,790	20,803
+ 6	89,820	17,831
+ 5	74,850	14,859
+ 4	59,880	11,887
+ 3	44,910	8,915
+ 2	29,940	5,944
+ 1	14,970	2,972
0	0	0
- 1	(14,970)	(2,972)
- 2	(29,940)	(5,944)
- 3	(44,910)	(8,915)
- 4	(59,880)	(11,887)
- 5	(74,850)	(14,859)
- 6	(89,820)	(17,831)
- 7	(104,790)	(20,803)
- 8	(119,760)	(23,774)
- 9	(134,730)	(26,746)
- 10	(149,700)	(29,718)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	7,269,526,697	
LINE 2	MONTH OF JANUARY	2008	$	7,251,954,910	
LINE 3	MONTH OF FEBRUARY	2008	$	7,283,251,291	
LINE 4	MONTH OF MARCH	2008	$	7,331,150,506	
LINE 5	MONTH OF APRIL	2008	$	7,387,662,695	
LINE 6	MONTH OF MAY	2008	$	7,465,114,899	
LINE 7	MONTH OF JUNE	2008	$	7,578,768,715	
LINE 8	MONTH OF JULY	2008	$	7,696,906,184	
LINE 9	MONTH OF AUGUST	2008	$	7,826,667,682	
LINE 10	MONTH OF SEPTEMBER	2008	$	7,946,903,916	
LINE 11	MONTH OF OCTOBER	2008	$	8,038,031,971	
LINE 12	MONTH OF NOVEMBER	2008	$	8,109,053,479	
LINE 13	MONTH OF DECEMBER	2008	$	8,127,808,777	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	7,639,446,000	
LINE 15	25 BASIS POINTS			0.0025	
LINE 16	REVENUE EXPANSION FACTOR			63.6941%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	29,984,908	
LINE 18	JURISDICTIONAL SALES			111,773,806,124	KWH
LINE 19	TOTAL SALES			112,777,460,444	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			99.11%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	29,718,060	

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	4.40	86.6	89.6	83.6	6,591.2	-6,591.2
Lauderdale 4	0.82	93.3	95.3	91.3	1,226.1	-1,226.1
Lauderdale 5	0.77	91.9	93.9	89.9	1,147.2	-1,147.2
Martin 2	0.25	94.9	97.4	92.4	376.9	-376.9
Martin 3	1.09	93.8	96.3	91.3	1,627.2	-1,627.2
Martin 4	0.76	82.4	84.4	80.4	1,144.1	-1,144.1
Sanford 4	2.17	94.1	96.1	92.1	3,242.2	-3,242.2
Sanford 5	2.89	85.5	88.5	82.5	4,322.2	-4,322.2
Scherer 4	3.69	85.6	87.6	83.6	5,525.5	-5,525.5
St. Lucie 1	9.38	82.4	85.4	79.4	14,045.8	-14,045.8
St. Lucie 2	9.03	93.6	96.6	90.6	13,522.3	-13,522.3
Turkey Point 3	8.82	90.9	93.9	87.9	13,207.8	-13,207.8
Turkey Point 4	7.98	81.7	84.7	78.7	11,943.2	-11,943.2
	52.05				77,921.7	-77,921.7

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	6.30	6,808	87.9	6,694	6,923	9,432.4	-9,432.4
Lauderdale 4	2.32	7,757	81.7	7,632	7,883	3,469.7	-3,469.7
Lauderdale 5	2.99	7,641	82.7	7,482	7,800	4,476.5	-4,476.5
Martin 2	6.12	9,892	67.4	9,501	10,284	9,155.7	-9,155.7
Martin 3	2.32	7,031	88.6	6,877	7,185	3,474.3	-3,474.3
Martin 4	1.34	6,973	88.2	6,873	7,073	1,998.7	-1,998.7
Sanford 4	4.15	6,920	88.9	6,815	7,025	6,218.0	-6,218.0
Sanford 5	4.27	6,915	88.4	6,794	7,036	6,398.5	-6,398.5
Scherer 4	0.85	10,163	97.7	10,041	10,285	1,278.4	-1,278.4
St. Lucie 1	2.90	10,881	97.4	10,779	10,983	4,346.5	-4,346.5
St. Lucie 2	2.82	11,052	97.5	10,949	11,155	4,225.5	-4,225.5
Turkey Point 3	5.76	11,125	97.5	10,903	11,347	8,625.5	-8,625.5
Turkey Point 4	5.80	11,070	97.6	10,823	11,317	8,678.0	-8,678.0
	47.95					71,777.8	-71,777.8

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

Plant/Unit	ANOHR	NOF	MW	ANOHR Equation a coef.	b coef.	Bounds	First	Last	Exclusions
Ft. Myers 2	6,808	87.9	1412	7183	-4.26	115	07-04	06-07	Nov-Dec '04, Dec '05
Lauderdale 4	7,757	81.7	437	10157	-29.38	125	07-04	06-07	May-June '07
Lauderdale 5	7,641	82.7	437	9050	-17.04	159	07-04	06-07	Nov '04, Nov-Dec '05
Martin 2	9,892	67.4	817	10261	-5.47	391	07-04	06-07	Jan-Mar '06, Dec '06, Feb-Mar '07
Martin 3	7,031	88.6	462	7526	-5.59	154	07-04	06-07	Dec '05, Nov '06
Martin 4	6,973	88.2	462	7570	-6.77	100	07-04	06-07	Feb-Apr '05, Mar '07
Sanford 4	6,920	88.9	944	7372	-5.07	105	07-04	06-07	May '07
Sanford 5	6,915	88.4	944	7386	-5.32	121	07-04	06-07	Apr 06, Dec '06
Scherer 4	10,163	97.7	637	10348	-1.89	122	07-04	06-07	Feb '05, Oct '05, May '06
St. Lucie 1	10,881	97.4	845	12939	-21.12	102	07-04	06-07	Nov '05, Apr-May '07
St. Lucie 2	11,052	97.5	719	13239	-22.43	103	07-04	06-07	Jan-Feb '05, May-Jun '06
Turkey Point 3	11,125	97.5	703	14017	-29.66	222	07-04	06-07	Oct-Dec '04, Oct '05
Turkey Point 4	11,070	97.6	703	13017	-19.94	247	07-04	06-07	Apr-May '05, Nov '06

DERIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Ft. Myers 2	EAF	5,212,452	5,205,861	6,591.2	4.40
Ft. Myers 2	ANOHR	5,212,452	5,203,020	9,432.4	6.30
Lauderdale 4	EAF	5,212,452	5,211,226	1,226.1	0.82
Lauderdale 4	ANOHR	5,212,452	5,208,982	3,469.7	2.32
Lauderdale 5	EAF	5,212,452	5,211,305	1,147.2	0.77
Lauderdale 5	ANOHR	5,212,452	5,207,975	4,476.5	2.99
Martin 2	EAF	5,212,452	5,212,075	376.9	0.25
Martin 2	ANOHR	5,212,452	5,203,296	9,155.7	6.12
Martin 3	EAF	5,212,452	5,210,825	1,627.2	1.09
Martin 3	ANOHR	5,212,452	5,208,978	3,474.3	2.32
Martin 4	EAF	5,212,452	5,211,308	1,144.1	0.76
Martin 4	ANOHR	5,212,452	5,210,453	1,998.7	1.34
Sanford 4	EAF	5,212,452	5,209,210	3,242.2	2.17
Sanford 4	ANOHR	5,212,452	5,206,234	6,218.0	4.15
Sanford 5	EAF	5,212,452	5,208,130	4,322.2	2.89
Sanford 5	ANOHR	5,212,452	5,206,053	6,398.5	4.27
Scherer 4	EAF	5,212,452	5,206,926	5,525.5	3.69
Scherer 4	ANOHR	5,212,452	5,211,174	1,278.4	0.85
St. Lucie 1	EAF	5,212,452	5,198,406	14,045.8	9.38
St. Lucie 1	ANOHR	5,212,452	5,208,105	4,346.5	2.90
St. Lucie 2	EAF	5,212,452	5,198,930	13,522.3	9.03
St. Lucie 2	ANOHR	5,212,452	5,208,226	4,225.5	2.82
Turkey Point 3	EAF	5,212,452	5,199,244	13,207.8	8.82
Turkey Point 3	ANOHR	5,212,452	5,203,826	8,625.5	5.76
Turkey Point 4	EAF	5,212,452	5,200,509	11,943.2	7.98
Turkey Point 4	ANOHR	5,212,452	5,203,774	8,678.0	5.80
	TOTAL			149,699.5	100.00

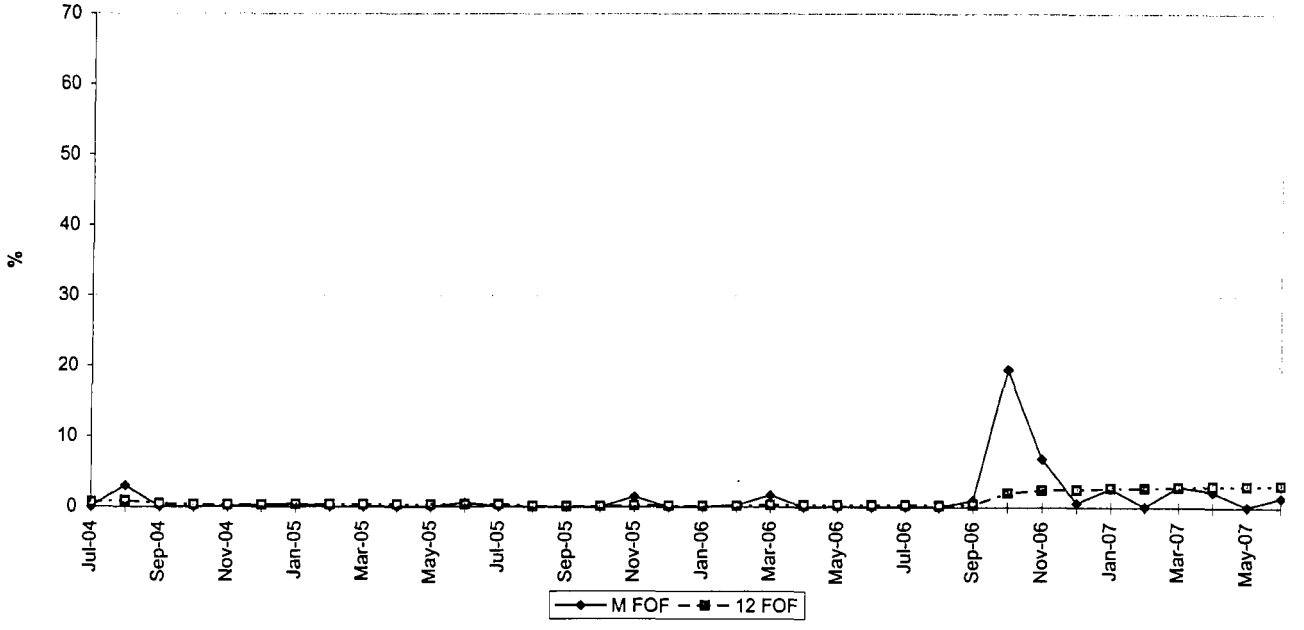
(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2008

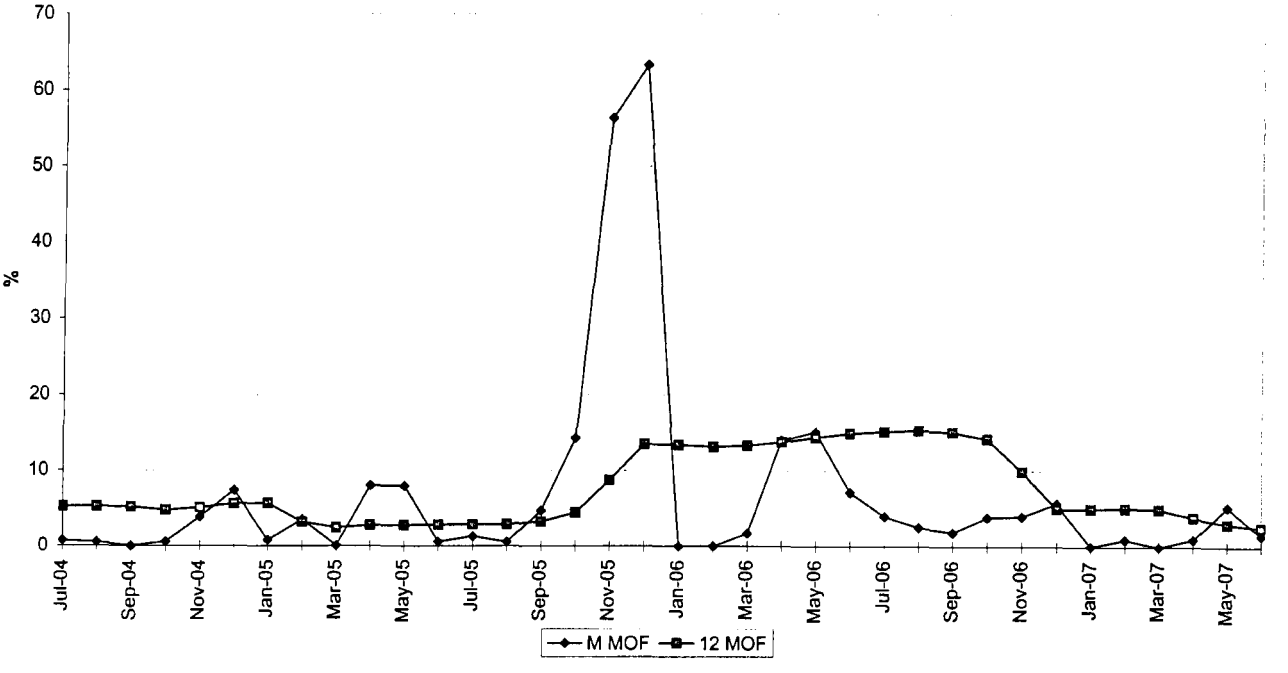
Plant/Unit	EAF	EPOF	EUOF	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET GEN
Ft. Myers 2	86.6	4.7	8.7	8784	7292	312	1180	416	176	589	9,052,636
Lauderdale 4	93.3	2.7	4.0	8784	8193	0	591	240	176	176	3,046,785
Lauderdale 5	91.9	4.1	4.0	8784	8073	0	711	360	176	176	3,041,271
Martin 2	94.9	0.0	5.1	8784	4536	3800	448	0	176	272	2,498,162
Martin 3	93.8	1.0	5.2	8784	6304	1939	541	84	176	281	2,579,515
Martin 4	82.4	13.4	4.2	8784	5506	1733	1545	1176	176	193	2,241,574
Sanford 4	94.1	1.9	4.0	8784	7907	358	519	168	176	176	6,636,144
Sanford 5	85.5	6.2	8.3	8784	7032	477	1275	546	343	386	5,870,531
Scherer 4	85.6	10.4	4.0	8784	7521	0	1263	912	176	176	4,893,259
St. Lucie 1	82.4	11.2	6.4	8784	7238	0	1546	984	281	281	6,420,882
St. Lucie 2	93.6	0.0	6.4	8784	8222	0	562	0	281	281	6,157,258
Turkey Point 3	90.9	0.0	9.1	8784	7985	0	799	0	518	281	6,020,510
Turkey Point 4	81.7	9.6	8.7	8784	7180	0	1604	840	483	281	5,451,815

EPOF = equivalent planned outage factor. EPOF=(EPOH/PH)*100
EUOF = equivalent unavailable outage factor. EUOF=((EFOH+EMOH)/PH)*100
PH = period hours
SH = service hours
RSH = reserve shutdown
UH = unavailable hours . UH=PH-SH-RSH
EPOH = equivalent planned outage hours
EFOH = equivalent forced outage hours
EMOH = equivalent maintenance outage hours

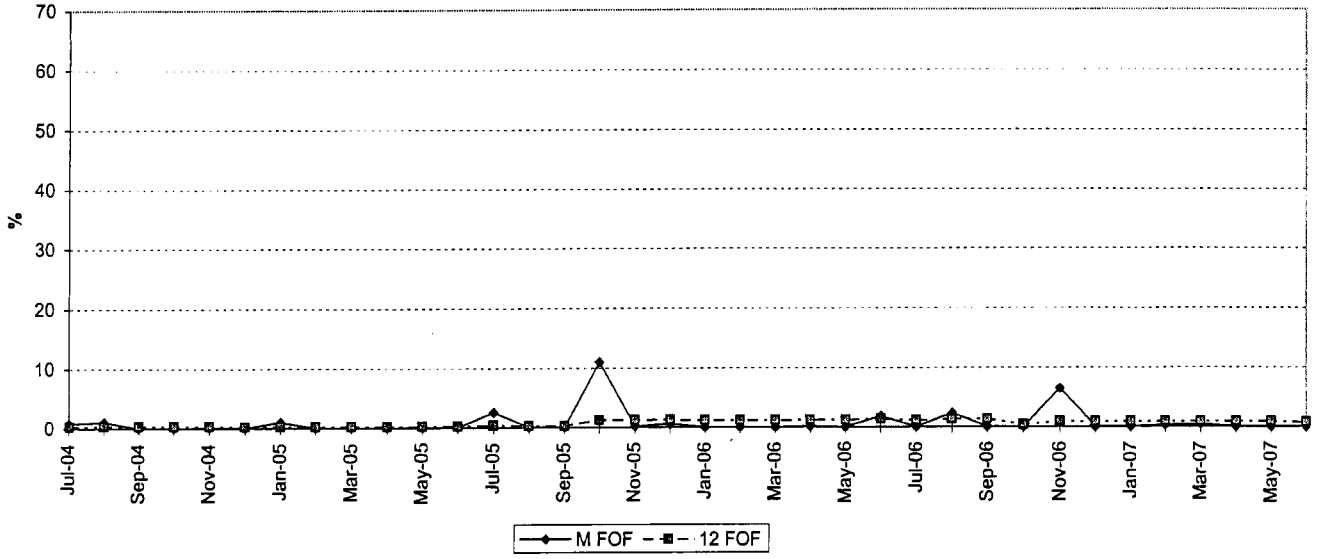
PFM 2
FORCED OUTAGE FACTOR



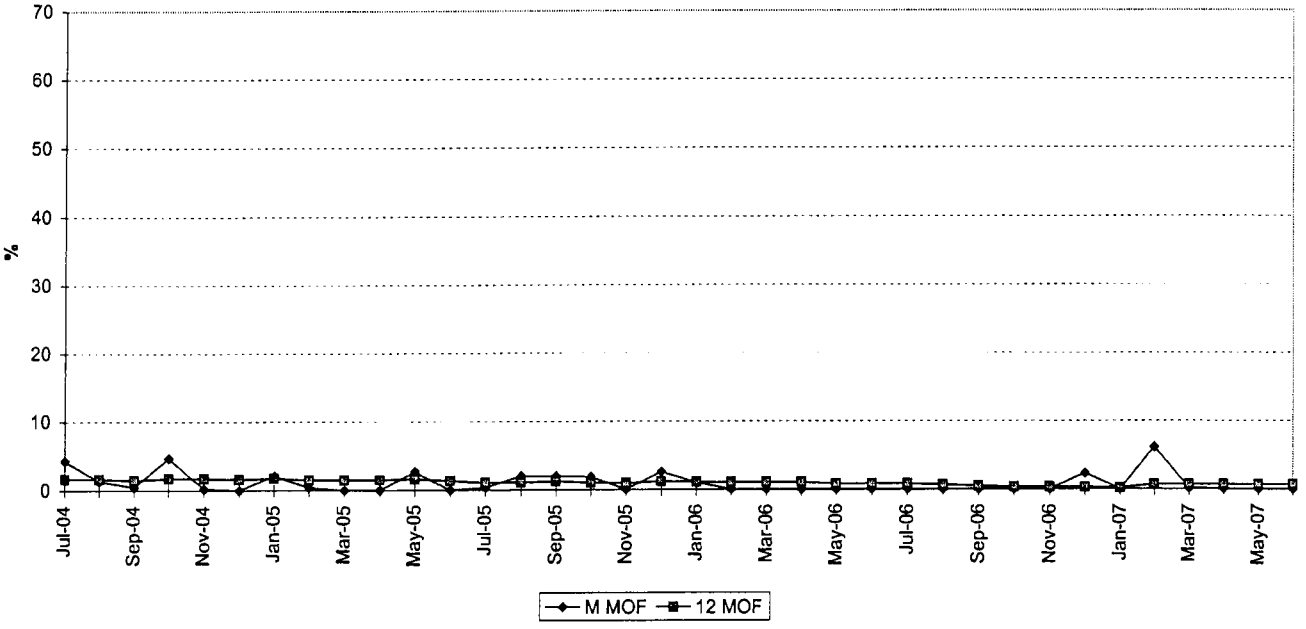
MAINTENANCE OUTAGE FACTOR



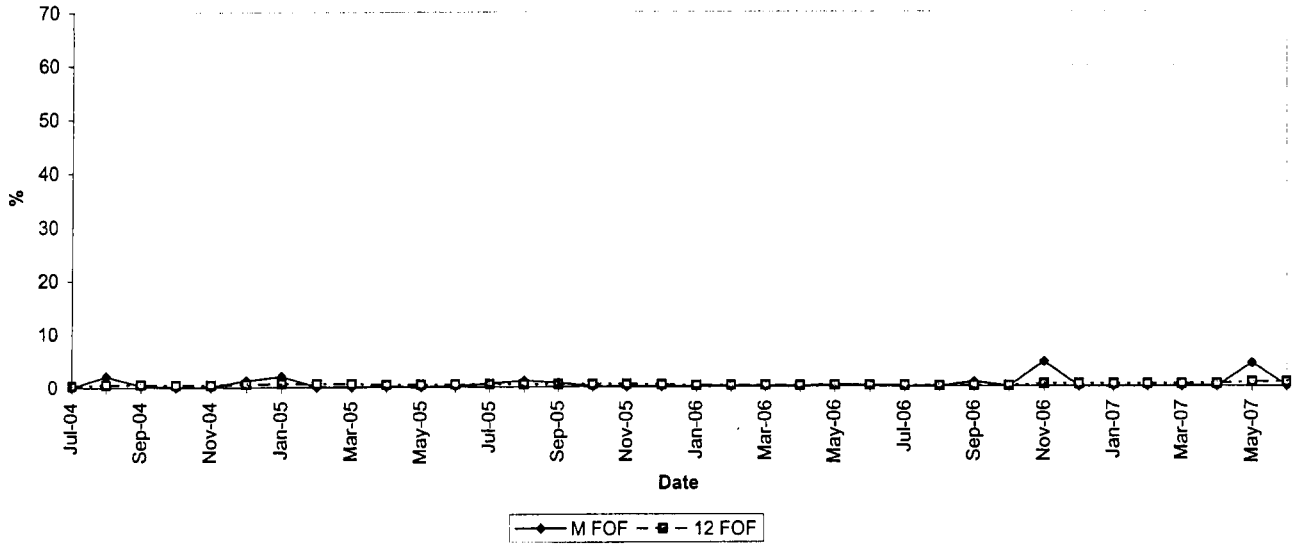
PFL 4
FORCED OUTAGE FACTOR



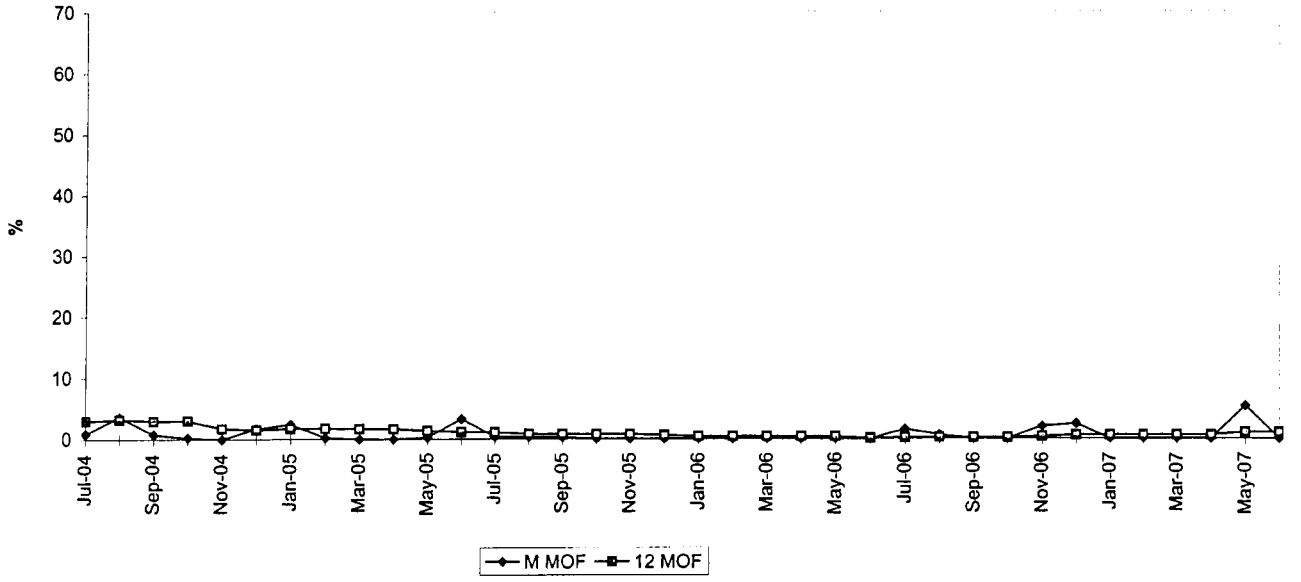
MAINTENANCE OUTAGE FACTOR



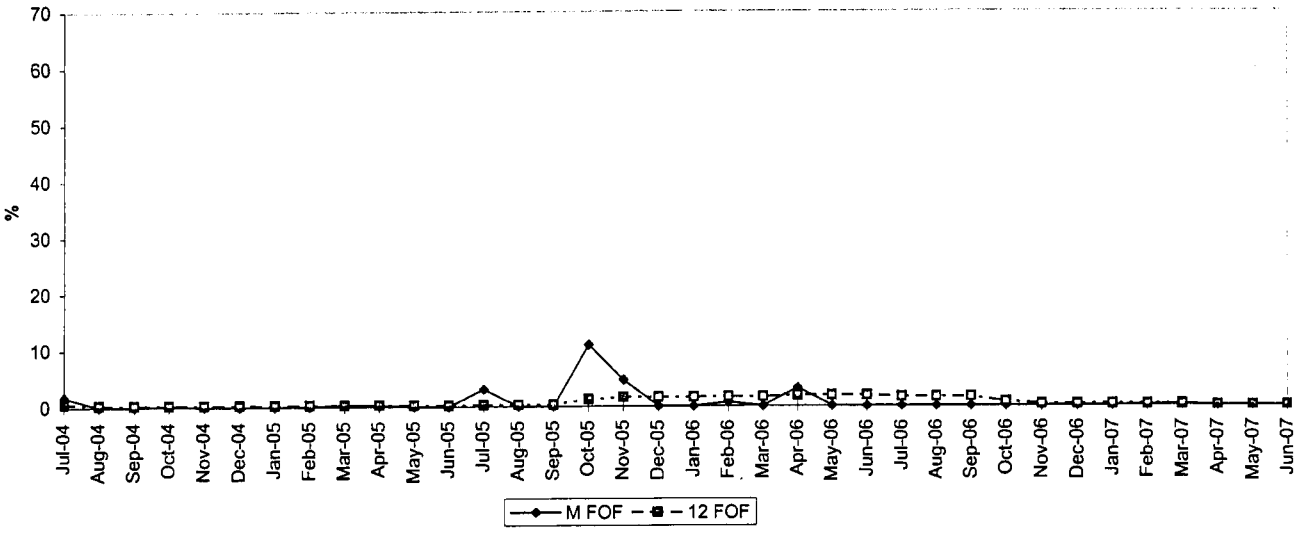
PFL 5
FORCED OUTAGE FACTOR



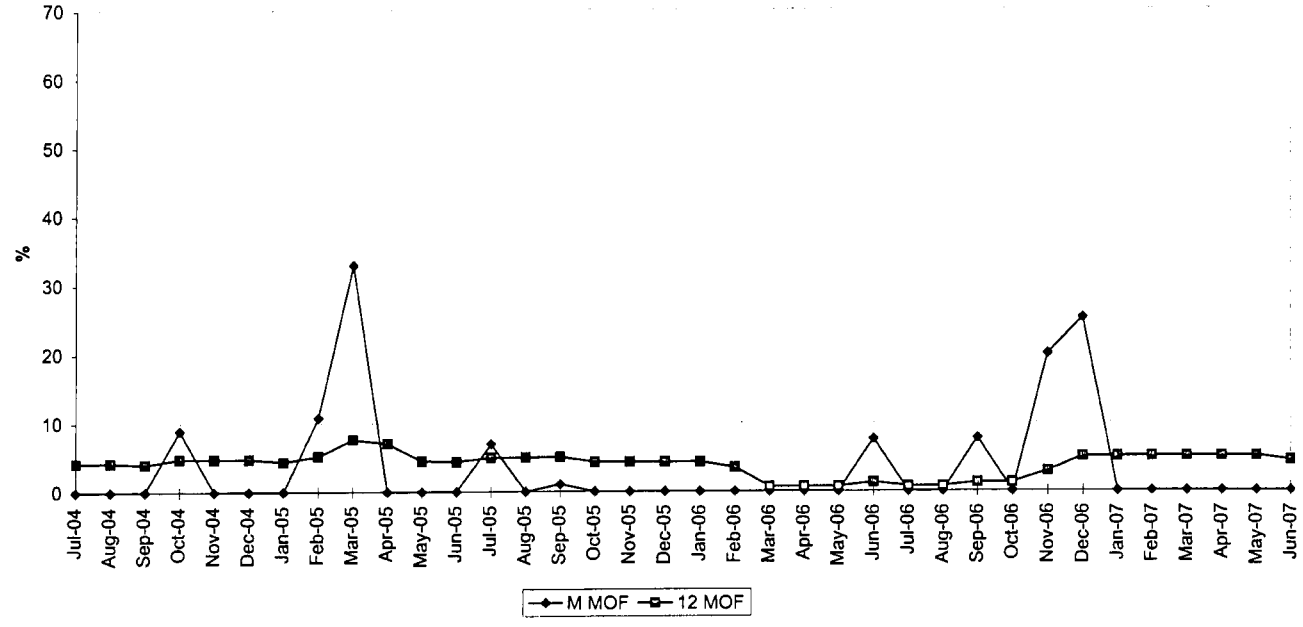
MAINTENANCE OUTAGE FACTOR



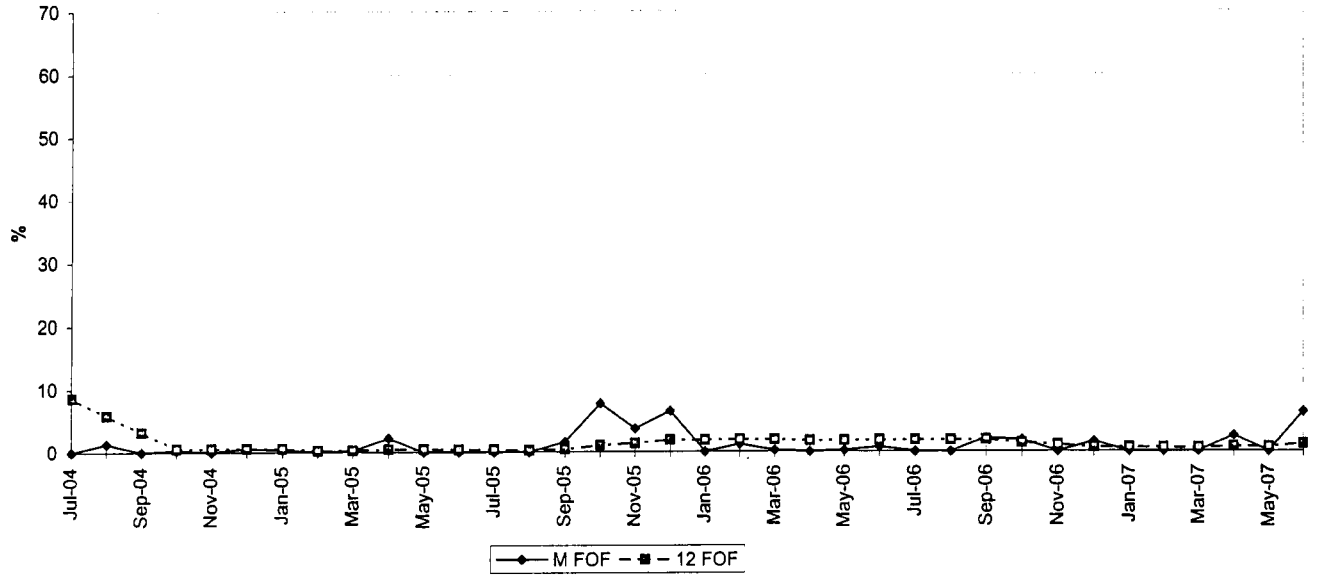
PMR 2
FORCED OUTAGE FACTOR



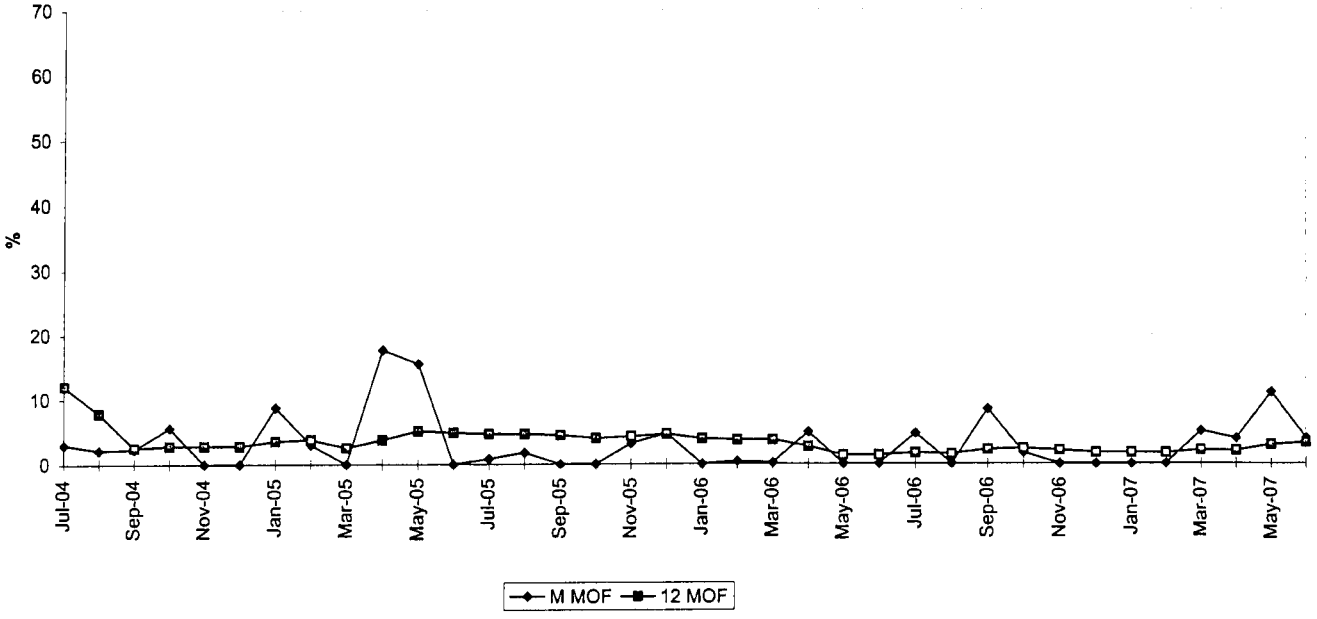
MAINTENANCE OUTAGE FACTOR



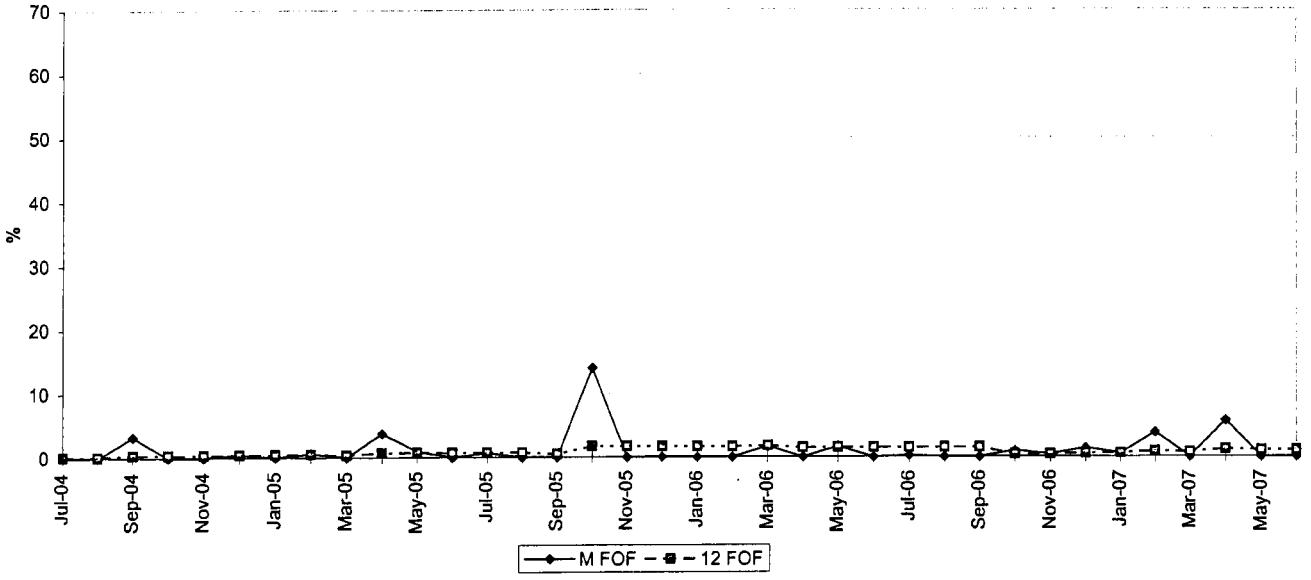
PMG 3
FORCED OUTAGE FACTOR



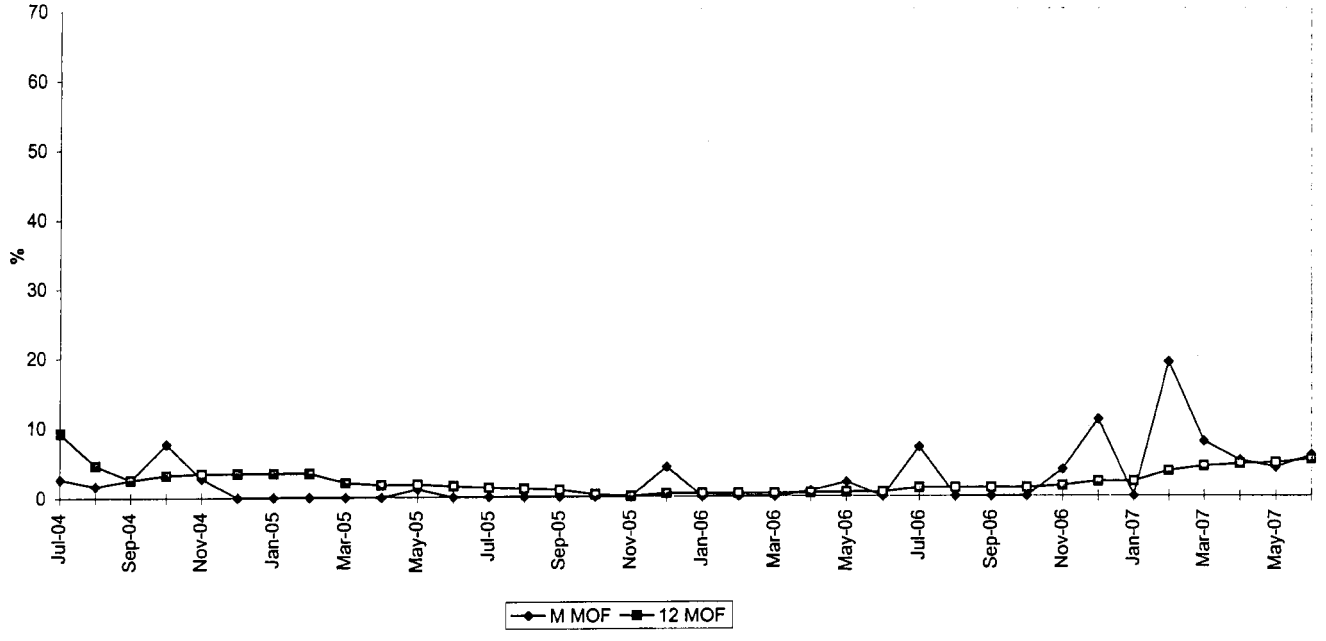
MAINTENANCE OUTAGE FACTOR



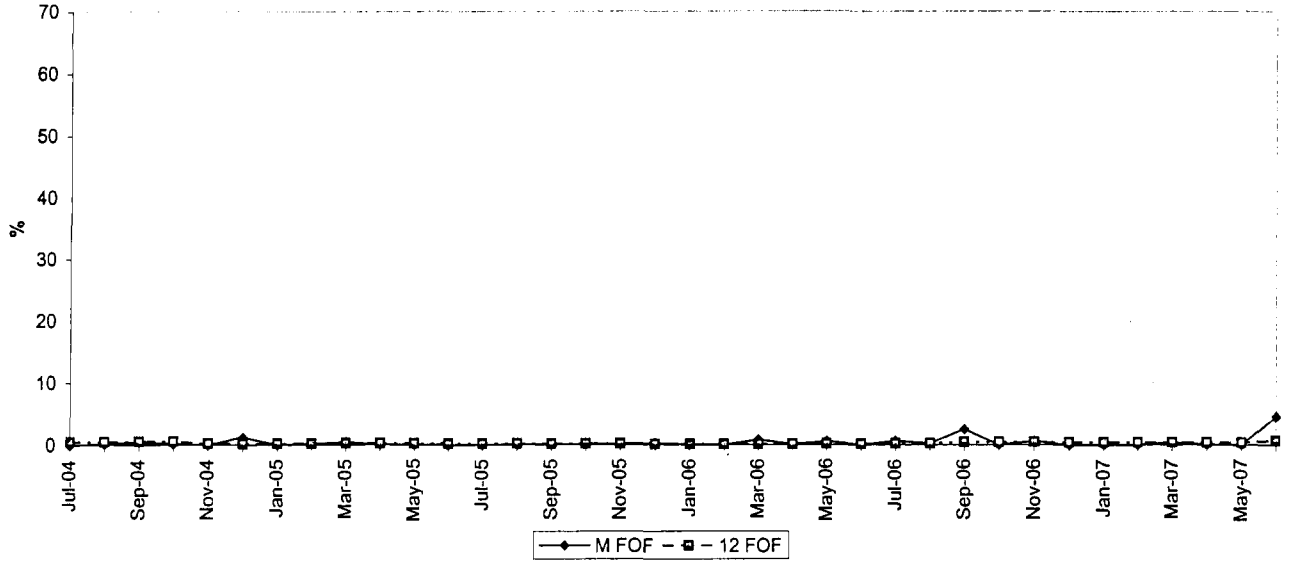
PMG 4
FORCED OUTAGE FACTOR



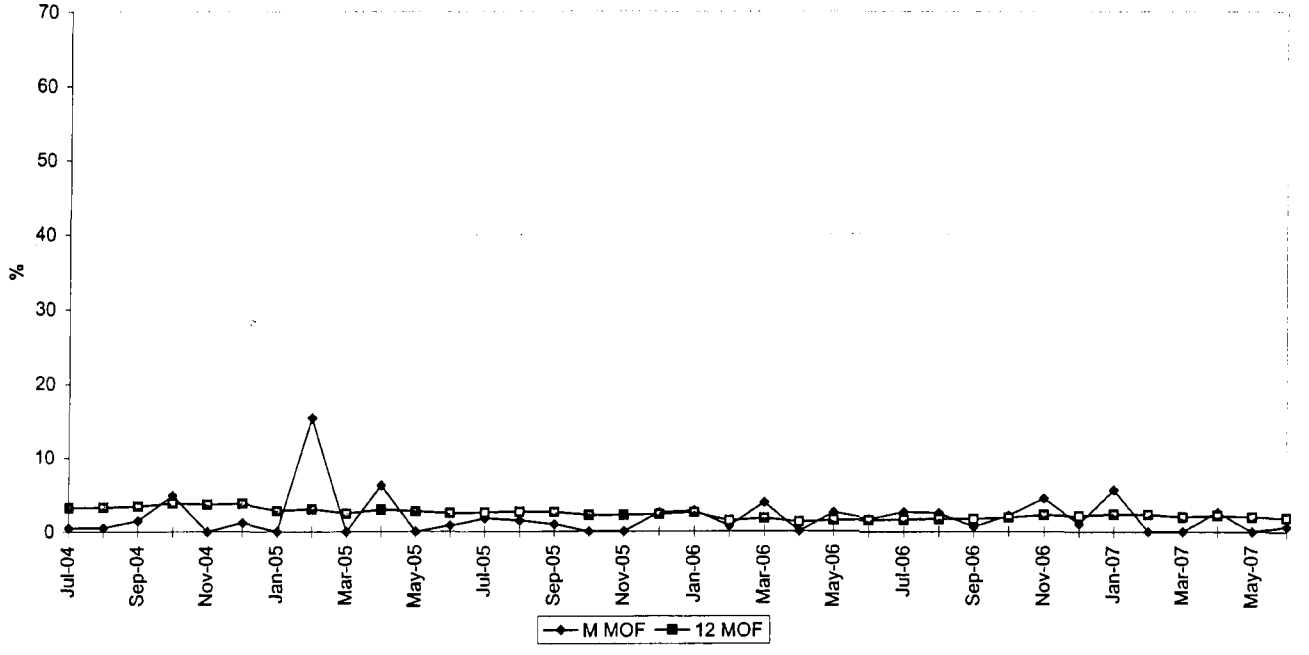
MAINTENANCE OUTAGE FACTOR



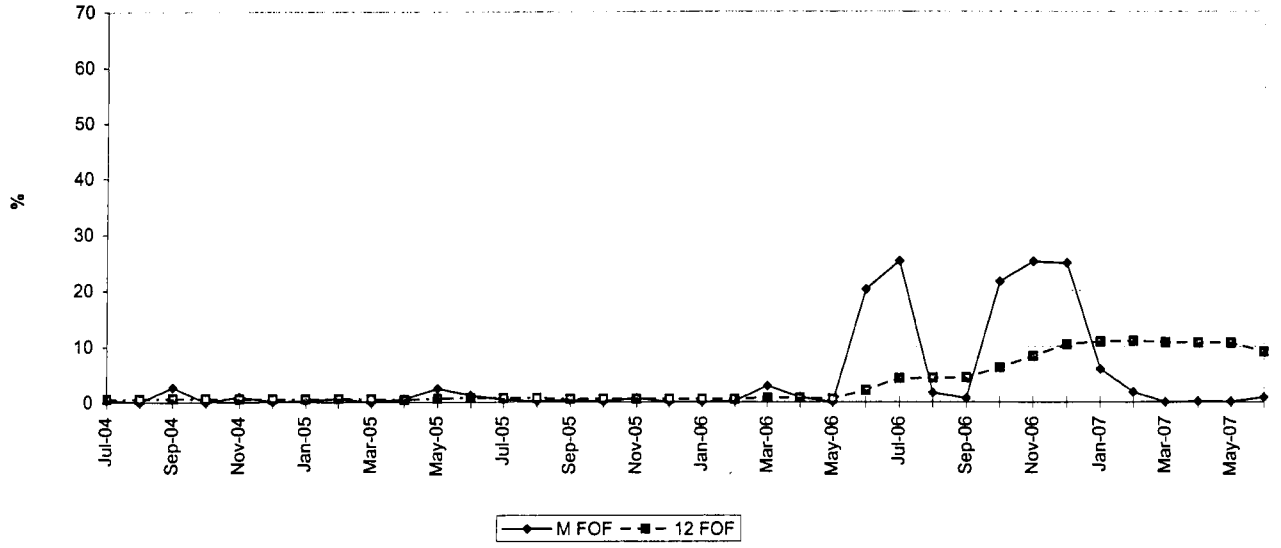
PSN 4
FORCED OUTAGE FACTOR



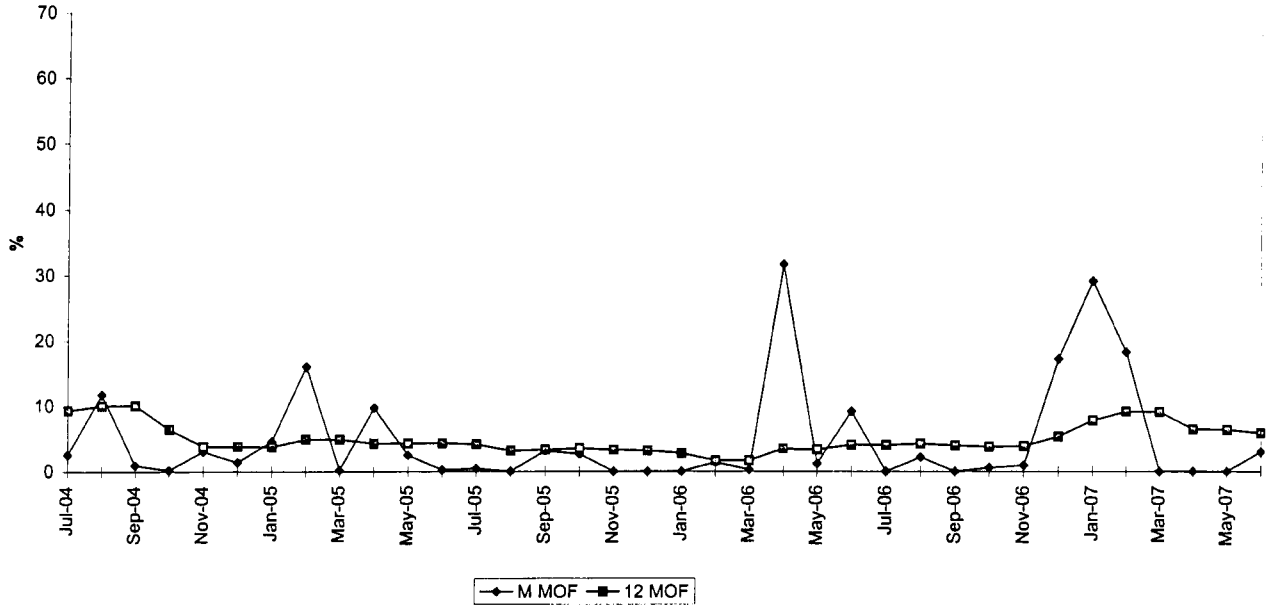
MAINTENANCE OUTAGE FACTOR



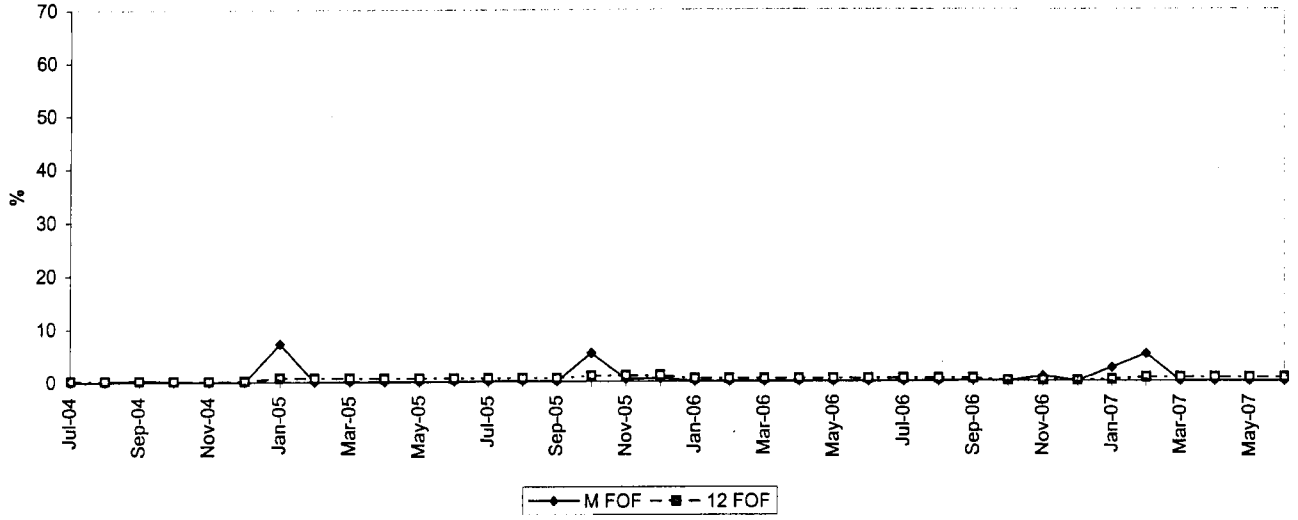
PSN 5
FORCED OUTAGE FACTOR



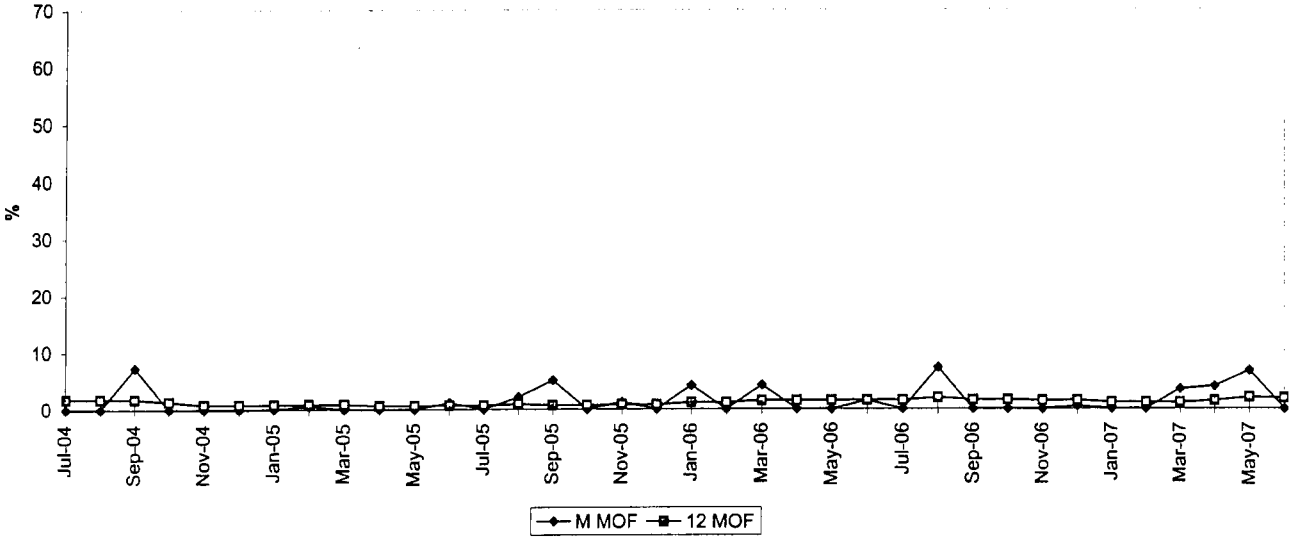
MAINTENANCE OUTAGE FACTOR



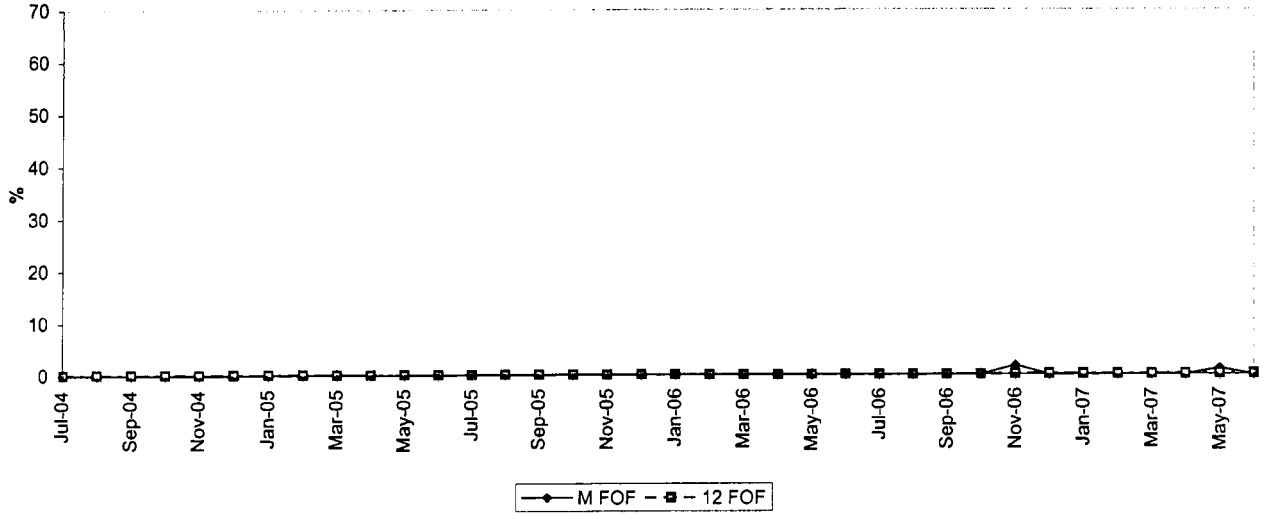
PSG 4
FORCED OUTAGE FACTOR



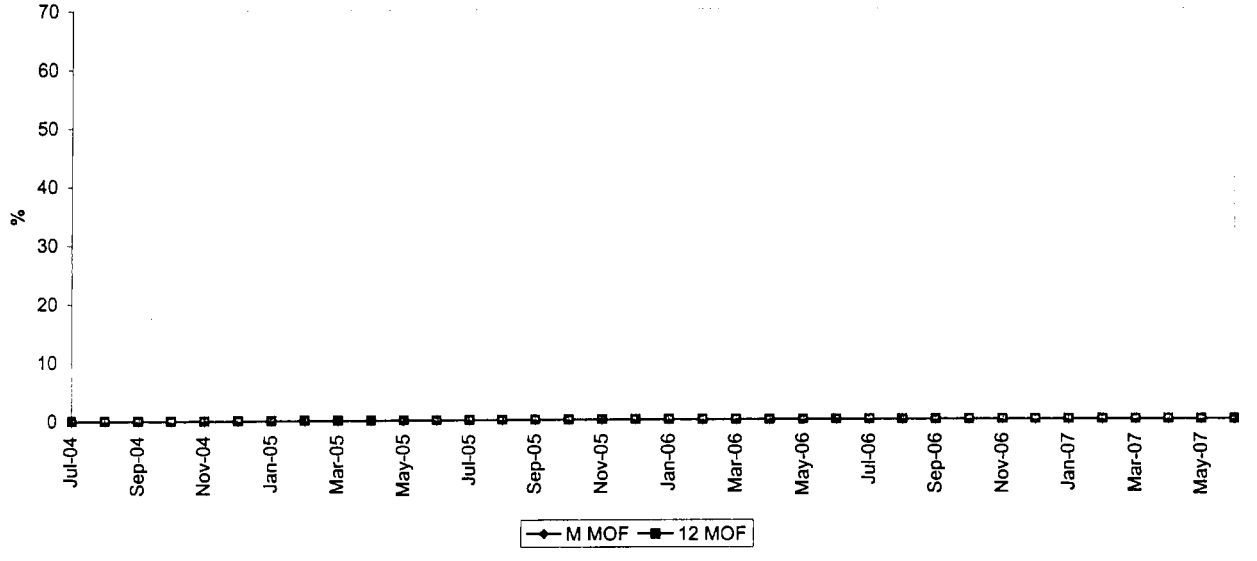
MAINTENANCE OUTAGE FACTOR



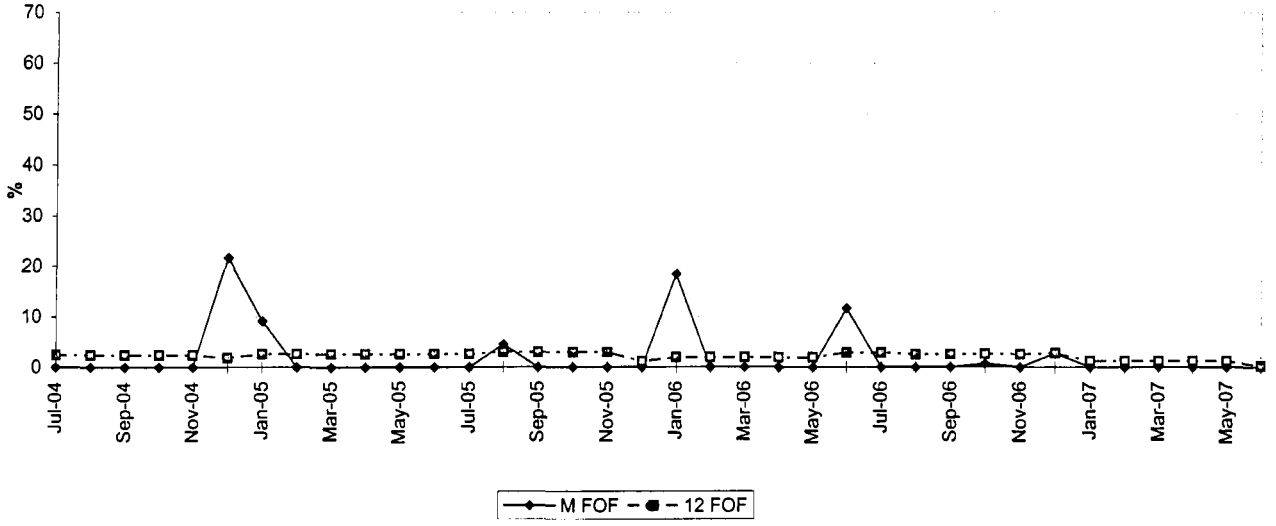
PSL 1
FORCED OUTAGE FACTOR



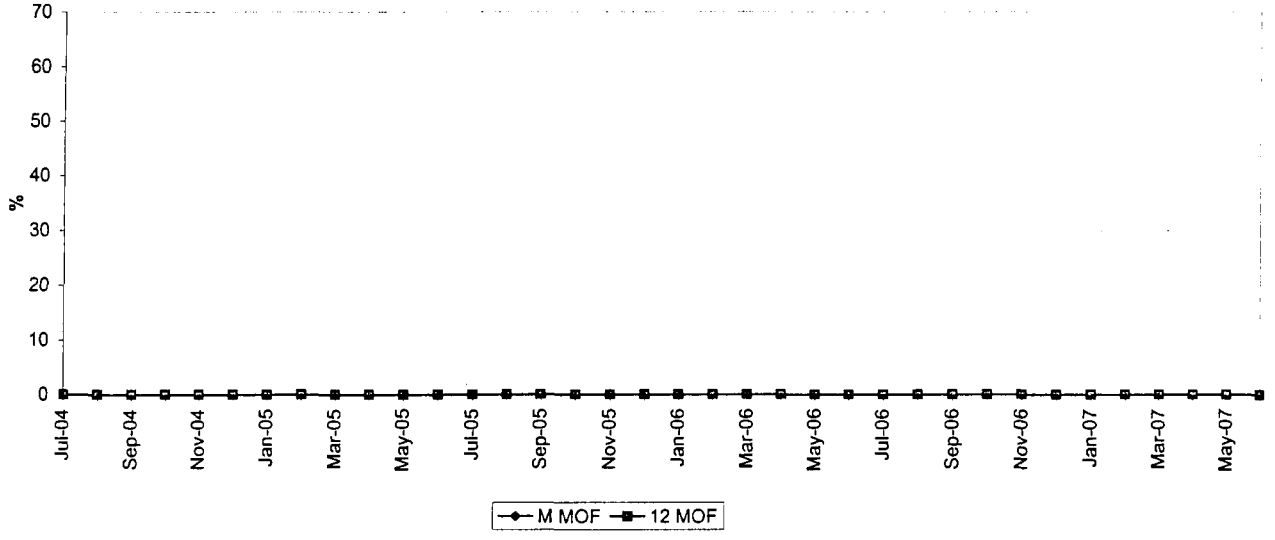
MAINTENANCE OUTAGE FACTOR



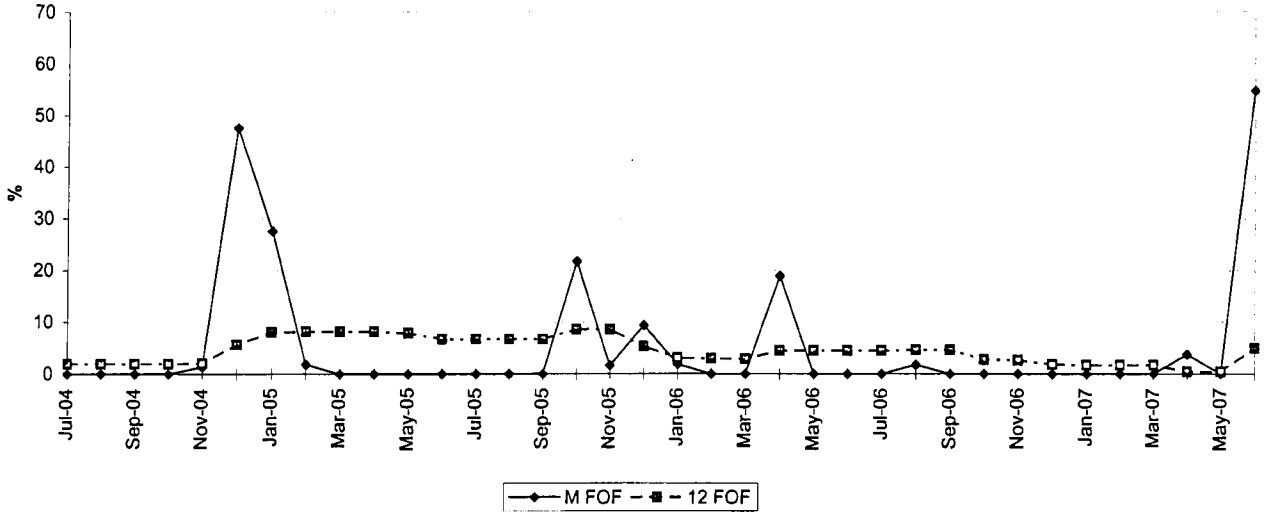
PSL 2
FORCED OUTAGE FACTOR



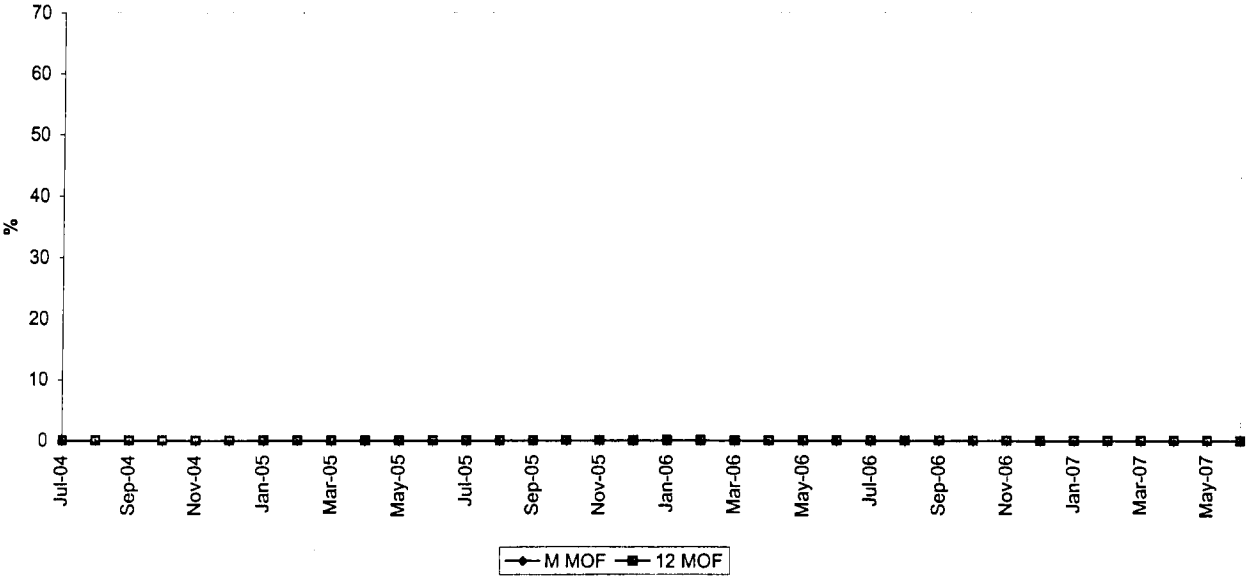
MAINTENANCE OUTAGE FACTOR



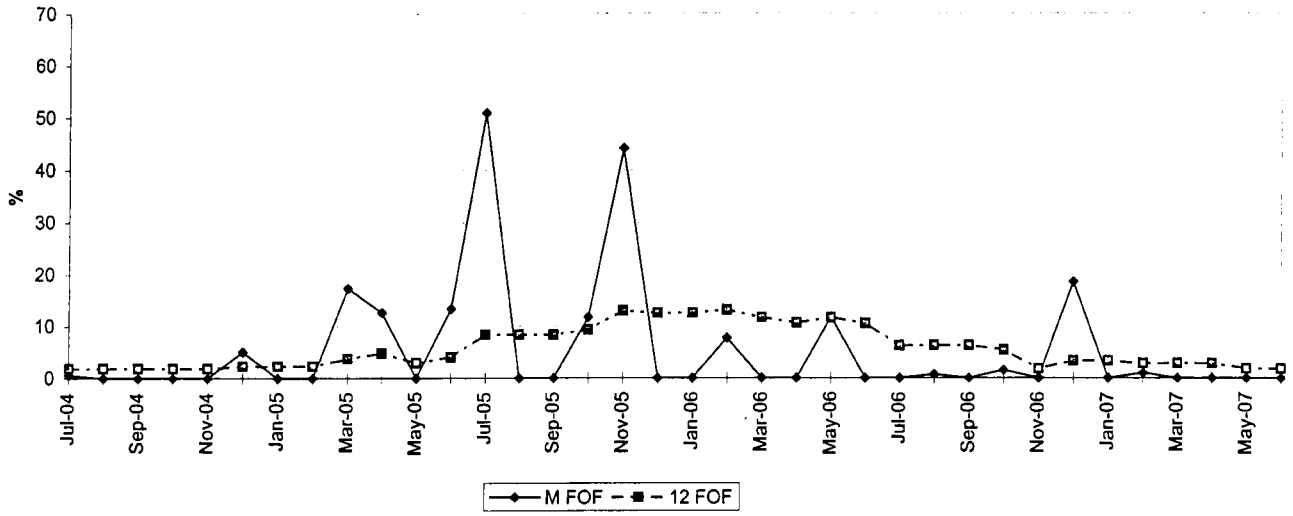
PTN 3
FORCED OUTAGE FACTOR



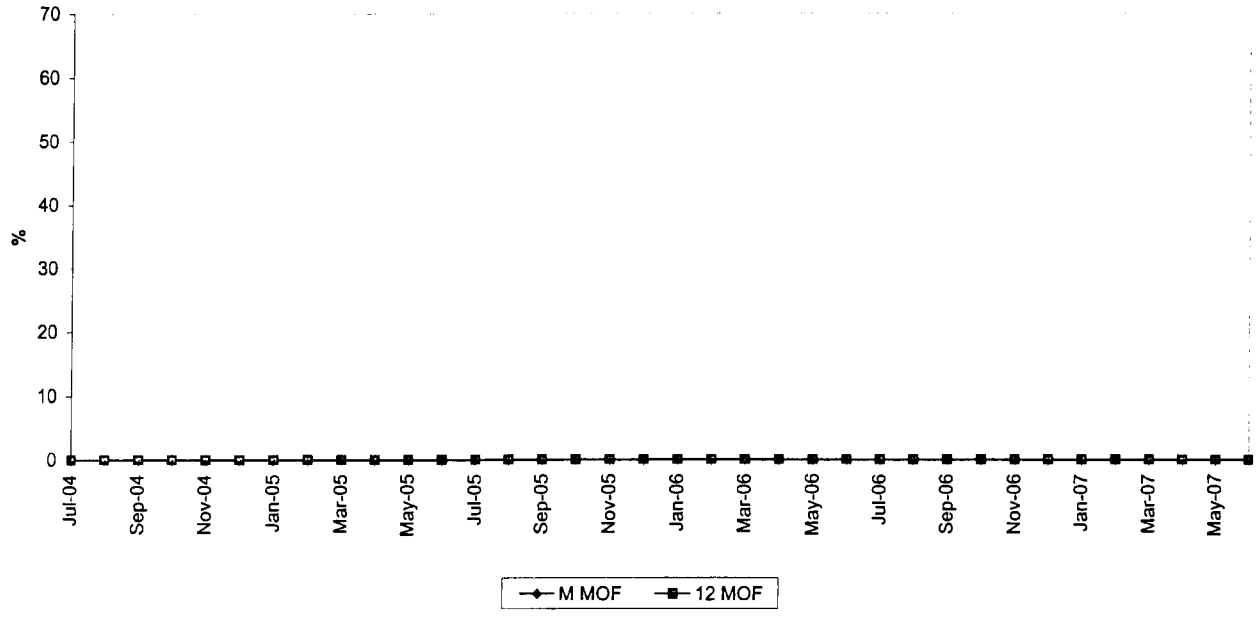
MAINTENANCE OUTAGE FACTOR



PTN 4
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2008

PLANT/UNIT	PLAN OUTAGE*	REASON FOR OUTAGE	LR MW**
Ft. Myers 2	01/12/2008 - 02/06/2008	A CT AND E CT MAJOR - 34% CURTAILMENT	483
Ft. Myers 2	02/09/2008 - 03/05/2008	C CT AND D CT MAJOR - 34% CURTAILMENT	483
Lauderdale 4	03/15/2008 - 03/23/2008	A CT COMBUSTOR INSP. AND B CT HOT GAS PATH INSP. - 100% CURTAILMENT	447
Lauderdale 5	11/01/2008 - 11/14/2008	A CT COMBUSTOR INSP. AND B CT HOT GAS PATH INSP. - 100% CURTAILMENT	447
Martin 2	NONE		
Martin 3	05/17/2008 - 05/23/2009	B CT COMBUSTOR INSP - 50% CURTAILMENT	239
Martin 4	03/01/2008 - 04/18/2008	A CT COMB INSP, B CT HGP, AND STEAM GEN OH - 100% CURTAILMENT	494
Sanford 4	02/02/2008 - 02/08/2008	LP EVAP - 25% CURTAILMENT	239
Sanford 4	02/09/2008 - 02/15/2008	LP EVAP - 25% CURTAILMENT	239
Sanford 4	02/16/2008 - 02/22/2008	LP EVAP - 25% CURTAILMENT	239
Sanford 4	02/23/2008 - 02/29/2008	LP EVAP - 25% CURTAILMENT	239
Sanford 5	02/09/2008 - 02/15/2008	C CT COMBUSTOR INSPECTION - 25% CURTAILMENT	239
Sanford 5	03/22/2008 - 04/04/2008	STEAM GENERATOR VALVES - 100% CURTAILMENT	239
Sanford 5	03/22/2008 - 04/11/2008	A CT/HRSG MAJOR - 25% CURTAILMENT	239
Sanford 5	07/07/2008 - 07/13/2008	B CT COMBUSTOR INSPECTION - 25% CURTAILMENT	240
Sanford 5	09/06/2008 - 09/19/2008	D CT COMBUSTOR INSPECTION - 25% CURTAILMENT	240
Scherer 4	02/02/2008 - 04/23/2008	BOILER/SV/CRV/CV/VENT - 100% CURTAILMENT	652
St. Lucie 1	10/20/2008 - 11/30/2008	REFUELING, REACTOR VESSEL IN-SERVICE INSPECTION, AND REACTOR COOLING POND SEAL REPLACEMENT	853
St. Lucie 2	NONE		
Turkey Point 3	NONE		
Turkey Point 4	03/30/2008 - 05/04/2008	REFUELING AND SPLIT PIN REPLACEMENT	693

*Dates are estimated from breaker open to breaker close

**Load Reduction MW are based on the unit's MW rating during the specified outage period

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 24
COMPANY FL Public Utilities Co.
WITNESS Cheryl Martin (CMM-2)
DATE 11-06-07

FLORIDA PUBLIC UTILITIES COMPANY

Schedule M1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION

ESTIMATED FOR THE PERIOD: JANUARY 2006 - DECEMBER 2006

BASED ON TWELVE MONTHS ACTUAL

MARIANNA DIVISION

			ACTUAL JANUARY 2006	ACTUAL FEBRUARY 2006	ACTUAL MARCH 2006	ACTUAL APRIL 2006	ACTUAL MAY 2006	ACTUAL JUNE 2006	ACTUAL JULY 2006	ACTUAL AUGUST 2006	ACTUAL SEPTEMBER 2006	ACTUAL OCTOBER 2006	ACTUAL NOVEMBER 2006	ACTUAL DECEMBER 2006	Total
Total System Sales - KWH			29,562,352	24,909,037	24,413,482	24,756,095	25,732,093	30,596,141	34,623,228	34,255,425	35,624,818	28,427,870	23,339,935	28,403,744	344,644,220
Total System Purchases - KWH			27,379,744	26,705,114	25,520,327	26,762,533	30,636,387	34,990,035	37,130,081	38,731,829	30,914,235	27,758,617	26,563,904	28,817,035	361,909,841
System Billing Demand - KW			57,440	73,750	45,613	62,137	66,480	73,095	71,860	71,223	60,385	62,902	55,614	71,300	771,799
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	
Demand and Non-Fuel:															
Demand Charge - $/KW			7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	
Customer Charge - $			660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	
Purchased Power Costs:															
Base Fuel Costs			632,472	616,888	589,520	618,215	707,701	808,270	857,705	894,705	714,119	641,224	613,626	665,674	8,360,119
Subtotal Fuel Costs			632,472	616,888	589,520	618,215	707,701	808,270	857,705	894,705	714,119	641,224	613,626	665,674	8,360,119
Demand and Non-Fuel Costs:															
Demand Charge			407,824	523,625	323,852	441,173	472,008	518,974	510,206	505,683	428,733	446,604	394,859	506,230	5,479,771
Customer Charge			660	660	660	660	660	660	660	660	660	660	660	660	7,920
Equipment Rental & Other			3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	45,216
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	446,532
Subtotal Demand & Non-Fuel Costs			449,463	565,264	365,491	482,812	513,647	560,613	551,845	547,322	470,372	488,243	436,498	547,869	5,979,439
Total System Purchased Power Costs			1,081,935	1,182,152	955,011	1,101,027	1,221,348	1,368,883	1,409,550	1,442,027	1,184,491	1,129,467	1,050,124	1,213,543	14,339,558
Special Costs			(326)	2,670	(8,304)	68	15,509	52,701	195	13,313	29,860	510	19,878	27,102	153,176
Total Costs and Charges			1,081,609	1,184,822	946,707	1,101,095	1,236,857	1,421,584	1,409,745	1,455,340	1,214,351	1,129,977	1,070,002	1,240,645	14,492,734
Sales Revenues - Fuel Adjustment Revenues:															
Residential	RS	.04526	657,537	526,746	488,457	455,423	459,968	597,328	712,271	700,502	713,725	515,625	420,331	589,809	6,837,722
Commercial, Small	GS	.04471	108,817	89,850	92,865	94,492	102,172	121,871	137,752	136,433	143,917	117,237	91,580	101,287	1,338,273
Commercial, Large	GSD	.04275	308,363	271,494	280,456	301,157	319,422	360,980	394,001	393,242	416,616	351,120	275,924	299,454	3,972,229
Industrial	GSLD	.04099	203,144	184,016	186,895	209,508	220,677	237,797	252,499	249,980	264,899	236,455	209,693	232,374	2,687,937
Outside Lighting Private	OL,OL-2	.03546	11,669	11,565	11,620	11,664	11,736	11,750	11,787	11,809	11,782	11,842	12,023	11,960	141,207
Street Lighting-Public	SL-1, 2, 3	.03553	3,547	3,339	3,365	3,361	3,358	3,367	3,366	3,366	3,373	3,371	3,360	3,358	40,531
Total Fuel Revenues			1,293,077	1,087,010	1,063,658	1,075,605	1,117,333	1,333,093	1,511,676	1,495,332	1,554,312	1,235,650	1,012,911	1,238,242	15,017,899
Non-Fuel Revenues			722,986	646,744	635,696	628,948	637,215	718,079	781,843	780,651	796,241	682,058	610,275	695,296	8,336,032
Total Sales Revenue			2,016,063	1,733,754	1,699,354	1,704,553	1,754,548	2,051,172	2,293,519	2,275,983	2,350,553	1,917,708	1,623,186	1,933,538	23,353,931
KWH Sales:															
Residential	RS		14,529,729	11,638,875	10,793,731	10,062,946	10,165,431	13,198,454	15,738,205	15,478,432	15,770,326	11,393,132	9,287,557	13,032,294	151,089,112
Commercial, Small	GS		2,434,000	2,009,711	2,077,138	2,113,535	2,285,305	2,725,948	3,081,146	3,051,677	3,219,053	2,623,637	2,048,407	2,265,526	29,935,083
Commercial, Large	GSD		7,213,445	6,350,857	6,560,489	7,044,742	7,471,987	8,444,121	9,216,559	9,198,831	9,745,564	8,213,479	6,454,463	7,004,902	92,919,439
Industrial	GSLD		4,955,884	4,489,232	4,559,488	5,111,112	5,383,628	5,801,264	6,159,944	6,098,472	6,462,464	5,768,552	5,115,648	5,669,000	65,574,688
Outside Lighting-Private	OL,OL-2		329,476	326,392	327,929	329,177	331,221	331,599	332,640	333,259	332,498	334,188	339,298	337,522	3,985,199
Street Lighting-Public	SL-1, 2, 3		99,818	93,970	94,707	94,583	94,521	94,755	94,734	94,754	94,913	94,882	94,562	94,500	1,140,699
Total KWH Sales			29,562,352	24,909,037	24,413,482	24,756,095	25,732,093	30,596,141	34,623,228	34,255,425	35,624,818	28,427,870	23,339,935	28,403,744	344,644,220
True-up Calculation:															to Date
Fuel Revenues			1,293,077	1,087,010	1,063,658	1,075,605	1,117,333	1,333,093	1,511,676	1,495,332	1,554,312	1,235,650	1,012,911	1,238,242	15,017,899
True-up Provision for the Period - collect/(refund)			61,856	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	742,173
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			1,231,221	1,025,163	1,001,811	1,013,758	1,055,486	1,271,246	1,449,829	1,433,485	1,492,465	1,173,803	951,064	1,176,395	14,275,726
Total Purchased Power Costs			1,081,609	1,184,822	946,707	1,101,095	1,236,857	1,421,584	1,409,745	1,455,340	1,214,351	1,129,977	1,070,002	1,240,645	14,492,734
True-up Provision for the Period			149,612	(159,659)	55,104	(87,337)	(181,371)	(150,338)	40,084	(21,855)	278,114	43,826	(118,938)	(64,250)	(217,008)
Interest Provision for the Period			(2,336)	(2,192)	(2,229)	(2,155)	(2,516)	(3,057)	(3,145)	(2,838)	(1,991)	(1,022)	(918)	(1,053)	(25,452)
True-up and Interest Provision															
Beginning of Period			(742,173)	(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(660,770)	(623,616)	(285,646)	(180,995)	(239,004)	(742,173)
True-up Collected or (Refunded)			61,856	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	742,173
End of Period, Net True-up			(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(660,770)	(623,616)	(285,646)	(180,995)	(239,004)	(242,460)	(242,460)
10% Rule - Interest Provision:															-1.69%
Beginning True-up Amount			(742,173)	(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(660,770)	(623,616)	(285,646)	(180,995)	(239,004)	
Ending True-up Amount Before Interest			(530,705)	(630,853)	(516,094)	(543,813)	(665,492)	(756,499)	(657,625)	(620,778)	(283,655)	(179,973)	(238,086)	(241,407)	
Total Beginning and Ending True-up			(1,272,878)	(1,163,894)	(1,149,139)	(1,062,136)	(1,211,460)	(1,424,507)	(1,417,181)	(1,281,548)	(907,271)	(465,619)	(419,081)	(480,411)	
Average True-up Amount			(636,439)	(581,947)	(574,570)	(531,068)	(605,730)	(712,254)	(708,591)	(640,774)	(453,636)	(232,810)	(209,541)	(240,206)	
Average Annual Interest Rate			4.4050%	4.5200%	4.6550%	4.8700%	4.9850%	5.1500%	5.3250%	5.3150%	5.2650%	5.2650%	5.2600%	5.2600%	
Monthly Average Interest Rate			0.3671%	0.3767%	0.3879%	0.4058%	0.4154%	0.4292%	0.4438%	0.4429%	0.4388%	0.4388%	0.4383%	0.4383%	
Interest Provision			(2,336)	(2,192)	(2,229)	(2,155)	(2,516)	(3,057)	(3,145)	(2,838)	(1,991)	(1,022)	(918)	(1,053)	

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 1 of 4

Schedule F1

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD

ESTIMATED FOR THE PERIOD: JANUARY 2006 THROUGH DECEMBER 2006

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH

	ACTUAL Jan 2006	ACTUAL Feb 2006	ACTUAL Mar 2006	ACTUAL Apr 2006	ACTUAL May 2006	ACTUAL Jun 2006	ACTUAL Jul 2006	ACTUAL Aug 2006	ACTUAL Sep 2006	ACTUAL Oct 2006	ACTUAL Nov 2006	ACTUAL Dec 2006	Total
Total System Sales - KWH	39,553,556	45,657,322	40,110,866	35,551,139	40,536,947	42,873,390	52,739,089	48,095,515	48,782,950	41,540,251	32,656,416	35,976,105	504,073,546
JSC Purchases - KWH	240,000	610,000	100,000	270,000	230,000	160,000	260,000	390,000	360,000	280,000	490,000	480,000	3,870,000
JEA Purchases - KWH	39,217,068	45,873,328	39,637,662	36,746,326	46,801,092	47,892,666	54,123,921	53,611,577	44,433,457	39,826,068	33,679,228	35,119,470	516,961,863
System Billing Demand - KW	77,549	123,603	75,622	70,157	82,611	83,731	87,763	88,301	77,146	66,842	71,098	72,352	976,775
Purchased Power Rates:													
CCA Fuel Costs - $/KWH	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	
Fuel Adjustment - $/KWH	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:													
Demand Charge - $/KW	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	
Purchased Power Costs: CCA Fuel Costs	4,488	11,407	1,870	5,049	4,301	2,992	4,862	7,293	6,732	5,236	9,163	8,976	72,369
JEA Base Fuel Costs	700,417	819,298	707,929	656,289	835,868	855,363	966,653	957,503	793,582	711,294	601,511	627,234	9,232,941
JEA Fuel Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Fuel Costs	704,905	830,705	709,799	661,338	840,169	858,355	971,515	964,796	800,314	716,530	610,674	636,210	9,305,310
Demand and Non-Fuel Cc Demand Charge	465,294	741,618	453,731	420,942	495,665	502,386	526,578	529,806	462,875	401,051	426,588	434,112	5,860,646
Customer Charge	225	225	225	225	225	225	225	225	225	225	225	225	2,700
Energy Charge	64,316	75,232	65,006	60,264	76,754	78,544	88,763	87,923	72,871	65,315	55,234	57,596	847,818
Subtotal Demand & Non-Fuel Costs	529,835	817,075	518,962	481,431	572,644	581,155	615,566	617,954	535,971	466,591	482,047	491,933	6,711,164
Total System Purchased Power Costs	1,234,740	1,647,780	1,228,761	1,142,769	1,412,813	1,439,510	1,587,081	1,582,750	1,336,285	1,183,121	1,092,721	1,128,143	16,016,474
Less Direct Billing To GSLD Class: Demand	67,442	233,433	140,836	88,332	85,082	90,875	75,783	59,705	56,178	49,037	84,110	67,035	1,097,848
Commodity	237,357	402,326	301,371	252,003	305,231	255,247	278,786	277,234	237,320	234,220	191,785	227,794	3,200,674
Net Purchased Power Costs	929,941	1,012,021	786,554	802,434	1,022,500	1,093,388	1,232,512	1,245,811	1,042,787	899,864	816,826	833,314	11,717,952
Special Costs	(239)	2,751	(8,197)	177	29,064	52,805	846	13,337	29,937	571	19,933	52,077	193,062
Total Costs and Charges	929,702	1,014,772	778,357	802,611	1,051,564	1,146,193	1,233,358	1,259,148	1,072,724	900,435	836,759	885,391	11,911,014
Sales Revenues - Fuel Adjustment Revenues:													
RS 0.03285	548,936	498,956	469,432	406,341	453,614	577,258	773,635	680,156	728,695	544,350	396,989	452,846	6,531,208
GS 0.03214	73,678	67,404	68,616	66,595	73,082	84,775	101,992	92,991	100,699	86,922	69,881	69,194	955,829
GSD 0.03091	193,435	183,662	192,842	192,344	215,342	227,818	292,097	249,148	278,566	250,767	203,956	194,294	2,674,271
GSLD 0.02996	69,088	65,999	67,747	64,839	63,346	70,031	73,294	72,226	72,452	68,184	59,991	65,166	812,363
OL 0.02261	2,714	2,411	2,031	2,301	2,375	2,391	2,449	2,393	2,404	2,406	2,424	2,431	28,730
SL,CSL 0.02301	1,511	1,509	1,513	1,513	1,518	1,536	1,538	1,543	1,543	1,545	1,545	1,547	18,361
Total Fuel Revenues (Excl. GSLD1)	889,362	819,941	802,181	733,933	809,277	963,809	1,245,005	1,098,457	1,184,359	954,174	734,786	785,478	11,020,762
GSLD1 Fuel Revenues	304,799	635,759	442,207	340,335	390,313	346,122	354,569	336,939	293,498	283,257	275,895	294,829	4,298,522
Non-Fuel Revenues	712,872	729,996	698,707	641,269	683,434	749,621	880,185	815,672	848,356	731,755	628,576	658,861	8,779,304
Total Sales Revenue	1,907,033	2,185,696	1,943,095	1,715,537	1,883,024	2,059,552	2,479,759	2,251,068	2,326,213	1,969,186	1,639,257	1,739,168	24,098,588
KWH Sales: RS	16,710,810	15,190,803	14,293,219	12,370,970	13,810,192	17,574,479	23,553,160	20,707,190	22,184,963	16,572,622	12,086,297	13,786,776	198,841,481
GS	2,292,994	2,097,534	2,136,621	2,072,217	2,274,095	2,637,914	3,173,681	2,893,595	3,133,456	2,704,768	2,174,458	2,153,096	29,744,429
GSD	6,255,947	5,944,040	6,239,276	6,223,158	6,967,244	7,370,920	9,450,622	8,061,020	9,012,785	8,113,392	6,598,855	6,286,235	86,523,494
GSLD	2,306,140	2,203,020	2,261,380	2,164,280	2,114,440	2,337,620	2,446,520	2,410,880	2,418,440	2,275,960	2,002,480	2,175,200	27,116,360
GSLD1	11,820,000	20,050,000	15,010,000	12,550,000	15,200,000	12,780,000	13,940,000	13,850,000	11,860,000	11,700,000	9,620,000	11,400,000	159,780,000
OL	102,008	106,349	104,609	104,753	105,014	105,701	108,269	105,788	106,264	106,354	107,171	107,562	1,269,842
SL,CSL	65,657	65,576	65,761	65,761	65,962	66,756	66,837	67,042	67,042	67,155	67,155	67,236	797,940
Total KWH Sales	39,553,556	45,657,322	40,110,866	35,551,139	40,536,947	42,873,390	52,739,089	48,095,515	48,782,950	41,540,251	32,656,416	35,976,105	504,073,546
True-up Calculation (Excl. GSLD1):													
Fuel Revenues	889,362	819,941	802,181	733,933	809,277	963,809	1,245,005	1,098,457	1,184,359	954,174	734,786	785,478	11,020,762
True-up Provision - collect/(refund)	(23,599)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(283,221)
Gross Receipts Tax Refund	0	0	0	0	0	0	0		0				0
Fuel Revenue	912,961	843,543	825,783	757,535	832,879	987,411	1,268,607	1,122,059	1,207,961	977,776	758,388	809,080	11,303,983
Net Purchased Power and Other Fuel Costs	929,702	1,014,772	778,357	802,611	1,051,564	1,146,193	1,233,358	1,259,148	1,072,724	900,435	836,759	885,391	11,911,014
True-up Provision for the Period	(16,741)	(171,229)	47,426	(45,076)	(218,685)	(158,782)	35,249	(137,089)	135,237	77,341	(78,371)	(76,311)	(607,031)
Interest Provision for the Period	966	552	238	159	(482)	(1,411)	(1,845)	(2,179)	(2,276)	(1,923)	(2,035)	(2,487)	(12,723)
Beginning of Period True-up and Interest Provision	283,221	243,847	49,568	73,630	5,111	(237,658)	(421,453)	(411,651)	(574,521)	(465,162)	(413,346)	(517,354)	283,221
True-up Collected or (Refunded)	(23,599)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(283,221)
End of Period, Net True-up and Int. Prov.	243,847	49,568	73,630	5,111	(237,658)	(421,453)	(411,651)	(574,521)	(465,162)	(413,346)	(517,354)	(619,754)	(619,754)
Beginning True-up Amount	283,221	243,847	49,568	73,630	5,111	(237,658)	(421,453)	(411,651)	(574,521)	(465,162)	(413,346)	(517,354)	
Ending True-up Amount Before Interest	242,881	49,016	73,392	4,952	(237,176)	(420,042)	(409,806)	(572,342)	(462,886)	(411,423)	(515,319)	(617,267)	10% Rule Interest Provision: -3.87%
Total Beginning and Ending True-up	526,102	292,863	122,960	78,582	(232,065)	(657,700)	(831,259)	(983,993)	(1,037,407)	(876,585)	(928,665)	(1,134,621)	
Average True-up Amount	263,051	146,432	61,480	39,291	(116,033)	(328,850)	(415,630)	(491,997)	(518,704)	(438,293)	(464,333)	(567,311)	
Average Annual Interest Rate	4.4050%	4.5200%	4.6550%	4.8700%	4.9850%	5.1500%	5.3250%	5.3150%	5.2650%	5.2650%	5.2600%	5.2600%	
Interest Provision	966	552	238	159	(482)	(1,411)	(1,845)	(2,179)	(2,276)	(1,923)	(2,035)	(2,487)	

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 2 of 4

Schedule E1-B

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD: JANUARY 2006 - DECEMBER 2006
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

MARIANNA DIVISION			ACTUAL JANUARY 2006	ACTUAL FEBRUARY 2006	ACTUAL MARCH 2006	ACTUAL APRIL 2006	ACTUAL MAY 2006	ACTUAL JUNE 2006	Estimated JULY 2006	Estimated AUGUST 2006	Estimated SEPTEMBER 2006	Estimated OCTOBER 2006	Estimated NOVEMBER 2006	Estimated DECEMBER 2006	Total
Total System Sales - KWH			29,562,352	24,909,037	24,413,482	24,756,095	25,732,093	30,596,141	32,258,200	31,570,600	30,086,600	26,930,000	23,833,900	25,641,200	330,289,700
Total System Purchases - KWH			27,379,744	26,705,114	25,520,327	26,762,533	30,636,387	34,990,035	34,009,915	34,484,049	29,636,857	26,125,396	24,802,581	31,542,814	352,595,752
System Billing Demand - KW			57,440	73,750	45,613	62,137	66,480	73,095	65,932	67,517	62,934	50,673	48,443	63,342	737,356
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	0.02310	
Demand and Non-Fuel:															
Demand Charge - $/KW			7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	
Customer Charge - $			660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	660.00	
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	
Purchased Power Costs:															
Base Fuel Costs			632,472	616,888	589,520	618,215	707,701	808,270	785,629	796,582	684,611	603,497	572,940	728,639	8,144,964
Subtotal Fuel Costs			632,472	616,888	589,520	618,215	707,701	808,270	785,629	796,582	684,611	603,497	572,940	728,639	8,144,964
Demand and Non-Fuel Costs:															
Demand Charge			407,824	523,625	323,852	441,173	472,008	518,974	468,116	479,370	446,830	359,777	343,944	449,727	5,235,220
Customer Charge			660	660	660	660	660	660	660	660	660	660	660	660	7,920
Equipment Rental & Other			3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	45,216
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	446,532
Subtotal Demand & Non-Fuel Costs			449,463	565,264	365,491	482,812	513,647	560,613	509,755	521,009	488,469	401,416	385,583	491,366	5,734,888
Total System Purchased Power Costs			1,081,935	1,182,152	955,011	1,101,027	1,221,348	1,368,883	1,295,384	1,317,591	1,173,080	1,004,913	958,523	1,220,005	13,879,852
Special Costs			(326)	2,670	(8,304)	68	15,509	52,701							62,318
Total Costs and Charges			1,081,609	1,184,822	946,707	1,101,095	1,236,857	1,421,584	1,295,384	1,317,591	1,173,080	1,004,913	958,523	1,220,005	13,942,170
Sales Revenues - Fuel Adjustment Revenues															
Residential	RS	0.04526	657,537	526,746	488,457	455,423	459,968	597,328	639,995	628,222	589,258	505,654	412,368	500,666	6,461,622
Commercial,Small	GS	0.04471	108,817	89,850	92,865	94,492	102,172	121,871	133,948	130,513	123,206	113,515	99,496	98,564	1,309,309
Commercial, Large	GSD	0.04275	308,363	271,494	280,456	301,157	319,422	360,980	393,521	393,672	372,738	356,739	325,675	321,603	4,005,820
Industrial	GSLD	0.04099	203,144	184,016	186,895	209,508	220,677	237,797	225,703	211,254	212,357	182,901	183,213	181,918	2,439,383
Outside Lighting Private	OL,OL-2	0.03546	11,669	11,565	11,620	11,664	11,736	11,750	11,485	11,432	11,546	11,553	11,471	11,588	139,079
Street Lighting, Public	SL-1,SL-2,SL-3	0.03553	3,547	3,339	3,365	3,361	3,358	3,367	3,073	3,066	3,063	3,063	3,059	3,088	38,749
Total Fuel Revenues			1,293,077	1,087,010	1,063,658	1,075,605	1,117,333	1,333,093	1,407,725	1,378,159	1,312,168	1,173,425	1,035,282	1,117,427	14,393,962
Non-Fuel Revenues			722,986	646,744	635,696	628,948	637,215	718,079	658,275	655,241	627,232	568,375	522,118	580,573	7,601,482
Total Sales Revenue			2,016,063	1,733,754	1,699,354	1,704,553	1,754,548	2,051,172	2,066,000	2,033,400	1,939,400	1,741,800	1,557,400	1,698,000	21,995,444
KWH Sales:															
Residential	RS		14,529,729	11,638,875	10,793,731	10,062,946	10,165,431	13,198,454	14,140,400	13,880,300	13,019,400	11,172,200	9,111,100	11,062,000	142,774,566
Commercial	GS		2,434,000	2,009,711	2,077,138	2,113,535	2,285,305	2,725,948	2,995,940	2,919,100	2,755,680	2,538,920	2,225,360	2,204,520	29,285,157
Commercial	GSD		7,213,445	6,350,857	6,560,489	7,044,742	7,471,987	8,444,121	9,205,160	9,208,700	8,719,020	8,344,780	7,618,140	7,522,880	93,704,321
Industrial	GSLD		4,955,884	4,489,232	4,559,488	5,111,112	5,383,628	5,801,264	5,506,300	5,153,800	5,180,700	4,462,100	4,469,700	4,438,100	59,511,308
Residential	OL,OL-2		329,476	326,392	327,929	329,177	331,221	331,599	323,900	322,400	325,600	325,800	323,500	326,800	3,923,794
Other	SL-1,SL-2,SL-3		99,818	93,970	94,707	94,583	94,521	94,755	86,500	86,300	86,200	86,200	86,100	86,900	1,090,554
Total KWH Sales			29,562,352	24,909,037	24,413,482	24,756,095	25,732,093	30,596,141	32,258,200	31,570,600	30,086,600	26,930,000	23,833,900	25,641,200	330,289,700
True-up Calculation:															to Date
Fuel Revenues			1,293,077	1,087,010	1,063,658	1,075,605	1,117,333	1,333,093	1,407,725	1,378,159	1,312,168	1,173,425	1,035,282	1,117,427	14,393,962
True-up Provision for the Period - collect/(refund)			61,856	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	742,173
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			1,231,221	1,025,163	1,001,811	1,013,758	1,055,486	1,271,246	1,345,878	1,316,312	1,250,321	1,111,578	973,435	1,055,580	13,651,789
Total Purchased Power Costs			1,081,609	1,184,822	946,707	1,101,095	1,236,857	1,421,584	1,295,384	1,317,591	1,173,080	1,004,913	958,523	1,220,005	13,942,170
True-up Provision for the Period			149,612	(159,659)	55,104	(87,337)	(181,371)	(150,338)	50,494	(1,279)	77,241	106,665	14,912	(164,425)	(290,381)
Interest Provision for the Period			(2,336)	(2,192)	(2,229)	(2,155)	(2,516)	(3,057)	(3,019)	(2,661)	(2,244)	(1,593)	(1,074)	(1,134)	(26,210)
True-up and Interest Provision															
Beginning of Period			(742,173)	(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(650,234)	(592,327)	(455,483)	(288,564)	(212,879)	(742,173)
True-up Collected or (Refunded)			61,856	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	61,847	742,173
End of Period, Net True-up			(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(650,234)	(592,327)	(455,483)	(288,564)	(212,879)	(316,591)	(316,591)
10% Rule - Interest Provision															-2.28%
Beginning True-up Amount			(742,173)	(533,041)	(633,045)	(518,323)	(545,968)	(668,008)	(759,556)	(650,234)	(592,327)	(455,483)	(288,564)	(212,879)	
Ending True-up Amount Before Interest			(530,705)	(630,853)	(516,094)	(543,813)	(665,492)	(756,499)	(647,215)	(589,666)	(453,239)	(286,971)	(211,805)	(315,457)	
Total Beginning and Ending True-up			(1,272,878)	(1,163,894)	(1,149,139)	(1,062,136)	(1,211,460)	(1,424,507)	(1,406,771)	(1,239,900)	(1,045,566)	(742,454)	(500,369)	(528,336)	
Average True-up Amount			(636,439)	(581,947)	(574,570)	(531,068)	(605,730)	(712,254)	(703,386)	(619,950)	(522,783)	(371,227)	(250,185)	(264,168)	
Average Annual Interest Rate			4.4050%	4.5200%	4.6550%	4.8700%	4.9850%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	
Monthly Average Interest Rate			0.3671%	0.3767%	0.3879%	0.4058%	0.4154%	0.4292%	0.4292%	0.4292%	0.4292%	0.4292%	0.4292%	0.4292%	
Interest Provision			(2,336)	(2,192)	(2,229)	(2,155)	(2,516)	(3,057)	(3,019)	(2,661)	(2,244)	(1,593)	(1,074)	(1,134)	

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 3 of 4

Schedule E1-B

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD

ESTIMATED FOR THE PERIOD: JANUARY 2006 THROUGH DECEMBER 2006

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH

		ACTUAL Jan 2006	ACTUAL Feb 2006	ACTUAL Mar 2006	ACTUAL Apr 2006	ACTUAL May 2006	ACTUAL June 2006	Estimated July 20056	Estimated Aug 2006	Estimated Sept 2006	Estimated Oct 2006	Estimated Nov 2006	Estimated Dec 2006	Total
Total System Sales - KWH		39,553,556	45,657,322	40,110,866	35,551,139	40,536,947	42,873,390	45,848,900	44,553,100	45,012,700	40,731,700	36,641,500	32,426,900	489,498,020
JSC Purchases - KWH		240,000	610,000	100,000	270,000	230,000	160,000	400,000	250,000	270,000	250,000	200,000	350,000	3,330,000
JEA Purchases - KWH		39,217,068	45,873,328	39,637,662	36,746,326	46,801,092	47,892,666	47,879,436	49,768,486	42,348,623	39,465,987	36,345,876	37,654,184	509,630,734
System Billing Demand - KW		77,549	123,603	75,622	70,157	82,611	83,731	108,000	98,000	75,000	78,000	71,000	78,000	1,021,273
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:														
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl Fuel) $/KWH		0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	
Purchased Power Costs:	CCA Fuel Costs	4,488	11,407	1,870	5,049	4,301	2,992	7,480	4,675	5,049	4,675	3,740	6,545	62,271
	JEA Base Fuel Costs	700,417	819,298	707,929	656,289	835,868	855,363	855,127	888,865	756,346	704,863	649,137	672,504	9,102,006
	JEA Fuel Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
	Subtotal Fuel Costs	704,905	830,705	709,799	661,338	840,169	858,355	862,607	893,540	761,395	709,538	652,877	679,049	9,164,277
Demand and Non-Fuel Costs:	Demand Charge	465,294	741,618	453,731	420,942	495,665	502,386	647,999	587,999	449,999	467,999	425,999	467,999	6,127,630
	Customer Charge	225	225	225	225	225	225	225	225	225	225	225	225	2,700
	Energy Charge	64,316	75,232	65,006	60,264	76,754	78,544	78,522	81,620	69,452	64,724	59,607	61,753	835,794
Subtotal Demand & Non-Fuel Costs		529,835	817,075	518,962	481,431	572,644	581,155	726,746	669,844	519,676	532,948	485,831	529,977	6,966,124
Total System Purchased Power Costs		1,234,740	1,647,780	1,228,761	1,142,769	1,412,813	1,439,510	1,589,353	1,563,384	1,281,071	1,242,486	1,138,708	1,209,026	16,130,401
Less Direct Billing To GSLD Class:	Demand	67,442	233,433	140,836	88,332	85,082	90,875	68,511	80,340	54,372	104,807	114,726	49,440	1,178,196
	Commodity	237,357	402,326	301,371	252,003	305,231	255,247	220,109	209,693	233,591	237,412	206,894	148,819	3,010,053
Net Purchased Power Costs		929,941	1,012,021	786,554	802,434	1,022,500	1,093,388	1,300,733	1,273,351	993,108	900,267	817,088	1,010,767	11,942,152
Special Costs		(239)	2,751	(8,197)	177	29,064	52,805							76,361
Total Costs and Charges		929,702	1,014,772	778,357	802,611	1,051,564	1,146,193	1,300,733	1,273,351	993,108	900,267	817,088	1,010,767	12,018,513
Sales Revenues - Fuel Adjustments Revenue														
RS	.03285	548,936	498,956	469,432	406,341	453,614	577,258	676,480	641,567	638,841	521,990	452,390	423,624	6,309,429
GS	.03214	73,678	67,404	68,616	66,595	73,082	84,775	94,051	96,872	87,552	80,594	74,878	69,178	937,275
GSD	.03091	193,435	183,662	192,842	192,344	215,342	227,818	274,410	275,434	280,633	255,586	240,695	228,134	2,760,335
GSLD	.02996	69,088	65,999	67,747	64,839	63,346	70,031	69,546	74,358	58,503	62,023	68,378	72,189	806,047
OL	.02261	2,714	2,411	2,031	2,301	2,375	2,391	2,725	2,546	2,627	2,523	2,433	2,605	29,682
SL,CSL	.02301	1,511	1,509	1,513	1,513	1,518	1,536	1,153	1,461	1,461	1,461	1,461	1,461	17,558
Total Fuel Revenues (Excl. GSLD1)		889,362	819,941	802,181	733,933	809,277	963,809	1,118,365	1,092,238	1,069,617	924,177	840,235	797,191	10,860,326
GSLD1 Fuel Revenues		304,799	635,759	442,207	340,335	390,313	346,122	288,620	290,033	287,963	342,219	321,620	198,259	4,188,249
Non-Fuel Revenues		712,872	729,996	698,707	641,269	683,434	749,621	948,815	933,829	913,820	835,604	780,845	746,350	9,375,162
Total Sales Revenue		1,907,033	2,185,696	1,943,095	1,715,537	1,883,024	2,059,552	2,355,800	2,316,100	2,271,400	2,102,000	1,942,700	1,741,800	24,423,737
KWH Sales:	RS	16,710,810	15,190,803	14,293,219	12,370,970	13,810,192	17,574,479	20,593,000	19,530,200	19,447,200	15,890,100	13,771,400	12,895,700	192,078,073
	GS	2,292,994	2,097,534	2,136,621	2,072,217	2,274,095	2,637,914	2,926,280	3,014,060	2,724,080	2,507,580	2,329,740	2,152,400	29,165,515
	GSD	6,255,947	5,944,040	6,239,276	6,223,158	6,967,244	7,370,920	8,877,720	8,910,840	9,079,020	8,268,720	7,786,960	7,380,600	89,304,445
	GSLD	2,306,140	2,203,020	2,261,380	2,164,280	2,114,440	2,337,620	2,321,300	2,481,900	1,952,700	2,070,200	2,282,300	2,409,500	26,904,780
	GSLD1	11,820,000	20,050,000	15,010,000	12,550,000	15,200,000	12,780,000	10,960,000	10,440,000	11,630,000	11,820,000	10,300,000	7,410,000	149,970,000
	OL	102,008	106,349	104,609	104,753	105,014	105,701	120,500	112,600	116,200	111,600	107,600	115,200	1,312,134
	SL,CSL	65,657	65,576	65,761	65,761	65,962	66,756	50,100	63,500	63,500	63,500	63,500	63,500	763,073
Total KWH Sales		39,553,556	45,657,322	40,110,866	35,551,139	40,536,947	42,873,390	45,848,900	44,553,100	45,012,700	40,731,700	36,641,500	32,426,900	489,498,020
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		889,362	819,941	802,181	733,933	809,277	963,809	1,118,365	1,092,238	1,069,617	924,177	840,235	797,191	10,860,326
True-up Provision - collect/(refund)		(23,599)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(283,221)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		912,961	843,543	825,783	757,535	832,879	987,411	1,141,967	1,115,840	1,093,219	947,779	863,837	820,793	11,143,547
Net Purchased Power Costs		929,702	1,014,772	778,357	802,611	1,051,564	1,146,193	1,300,733	1,273,351	993,108	900,267	817,088	1,010,767	12,018,513
True-up Provision for the Period		(16,741)	(171,229)	47,426	(45,076)	(218,685)	(158,782)	(158,766)	(157,511)	100,111	47,512	46,749	(189,974)	(874,966)
Interest Provision for the Period		966	552	238	159	(482)	(1,411)	(2,200)	(2,990)	(3,227)	(3,025)	(2,937)	(3,359)	(17,716)
Beginning ofTrue-up and Interest Provision		283,221	243,847	49,568	73,630	5,111	(237,658)	(421,453)	(606,021)	(790,124)	(716,842)	(695,957)	(675,747)	283,221
True-up Collected or (Refunded)		(23,599)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(23,602)	(283,221)
End of Period, Net True-up and Int. Prov.		243,847	49,568	73,630	5,111	(237,658)	(421,453)	(606,021)	(790,124)	(716,842)	(695,957)	(675,747)	(892,682)	(892,682)
Beginning True-up Amount		283,221	243,847	49,568	73,630	5,111	(237,658)	(421,453)	(606,021)	(790,124)	(716,842)	(695,957)	(675,747)	
Ending True-up Amount Before Interest		242,881	49,016	73,392	4,952	(237,176)	(420,042)	(603,821)	(787,134)	(713,615)	(692,932)	(672,810)	(889,323)	
Total Beginning and Ending True-up		526,102	292,863	122,960	78,582	(232,065)	(657,700)	(1,025,274)	(1,393,155)	(1,503,739)	(1,409,774)	(1,368,767)	(1,565,070)	
Average True-up Amount		263,051	146,432	61,480	39,291	(116,033)	(328,850)	(512,637)	(696,578)	(751,870)	(704,887)	(684,384)	(782,535)	
Average Annual Interest Rate		4.4050%	4.5200%	4.6550%	4.8700%	4.9850%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	5.1500%	
Interest Provision		966	552	238	159	(482)	(1,411)	(2,200)	(2,990)	(3,227)	(3,025)	(2,937)	(3,359)	

10% Rule Interest Provision:
-5.53%

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 4 of 4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 25
COMPANY Florida Public Utilities Co.
WITNESS Cheryl Martin (CMM-2)
DATE 11-06-07

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2007 - DECEMBER 2007
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2007 - December 2007. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2007)(Estimated)	$	(690,530)

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 1 of 6

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD: JANUARY 2007 - DECEMBER 2007
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Schedule E1-B

MARIANNA DIVISION

			ACTUAL JANUARY 2007	ACTUAL FEBRUARY 2007	ACTUAL MARCH 2007	ACTUAL APRIL 2007	ACTUAL MAY 2007	ACTUAL JUNE 2007	Estimated JULY 2007	Estimated AUGUST 2007	Estimated SEPTEMBER 2007	Estimated OCTOBER 2007	Estimated NOVEMBER 2007	Estimated DECEMBER 2007	Total
Total System Sales - KWH			27,900,167	27,200,186	26,306,274	23,246,285	24,352,372	29,393,524	31,459,470	30,296,766	29,423,174	25,743,548	22,941,252	25,363,740	323,626,758
Total System Purchases - KWH			29,666,454	27,779,249	25,545,303	25,055,771	30,275,669	34,602,974	33,504,336	32,266,056	31,335,680	27,416,879	24,432,433	27,012,383	348,893,187
System Billing Demand - KW			72,065	70,474	62,166	45,428	58,163	71,504	66,591	68,192	63,563	50,369	48,002	63,975	740,492
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	0.02380	
Demand and Non-Fuel:															
Demand Charge - $/KW			7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	
Customer Charge - $			660.00	660.00	660.00	660.00	660.00	660.00	0.00	0.00	0.00	0.00	0.00	0.00	
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	
Purchased Power Costs:															
Base Fuel Costs			706,062	661,146	607,978	596,327	720,561	823,551	797,403	767,932	745,789	652,522	581,492	642,895	8,303,658
Subtotal Fuel Costs			706,062	661,146	607,978	596,327	720,561	823,551	797,403	767,932	745,789	652,522	581,492	642,895	8,303,658
Demand and Non-Fuel Costs:															
Demand Charge			522,471	510,936	450,703	329,353	421,682	518,404	482,785	494,392	460,832	365,175	348,015	463,819	5,368,567
Customer Charge			660	660	660	660	660	660	0	0	0	0	0	0	3,960
Equipment Rental & Other			3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	45,216
Transformation Charge			37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	446,532
Subtotal Demand & Non-Fuel Costs			564,110	552,575	492,342	370,992	463,321	560,043	523,764	535,371	501,811	406,154	388,994	504,798	5,864,275
Total System Purchased Power Costs			1,270,172	1,213,721	1,100,320	967,319	1,183,882	1,383,594	1,321,167	1,303,303	1,247,600	1,058,676	970,486	1,147,693	14,167,933
Special Costs			(5,430)	6,523	8,500	1,225	2,979	5,597							19,394
Total Costs and Charges			1,264,742	1,220,244	1,108,820	968,544	1,186,861	1,389,191	1,321,167	1,303,303	1,247,600	1,058,676	970,486	1,147,693	14,187,327
Sales Revenues - Fuel Adjustment Revenues															
Residential	RS	.04417	578,320	598,363	537,878	419,345	438,784	557,501	619,746	593,858	585,766	488,707	395,354	499,904	6,313,526
Commercial,Small	GS	.04363	104,150	99,803	100,224	91,230	96,433	116,360	129,091	125,708	120,031	109,496	95,144	101,084	1,288,754
Commercial, Large	GSD	.04174	293,082	267,476	279,519	271,088	285,742	332,404	333,434	328,026	312,246	300,384	272,396	268,870	3,544,667
Industrial	GSLD	.03998	198,219	180,714	187,781	189,071	197,004	228,118	242,659	227,954	220,546	182,293	194,807	194,799	2,443,965
Outside Lighting Private	OL,OL-2	.03445	11,866	11,793	11,824	11,799	11,676	11,732	10,986	10,934	11,045	11,052	10,976	11,086	136,769
Street Lighting, Public	SL-1,SL-2,SL-3	.03461	3,269	3,267	3,264	3,265	3,259	3,259	3,219	3,212	3,208	3,208	3,205	3,233	38,868
Total Fuel Revenues			1,188,906	1,161,416	1,120,490	985,798	1,032,898	1,249,374	1,339,135	1,289,692	1,252,842	1,095,140	971,882	1,078,976	13,766,549
Non-Fuel Revenues			697,091	694,215	672,532	616,240	631,362	707,314	855,965	839,708	818,758	740,860	686,018	756,324	8,716,387
Total Sales Revenue			1,885,997	1,855,631	1,793,022	1,602,038	1,664,260	1,956,688	2,195,100	2,129,400	2,071,600	1,836,000	1,657,900	1,835,300	22,482,936
KWH Sales:															
Residential	RS		13,093,518	13,547,367	12,177,959	9,494,279	9,935,341	12,622,236	14,030,933	13,444,833	13,261,633	11,064,233	8,950,733	11,317,735	142,940,800
Commercial	GS		2,387,084	2,287,539	2,297,191	2,091,065	2,210,319	2,667,051	2,958,773	2,881,233	2,751,113	2,509,653	2,180,693	2,316,853	29,538,567
Commercial	GSD		7,021,438	6,408,162	6,696,659	6,494,683	6,845,758	7,963,679	7,988,364	7,858,800	7,480,728	7,196,562	6,526,026	6,441,552	84,922,411
Industrial	GSLD		4,957,816	4,519,952	4,696,732	4,728,992	4,927,412	5,705,644	6,069,500	5,701,700	5,516,400	4,559,600	4,872,600	4,872,400	61,128,748
Residential	OL,OL-2		345,863	342,770	343,422	342,914	339,375	340,739	318,900	317,400	320,600	320,800	318,600	321,800	3,973,183
Other	SL-1,SL-2,SL-3		94,448	94,396	94,311	94,352	94,167	94,175	93,000	92,800	92,700	92,700	92,600	93,400	1,123,049
Total KWH Sales			27,900,167	27,200,186	26,306,274	23,246,285	24,352,372	29,393,524	31,459,470	30,296,766	29,423,174	25,743,548	22,941,252	25,363,740	323,626,758
True-up Calculation:															to Date
Fuel Revenues			1,188,906	1,161,416	1,120,490	985,798	1,032,898	1,249,374	1,339,135	1,289,692	1,252,842	1,095,140	971,882	1,078,976	13,766,549
True-up Provision for the Period - collect/(refund)			20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	242,460
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			1,168,701	1,141,211	1,100,285	965,593	1,012,693	1,229,169	1,318,930	1,269,487	1,232,637	1,074,935	951,677	1,058,771	13,524,089
Total Purchased Power Costs			1,264,742	1,220,244	1,108,820	968,544	1,186,861	1,389,191	1,321,167	1,303,303	1,247,600	1,058,676	970,486	1,147,693	14,187,327
True-up Provision for the Period			(96,041)	(79,033)	(8,535)	(2,951)	(174,168)	(160,022)	(2,237)	(33,816)	(14,963)	16,259	(18,809)	(88,922)	(663,238)
Interest Provision for the Period			(1,230)	(1,529)	(1,639)	(1,583)	(1,890)	(2,547)	(2,826)	(2,829)	(2,860)	(2,780)	(2,710)	(2,869)	(27,292)
True-up and Interest Provision															
Beginning of Period			(242,460)	(319,526)	(379,883)	(369,852)	(354,181)	(510,034)	(652,398)	(637,256)	(653,696)	(651,314)	(617,630)	(618,944)	(242,460)
True-up Collected or (Refunded)			20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	20,205	242,460
End of Period, Net True-up			(319,526)	(379,883)	(369,852)	(354,181)	(510,034)	(652,398)	(637,256)	(653,696)	(651,314)	(617,630)	(618,944)	(690,530)	(690,530)
10% Rule - Interest Provision															-4.87%
Beginning True-up Amount			(242,460)	(319,526)	(379,883)	(369,852)	(354,181)	(510,034)	(652,398)	(637,256)	(653,696)	(651,314)	(617,630)	(618,944)	
Ending True-up Amount Before Interest			(318,296)	(378,354)	(368,213)	(352,598)	(508,144)	(649,851)	(634,430)	(650,867)	(648,454)	(614,850)	(616,234)	(687,661)	
Total Beginning and Ending True-up			(560,756)	(697,880)	(748,096)	(722,450)	(862,325)	(1,159,885)	(1,286,828)	(1,288,123)	(1,302,150)	(1,266,164)	(1,233,864)	(1,306,605)	
Average True-up Amount			(280,378)	(348,940)	(374,048)	(361,225)	(431,163)	(579,943)	(643,414)	(644,062)	(651,075)	(633,082)	(616,932)	(653,303)	
Average Annual Interest Rate			5.2650%	5.2600%	5.2600%	5.2600%	5.2600%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	
Monthly Average Interest Rate			0.4388%	0.4383%	0.4383%	0.4383%	0.4383%	0.4392%	0.4392%	0.4392%	0.4392%	0.4392%	0.4392%	0.4392%	
Interest Provision			(1,230)	(1,529)	(1,639)	(1,583)	(1,890)	(2,547)	(2,826)	(2,829)	(2,860)	(2,780)	(2,710)	(2,869)	

Exhibit No. _____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(CMM-2)
Page 2 of 6

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

SCHEDULE E1-B1

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	8,303,658	8,248,070	55,588	0.7%	348,893	346,557	2,336	0.7%	2.38000	2.38000	0.00000	0.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	5,864,275	5,672,237	192,038	3.4%	348,893	346,557	2,336	0.7%	1.68082	1.63674	0.04408	2.7%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	14,167,933	13,920,307	247,626	1.8%	348,893	346,557	2,336	0.7%	4.06082	4.01674	0.04408	1.1%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					348,893	346,557	2,336	0.7%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Other Fuel Related Costs	65,832											
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	65,832	0	65,832	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,233,765	13,920,307	313,458	2.3%	348,893	346,557	2,336	0.7%	4.07969	4.01674	0.06295	1.6%
21	Net Unbilled Sales	449,378 *	(88,007) *	537,385	-610.6%	11,015	(2,191)	13,206	-602.7%	0.13886	(0.02631)	0.16517	-627.8%
22	Company Use	12,035 *	14,139 *	(2,104)	-14.9%	295	352	(57)	-16.2%	0.00372	0.00423	(0.00051)	-12.1%
23	T & D Losses	569,362 *	556,800 *	12,562	2.3%	13,956	13,862	94	0.7%	0.17593	0.16644	0.00949	5.7%
24	SYSTEM KWH SALES	14,233,765	13,920,307	313,458	2.3%	323,627	334,534	(10,907)	-3.3%	4.39820	4.16110	0.23710	5.7%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	14,233,765	13,920,307	313,458	2.3%	323,627	334,534	(10,907)	-3.3%	4.39820	4.16110	0.23710	5.7%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	14,233,765	13,920,307	313,458	2.3%	323,627	334,534	(10,907)	-3.3%	4.39820	4.16110	0.23710	5.7%
28	GPIF**												
29	TRUE-UP**	242,460	316,591	(74,131)	-23.4%	323,627	334,534	(10,907)	-3.3%	0.07492	0.09464	(0.01972)	-20.8%
30	TOTAL JURISDICTIONAL FUEL COST	14,476,225	14,236,898	239,327	1.7%	323,627	334,534	(10,907)	-3.3%	4.47312	4.25574	0.21738	5.1%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									4.47634	4.25880	0.21754	5.1%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									4.476	4.259	0.217	5.1%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CMM-2)
PAGE 3 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2007 - DECEMBER 2007
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Under-recovery of purchased power costs for the period January 2007 - December 2007. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2007.)(Estimated)	$	(915,677)

FLORIDA PUBLIC UTILITIES COMPANY Schedule E1-B

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD

ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH

		ACTUAL Jan 2007	ACTUAL Feb 2007	ACTUAL Mar 2007	ACTUAL Apr 2007	ACTUAL May 2007	ACTUAL June 2007	Estimated July 2007	Estimated Aug 2007	Estimated Sept 2007	Estimated Oct 2007	Estimated Nov 2007	Estimated Dec 2007	Total
Total System Sales - KWH		37,229,194	38,711,439	33,812,786	34,494,204	35,063,354	37,734,458	41,083,350	42,369,127	43,232,686	39,463,171	35,578,426	31,587,835	450,360,030
JSC Purchases - KWH		580,000	200,000	2,058,667	697,139	710,194	412,667	367,100	234,900	271,200	245,900	189,600	345,700	6,313,067
JEA Purchases - KWH		40,473,652	38,734,863	32,592,023	35,656,297	39,583,748	43,114,724	43,386,668	44,888,220	45,771,804	41,782,377	37,701,424	33,295,344	476,981,144
System Billing Demand - KW		86,643	82,835	81,312	77,594	70,202	79,475	95,000	97,000	78,000	72,000	74,000	77,000	971,061
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	0.025100	
Base Fuel Costs - $/KWH		0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	0.01786	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:														
Demand Charge - $/KW		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	
Customer Charge - $		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Energy Charge (Excl. Fuel) $/KWH		0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	0.01350	
Purchased Power Costs:	CCA Fuel Costs	14,558	4,739	51,673	17,498	17,826	10,358	9,214	5,896	6,807	6,172	4,759	8,677	158,177
	JEA Base Fuel Costs	722,859	691,805	582,094	636,821	706,966	770,029	774,886	801,704	817,484	746,233	673,347	594,655	8,518,883
	JEA Fuel Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
	Subtotal Fuel Costs	737,417	696,544	633,767	654,319	724,792	780,387	784,100	807,600	824,291	752,405	678,106	603,332	8,677,060
Demand and Non-Fuel Costs:	Demand Charge	601,250	579,844	569,184	543,157	491,414	556,325	665,000	679,000	546,000	504,000	518,000	539,000	6,792,174
	Customer Charge	0	0	0	0	0	0	0	0	0	0	0	0	0
	Energy Charge	517,302	522,921	439,992	481,360	534,381	582,049	585,720	605,991	617,919	564,062	508,969	449,487	6,410,153
Subtotal Demand & Non-Fuel Costs		1,118,552	1,102,765	1,009,176	1,024,517	1,025,795	1,138,374	1,250,720	1,284,991	1,163,919	1,068,062	1,026,969	988,487	13,202,327
Total System Purchased Power Costs		1,855,969	1,799,309	1,642,943	1,678,836	1,750,587	1,918,761	2,034,820	2,092,591	1,988,210	1,820,467	1,705,075	1,591,819	21,879,387
Less Direct Billing To GSLD Class:	Demand	99,937	91,076	149,394	185,911	81,588	55,889	66,332	84,357	69,216	85,078	136,990	30,282	1,136,050
	Commodity	395,965	418,033	294,614	396,781	366,267	278,510	259,258	324,928	348,360	348,666	357,575	251,649	4,040,606
Net Purchased Power Costs		1,360,067	1,290,200	1,198,935	1,096,144	1,302,732	1,584,362	1,709,230	1,683,306	1,570,634	1,386,723	1,210,510	1,309,888	16,702,731
Special Costs		(5,366)	8,514	8,619	366	4,077	5,747							21,957
Total Costs and Charges		1,354,701	1,298,714	1,207,554	1,096,510	1,306,809	1,590,109	1,709,230	1,683,306	1,570,634	1,386,723	1,210,510	1,309,888	16,724,688
Sales Revenues - Fuel Adjustments Revenue														
RS	0.05166	736,149	800,839	751,146	628,643	682,915	849,271	1,000,386	954,066	970,289	798,621	658,083	642,799	9,473,207
GS	0.05052	111,928	105,160	111,901	106,427	111,871	130,742	155,836	156,058	156,281	134,709	116,713	113,238	1,510,864
GSD	0.04809	314,466	280,231	300,151	314,348	308,164	375,232	386,113	393,230	387,411	387,411	344,563	323,139	4,114,459
GSLD	0.04847	106,788	109,147	102,161	98,357	98,915	113,653	115,783	115,783	112,695	111,151	101,889	106,520	1,292,842
OL	0.03681	4,048	4,067	4,096	4,173	4,123	4,075	3,836	3,836	3,836	3,843	3,843	3,843	47,619
SL,CSL	0.03694	2,487	2,488	2,488	2,519	2,524	2,524	2,438	2,438	2,438	2,438	2,438	2,438	29,658
Total Fuel Revenues (Excl. GSLD1)		1,275,866	1,301,932	1,271,943	1,154,467	1,208,512	1,475,497	1,664,392	1,625,411	1,632,950	1,438,173	1,227,529	1,191,977	16,468,649
GSLD1 Fuel Revenues		495,902	509,109	444,008	582,692	447,855	334,399	161,608	202,382	217,044	217,285	222,789	156,989	3,992,062
Non-Fuel Revenues		712,790	757,527	705,915	673,138	678,111	741,407	244,610	267,998	256,797	271,965	338,020	236,525	5,884,803
Total Sales Revenue		2,484,558	2,568,568	2,421,866	2,410,297	2,334,478	2,551,303	2,181,000	2,201,600	2,213,900	2,017,400	1,863,500	1,659,600	26,908,070
KWH Sales:	RS	14,247,565	15,502,346	14,539,379	12,169,435	13,219,151	16,439,199	19,364,800	18,468,177	18,782,218	15,459,171	12,738,726	12,442,885	183,373,052
	GS	2,213,919	2,081,406	2,214,821	2,106,499	2,214,236	2,587,746	3,084,640	3,089,040	3,093,440	2,666,440	2,310,240	2,241,440	29,903,867
	GSD	6,557,019	5,827,787	6,242,039	6,537,274	6,408,684	7,803,449	8,028,960	8,176,960	8,055,960	8,055,960	7,164,960	6,719,460	85,578,512
	GSLD	2,203,400	2,252,060	2,107,920	2,029,440	2,040,960	2,345,040	2,388,750	2,388,750	2,325,050	2,293,200	2,102,100	2,197,650	26,674,320
	GSLD1	11,830,000	12,870,000	8,530,000	11,470,000	11,000,000	8,380,000	8,046,000	10,076,000	10,806,000	10,818,000	11,092,000	7,816,000	122,734,000
	OL	109,974	110,490	111,269	113,356	112,000	110,701	104,200	104,200	104,200	104,400	104,400	104,400	1,293,590
	SL,CSL	67,317	67,350	67,358	68,200	68,323	68,323	66,000	66,000	66,000	66,000	66,000	66,000	802,871
Total KWH Sales		37,229,194	38,711,439	33,812,786	34,494,204	35,063,354	37,734,458	41,083,350	42,369,127	43,232,868	39,463,171	35,578,426	31,587,835	450,360,212
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		1,275,866	1,301,932	1,271,943	1,154,467	1,208,512	1,475,497	1,664,392	1,625,411	1,632,950	1,438,173	1,227,529	1,191,977	16,468,649
True-up Provision - collect/(refund)		51,648	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	619,754
Gross Receipts Tax Refund		0	0	0	0	0	0	0		0				0
Fuel Revenue		1,224,218	1,250,286	1,220,297	1,102,821	1,156,866	1,423,851	1,612,746	1,573,765	1,581,304	1,386,527	1,175,883	1,140,331	15,848,895
Net Purchased Power Costs		1,354,701	1,298,714	1,207,554	1,096,510	1,306,809	1,590,109	1,709,230	1,683,306	1,570,634	1,386,723	1,210,510	1,309,888	16,724,688
True-up Provision for the Period		(130,483)	(48,428)	12,743	6,311	(149,943)	(166,258)	(96,484)	(109,541)	10,670	(196)	(34,627)	(169,557)	(875,793)
Interest Provision for the Period		(2,892)	(3,068)	(2,933)	(2,678)	(2,778)	(3,263)	(3,628)	(3,869)	(3,876)	(3,644)	(3,509)	(3,746)	(39,884)
Beginning ofTrue-up and Interest Provision		(619,754)	(701,481)	(701,331)	(639,875)	(584,596)	(685,671)	(803,546)	(852,012)	(913,775)	(855,335)	(807,529)	(794,020)	(619,754)
True-up Collected or (Refunded)		51,648	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	51,646	619,754
End of Period, Net True-up and Int. Prov.		(701,481)	(701,331)	(639,875)	(584,596)	(685,671)	(803,546)	(852,012)	(913,775)	(855,335)	(807,529)	(794,020)	(915,677)	(915,677)
Beginning True-up Amount		(619,754)	(701,481)	(701,331)	(639,875)	(584,596)	(685,671)	(803,546)	(852,012)	(913,775)	(855,335)	(807,529)	(794,020)	
Ending True-up Amount Before Interest		(698,589)	(698,263)	(636,942)	(581,918)	(682,893)	(800,283)	(848,384)	(909,906)	(851,459)	(803,885)	(790,511)	(911,931)	
Total Beginning and Ending True-up		(1,318,343)	(1,399,744)	(1,338,273)	(1,221,793)	(1,267,489)	(1,485,954)	(1,651,930)	(1,761,918)	(1,765,234)	(1,659,221)	(1,598,040)	(1,705,951)	
Average True-up Amount		(659,172)	(699,872)	(669,137)	(610,897)	(633,745)	(742,977)	(825,965)	(880,959)	(882,617)	(829,610)	(799,020)	(852,975)	
Average Annual Interest Rate		5.2650%	5.2600%	5.2600%	5.2600%	5.2600%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	5.2700%	
Interest Provision		(2,892)	(3,068)	(2,933)	(2,678)	(2,778)	(3,263)	(3,628)	(3,869)	(3,876)	(3,644)	(3,509)	(3,746)	

10% Rule Interest Provision:
-4.19%

Exhibit No._____
DOCKET NO. 070001
Florida Public Utilities C
(CMM-2)
Page 5 of 6

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2007 - DECEMBER 2007

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	8,518,883	8,741,883	(223,000)	-2.6%	476,981	489,467	(12,486)	-2.6%	1.78600	1.78600	0.00000	0.0%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	13,202,327	13,407,606	(205,279)	-1.5%	476,981	489,467	(12,486)	-2.6%	2.76789	2.73923	0.02866	1.1%
11 Energy Payments to Qualifying Facilities (A8a)	158,177	54,263	103,914	191.5%	6,313	2,997	3,316	110.6%	2.50558	1.81058	0.69500	38.4%
12 TOTAL COST OF PURCHASED POWER	21,879,387	22,203,752	(324,365)	-1.5%	483,294	492,464	(9,170)	-1.9%	4.52714	4.50871	0.01843	0.4%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					483,294	492,464	(9,170)	-1.9%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)												
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	21,879,387	22,203,752	(324,365)	-1.5%	483,294	492,464	(9,170)	-1.9%	4.52714	4.50871	0.01843	0.4%
21 Net Unbilled Sales (A4)	157,182 *	(1,041,061) *	1,198,243	-115.1%	3,472	(23,090)	26,562	-115.0%	0.03490	(0.21443)	0.24933	-116.3%
22 Company Use (A4)	21,006 *	22,814 *	(1,808)	-7.9%	464	506	(42)	-8.3%	0.00466	0.00470	(0.00004)	-0.9%
23 T & D Losses (A4)	1,312,780 *	1,332,234 *	(19,454)	-1.5%	28,998	29,548	(550)	-1.9%	0.29150	0.27440	0.01710	6.2%
24 SYSTEM KWH SALES	21,879,387	22,203,752	(324,365)	-1.5%	450,360	485,500	(35,140)	-7.2%	4.85820	4.57338	0.28482	6.2%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	21,879,387	22,203,752	(324,365)	-1.5%	450,360	485,500	(35,140)	-7.2%	4.85820	4.57338	0.28482	6.2%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	21,879,387	22,203,752	(324,365)	-1.5%	450,360	485,500	(35,140)	-7.2%	4.85820	4.57338	0.28482	6.2%
28 GPIF**												
29 TRUE-UP**	619,754	892,682	(272,928)	-30.6%	450,360	485,500	(35,140)	-7.2%	0.13761	0.18387	(0.04626)	-25.2%
30 TOTAL JURISDICTIONAL FUEL COST	22,499,141	23,096,434	(597,293)	-2.6%	450,360	485,500	(35,140)	-7.2%	4.99581	4.75725	0.23856	5.0%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									4.99941	4.76068	0.23873	5.0%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									4.999	4.761	0.238	5.0%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CMM-2)
PAGE 6 OF 6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 26
COMPANY Florida Public Utilities Co.
WITNESS Mehrdad Khojasteh (MK-1)
DATE 11-06-07

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

SCHEDULE E1
PAGE 1 OF 2

MARIANNA (NORTHWEST DIVISION)

		(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)		0	
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	15,711,972	383,453	4.09750
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Transformation Cost of Purch Power (E2)	11,349,434	383,453	2.95980
10a	Demand Costs of Purchased Power	10,365,194 *		
10b	Transformation Energy & Customer Costs of Purchased Power	984,240 *		
11	Energy Payments to Qualifying Facilities (E8a)			
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	27,061,406	383,453	7.05729
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	27,061,406	383,453	7.05729
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	27,061,406	383,453	7.05729
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	24,136 *	342	0.00680
23	T & D Losses	2,000,107 *	28,341	0.56378
24	SYSTEM MWH SALES	27,061,406	354,770	7.62787
25	Less Total Demand Cost Recovery	10,365,194 ***		
26	Jurisdictional MWH Sales	16,696,212	354,770	4.70621
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	16,696,212	354,770	4.70621
28	GPIF **			
29	TRUE-UP **	3,856	354,770	0.00109
30	TOTAL JURISDICTIONAL FUEL COST	16,700,068	354,770	4.70729
31	Revenue Tax Factor			1.00072
32	Fuel Factor Adjusted for Taxes			4.71068
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH			4.711

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 1 OF 14

DOCUMENT NUMBER-DATE
09754 OCT 25 5
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008
0

MARIANNA (NORTHWEST DIVISION)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	156,110,893	61.971%	57,513.6	1.089	1.030	62,632.3	160,794,220	49.06%	44.00%
35	GS	30,861,060	64.200%	10,974.9	1.089	1.030	11,951.7	31,786,892	9.36%	8.70%
36	GSD	96,134,852	73.168%	29,997.5	1.089	1.030	32,667.3	99,018,898	25.58%	27.10%
37	GSLD	66,464,661	84.178%	18,026.8	1.089	1.030	19,631.2	68,458,601	15.37%	18.73%
38	OL, OL1	4,040,542	160.732%	573.9	1.089	1.030	625.0	4,161,758	0.49%	1.14%
39	SL1, SL2 & SL3	1,156,154	160.732%	164.2	1.089	1.030	178.8	1,190,839	0.14%	0.33%
40	TOTAL	354,768,162		117,250.9			127,686.3	365,411,208	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072 Demand Cost Recovery	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	45.28%	3.39%	48.67%	[redacted]	0.03232	0.03234	[redacted]	$0.07945
42	GS	8.64%	0.67%	9.31%		0.03127	0.03129		$0.07840
43	GSD	23.61%	2.08%	25.69%		0.02770	0.02772		$0.07483
44	GSLD	14.19%	1.44%	15.63%		0.02438	0.02440		$0.07151
45	OL, OL1	0.45%	0.09%	0.54%		0.01385	0.01386		$0.06097
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%		0.01434	0.01435		$0.06146
47	TOTAL	92.30%	7.70%	100.00%					

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	156,110,893	$0.07945	$12,403,010
49	RS	<= 1,000kWh/mo.	103,746,616	$0.07610	$7,894,671
50	RS	> 1,000 kWh/mo.	52,364,277	$0.08610	$4,508,339
51	RS	Total Sales	156,110,893		$12,403,010

(2) From Gulf Power Co. 2003 Load Research results.
(4) From Fernandina Rate Case.

EXHIBIT NO._____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 2 OF 14

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2007 - DECEMBER 2007
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

MARIANNA (NORTHWEST DIVISION)

Under-recovery of purchased power costs for the period January 2007 - December 2007. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2007; (Estimated)	$	(3,856)
Estimated kilowatt hour sales for the months of January 2008 - December 2008 as per estimate filed with the Commission.		354,768,162
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2008 - December 2008.		(0.00109)

Exhibit No._____
DOCKET NO. _070001-EI
Florida Public Utilities Company
(MK-1)
Page 3 of 14

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA (NORTHWEST DIVISION)
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

LINE NO.			(a) 2008 JANUARY	(b) 2008 FEBRUARY	(c) 2008 MARCH	(d) 2008 APRIL	(e) 2008 MAY	(f) 2008 JUNE	(g) 2008 JULY	(h) 2008 AUGUST	(i) 2008 SEPTEMBER	(j) 2008 OCTOBER	(k) 2008 NOVEMBER	(l) 2008 DECEMBER	(m) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,383,804	1,131,127	1,142,270	1,120,299	1,127,290	1,416,801	1,556,985	1,505,091	1,500,404	1,403,780	1,053,915	1,267,208	15,711,972	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		968,755	943,572	918,661	901,210	939,270	954,353	967,475	958,973	955,469	932,246	924,515	974,935	11,349,434	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,352,559	2,074,699	2,060,931	2,021,509	2,066,560	2,371,154	2,524,458	2,475,064	2,455,873	2,336,026	1,978,430	2,242,143	27,061,406	5
6	LESS: TOTAL DEMAND COST RECOVERY		886,735	861,552	836,641	819,190	857,250	872,333	885,455	886,953	873,449	850,226	842,495	892,915	10,365,194	6
7	TOTAL OTHER COST TO BE RECOVERED		1,465,824	1,213,147	1,224,290	1,202,319	1,209,310	1,498,821	1,641,003	1,588,111	1,582,424	1,485,800	1,135,935	1,349,228	16,696,212	7
7a	SYSTEM KWH SOLD (MWH)		31,246	25,540	25,792	25,296	25,454	31,991	35,201	34,007	36,136	31,697	23,797	28,613	354,770	7a
7b	COST PER KWH SOLD (CENTS/KWH)		4.69124	4.74999	4.74678	4.753	4.75096	4.68513	4.66181	4.66995	4.65581	4.68751	4.77344	4.71544	4.70621	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		4.69124	4.74999	4.74678	4.75300	4.75096	4.68513	4.66181	4.66995	4.65581	4.68751	4.77344	4.71544	4.70621	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	11
12	TOTAL		4.69233	4.75108	4.74787	4.75409	4.75205	4.68622	4.66290	4.67104	4.65690	4.68860	4.77453	4.71653	4.70730	12
13	REVENUE TAX FACTOR	0.00072	0.00338	0.00342	0.00342	0.00342	0.00342	0.00337	0.00336	0.00336	0.00335	0.00338	0.00344	0.00340	0.00339	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		4.69571	4.75450	4.75129	4.75751	4.75547	4.68959	4.66626	4.67440	4.66025	4.69198	4.77797	4.71993	4.71069	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		4.696	4.754	4.751	4.758	4.755	4.690	4.666	4.674	4.660	4.692	4.778	4.720	4.711	15

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 4 OF 14

DOCUMENT NUMBER-DATE
09754 OCT 25 0
FPSC-COMMISSION CLERK

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA (NORTHWEST DIVISION)
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2008	GULF POWER COMPANY	RE	33,771,952			33,771,952	4.097495	6.966014	1,383,804
FEBRUARY 2008	GULF POWER COMPANY	RE	27,605,321			27,605,321	4.097496	7.515576	1,131,127
MARCH 2008	GULF POWER COMPANY	RE	27,877,261			27,877,261	4.097498	7.392875	1,142,270
APRIL 2008	GULF POWER COMPANY	RE	27,341,053			27,341,053	4.097498	7.393677	1,120,299
MAY 2008	GULF POWER COMPANY	RE	27,511,673			27,511,673	4.097496	7.511575	1,127,290
JUNE 2008	GULF POWER COMPANY	RE	34,577,240			34,577,240	4.097495	6.857557	1,416,801
JULY 2008	GULF POWER COMPANY	RE	38,047,206			38,047,206	4.097498	6.640325	1,558,983
AUGUST 2008	GULF POWER COMPANY	RE	36,756,345			36,756,345	4.097498	6.733703	1,506,091
SEPTEMBER 2008	GULF POWER COMPANY	RE	39,058,077			39,058,077	4.097498	6.543776	1,600,404
OCTOBER 2008	GULF POWER COMPANY	RE	34,259,455			34,259,455	4.097495	6.818632	1,403,780
NOVEMBER 2008	GULF POWER COMPANY	RE	25,720,954			25,720,954	4.097494	7.691900	1,053,915
DECEMBER 2008	GULF POWER COMPANY	RE	30,926,387			30,926,387	4.097496	7.249935	1,267,208
TOTAL			383,452,924	0	0	383,452,924	4.097497	7.057295	15,711,972

EXHIBIT NO. _____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 5 OF 14

DOCUMENT NUMBER-DATE
09754 OCT 25 08
FPSC-COMMISSION CLERK

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA (NORTHWEST DIVISION)

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

	JANUARY 2008	FEBRUARY 2008	MARCH 2008	APRIL 2008	MAY 2008	JUNE 2008	JULY 2008
BASE RATE REVENUES ** $							
FUEL RECOVERY FACTOR CENTS/KWH							
GROUP LOSS MULTIPLIER							
FUEL RECOVERY REVENUES $							
GROSS RECEIPTS TAX							
TOTAL REVENUES *** $	103.01	103.01	103.01	103.01	103.01	103.01	103.01

	AUGUST 2008	SEPTEMBER 2008	OCTOBER 2008	NOVEMBER 2008	DECEMBER 2008	PERIOD TOTAL
BASE RATE REVENUES ** $						
FUEL RECOVERY FACTOR CENTS/KWH						
GROUP LOSS MULTIPLIER						
FUEL RECOVERY REVENUES $						
GROSS RECEIPTS TAX						
TOTAL REVENUES *** $	103.01	103.01	103.01	103.01	103.01	1,236.12

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE
CENTS/KWH
CONSERVATION FACTOR

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 6 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

	FERNANDINA BEACH (NORTHEAST DIVISION)	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	20,909,817	520,922	4.01400
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Non Fuel Cost of Purch Power (E2)	10,625,615	520,922	2.03977
10a	Demand Costs of Purchased Power	9,062,848 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	1,562,767 *		
11	Energy Payments to Qualifying Facilities (E8a)	347,292	8,400	4.13443
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,882,724	529,322	6.02331
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,882,724	529,322	6.02331
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	31,882,724	529,322	6.02331
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	30,478 *	506	0.00606
23	T & D Losses	1,577,445 *	26,189	0.31384
24	SYSTEM MWH SALES	31,882,724	502,627	6.34322
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	31,882,724	502,627	6.34322
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	31,882,724	502,627	6.34322
27a	GSLD1 MWH Sales		159,781	
27b	Other Classes MWH Sales		342,846	
27c	GSLD1 CP KW		176,448 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	5,040	502,627	0.00100
30	TOTAL JURISDICTIONAL FUEL COST	31,887,764	502,627	6.34422
30a	Demand Purchased Power Costs (Line 10a)	9,062,848 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	22,819,876 *		
30c	True up Over/Under Recovery (Line 29)	5,040 *		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 7 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

	FERNANDINA BEACH (NORTHEAST DIVISION)	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	9,062,848		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $8.83)	1,558,557	176,448 (KW)	$8.83 /KW
33	Balance to Other Classes	7,504,291	342,846	2.18882
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	22,819,876		
35	Total KWH Purchased (Line 12)		529,322	
36	Average Cost per KWH Purchased			4.31115
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			4.44045
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	7,094,991	159,781	4.44045
39	Balance to Other Classes	15,724,885	342,846	4.58657
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,558,557	176,448 (KW)	$8.83 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$8.84 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	7,094,991	159,781	4.44045
40e	Total Non-demand Costs Including True-up	7,094,991	159,781	4.44045
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			4.44365
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	23,229,176	342,846	6.77540
41b	Less: Total Demand Cost Recovery	7,504,291 ***		
41c	Total Other Costs to be Recovered	15,724,885	342,846	4.58657
41d	Other Classes' Portion of True-up (Line 30c)	5,040	342,846	0.00147
41e	Total Demand & Non-demand Costs Including True-up	15,729,925	342,846	4.58804
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			4.591

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 8 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

FERNANDINA BEACH (NORTHEAST DIVISION)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	196,751,257	61.793%	72,694.9	1.089	1.030	79,164.7	202,653,795	62.54%	57.38%
45	GS	29,904,995	66.413%	10,280.6	1.089	1.030	11,195.6	30,802,145	8.85%	8.72%
46	GSD	87,275,450	79.105%	25,189.2	1.089	1.030	27,431.0	89,893,714	21.68%	25.46%
47	GSLD	26,834,384	76.791%	7,978.2	1.089	1.030	8,688.3	27,639,416	6.87%	7.83%
48	OL	1,269,456	696.444%	41.6	1.089	1.030	45.3	1,307,540	0.04%	0.37%
49	SL	812,111	696.444%	26.6	1.089	1.030	29.0	836,474	0.02%	0.24%
	TOTAL	342,847,653		116,211.1			126,553.9	353,133,084	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	57.73%	4.41%	62.14%	$4,663,167	0.02370	0.02372	0.04591	0.06963
51	GS	8.17%	0.67%	8.84%	663,379	0.02218	0.02220	0.04591	0.06811
52	GSD	20.01%	1.96%	21.97%	1,648,693	0.01889	0.01890	0.04591	0.06481
53	GSLD	6.34%	0.60%	6.94%	520,798	0.01941	0.01942	0.04591	0.06533
54	OL	0.04%	0.03%	0.07%	5,253	0.00414	0.00414	0.04591	0.05005
55	SL	0.02%	0.02%	0.04%	3,002	0.00370	0.00370	0.04591	0.04961
	TOTAL	92.31%	7.69%	100.00%	$7,504,291				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	196,751,257	$0.06963	$13,699,790
49	RS	<= 1,000kWh/mo.	130,754,983	$0.06628	$8,665,878
50	RS	> 1,000 kWh/mo.	65,996,274	$0.07628	$5,033,912
51	RS	Total Sales	196,751,257		$13,699,790

(2) From Florida Power & Light Co. 2003 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2007 - DECEMBER 2007
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FERNANDINA BEACH (NORTHEAST DIVISION)

Under-recovery of purchased power costs for the period January 2007 - December 2007. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2007.)(Estimated)	$	(5,040)
Estimated kilowatt hour sales for the months of January 2008-December 2008 as per estimate filed with the Commission. (Excludes GSLD1 customers)		342,847,653
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2008 - December 2008		-0.00147

Exhibit No._____
DOCKET NO. 070001-EI
Florida Public Utilities Company
(MK-1)
Page 10 of 14

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH (NORTHEAST DIVISION)

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,647,688	1,926,215	1,724,437	1,486,545	1,676,525	1,813,347	2,234,343	1,869,309	1,898,790	1,767,581	1,366,771	1,498,266	20,909,817	3
3a	DEMAND & NON FUEL COST OF PUR POWER		845,327	1,277,550	822,702	760,655	892,786	912,964	984,525	964,515	861,974	755,943	761,342	785,332	10,625,615	3a
3b	QUALIFYING FACILITIES		28,941	28,941	28,941	28,941	28,941	28,941	28,941	28,941	28,941	28,941	28,941	28,941	347,292	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,521,956	3,232,706	2,576,080	2,276,141	2,598,252	2,755,252	3,247,809	2,862,765	2,789,705	2,552,465	2,157,054	2,312,539	31,882,724	5
5a	LESS: TOTAL DEMAND COST RECOVERY		625,796	799,976	492,544	523,312	645,891	649,527	710,867	740,769	640,988	554,816	540,804	579,000	7,504,290	5a
5b	TOTAL OTHER COST TO BE RECOVERED		1,896,160	2,432,730	2,083,536	1,752,829	1,952,361	2,105,725	2,536,942	2,121,996	2,148,717	1,997,649	1,616,250	1,733,539	24,378,434	5b
6	APPORTIONMENT TO GSLD1 CLASS		621,396	1,220,543	868,202	686,684	795,602	695,525	724,021	701,330	604,132	586,961	544,012	605,140	8,653,549	6
6a	BALANCE TO OTHER CLASSES		1,274,764	1,212,187	1,215,334	1,066,145	1,156,759	1,410,200	1,812,921	1,420,666	1,544,585	1,410,688	1,072,238	1,128,399	15,724,885	6a
6b	SYSTEM KWH SOLD (MWH)		39,643	46,232	41,459	35,831	40,325	43,562	53,521	44,886	45,583	42,479	32,998	36,108	502,627	6b
7	GSLD1 MWH SOLD		11,824	19,973	15,019	12,623	15,179	12,782	13,901	13,901	11,824	11,664	9,587	11,504	159,781	7
7a	BALANCE MWH SOLD OTHER CLASSES		27,819	26,259	26,440	23,208	25,146	30,780	39,620	30,985	33,759	30,815	23,411	24,604	342,846	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		4.58235	4.61627	4.59657	4.59387	4.60017	4.58155	4.57577	4.58501	4.57533	4.57793	4.58006	4.58624	4.58657	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		4.58235	4.61627	4.59657	4.59387	4.60017	4.58155	4.57577	4.58501	4.57533	4.57793	4.58006	4.58624	4.58657	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	5,040	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	0.00147	11
12	TOTAL		4.58382	4.61774	4.59804	4.59534	4.60164	4.58302	4.57724	4.58648	4.57680	4.57940	4.58153	4.58771	4.58804	12
13	REVENUE TAX FACTOR	0.00072	0.00330	0.00332	0.00331	0.00331	0.00331	0.00330	0.00330	0.00330	0.00330	0.00330	0.00330	0.00330	0.00330	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		4.58712	4.62106	4.60135	4.59865	4.60495	4.58632	4.58054	4.58978	4.58010	4.58270	4.58483	4.59101	4.59134	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		4.587	4.621	4.601	4.599	4.605	4.586	4.581	4.59	4.58	4.583	4.585	4.591	4.591	15

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 11 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH (NORTHEAST DIVISION)
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	41,048,519			41,048,519	4.014001	6.073337	1,647,688
FEBRUARY 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	47,987,424			47,987,424	4.014000	6.676260	1,926,215
MARCH 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	42,960,554			42,960,554	4.014001	5.929018	1,724,437
APRIL 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,034,006			37,034,006	4.014000	6.067937	1,486,545
MAY 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	41,766,945			41,766,945	4.014000	6.151542	1,676,525
JUNE 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	45,175,571			45,175,571	4.013999	6.034923	1,813,347
JULY 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	55,663,763			55,663,763	4.013999	5.782699	2,234,343
AUGUST 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	46,569,728			46,569,728	4.014000	6.085120	1,869,309
SEPTEMBER 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	47,304,177			47,304,177	4.014001	5.836195	1,898,790
OCTOBER 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	44,035,400			44,035,400	4.014000	5.730671	1,767,581
NOVEMBER 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,050,106			34,050,106	4.013999	6.249945	1,366,771
DECEMBER 2008	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,326,015			37,326,015	4.013999	6.117980	1,498,266
TOTAL			520,922,208	0	0	520,922,208	4.014000	6.053770	20,909,817

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 12 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH (NORTHEAST DIVISION)
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
FEBRUARY 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
MARCH 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
APRIL 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
MAY 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
JUNE 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
JULY 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
AUGUST 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
SEPTEMBER 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
OCTOBER 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
NOVEMBER 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
DECEMBER 2008	JEFFERSON SMURFIT CORPORATION		700,000			700,000	4.134429	4.134429	28,941
TOTAL			8,400,000	0	0	8,400,000	4.134429	4.134429	347,292

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 13 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH (NORTHEAST DIVISION)
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

	JANUARY 2008	FEBRUARY 2008	MARCH 2008	APRIL 2008	MAY 2008	JUNE 2008	JULY 2008
BASE RATE REVENUES ** $	24.33	24.33	24.33	24.33	24.33	24.33	24.33
FUEL RECOVERY FACTOR CENTS/KWH	6.63	6.63	6.63	6.63	6.63	6.63	6.63
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	66.28	66.28	66.28	66.28	66.28	66.28	66.28
GROSS RECEIPTS TAX	2.32	2.32	2.32	2.32	2.32	2.32	2.32
TOTAL REVENUES *** $	92.93	92.93	92.93	92.93	92.93	92.93	92.93

	AUGUST 2008	SEPTEMBER 2008	OCTOBER 2008	NOVEMBER 2008	DECEMBER 2008	PERIOD TOTAL
BASE RATE REVENUES ** $	24.33	24.33	24.33	24.33	24.33	291.96
FUEL RECOVERY FACTOR CENTS/KWH	6.63	6.63	6.63	6.63	6.63	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	66.28	66.28	66.28	66.28	66.28	795.36
GROSS RECEIPTS TAX	2.32	2.32	2.32	2.32	2.32	27.84
TOTAL REVENUES *** $	92.93	92.93	92.93	92.93	92.93	1,115.16

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	10.00
CENTS/KWH	13.73
CONSERVATION FACTOR	0.600
	24.33

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 14 OF 14

REDACTED

MEMORANDUM

October 19, 2007

TO: OFFICE OF COMMISSION CLERK

FROM: OFFICE OF THE GENERAL COUNSEL (ZELLNER) P.Z.

RE: DOCKET NO. 070001-EI – FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.

Please file the attached REDACTED Exhibit MK-1 to the prefiled testimony of FPUC witness Mehrdad Khojasteh, in the above-referenced docket.

DATE TRANSFERRED TO CLK 10/19/07.

PZ
Attachment

CMP _____
COM _____
CTR _____
ECR _____
GCL _____
OPC _____
RCA _____
SCR _____
SGA _____
SEC _____
OTH M-L

DOCUMENT NUMBER-DATE
09571 OCT 19 07
FPSC-COMMISSION CLERK

LAW OFFICES
MESSER, CAPARELLO & SELF, P.A.
A PROFESSIONAL ASSOCIATION
P.O. BOX 15579
TALLAHASSEE, FLORIDA 32317
STREET ADDRESS: 2618 CENTENNIAL PLACE (32308)
TELEPHONE: (850) 222-0720
TELECOPIER: (850)224-4359

TELECOPY MEMORANDUM

TO: Patty

FAX PHONE NO.: 413-6209

FROM: Norman H. Horton, Jr.

DATE: October 19, 2007

SUBJECT/
MESSAGE: Docket No. 070001-EI

Florida Public Utilities Company's Redacted version of Exhibit MK-1 filed on September 5, 2007

Number of Pages (including this cover page): 7

Contact: Please call Ann Bassett at 201-5225 if you have problems or questions about this transmission.

THE INFORMATION CONTAINED IN THIS TELECOPY MESSAGE IS CONFIDENTIAL, ATTORNEY-CLIENT PRIVILEGED INFORMATION INTENDED ONLY FOR THE USE OF THE INDIVIDUAL OR ENTITY NAMED ABOVE. IF THE READER OF THIS MESSAGE IS NOT THE INTENDED RECIPIENT, YOU ARE HEREBY NOTIFIED THAT ANY DISSEMINATION, DISTRIBUTION, OR COPYING OF THIS COMMUNICATION IS STRICTLY PROHIBITED. IF YOU HAVE RECEIVED THIS COMMUNICATION IN ERROR, PLEASE IMMEDIATELY NOTIFY US BY TELEPHONE, AND RETURN THE ORIGINAL MESSAGE TO US AT THE ABOVE ADDRESS VIA THE U.S. POSTAL SERVICE. THANK YOU.

DOCUMENT NUMBER-DATE
09571 OCT 19 07
FPSC-COMMISSION CLERK

EXHIBIT "A"

Identification	Page	Lines	Columns
Direct Testimony of Mehrdad Khojasteh	4	29	
Exhibit MK-1; (Schedule E1)	1 of 14	6	a and c
		10	a and c
		10a	a
		12	a and c
		13	a and c
		20	a and c
		24	a and c
		25	a
		26	a and c
		27	a and c
		30	a and c
		32	c
		33	c
Exhibit MK-1, (Schedule E1)	2 of 14	41 - 47	13
		41 - 46	16
Exhibit MK-1 (Schedule E2)	4 of 14	3	a - m
		3a	a - m
		5	a - m
		6	a - m
		7	a - m
		7b	a - m
		9	a - m
		12	a - m
Exhibit MK-1 (Schedule E-7)	5 of 14	all	8 - 10
Exhibit MK-1 (Schedule E-10)	6 of 14	all but total	all

DOCUMENT NUMBER-DATE
09571 OCT 19 07
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

SCHEDULE E1
PAGE 1 OF 2

	MARIANNA (NORTHWEST DIVISION)	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)		0	
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)		383,453	
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Transformation Cost of Purch Power (E2)		383,453	
10a	Demand Costs of Purchased Power	*		
10b	Transformation Energy & Customer Costs of Purchased Power	984,240 *		
11	Energy Payments to Qualifying Facilities (E8a)			
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)		383,453	
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)		383,453	
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)		383,453	
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	24,136 *	342	0.00680
23	T & D Losses	2,000,107 *	28,341	0.56378
24	SYSTEM MWH SALES		354,770	
25	Less Total Demand Cost Recovery	***		
26	Jurisdictional MWH Sales		354,770	
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses		354,770	
28	GPIF **			
29	TRUE-UP **	3,856	354,770	0.00109
30	TOTAL JURISDICTIONAL FUEL COST		354,770	
31	Revenue Tax Factor			1.00072
32	Fuel Factor Adjusted for Taxes			
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH			

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 1 OF 14

SCHEDULE E 1
PAGE 2 OF 2

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008
0

MARIANNA (NORTHWEST DIVISION)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	156,110,893	61.971%	57,513.6	1.089	1.030	62,632.3	160,794,220	49.06%	44.00%
35	GS	30,861,060	64.200%	10,974.9	1.089	1.030	11,951.7	31,786,892	9.36%	8.70%
36	GSD	96,134,852	73.168%	29,997.5	1.089	1.030	32,667.3	99,018,898	25.58%	27.10%
37	GSLD	66,464,661	84.178%	18,026.8	1.089	1.030	19,631.2	68,458,601	15.37%	18.73%
38	OL, OL1	4,040,542	160.732%	573.9	1.089	1.030	625.0	4,161,758	0.49%	1.14%
39	SL1, SL2 & SL3	1,156,154	160.732%	164.2	1.089	1.030	178.8	1,190,839	0.14%	0.33%
40	TOTAL	354,768,162		117,250.9			127,686.3	365,411,208	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072 Demand Cost Recovery	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	45.28%	3.39%	48.67%	[redacted]	0.03232	0.03234	[redacted]	$0.07945
42	GS	8.64%	0.67%	9.31%		0.03127	0.03129		$0.07840
43	GSD	23.61%	2.08%	25.69%		0.02770	0.02772		$0.07483
44	GSLD	14.19%	1.44%	15.63%		0.02438	0.02440		$0.07151
45	OL, OL1	0.45%	0.09%	0.54%		0.01385	0.01386		$0.06097
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%		0.01434	0.01435		$0.06145
47	TOTAL	92.30%	7.70%	100.00%					

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	156,110,893	$0.07945	$12,403,010
49	RS	<= 1,000kWh/mo.	103,746,616	$0.07610	$7,894,671
50	RS	> 1,000 kWh/mo.	52,364,277	$0.08610	$4,508,339
51	RS	Total Sales	156,110,893		$12,403,010

(2) From Gulf Power Co. 2003 Load Research results.
(4) From Fernandina Rate Case.

EXHIBIT NO._____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 2 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA (NORTHWEST DIVISION)
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

LINE NO.			(a) 2008 JANUARY	(b) 2008 FEBRUARY	(c) ESTIMATED 2008 MARCH	(d) 2008 APRIL	(e) 2008 MAY	(f) 2008 JUNE	(g) 2008 JULY	(h) 2008 AUGUST	(i) 2008 SEPTEMBER	(j) 2008 OCTOBER	(k) 2008 NOVEMBER	(l) 2008 DECEMBER	(m) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER															3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER															3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)															5
6	LESS: TOTAL DEMAND COST RECOVERY															6
7	TOTAL OTHER COST TO BE RECOVERED															7
7a	SYSTEM KWH SOLD (MWH)		31,248	25,540	25,792	25,295	25,454	31,991	35,201	34,007	36,136	31,697	23,797	28,813	354,770	7a
7b	COST PER KWH SOLD (CENTS/KWH)															7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)															9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	0.00109	11
12	TOTAL															12
13	REVENUE TAX FACTOR	0.00072	0.00338	0.00342	0.00342	0.00342	0.00342	0.00337	0.00336	0.00338	0.00335	0.00338	0.00344	0.00340	0.00339	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		4.69571	4.75450	4.75129	4.75751	4.75547	4.68959	4.66626	4.67440	4.66025	4.69198	4.77797	4.71993	4.71069	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENTS/KWH		4.696	4.754	4.751	4.758	4.755	4.690	4.666	4.674	4.660	4.692	4.778	4.720	4.711	15

EXHIBIT NO. _____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 4 OF 14

Oct 19 2007 10:50 P.05
MESSER CAPARELLO &SELF Fax:8502244359

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA (NORTHWEST DIVISION)
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(9) CENTS/KWH (B) TOTAL COST	(10) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2008	GULF POWER COMPANY	RE	33,771,952			33,771,952	[redacted]		
FEBRUARY 2008	GULF POWER COMPANY	RE	27,605,321			27,605,321			
MARCH 2008	GULF POWER COMPANY	RE	27,877,261			27,877,261			
APRIL 2008	GULF POWER COMPANY	RE	27,341,053			27,341,053			
MAY 2008	GULF POWER COMPANY	RE	27,511,673			27,511,673			
JUNE 2008	GULF POWER COMPANY	RE	34,577,240			34,577,240			
JULY 2008	GULF POWER COMPANY	RE	38,047,206			38,047,206			
AUGUST 2008	GULF POWER COMPANY	RE	36,756,345			36,756,345			
SEPTEMBER 2008	GULF POWER COMPANY	RE	39,058,077			39,058,077			
OCTOBER 2008	GULF POWER COMPANY	RE	34,259,455			34,259,455			
NOVEMBER 2008	GULF POWER COMPANY	RE	25,720,954			25,720,954			
DECEMBER 2008	GULF POWER COMPANY	RE	30,926,387			30,926,387			
TOTAL			383,452,924	0	0	383,452,924	[redacted]		

EXHIBIT NO. _____
DOCKET NO. _070001-E1
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 5 OF 14

MESSER CAPARELLO &SELF FAX:8502244359 OCT 19 2007 10:50 P.06

MESSER CAPARELLO &SELF Fax:8502244359 Oct 19 2007 10:51 P.07

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA (NORTHWEST DIVISION)
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

	JANUARY 2008	FEBRUARY 2008	MARCH 2008	APRIL 2008	MAY 2008	JUNE 2008	JULY 2008
BASE RATE REVENUES ** $	[redacted]						
FUEL RECOVERY FACTOR CENTS/KWH							
GROUP LOSS MULTIPLIER							
FUEL RECOVERY REVENUES $							
GROSS RECEIPTS TAX							
TOTAL REVENUES *** $	103.01	103.01	103.01	103.01	103.01	103.01	103.01

	AUGUST 2008	SEPTEMBER 2008	OCTOBER 2008	NOVEMBER 2008	DECEMBER 2008	PERIOD TOTAL
BASE RATE REVENUES ** $	[redacted]					[redacted]
FUEL RECOVERY FACTOR CENTS/KWH						
GROUP LOSS MULTIPLIER						
FUEL RECOVERY REVENUES $						
GROSS RECEIPTS TAX						
TOTAL REVENUES *** $	103.01	103.01	103.01	103.01	103.01	1,236.12

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE [redacted]
CENTS/KWH
CONSERVATION FACTOR

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. _070001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MK-1)
PAGE 6 OF 14

GULF POWER COMPANY
COAL SUPPLIERS
January 1, 2006 – December 31, 2006

Contract Coal Suppliers	Tons Purchased (1)(2)	
Peabody Coaltrade LLC	756,948	
Interocean Coal Sales, LDC	704,092	
International Coal Group, LLC	247,581	
Twentymile Coal Company (Plant Daniel)	543,525	
Interocean Coal Sales, LDC (Plant Daniel)	135,180	
Oxbow Carbon & Minerals (Plant Daniel)	60,429	
TOTAL Contract Coal		2,387,326

Spot Coal Suppliers	Tons Purchased (1)(2)	
Interocean Coal Sales, LDC	1,207,121	
Glencore Ltd.	730,529	
Peabody Coaltrade LLC	302,596	
The American Coal Company	163,188	
Drummond Coal Sales, Inc.	75,965	
Powell Mountain Coal Company	41,435	
Logan & Kanawha Coal Co., Inc.	9,312	
Arch Coal Inc. (Plant Daniel	643476	
Arch Coal Sales Company, Inc. (Plant Daniel)	60652	
Interocean Coal Sales, LDC (Plant Daniel)	64233	
Twentymile Coal Company (Plant Daniel)	128,108	
Glencore Ltd. (Plant Daniel)	78,015	
Oxbow Carbon & Minerals (Plant Daniel)	24,033	
Roundup Trading Int., LLC (Plant Daniel)	13,514	
TOTAL Spot Coal		3,542,177

GRAND TOTAL COAL PURCHASES	5,929,502

(1) Excludes Plant Scherer.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 27
COMPANY Gulf Power Co.
WITNESS H.R. Ball (HRB-1)
DATE 11-06-07

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 1 of 1

This information has been provided pursuant to the Request for Confidential Classification filed on March 1, 2007.

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB 1)
Schedule 2
Page 1 of 18

	Invoice for Totals by	GULF for the	NYMEX	Settlement	for January 2006	2/1/2006

Counter Party	Swap Total	Option Total	Counter Party Total
BANKAMER	$ (105,250)	$ -	$ (105,250)
BARCLAYS	$ 12,600	$ -	$ 12,600
CIBC	$ (58,700)	$ -	$ (58,700)
DETM	$ -	$ -	$ -
DEUTSCHE	$ (36,740)	$ -	$ (36,740)
EPPS	$ -	$ -	$ -
JPMORGAN	$ 41,700	$ -	$ 41,700
MITSUI	$ 94,350	$ -	$ 94,350
MORGAN	$ -	$ -	$ -
Total for GULF	**$ (52,040)**	**$ -**	**$ (52,040)**

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CP Index	CPSettlef	SoCoPrice	Index	SettlePrice	SettleAmount
GULF		50 BANKAMER	Swap	6-Jan	50000	[redacted]						
GULF		50 BANKAMER	Swap	6-Jan	20000							
GULF		50 BANKAMER	Swap	6-Jan	20000							
GULF		50 BANKAMER	Swap	6-Jan	10000							
GULF		50 BANKAMER	Swap	6-Jan	10000							
GULF		50 BANKAMER	Swap	6-Jan	20000							
		BANKAMER Total:										
GULF		50 BARCLAYS	Swap	6-Jan	40000							
GULF		50 BARCLAYS	Swap	6-Jan	50000							
GULF		50 BARCLAYS	Swap	6-Jan	50000							
GULF		50 BARCLAYS	Swap	6-Jan	20000							
GULF		50 BARCLAYS	Swap	6-Jan	10000							
GULF		50 BARCLAYS	Swap	6-Jan	20000							
GULF		50 BARCLAYS	Swap	6-Jan	80000							
		BARCLAYS Total:										
GULF		50 CIBC	Swap	6-Jan	50000							
GULF		50 CIBC	Swap	6-Jan	20000							
GULF		50 CIBC	Swap	6-Jan	20000							
GULF		50 CIBC	Swap	6-Jan	10000							
GULF		50 CIBC	Swap	6-Jan	10000							
GULF		50 CIBC	Swap	6-Jan	80000							
GULF		50 CIBC	Swap	6-Jan	60000							
		CIBC Total:										
GULF		50 DEUTSCHE	Swap	6-Jan	50000							
GULF		50 DEUTSCHE	Swap	6-Jan	20000							
GULF		50 DEUTSCHE	Swap	6-Jan	10000							
GULF		50 DEUTSCHE	Swap	6-Jan	30000							
GULF		50 DEUTSCHE	Swap	6-Jan	60000							
GULF		50 DEUTSCHE	Swap	6-Jan	50000							
GULF		50 DEUTSCHE	Swap	6-Jan	80000							
		DEUTSCHE Total:										
GULF		50 JPMORGAN	Swap	6-Jan	60000							
		JPMORGAN Total:										
GULF		50 MITSUI	Swap	6-Jan	40000							
GULF		50 MITSUI	Swap	6-Jan	50000							
GULF		50 MITSUI	Swap	6-Jan	50000							
GULF		50 MITSUI	Swap	6-Jan	20000							
GULF		50 MITSUI	Swap	6-Jan	30000							
GULF		50 MITSUI	Swap	6-Jan	20000							
		MITSUI Total:										

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB 1)
Schedule 2
Page 2 of 18

	Invoice for Totals by	GULF for the	NYMEX	Settlement	for February 2006	3/1/2006

Counter Party	Swap Total	Option Total	Counter Party Total
BANKAMER	$ (185,270.00)	$ -	$ (185,270.00)
BARCLAYS	$ (213,650.00)	$ -	$ (213,650.00)
CIBC	$ (255,220.00)	$ -	$ (255,220.00)
DETM	$ -	$ -	$ -
DEUTSCHE	$ (186,260.00)	$ -	$ (186,260.00)
EPPS	$ -	$ -	$ -
JPMORGAN	$ 40,133.00	$ -	$ 40,133.00
MITSUI	$ (94,700.00)	$ -	$ (94,700.00)
MORGAN	$ -	$ -	$ -
Total for GULF	**$ (894,967.00)**	**$ -**	**$ (894,967.00)**

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CP Index	CPSettlePric	SoCoPrice	Index	SettlePrice	SettleAmount
GULF	50	BANKAMER	Swap	6-Feb	50000							
GULF	50	BANKAMER	Swap	6-Feb	20000							
GULF	50	BANKAMER	Swap	6-Feb	20000							
GULF	50	BANKAMER	Swap	6-Feb	10000							
GULF	50	BANKAMER	Swap	6-Feb	20000							
GULF	50	BANKAMER	Swap	6-Feb	120000							
		BANKAMER Total:										
GULF	50	BARCLAYS	Swap	6-Feb	40000							
GULF	50	BARCLAYS	Swap	6-Feb	50000							
GULF	50	BARCLAYS	Swap	6-Feb	50000							
GULF	50	BARCLAYS	Swap	6-Feb	20000							
GULF	50	BARCLAYS	Swap	6-Feb	10000							
GULF	50	BARCLAYS	Swap	6-Feb	30000							
GULF	50	BARCLAYS	Swap	6-Feb	20000							
GULF	50	BARCLAYS	Swap	6-Feb	110000							
		BARCLAYS Total:										
GULF	50	CIBC	Swap	6-Feb	50000							
GULF	50	CIBC	Swap	6-Feb	20000							
GULF	50	CIBC	Swap	6-Feb	20000							
GULF	50	CIBC	Swap	6-Feb	10000							
GULF	50	CIBC	Swap	6-Feb	10000							
GULF	50	CIBC	Swap	6-Feb	20000							
GULF	50	CIBC	Swap	6-Feb	10000							
GULF	50	CIBC	Swap	6-Feb	20000							
GULF	50	CIBC	Swap	6-Feb	20000							
		CIBC Total:										
GULF	50	DEUTSCHE	Swap	6-Feb	50000							
GULF	50	DEUTSCHE	Swap	6-Feb	20000							
GULF	50	DEUTSCHE	Swap	6-Feb	10000							
GULF	50	DEUTSCHE	Swap	6-Feb	30000							
GULF	50	DEUTSCHE	Swap	6-Feb	10000							
GULF	50	DEUTSCHE	Swap	6-Feb	20000							
		DEUTSCHE Total:										
GULF	50	JPMORGAN	Swap	6-Feb	30000							
GULF	50	JPMORGAN	Swap	6-Feb	20000							
		JPMORGAN Total:										
GULF	50	MITSUI	Swap	6-Feb	40000							
GULF	50	MITSUI	Swap	6-Feb	50000							
GULF	50	MITSUI	Swap	6-Feb	50000							
GULF	50	MITSUI	Swap	6-Feb	20000							
GULF	50	MITSUI	Swap	6-Feb	10000							
GULF	50	MITSUI	Swap	6-Feb	80000							
GULF	50	MITSUI	Swap	6-Feb	30000							
		MITSUI Total:										

	Invoice for Totals by	GULF for the	NYMEX	Settlement	for March 2006	3/31/2006
	Counter Party	Swap Total	Option Total	Counter Party Total		
	BANKAMER	$ (206,840.00)	$ -	$ (206,840.00)		
	BARCLAYS	$ (390,680.00)	$ -	$ (390,680.00)		
	CIBC	$ (1,151,430.00)	$ -	$ (1,151,430.00)		
	DEUTSCHE	$ (221,400.00)	$ -	$ (221,400.00)		
	JPMORGAN	$ (60,920.00)	$ -	$ (60,920.00)		
	MITSUI	$ (338,480.00)	$ -	$ (338,480.00)		
	Total for GULF	**$ (2,369,750.00)**	**$ -**	**$ (2,369,750.00)**		

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrice	SoCoPrice	SoCoNdx	SoCoSettlePr	SettleAmount
GULF	50	BANKAMER	Swap	6-Mar	30000							
GULF	50	BANKAMER	Swap	6-Mar	20000							
GULF	50	BANKAMER	Swap	6-Mar	20000							
GULF	50	BANKAMER	Swap	6-Mar	10000							
		BANKAMER Total:										
GULF	50	BARCLAYS	Swap	6-Mar	50000							
GULF	50	BARCLAYS	Swap	6-Mar	30000							
GULF	50	BARCLAYS	Swap	6-Mar	40000							
GULF	50	BARCLAYS	Swap	6-Mar	20000							
GULF	50	BARCLAYS	Swap	6-Mar	30000							
GULF	50	BARCLAYS	Swap	6-Mar	30000							
		BARCLAYS Total:										
GULF	50	CIBC	Swap	6-Mar	10000							
GULF	50	CIBC	Swap	6-Mar	250000							
GULF	50	CIBC	Swap	6-Mar	30000							
GULF	50	CIBC	Swap	6-Mar	30000							
GULF	50	CIBC	Swap	6-Mar	30000							
GULF	50	CIBC	Swap	6-Mar	20000							
GULF	50	CIBC	Swap	6-Mar	60000							
GULF	50	CIBC	Swap	6-Mar	20000							
		CIBC Total:										
GULF	50	DEUTSCHE	Swap	6-Mar	30000							
GULF	50	DEUTSCHE	Swap	6-Mar	20000							
GULF	50	DEUTSCHE	Swap	6-Mar	10000							
GULF	50	DEUTSCHE	Swap	6-Mar	20000							
GULF	50	DEUTSCHE	Swap	6-Mar	20000							
GULF	50	DEUTSCHE	Swap	6-Mar	30000							
GULF	50	DEUTSCHE	Swap	6-Mar	20000							
		DEUTSCHE Total:										
GULF	50	JPMORGAN	Swap	6-Mar	50000							
GULF	50	JPMORGAN	Swap	6-Mar	30000							
GULF	50	JPMORGAN	Swap	6-Mar	40000							
GULF	50	JPMORGAN	Swap	6-Mar	20000							
		JPMORGAN Total:										
GULF	50	MITSUI	Swap	6-Mar	20000							
GULF	50	MITSUI	Swap	6-Mar	20000							
GULF	50	MITSUI	Swap	6-Mar	30000							
GULF	50	MITSUI	Swap	6-Mar	10000							
GULF	50	MITSUI	Swap	6-Mar	80000							
GULF	50	MITSUI	Swap	6-Mar	30000							
GULF	50	MITSUI	Swap	6-Mar	10000							
		MITSUI Total:										

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 4 of 18

	Invoice for	GULF for the	NYMEX	Settlement	for April 2006	5/1/2006
	Totals by					
	Counter Party	Swap Total	Option Total	Counter Party Total		
	BANKAMER	$ (201,370.00)	$ -	$ (201,370.00)		
	BARCLAYS	$ (11,120.00)	$ -	$ (11,120.00)		
	CIBC	$ (29,220.00)	$ -	$ (29,220.00)		
	DEUTSCHE	$ (350,540.00)	$ -	$ (350,540.00)		
	JPMORGAN	$ (308,210.00)	$ -	$ (308,210.00)		
	MITSUI	$ 4,600.00	$ -	$ 4,600.00		
	System-PPLR	$ (80,540.00)	$ -	$ (80,540.00)		
	Total for GULF	**$ (976,400.00)**	**$ -**	**$ (976,400.00)**		

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoSettleP	SettleAmount
GULF		50 BANKAMER	Swap	6-Apr	50000							
GULF		50 BANKAMER	Swap	6-Apr	20000							
GULF		50 BANKAMER	Swap	6-Apr	20000							
GULF		50 BANKAMER	Swap	6-Apr	40000							
GULF		50 BANKAMER	Swap	6-Apr	20000							
		BANKAMER Total:										
GULF		50 BARCLAYS	Swap	6-Apr	50000							
GULF		50 BARCLAYS	Swap	6-Apr	60000							
GULF		50 BARCLAYS	Swap	6-Apr	10000							
GULF		50 BARCLAYS	Swap	6-Apr	20000							
GULF		50 BARCLAYS	Swap	6-Apr	20000							
GULF		50 BARCLAYS	Swap	6-Apr	50000							
GULF		50 BARCLAYS	Swap	6-Apr	20000							
GULF		50 BARCLAYS	Swap	6-Apr	50000							
GULF		50 BARCLAYS	Swap	6-Apr	60000							
		BARCLAYS Total:										
GULF		50 CIBC	Swap	6-Apr	10000							
GULF		50 CIBC	Swap	6-Apr	50000							
GULF		50 CIBC	Swap	6-Apr	20000							
GULF		50 CIBC	Swap	6-Apr	20000							
GULF		50 CIBC	Swap	6-Apr	40000							
GULF		50 CIBC	Swap	6-Apr	20000							
GULF		50 CIBC	Swap	6-Apr	20000							
GULF		50 CIBC	Swap	6-Apr	30000							
GULF		50 CIBC	Swap	6-Apr	50000							
		CIBC Total:										

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB 1)
Schedule 2
Page 6 of 18

	Invoice for	GULF for the	NYMEX	Settlement	for May 2006	5/31/2006
	Totals by					
	Counter Party	Swap Total	Option Total	Counter Party Total		
	BANKAMER	$ (188,560.00)	$ -	$ (188,560.00)		
	BARCLAYS	$ (106,600.00)	$ -	$ (106,600.00)		
	CIBC	$ (330,225.00)	$ -	$ (330,225.00)		
	DEUTSCHE	$ (436,150.00)	$ -	$ (436,150.00)		
	JPMORGAN	$ (84,510.00)	$ -	$ (84,510.00)		
	MITSUI	$ (202,800.00)	$ -	$ (202,800.00)		
	Total for GULF	**$ (1,348,845.00)**	**$ -**	**$ (1,348,845.00)**		

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SettlePrice	SettleAmount
GULF		50 BANKAMER	Swap	6-May	50000	[redacted]						
GULF		50 BANKAMER	Swap	6-May	20000							
GULF		50 BANKAMER	Swap	6-May	20000							
GULF		50 BANKAMER	Swap	6-May	40000							
GULF		50 BANKAMER	Swap	6-May	20000							
GULF		50 BANKAMER	Swap	6-May	20000							
		BANKAMER Total:										
GULF		50 BARCLAYS	Swap	6-May	50000							
GULF		50 BARCLAYS	Swap	6-May	20000							
GULF		50 BARCLAYS	Swap	6-May	70000							
GULF		50 BARCLAYS	Swap	6-May	50000							
GULF		50 BARCLAYS	Swap	6-May	60000							
GULF		50 BARCLAYS	Swap	6-May	20000							
GULF		50 BARCLAYS	Swap	6-May	20000							
GULF		50 BARCLAYS	Swap	6-May	20000							
GULF		50 BARCLAYS	Swap	6-May	70000							
GULF		50 BARCLAYS	Swap	6-May	50000							
		BARCLAYS Total:										
GULF		50 CIBC	Swap	6-May	100000							
GULF		50 CIBC	Swap	6-May	30000							
GULF		50 CIBC	Swap	6-May	20000							
GULF		50 CIBC	Swap	6-May	30000							
GULF		50 CIBC	Swap	6-May	10000							
GULF		50 CIBC	Swap	6-May	40000							
GULF		50 CIBC	Swap	6-May	50000							
GULF		50 CIBC	Swap	6-May	20000							
GULF		50 CIBC	Swap	6-May	20000							
GULF		50 CIBC	Swap	6-May	40000							
GULF		50 CIBC	Swap	6-May	50000							
GULF		50 CIBC	Swap	6-May	90000							
		CIBC Total:										

GULF	50 DEUTSCHE	Swap	6-May	30000	[redacted]
GULF	50 DEUTSCHE	Swap	6-May	30000	
GULF	50 DEUTSCHE	Swap	6-May	40000	
GULF	50 DEUTSCHE	Swap	6-May	70000	
GULF	50 DEUTSCHE	Swap	6-May	20000	
GULF	50 DEUTSCHE	Swap	6-May	20000	
GULF	50 DEUTSCHE	Swap	6-May	40000	
GULF	50 DEUTSCHE	Swap	6-May	20000	
GULF	50 DEUTSCHE	Swap	6-May	70000	
	DEUTSCHE Total:				
GULF	50 JPMORGAN	Swap	6-May	70000	
GULF	50 JPMORGAN	Swap	6-May	20000	
GULF	50 JPMORGAN	Swap	6-May	20000	
GULF	50 JPMORGAN	Swap	6-May	70000	
	JPMORGAN Total:				
GULF	50 MITSUI	Swap	6-May	50000	
GULF	50 MITSUI	Swap	6-May	30000	
GULF	50 MITSUI	Swap	6-May	70000	
GULF	50 MITSUI	Swap	6-May	30000	
GULF	50 MITSUI	Swap	6-May	20000	
GULF	50 MITSUI	Swap	6-May	20000	
GULF	50 MITSUI	Swap	6-May	20000	
GULF	50 MITSUI	Swap	6-May	60000	
GULF	50 MITSUI	Swap	6-May	20000	
GULF	50 MITSUI	Swap	6-May	70000	
GULF	50 MITSUI	Swap	6-May	30000	
	MITSUI Total:				

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 8 of 18

	Invoice for	GULF for the	NYMEX	Settlement	for June 2006	6/29/2006
	Totals by					
	Counter Party	Swap Total	Option Total	Counter Party Total		
	BANKAMER	$ (459,960.00)	$ -	$ (459,960.00)		
	BARCLAYS	$ (329,740.00)	$ -	$ (329,740.00)		
	CIBC	$ (629,801.00)	$ -	$ (629,801.00)		
	DEUTSCHE	$ (365,750.00)	$ -	$ (365,750.00)		
	JPMORGAN	$ (52,060.00)	$ -	$ (52,060.00)		
	MITSUI	$ (137,259.00)	$ -	$ (137,259.00)		
	Suisse	$ 6,120.00	$ -	$ 6,120.00		
	GAS DAILY	$ 89,160.00	$ -	$ 89,160.00		
	Total for GULF	**$ (1,879,290.00)**	**$ -**	**$ (1,879,290.00)**		

OpCo	ContractID	CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SettlePrice	SettleAmount
GULF	50	BANKAMER	Swap	6-Jun	50000	[redacted]						
GULF	50	BANKAMER	Swap	6-Jun	40000							
GULF	50	BANKAMER	Swap	6-Jun	30000							
GULF	50	BANKAMER	Swap	6-Jun	30000							
GULF	50	BANKAMER	Swap	6-Jun	30000							
GULF	50	BANKAMER	Swap	6-Jun	50000							
GULF	50	BANKAMER	Swap	6-Jun	30000							
GULF	50	BANKAMER	Swap	6-Jun	10000							
GULF	50	BANKAMER	Swap	6-Jun	50000							
		BANKAMER Total:										
GULF	50	BARCLAYS	Swap	6-Jun	50000							
GULF	50	BARCLAYS	Swap	6-Jun	40000							
GULF	50	BARCLAYS	Swap	6-Jun	100000							
GULF	50	BARCLAYS	Swap	6-Jun	30000							
GULF	50	BARCLAYS	Swap	6-Jun	10000							
GULF	50	BARCLAYS	Swap	6-Jun	60000							
GULF	50	BARCLAYS	Swap	6-Jun	30000							
GULF	50	BARCLAYS	Swap	6-Jun	20000							
GULF	50	BARCLAYS	Swap	6-Jun	20000							
GULF	50	BARCLAYS	Swap	6-Jun	10000							
GULF	50	BARCLAYS	Swap	6-Jun	20000							
GULF	50	BARCLAYS	Swap	6-Jun	10000							
GULF	50	BARCLAYS	Swap	6-Jun	60000							
		BARCLAYS Total:										
GULF	50	CIBC	Swap	6-Jun	100000							
GULF	50	CIBC	Swap	6-Jun	30000							
GULF	50	CIBC	Swap	6-Jun	40000							
GULF	50	CIBC	Swap	6-Jun	30000							
GULF	50	CIBC	Swap	6-Jun	30000							
GULF	50	CIBC	Swap	6-Jun	30000							
GULF	50	CIBC	Swap	6-Jun	10000							
GULF	50	CIBC	Swap	6-Jun	30000							
GULF	50	CIBC	Swap	6-Jun	10000							
GULF	50	CIBC	Swap	6-Jun	60000							
GULF	50	CIBC	Swap	6-Jun	20000							
GULF	50	CIBC	Swap	6-Jun	30000							
		CIBC Total:										

GULF	50	DEUTSCHE	Swap	6-Jun	30000	[redacted]
GULF	50	DEUTSCHE	Swap	6-Jun	30000	
GULF	50	DEUTSCHE	Swap	6-Jun	30000	
GULF	50	DEUTSCHE	Swap	6-Jun	30000	
GULF	50	DEUTSCHE	Swap	6-Jun	10000	
GULF	50	DEUTSCHE	Swap	6-Jun	30000	
GULF	50	DEUTSCHE	Swap	6-Jun	20000	
GULF	50	DEUTSCHE	Swap	6-Jun	20000	
GULF	50	DEUTSCHE	Swap	6-Jun	10000	
GULF	50	DEUTSCHE	Swap	6-Jun	30000	
GULF	50	DEUTSCHE	Swap	6-Jun	10000	
GULF	50	DEUTSCHE	Swap	6-Jun	20000	
		DEUTSCHE Total:				
GULF	50	JPMORGAN	Swap	6-Jun	100000	
GULF	50	JPMORGAN	Swap	6-Jun	30000	
GULF	50	JPMORGAN	Swap	6-Jun	40000	
GULF	50	JPMORGAN	Swap	6-Jun	60000	
GULF	50	JPMORGAN	Swap	6-Jun	60000	
GULF	50	JPMORGAN	Swap	6-Jun	30000	
GULF	50	JPMORGAN	Swap	6-Jun	40000	
		JPMORGAN Total:				
GULF	50	MITSUI	Swap	6-Jun	50000	
GULF	50	MITSUI	Swap	6-Jun	30000	
GULF	50	MITSUI	Swap	6-Jun	30000	
GULF	50	MITSUI	Swap	6-Jun	60000	
GULF	50	MITSUI	Swap	6-Jun	20000	
GULF	50	MITSUI	Swap	6-Jun	20000	
GULF	50	MITSUI	Swap	6-Jun	10000	
GULF	50	MITSUI	Swap	6-Jun	10000	
GULF	50	MITSUI	Swap	6-Jun	30000	
GULF	50	MITSUI	Swap	6-Jun	60000	
GULF	50	MITSUI	Swap	6-Jun	30000	
		MITSUI Total:				
GULF	50	Suisse	Swap	6-Jun	20000	
GULF	50	Suisse	Swap	6-Jun	20000	
		Suisse Total:				

OpCo	ContractID	Swap Deal Detail CounterParty	DealType	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoAdd	SettleAmount
GULF		50 BANKAMER	Swap	6-Jun	300000	[redacted]						
		BANKAMER Total:										

[redacted]

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 10 of 18

Invoice for GULF for the NYMEX Settlement for July 2006

Totals by

Counter Party	Swap Total	Option Total	Counter Party Total
BANKAMER	$ (581,220.00)	$ -	$ (581,220.00)
BARCLAYS	$ (449,840.00)	$ -	$ (449,840.00)
CIBC	$ (1,059,710.00)	$ -	$ (1,059,710.00)
DEUTSCHE	$ (444,250.00)	$ -	$ (444,250.00)
JPMORGAN	$ (191,500.00)	$ -	$ (191,500.00)
MITSUI	$ (358,190.00)	$ -	$ (358,190.00)
Suisse	$ 23,870.00	$ -	$ 23,870.00
GAS DAILY	$ 40,083.00	$ -	$ 40,083.00
Total for GULF	**$ (3,020,757.00)**	**$ -**	**$ (3,020,757.00)**

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoSettleP	SettleAmount
GULF	50	BANKAMER	Swap	2005.34469	1/3/2005 17:40	6-Jul	50000	[redacted]						
GULF	50	BANKAMER	Swap	2005.35953	9/14/2005 15:24	6-Jul	40000							
GULF	50	BANKAMER	Swap	2005.35964	9/15/2005 20:17	6-Jul	30000							
GULF	50	BANKAMER	Swap	2005.35988	9/20/2005 15:14	6-Jul	30000							
GULF	50	BANKAMER	Swap	2006.36647	1/4/2006 17:41	6-Jul	30000							
GULF	50	BANKAMER	Swap	2006.3749	6/26/2006 18:12	6-Jul	30000							
GULF	50	BANKAMER	Swap	2006.37552	7/11/2006 15:28	6-Jul	20000							
GULF	50	BANKAMER	Swap	2006.3749	6/26/2006 18:12	6-Jul	30000							
GULF	50	BANKAMER	Swap	2006.3766	7/25/2006 17:52	6-Jul	20000							
		BANKAMER Total:												
GULF	50	BARCLAYS	Swap	2004.33789	8/16/2004 19:04	6-Jul	50000							
GULF	50	BARCLAYS	Swap	2005.36108	9/30/2005 15:12	6-Jul	40000							
GULF	50	BARCLAYS	Swap	2006.36679	1/9/2006 19:21	6-Jul	10000							
GULF	50	BARCLAYS	Swap	2006.3712	4/28/2006 16:41	6-Jul	100000							
GULF	50	BARCLAYS	Swap	2006.3744	6/22/2006 16:24	6-Jul	50000							
GULF	50	BARCLAYS	Swap	2006.37482	6/26/2006 16:11	6-Jul	30000							
GULF	50	BARCLAYS	Swap	2006.37518	6/30/2006 14:34	6-Jul	100000							
GULF	50	BARCLAYS	Swap	2006.37565	7/13/2006 14:42	6-Jul	30000							
GULF	50	BARCLAYS	Swap	2006.37608	7/20/2006 14:23	6-Jul	20000							
GULF	50	BARCLAYS	Swap	2006.3744	6/22/2006 16:24	6-Jul	50000							
GULF	50	BARCLAYS	Swap	2006.37482	6/26/2006 16:11	6-Jul	30000							
GULF	50	BARCLAYS	Swap	2006.37682	7/27/2006 16:10	6-Jul	70000							
		BARCLAYS Total:												
GULF	50	CIBC	Swap	2004.33827	8/18/2004 16:02	6-Jul	100000							
GULF	50	CIBC	Swap	2005.36022	9/22/2005 18:31	6-Jul	30000							
GULF	50	CIBC	Swap	2005.36039	9/23/2005 18:17	6-Jul	40000							
GULF	50	CIBC	Swap	2005.36051	9/26/2005 15:45	6-Jul	30000							
GULF	50	CIBC	Swap	2005.3613	10/5/2005 17:49	6-Jul	30000							
GULF	50	CIBC	Swap	2005.36603	12/27/2005 19:30	6-Jul	100000							
GULF	50	CIBC	Swap	2006.36658	1/5/2006 18:46	6-Jul	30000							
GULF	50	CIBC	Swap	2006.37425	6/21/2006 18:04	6-Jul	30000							
GULF	50	CIBC	Swap	2006.37478	6/26/2006 16:00	6-Jul	80000							
GULF	50	CIBC	Swap	2006.375	6/26/2006 20:24	6-Jul	70000							
GULF	50	CIBC	Swap	2006.37548	7/10/2006 15:54	6-Jul	20000							
GULF	50	CIBC	Swap	2006.37425	6/21/2006 18:04	6-Jul	30000							
GULF	50	CIBC	Swap	2006.37645	7/24/2006 15:20	6-Jul	20000							
GULF	50	CIBC	Swap	2006.37478	6/26/2006 16:00	6-Jul	80000							
GULF	50	CIBC	Swap	2006.375	6/26/2006 20:24	6-Jul	70000							
		CIBC Total:												

GULF	50	DEUTSCHE	Swap	2005.36099	9/29/2005 15:20	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2005.36117	10/3/2005 16:06	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.36692	1/12/2006 20:40	6-Jul	20000
GULF	50	DEUTSCHE	Swap	2006.37436	6/22/2006 15:41	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.37467	6/23/2006 17:07	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.37494	6/26/2006 18:46	6-Jul	80000
GULF	50	DEUTSCHE	Swap	2006.37524	7/5/2006 14:42	6-Jul	20000
GULF	50	DEUTSCHE	Swap	2006.37573	7/14/2006 15:24	6-Jul	90000
GULF	50	DEUTSCHE	Swap	2006.37602	7/19/2006 16:07	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.37436	6/22/2006 15:41	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.37467	6/23/2006 17:07	6-Jul	30000
GULF	50	DEUTSCHE	Swap	2006.37494	6/26/2006 18:46	6-Jul	80000
		DEUTSCHE Total:					
GULF	50	JPMORGAN	Swap	2006.36884	3/2/2006 19:54	6-Jul	100000
GULF	50	JPMORGAN	Swap	2006.37463	6/23/2006 16:09	6-Jul	50000
GULF	50	JPMORGAN	Swap	2006.37486	6/26/2006 17:48	6-Jul	30000
GULF	50	JPMORGAN	Swap	2006.3756	7/12/2006 15:26	6-Jul	20000
GULF	50	JPMORGAN	Swap	2006.37463	6/23/2006 16:09	6-Jul	50000
GULF	50	JPMORGAN	Swap	2006.37486	6/26/2006 17:48	6-Jul	30000
GULF	50	JPMORGAN	Swap	2006.37626	7/21/2006 14:58	6-Jul	90000
		JPMORGAN Total:					
GULF	50	MITSUI	Swap	2004.33811	8/17/2004 18:54	6-Jul	50000
GULF	50	MITSUI	Swap	2005.36137	10/6/2005 22:12	6-Jul	30000
GULF	50	MITSUI	Swap	2006.37447	6/22/2006 20:35	6-Jul	50000
GULF	50	MITSUI	Swap	2006.3746	6/23/2006 15:31	6-Jul	30000
GULF	50	MITSUI	Swap	2006.37542	7/7/2006 16:01	6-Jul	70000
GULF	50	MITSUI	Swap	2006.3758	7/17/2006 16:10	6-Jul	40000
GULF	50	MITSUI	Swap	2005.36609	12/27/2005 19:46	6-Jul	40000
GULF	50	MITSUI	Swap	2006.37447	6/22/2006 20:35	6-Jul	50000
GULF	50	MITSUI	Swap	2006.3746	6/23/2006 15:31	6-Jul	30000
GULF	50	MITSUI	Swap	2006.37671	7/26/2006 14:19	6-Jul	30000
		MITSUI Total:					
GULF	50	Suisse	Swap	2006.37456	6/23/2006 15:15	6-Jul	30000
GULF	50	Suisse	Swap	2006.37509	6/27/2006 14:33	6-Jul	50000
GULF	50	Suisse	Swap	2006.37532	7/6/2006 14:31	6-Jul	20000
GULF	50	Suisse	Swap	2006.3759	7/18/2006 14:49	6-Jul	20000
GULF	50	Suisse	Swap	2006.37456	6/23/2006 15:15	6-Jul	30000
GULF	50	Suisse	Swap	2006.37509	6/27/2006 14:33	6-Jul	50000
		Suisse Total:					

[redacted]

Option Deals

OpCo	ContractID	CounterParty	DealType	BuySell	DealNumber	TransactionDate	ContractMonth	HedgeMont	Quantity	StrikePrice	SettlePrice	SettlementN	StrikeFlag	SettleAmount
GULF	50	MITSUI	Put-mm	Sell	2004.32622	1/5/2004 19:20	6-Jul	6-Jul	300000	[redacted]				
GULF	50	MITSUI	Put-mm	Buy	2004.33444	6/25/2004 16:38	6-Jul	6-Jul	300000					
		MITSUI Total:												

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	ContractMonth	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrice	SoCoNdx	SoCoAdd	SoCoSettlePr	SettleAmount
GULF	50	MITSUI	Swap	2006.37444	6-Jul	6-Jul	310000	0	Gas Dly	[redacted]				
		MITSUI Total:												

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB_1)
Schedule 2
Page 12 of 18

Invoice for GULF for the NYMEX Settlement for August 2006

Totals by

Counter Party	Swap Total	Option Total	Counter Party Total
BANKAMER	$ (415,050.00)	$ -	$ (415,050.00)
BARCLAYS	$ (161,460.00)	$ -	$ (161,460.00)
CIBC	$ (955,921.00)	$ -	$ (955,921.00)
DEUTSCHE	$ (364,390.00)	$ -	$ (364,390.00)
JPMORGAN	$ (57,050.00)	$ -	$ (57,050.00)
MITSUI	$ (20,912.00)	$ -	$ (20,912.00)
Suisse	$ (39,730.00)	$ -	$ (39,730.00)
GAS DAILY	$ 53,537.00	$ -	$ 53,537.00
Total for GULF	**$ (1,960,976.00)**	**$ -**	**$ (1,960,976.00)**

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoSettleP	SoCoSettleAmount
GULF		50 BANKAMER	Swap	2005.34469	1/3/2005 17:40	6-Aug	50000	[redacted]						
GULF		50 BANKAMER	Swap	2005.35953	9/14/2005 15:24	6-Aug	40000							
GULF		50 BANKAMER	Swap	2005.35964	9/15/2005 20:17	6-Aug	30000							
GULF		50 BANKAMER	Swap	2005.35988	9/20/2005 15:14	6-Aug	30000							
GULF		50 BANKAMER	Swap	2006.36647	1/4/2006 17:41	6-Aug	30000							
GULF		50 BANKAMER	Swap	2006.37656	7/24/2006 19:14	Aug-06	150000							
GULF		50 BANKAMER	Swap	2006.37774	8/14/2006 19:08	Aug-06	30000							
GULF		50 BANKAMER	Swap	2006.37838	8/23/2006 15:18	Aug-06	30000							
GULF		50 BANKAMER	Swap	2006.37656	7/24/2006 19:14	6-Aug	150000							
		BANKAMER Total:												
GULF		50 BARCLAYS	Swap	2004.33789	8/16/2004 19:04	6-Aug	50000							
GULF		50 BARCLAYS	Swap	2005.36108	9/30/2005 15:12	6-Aug	40000							
GULF		50 BARCLAYS	Swap	2006.36679	1/9/2006 19:21	6-Aug	10000							
GULF		50 BARCLAYS	Swap	2006.3712	4/28/2006 16:41	6-Aug	100000							
GULF		50 BARCLAYS	Swap	2006.3763	7/21/2006 15:33	Aug-06	70000							
GULF		50 BARCLAYS	Swap	2006.37679	7/26/2006 21:03	Aug-06	70000							
GULF		50 BARCLAYS	Swap	2006.37714	8/3/2006 14:21	Aug-06	20000							
GULF		50 BARCLAYS	Swap	2006.37751	8/10/2006 19:08	Aug-06	30000							
GULF		50 BARCLAYS	Swap	2006.37826	8/22/2006 14:47	Aug-06	20000							
GULF		50 BARCLAYS	Swap	2006.3763	7/21/2006 15:33	6-Aug	70000							
GULF		50 BARCLAYS	Swap	2006.37679	7/26/2006 21:03	6-Aug	70000							
		BARCLAYS Total:												
GULF		50 CIBC	Swap	2004.33827	8/18/2004 16:02	6-Aug	100000							
GULF		50 CIBC	Swap	2005.36022	9/22/2005 18:31	6-Aug	30000							
GULF		50 CIBC	Swap	2005.36039	9/23/2005 18:17	6-Aug	40000							
GULF		50 CIBC	Swap	2005.36051	9/26/2005 15:45	6-Aug	30000							
GULF		50 CIBC	Swap	2005.3613	10/5/2005 17:49	Aug-06	30000							
GULF		50 CIBC	Swap	2006.37635	7/21/2006 16:12	Aug-06	70000							
GULF		50 CIBC	Swap	2006.37722	8/4/2006 14:41	Aug-06	60000							
GULF		50 CIBC	Swap	2006.3778	8/15/2006 15:21	Aug-06	30000							
GULF		50 CIBC	Swap	2005.36603	12/27/2005 19:30	6-Aug	160000							
GULF		50 CIBC	Swap	2006.36658	1/5/2006 18:46	6-Aug	30000							
GULF		50 CIBC	Swap	2006.37635	7/21/2006 16:12	6-Aug	70000							
GULF		50 CIBC	Swap	2006.37868	8/25/2006 14:50	Aug-06	90000							
		CIBC Total:												

GULF	50 DEUTSCHE	Swap	2005.36099	9/29/2005 15:20	6-Aug	30000	[redacted]
GULF	50 DEUTSCHE	Swap	2005.36117	10/3/2005 16:06	6-Aug	30000	
GULF	50 DEUTSCHE	Swap	2006.36692	1/12/2006 20:40	6-Aug	20000	
GULF	50 DEUTSCHE	Swap	2006.37622	7/20/2006 18:19	Aug-06	70000	
GULF	50 DEUTSCHE	Swap	2006.37667	7/25/2006 19:24	Aug-06	70000	
GULF	50 DEUTSCHE	Swap	2006.37688	7/31/2006 15:11	Aug-06	20000	
GULF	50 DEUTSCHE	Swap	2006.37747	8/9/2006 15:09	Aug-06	30000	
GULF	50 DEUTSCHE	Swap	2006.37789	8/16/2006 14:31	Aug-06	30000	
GULF	50 DEUTSCHE	Swap	2006.37622	7/20/2006 18:19	6-Aug	70000	
GULF	50 DEUTSCHE	Swap	2006.37667	7/25/2006 19:24	6-Aug	70000	
GULF	50 DEUTSCHE	Swap	2006.37877	8/28/2006 14:28	Aug-06	30000	
	DEUTSCHE Total:						
GULF	50 JPMORGAN	Swap	2006.37613	7/20/2006 15:09	6-Aug	50000	
GULF	50 JPMORGAN	Swap	2006.37613	7/20/2006 15:09	Aug-06	50000	
GULF	50 JPMORGAN	Swap	2006.3765	7/24/2006 18:50	Aug-06	40000	
GULF	50 JPMORGAN	Swap	2006.37704	8/2/2006 14:25	Aug-06	20000	
GULF	50 JPMORGAN	Swap	2006.37741	8/8/2006 15:43	Aug-06	20000	
GULF	50 JPMORGAN	Swap	2006.3782	8/21/2006 14:51	Aug-06	30000	
GULF	50 JPMORGAN	Swap	2006.3765	7/24/2006 18:50	6-Aug	40000	
GULF	50 JPMORGAN	Swap	2006.36884	3/2/2006 19:54	6-Aug	100000	
GULF	50 JPMORGAN	Swap	2006.37894	8/29/2006 15:38	Aug-06	40000	
	JPMORGAN Total:						
GULF	50 MITSUI	Swap	2004.33811	8/17/2004 18:54	6-Aug	50000	
GULF	50 MITSUI	Swap	2005.36137	10/6/2005 22:12	Aug-06	30000	
GULF	50 MITSUI	Swap	2006.37617	7/20/2006 15:20	Aug-06	30000	
GULF	50 MITSUI	Swap	2006.37692	8/1/2006 14:21	Aug-06	20000	
GULF	50 MITSUI	Swap	2006.37732	8/7/2006 18:23	Aug-06	20000	
GULF	50 MITSUI	Swap	2006.37762	8/11/2006 18:50	Aug-06	60000	
GULF	50 MITSUI	Swap	2006.37797	8/17/2006 15:17	Aug-06	30000	
GULF	50 MITSUI	Swap	2006.37617	7/20/2006 15:20	6-Aug	30000	
GULF	50 MITSUI	Swap	2006.37852	8/24/2006 14:37	Aug-06	30000	
	MITSUI Total:						
GULF	50 Suisse	Swap	2006.3764	7/21/2006 22:50	6-Aug	70000	
GULF	50 Suisse	Swap	2006.3764	7/21/2006 22:50	Aug-06	70000	
GULF	50 Suisse	Swap	2006.37805	8/18/2006 14:43	Aug-06	60000	
	Suisse Total:						

Option Deals

OpCo	ContractID	CounterParty	DealType	BuySell	DealNumber	TransactionDate	ContractMor	HedgeMonth	Quantity	StrikePrice	SettlePrice	SettlementN	StrikeFlag	SettleAmount
GULF		50 MITSUI	Put-mm	Sell	2004.32622	1/5/2004 19:20	6-Aug	6-Aug	300000	[redacted]				
GULF		50 MITSUI	Put-mm	Buy	2004.33444	6/25/2004 16:38	6-Aug	6-Aug	300000					
		MITSUI Total:												

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoAdd	SoCoSettleP	SettleAmount
GULF		50 Suisse	Swap	2006.37642	6-Aug	310000	0	Gas Dly	[redacted]					
		Suisse Total:												

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 14 of 18

Invoice for GULF for the NYMEX Settlement for Sep 2006

Totals by

Counter Party	Swap Total	Option Total	Counter Party Total
ABNAMRO	$ 16,180	$ -	$ 16,180.00
BANKAMER	$ (427,180.00)	$ -	$ (427,180.00)
BARCLAYS	$ (367,440.00)	$ -	$ (367,440.00)
CIBC	$ (602,540.00)	$ -	$ (602,540.00)
DEUTSCHE	$ (432,600.00)	$ -	$ (432,600.00)
JPMORGAN	$ (202,530.00)	$ -	$ (202,530.00)
MITSUI	$ (239,590.00)	$ -	$ (239,590.00)
Suisse	$ 15,390.00	$ -	$ 15,390.00
GAS DAILY	$ (576,090.00)	$ -	$ (576,090.00)
Total for GULF	**$ (2,816,400.00)**	**$ -**	**$ (2,816,400.00)**

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrice	SoCoPrice	SoCoNdx	SoCoSettlePr	SettleAmount
GULF		50 ABNAMRO	Swap	2006.38029	9/19/2006 15:20	Sep-06	20000	[redacted]						
		ABNAMRO Total:												
GULF		50 BANKAMER	Swap	2005.34469	1/3/2005 17:40	Sep-06	50000							
GULF		50 BANKAMER	Swap	2005.35953	9/14/2005 15:24	Sep-06	40000							
GULF		50 BANKAMER	Swap	2005.35964	9/15/2005 20:17	Sep-06	30000							
GULF		50 BANKAMER	Swap	2005.35988	9/20/2005 15:14	Sep-06	30000							
GULF		50 BANKAMER	Swap	2006.37873	8/25/2006 22:05	Sep-06	20000							
GULF		50 BANKAMER	Swap	2006.3789	8/28/2006 18:40	Sep-06	40000							
GULF		50 BANKAMER	Swap	2006.37873	8/25/2006 22:05	Sep-06	20000							
GULF		50 BANKAMER	Swap	2006.3789	8/28/2006 18:40	Sep-06	40000							
GULF		50 BANKAMER	Swap	2006.37927	9/7/2006 14:20	Sep-06	20000							
GULF		50 BANKAMER	Swap	2006.38053	9/22/2006 16:28	Sep-06	60000							
		BANKAMER Total:												
GULF		50 BARCLAYS	Swap	2004.33789	8/16/2004 19:04	Sep-06	50000							
GULF		50 BARCLAYS	Swap	2005.36108	9/30/2005 15:12	Sep-06	40000							
GULF		50 BARCLAYS	Swap	2006.3712	4/28/2006 16:41	Sep-06	100000							
GULF		50 BARCLAYS	Swap	2006.37857	8/24/2006 15:32	Sep-06	90000							
GULF		50 BARCLAYS	Swap	2006.37857	8/24/2006 15:32	Sep-06	90000							
GULF		50 BARCLAYS	Swap	2006.37914	9/5/2006 15:25	Sep-06	20000							
GULF		50 BARCLAYS	Swap	2006.37979	9/13/2006 15:11	Sep-06	10000							
		BARCLAYS Total:												
GULF		50 CIBC	Swap	2004.33827	8/18/2004 16:02	Sep-06	100000							
GULF		50 CIBC	Swap	2005.36022	9/22/2005 18:31	Sep-06	30000							
GULF		50 CIBC	Swap	2005.36039	9/23/2005 18:17	Sep-06	40000							
GULF		50 CIBC	Swap	2005.36051	9/26/2005 15:45	Sep-06	30000							
GULF		50 CIBC	Swap	2006.37834	8/22/2006 20:33	Sep-06	40000							
GULF		50 CIBC	Swap	2005.3613	10/5/2005 17:49	Sep-06	30000							
GULF		50 CIBC	Swap	2006.37834	8/22/2006 20:33	Sep-06	40000							
GULF		50 CIBC	Swap	2006.37923	9/6/2006 18:03	Sep-06	20000							
GULF		50 CIBC	Swap	2006.38085	9/27/2006 15:52	Sep-06	50000							
		CIBC Total:												

GULF		50 DEUTSCHE	Swap	2005.36099	9/29/2005 15:20	Sep-06	30000	[redacted]
GULF		50 DEUTSCHE	Swap	2005.36117	10/3/2005 16:06	Sep-06	30000	
GULF		50 DEUTSCHE	Swap	2006.37861	8/24/2006 15:47	Sep-06	90000	
GULF		50 DEUTSCHE	Swap	2006.37881	8/28/2006 17:46	Sep-06	20000	
GULF		50 DEUTSCHE	Swap	2006.37861	8/24/2006 15:47	Sep-06	90000	
GULF		50 DEUTSCHE	Swap	2006.37881	8/28/2006 17:46	Sep-06	20000	
GULF		50 DEUTSCHE	Swap	2006.3791	9/1/2006 15:04	Sep-06	90000	
GULF		50 DEUTSCHE	Swap	2006.38011	9/15/2006 16:40	Sep-06	40000	
GULF		50 DEUTSCHE	Swap	2006.38048	9/21/2006 15:01	Sep-06	20000	
		DEUTSCHE Total:						
GULF		50 JPMORGAN	Swap	2006.36884	3/2/2006 19:54	Sep-06	100000	
GULF		50 JPMORGAN	Swap	2006.3783	8/22/2006 15:39	Sep-06	70000	
GULF		50 JPMORGAN	Swap	2006.37847	8/23/2006 15:44	Sep-06	20000	
GULF		50 JPMORGAN	Swap	2006.3783	8/22/2006 15:39	Sep-06	70000	
GULF		50 JPMORGAN	Swap	2006.37847	8/23/2006 15:44	Sep-06	20000	
GULF		50 JPMORGAN	Swap	2006.37932	9/8/2006 14:38	Sep-06	40000	
GULF		50 JPMORGAN	Swap	2006.37991	9/14/2006 14:27	Sep-06	20000	
GULF		50 JPMORGAN	Swap	2006.38034	9/20/2006 14:35	Sep-06	10000	
GULF		50 JPMORGAN	Swap	2006.38068	9/25/2006 18:14	Sep-06	10000	
		JPMORGAN Total:						
GULF		50 MITSUI	Swap	2004.33811	8/17/2004 18:54	Sep-06	50000	
GULF		50 MITSUI	Swap	2006.37843	8/23/2006 15:33	Sep-06	40000	
GULF		50 MITSUI	Swap	2006.37886	8/28/2006 18:12	Sep-06	20000	
GULF		50 MITSUI	Swap	2005.36137	10/6/2005 22:12	Sep-06	30000	
GULF		50 MITSUI	Swap	2006.37843	8/23/2006 15:33	Sep-06	40000	
GULF		50 MITSUI	Swap	2006.37886	8/28/2006 18:12	Sep-06	20000	
GULF		50 MITSUI	Swap	2006.37903	8/31/2006 19:36	Sep-06	20000	
GULF		50 MITSUI	Swap	2006.37946	9/11/2006 15:56	Sep-06	20000	
GULF		50 MITSUI	Swap	2006.38024	9/18/2006 16:04	Sep-06	20000	
GULF		50 MITSUI	Swap	2006.38077	9/26/2006 14:49	Sep-06	10000	
		MITSUI Total:						
GULF		50 Suisse	Swap	2006.37959	9/12/2006 14:36	Sep-06	10000	
		Suisse Total:						

Option Deals

OpCo	ContractID	CounterParty	DealType	BuySell	DealNumber	ContractMonth	HedgeMonth	Quantity	StrikePrice	SettlePrice	SettlementNc	StrikeFlag	SettleAmount
GULF		50 MITSUI	Put-mm	Sell	2004.32622	Sep-06	6-Sep	300000	[redacted]				
GULF		50 MITSUI	Put-mm	Buy	2004.33444	Sep-06	6-Sep	300000					
		MITSUI Total:											

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrici	SoCoPrice	SoCoNdx	SoCoAdd	SoCoSettlePi	SettleAmount
GULF		50 MITSUI	Swap	2006.37863	6-Sep	300000	0	Gas Dly	[redacted]					
		MITSUI Total:												

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB 1)
Schedule 2
Page 16 of 18

	Invoice for Totals by	**GULF for the**	**NYMEX**	**Settlement**	**for Oct 2006**
	Counter Party	**Swap Total**	**Option Total**	**Counter Party Total**	
	BANKAMER	(528,580.00)	-	(528,580.00)	
	BARCLAYS	(243,590.00)	-	(243,590.00)	
	CIBC	(621,800.00)	-	(621,800.00)	
	DEUTSCHE	(404,480.00)	-	(404,480.00)	
	JPMORGAN	57,740.00	-	57,740.00	
	MITSUI	(182,280.00)	-	(182,280.00)	
	Peak Period Load Rati	(27,169.23)	-	(27,169.23)	
	GAS DAILY	437,689.00	-	437,689.00	
	Total for GULF	**(1,512,470.23)**	**-**	**(1,512,470.23)**	

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoSettleP	SettleAmount
GULF		50 BANKAMER	Swap	2005.34469	1/3/2005 17:40	6-Oct	50000							
GULF		50 BANKAMER	Swap	2005.35953	9/14/2005 15:24	6-Oct	20000							
GULF		50 BANKAMER	Swap	2005.35964	9/15/2005 20:17	6-Oct	20000							
GULF		50 BANKAMER	Swap	2005.35988	9/20/2005 15:14	6-Oct	30000							
		BANKAMER Total:												
GULF		50 BARCLAYS	Swap	2004.33789	8/16/2004 19:04	6-Oct	50000							
GULF		50 BARCLAYS	Swap	2005.36108	9/30/2005 15:12	6-Oct	20000							
GULF		50 BARCLAYS	Swap	2006.38101	10/4/2006 15:29	6-Oct	10000							
GULF		50 BARCLAYS	Swap	2006.38128	10/18/2006 20:14	6-Oct	10000							
		BARCLAYS Total:												
GULF		50 CIBC	Swap	2005.36022	9/22/2005 18:31	6-Oct	20000							
GULF		50 CIBC	Swap	2005.36039	9/23/2005 18:17	6-Oct	30000							
GULF		50 CIBC	Swap	2005.36051	9/26/2005 15:45	6-Oct	20000							
GULF		50 CIBC	Swap	2005.3613	10/5/2005 17:49	6-Oct	30000							
GULF		50 CIBC	Swap	2006.38152	10/27/2006 14:19	6-Oct	20000							
		CIBC Total:												
GULF		50 DEUTSCHE	Swap	2005.36099	9/29/2005 15:20	6-Oct	20000							
GULF		50 DEUTSCHE	Swap	2005.36117	10/3/2005 16:06	6-Oct	30000							
GULF		50 DEUTSCHE	Swap	2006.38121	10/13/2006 16:54	6-Oct	10000							
		DEUTSCHE Total:												
GULF		50 JPMORGAN	Swap	2006.38073	9/25/2006 18:28	6-Oct	50000							
GULF		50 JPMORGAN	Swap	2006.38073	9/25/2006 18:28	6-Oct	50000							
GULF		50 JPMORGAN	Swap	2006.38098	10/3/2006 17:17	6-Oct	10000							
GULF		50 JPMORGAN	Swap	2006.38116	10/11/2006 15:44	6-Oct	10000							
		JPMORGAN Total:												
GULF		50 MITSUI	Swap	2004.33811	8/17/2004 18:54	6-Oct	50000							
GULF		50 MITSUI	Swap	2005.36137	10/6/2005 22:12	6-Oct	20000							
GULF		50 MITSUI	Swap	2006.3809	9/29/2006 14:26	6-Oct	10000							
GULF		50 MITSUI	Swap	2006.38108	10/6/2006 15:33	6-Oct	10000							
GULF		50 MITSUI	Swap	2006.3814	10/24/2006 14:31	6-Oct	10000							
		MITSUI Total:												

Option Deals

OpCo	ContractID	CounterParty	DealType	BuySell	DealNumber	ContractMonth	HedgeMonth	Quantity	StrikePrice	SettlePrice	SettlementNdx	SettleAmount
GULF		50 MITSUI	Put-mm	Sell	2004.32622	6-Oct	6-Oct	300000				
GULF		50 MITSUI	Put-mm	Buy	2004.33444	6-Oct	6-Oct	300000				
		MITSUI Total:										

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoNdx	SoCoAdd	SoCoSettleP	SettleAmount
GULF		50 MITSUI	Swap	2006.38061	9/22/2006 18:49	6-Oct	310000		0 Gas Dly					
		MITSUI Total:												

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 17 of 18

Invoice for GULF for the NYMEX Settlement for Nov 2006

Totals by Counter Party

Counter Party	Swap Total	Option Total	Counter Party Total
BANKAMER	$ (52,140.00)	$ -	$ (52,140.00)
BARCLAYS	$ (63,840.00)	$ -	$ (63,840.00)
CIBC	$ (406,825.00)	$ -	$ (406,825.00)
DEUTSCHE	$ (86,950.00)	$ -	$ (86,950.00)
JPMORGAN	$ (74,610.00)	$ -	$ (74,610.00)
MITSUI	$ (119,145.00)	$ -	$ (119,145.00)
Suisse	$ (71,440.00)	$ -	$ (71,440.00)
Peak Period Load Ra	$ (14,893.39)	$ -	$ (14,893.39)
GAS DAILY	$ 33,232.50	$ -	$ 33,232.50
Total for GULF	**$ (856,610.89)**	**$ -**	**$ (856,610.89)**

Swap Deal Detail

OpCo	ContractID		CounterParty	DealType	DealNumber	TransactionDate	ContractMor	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoPrice	SoCoNdx	SoCoSettleP	SettleAmount
GULF		50	BANKAMER	Swap	2006.37285	5/25/2006 16:44	6-Nov	6-Nov	20000							
			BANKAMER Total:													
GULF		50	BARCLAYS	Swap	2006.36675	1/9/2006 16:36	6-Nov	6-Nov	10000							
GULF		50	BARCLAYS	Swap	2006.36896	3/8/2006 17:29	6-Nov	6-Nov	10000							
			BARCLAYS Total:													
GULF		50	CIBC	Swap	2005.3659	12/27/2005 16:03	6-Nov	6-Nov	60000							
GULF		50	CIBC	Swap	2006.36643	1/4/2006 17:35	6-Nov	6-Nov	20000							
GULF		50	CIBC	Swap	2006.36663	1/5/2006 19:08	6-Nov	6-Nov	20000							
GULF		50	CIBC	Swap	2006.38146	10/25/2006 18:17	6-Nov	6-Nov	25000							
GULF		50	CIBC	Swap	2006.38146	10/25/2006 18:17	6-Dec	6-Nov	25000							
			CIBC Total:													
GULF		50	DEUTSCHE	Swap	2006.36692	1/12/2006 20:40	6-Nov	6-Nov	10000							
GULF		50	DEUTSCHE	Swap	2006.37536	7/6/2006 16:29	6-Nov	6-Nov	10000							
GULF		50	DEUTSCHE	Swap	2006.37584	7/17/2006 17:42	6-Nov	6-Nov	10000							
GULF		50	DEUTSCHE	Swap	2006.38177	11/21/2006 15:58	6-Dec	6-Nov	5000							
			DEUTSCHE Total:													
GULF		50	JPMORGAN	Swap	2006.36826	2/15/2006 19:15	6-Nov	6-Nov	10000							
GULF		50	JPMORGAN	Swap	2006.37596	7/18/2006 20:04	6-Nov	6-Nov	10000							
GULF		50	JPMORGAN	Swap	2006.37758	8/11/2006 17:45	6-Nov	6-Nov	10000							
			JPMORGAN Total:													
GULF		50	MITSUI	Swap	2005.36614	12/27/2005 20:58	6-Nov	6-Nov	20000							
GULF		50	MITSUI	Swap	2006.37253	5/24/2006 14:44	6-Nov	6-Nov	10000							
GULF		50	MITSUI	Swap	2006.38173	11/16/2006 15:28	6-Dec	6-Nov	5000							
GULF		50	MITSUI	Swap	2006.38194	11/28/2006 17:07	6-Dec	6-Nov	15000							
			MITSUI Total:													
GULF		50	Suisse	Swap	2006.37701	8/1/2006 16:41	6-Nov	6-Nov	10000							
GULF		50	Suisse	Swap	2006.37726	8/4/2006 18:47	6-Nov	6-Nov	10000							
			Suisse Total:													

Swap Deal Detail

OpCo	ContractID		CounterParty	DealType	DealNumber	TransactionDate	ContractMor	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePric	SoCoNdx	SoCoAdd	SoCoSettleP	SettleAmount
GULF		50	Suisse	Swap	2006.38136	10/23/2006 16:21	6-Nov	6-Nov	225000		0 Gas Dly					
			Suisse Total:													

Florida Public Service Commission
Docket No. 070001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB 1)
Schedule 2
Page 18 of 18

	Invoice for	GULF for the	NYMEX	Settlement	for Dec 2006
	Totals by				
	Counter Party	Swap Total	Option Total	Counter Party Total	
	BANKAMER	(20,570.00)	-	(20,570.00)	
	BARCLAYS	(31,180.00)	-	(31,180.00)	
	CIBC	(302,200.00)	-	(302,200.00)	
	DEUTSCHE	(49,930.00)	-	(49,930.00)	
	JPMORGAN	(89,185.00)	-	(89,185.00)	
	MITSUI	(79,460.00)	-	(79,460.00)	
	Suisse	(48,140.00)	-	(48,140.00)	
	Peak Period Load Ratio	(51,432.00)		(51,432.00)	
	GAS DAILY	(350,796.00)		(350,796.00)	
	Total for GULF	***(1,022,893.00)***	-	***(1,022,893.00)***	

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	ContractMon	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrice	SoCoPrice	SoCoNdx	SoCoSettlePr	SettleAmount
GULF		50 BANKAMER	Swap	2006.37285	5/25/2006 16:44	6-Dec	6-Dec	20000							
GULF		50 BANKAMER	Swap	2006.38274	12/22/2006 15:08	7-Jan	6-Dec	10000							
		BANKAMER Total:													
GULF		50 BARCLAYS	Swap	2006.36675	1/9/2006 16:36	6-Dec	6-Dec	10000							
GULF		50 BARCLAYS	Swap	2006.36896	3/8/2006 17:29	6-Dec	6-Dec	10000							
GULF		50 BARCLAYS	Swap	2006.38219	12/8/2006 15:47	7-Jan	6-Dec	5000							
		BARCLAYS Total:													
GULF		50 CIBC	Swap	2005.3659	12/27/2005 16:03	6-Dec	6-Dec	60000							
GULF		50 CIBC	Swap	2006.36643	1/4/2006 17:35	6-Dec	6-Dec	20000							
GULF		50 CIBC	Swap	2006.36663	1/5/2006 19:08	6-Dec	6-Dec	20000							
		CIBC Total:													
GULF		50 DEUTSCHE	Swap	2006.36692	1/12/2006 20:40	6-Dec	6-Dec	10000							
GULF		50 DEUTSCHE	Swap	2006.37536	7/6/2006 16:29	6-Dec	6-Dec	10000							
GULF		50 DEUTSCHE	Swap	2006.37584	7/17/2006 17:42	6-Dec	6-Dec	10000							
GULF		50 DEUTSCHE	Swap	2006.38283	12/27/2006 15:54	7-Jan	6-Dec	2500							
		DEUTSCHE Total:													
GULF		50 JPMORGAN	Swap	2006.36826	2/15/2006 19:15	6-Dec	6-Dec	10000							
GULF		50 JPMORGAN	Swap	2006.37596	7/18/2006 20:04	6-Dec	6-Dec	10000							
GULF		50 JPMORGAN	Swap	2006.37758	8/11/2006 17:45	6-Dec	6-Dec	10000							
GULF		50 JPMORGAN	Swap	2006.38191	11/28/2006 17:03	6-Dec	6-Dec	17500							
GULF		50 JPMORGAN	Swap	2006.38191	11/28/2006 17:03	7-Jan	6-Dec	17500							
		JPMORGAN Total:													
GULF		50 MITSUI	Swap	2005.36614	12/27/2005 20:58	6-Dec	6-Dec	20000							
GULF		50 MITSUI	Swap	2006.37253	5/24/2006 14:44	6-Dec	6-Dec	10000							
		MITSUI Total:													
GULF		50 Suisse	Swap	2006.37701	8/1/2006 16:41	6-Dec	6-Dec	10000							
GULF		50 Suisse	Swap	2006.37726	8/4/2006 18:47	6-Dec	6-Dec	10000							
		Suisse Total:													

Swap Deal Detail

OpCo	ContractID	CounterParty	DealType	DealNumber	TransactionDate	ContractMon	HedgeMonth	Quantity	CPPrice	CPNdx	CPSettlePrice	SoCoNdx	SoCoAdd	SoCoSettlePr	SettleAmount
GULF		50 MITSUI	Swap	2006.38185	11/27/2006 19:11	6-Dec	6-Dec	232500		0 Gas Dly					
		MITSUI Total:													

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 28th day of February, 2007

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

THERESA TUCKER
MY COMMISSION # DD 303630
EXPIRES: March 25, 2008
Bonded Thru Notary Public Underwriters

GULF POWER COMPANY
PROJECTED VS. ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents / KWH Fuel Cost

Period Ending	Projected	Actual[1]	% Difference
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5291	1.5696	2.65
December 2000	1.6048	1.6460	2.57
December 2001	1.5782	1.7218	9.10
December 2002	2.0241	2.0505	1.30
December 2003	1.9639	2.1133	7.61
December 2004	2.0936	2.3270	11.15
December 2005	2.6566	2.8817	8.47
December 2006	2.9215	3.0902	5.77
December 2007	3.3336[2]		
December 2008	3.5632[2]		

(1) Line No. 1 from FPSC Schedule A-1, December, Period To Date
(2) Line No. 1 from FPSC Schedule E-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI 28
COMPANY Gulf Power Co.
WITNESS H. R. Ball (HRB-2)
DATE 11-06-07

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor**

Docket No.: **070001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by U. S. mail this 5TH day of October, 2007, on the following:

William G. Walker, III
Vice President
Florida Power & Light Co.
215 S. Monroe Street, Ste. 810
Tallahassee FL 32301-1859

Cheryl Martin
Florida Public Utilities Company
P. O. Box 3395
West Palm Beach FL 33402-3395

Lisa Bennett, Esq.
FL Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0863

John T. Burnett, Esq.
Progress Energy Service Co.
P. O. Box 14042
St. Petersburg FL 33733-4042

R. Wade Litchfield, Esq.
Florida Power & Light Company
700 Universe Boulevard
Juno Beach FL 33408-0420

Patricia Ann Christensen, Esq.
Office of Public Counsel
111 W. Madison St., Room 812
Tallahassee FL 32399-1400

James W. Brew, Esq.
Brickfield, Burchette, *et al.*
1025 Thomas Jefferson St., NW
8th Floor, West Tower
Washington DC 20007

Lee L. Willis, Esq.
James D. Beasley, Esq.
Ausley & McMullen
P. O. Box 391
Tallahassee FL 32302

Paula K. Brown, Administrator
Regulatory Coordination
Tampa Electric Company
P. O. Box 111
Tampa FL 33601

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 E. College Ave., Ste. 800
Tallahassee FL 32301-7740

John T. Butler, Esq.
Florida Power & Light Company
700 Universe Boulevard
Juno Beach FL 33408-0420

G. Sasso/J. Walls/D. Triplett
Carlton, Fields, *et al.*
P. O. Box 3239
Tampa FL 33601-3239

John W. McWhirter, Jr., Esq.
McWhirter Reeves & Davidson
400 N Tampa St., Suite 2450
Tampa FL 33602

Norman H. Horton, Jr., Esq.
Messer, Caparello & Self, P.A.
P. O. Box 15579
Tallahassee FL 32317

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

Florida Public Service Commission
Docket No. 070001-EI
Gulf Power Company
Witness: R.J. Martin
Exhibit No.____ (RJM-1)
Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
January 2006 - December 2006

1.	Estimated over/(under) - recovery for the period January 2006 - December 2006 (Schedule E-1A approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006)	$ (26,505,347)
2.	Actual over/(under)-recovery for the period January 2006 - December 2006 (DECEMBER 2006 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7 + 8)	(57,306,196)
3.	Amount to be refunded/(recovered) in the JANUARY 2008 - DECEMBER 2008 projection period (Line 2 - Line 1)	$ (30,800,849)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 29
COMPANY Gulf Power Co.
WITNESS R. J. Martin (RJM-1)
DATE 11-06-07

Florida Public Service Commission
Docket No. 070001-EI
Gulf Power Company
Witness: R.J. Martin
Exhibit No. ____ (RJM-1)
Schedule CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
JANUARY 2006 - DECEMBER 2006

1. Estimated over/(under)-recovery for the period JANUARY 2006 - DECEMBER 2006 (Schedule CCE-1a approved in FPSC Order No. PSC-06-1057-FOF-EI dated December 22, 2006)	$ (223,116)
2. Actual over/(under)-recovery for the period JANUARY 2006 - DECEMBER 2006 (Schedule CCA-2 Line 9 + 10 in the Total column)	234,968
3. Amount to be refunded/(recovered) in the JANUARY 2008 - DECEMBER 2008 projection period (Line 2 - Line 1)	$ 458,084

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2006 - DECEMBER 2006

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1. IIC Payments / (Receipts) ($)		1,688,635	445,165	602,636	104,416	662,264	3,759,953	8,534,480	9,620,041	3,685,764	343,426	216,275	224,324	29,887,379
2. Transmission Revenue ($)		(9,032)	(10,499)	(11,348)	(4,830)	(5,550)	(9,921)	(15,453)	(10,415)	(3,622)	(9,032)	(43,601)	(20,340)	(153,643)
3. Total Capacity Payments/(Receipts) (Line 1 + 2) ($)		1,679,603	434,666	591,288	99,586	656,714	3,750,032	8,519,027	9,609,626	3,682,142	334,394	172,674	203,984	29,733,736
4. Jurisdictional %		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872
5. Total Jurisdictional Recovery Amount (Line 3 * 4) ($)		1,623,315	420,099	571,472	96,249	634,706	3,624,358	8,233,531	9,287,581	3,558,743	323,188	166,887	197,148	28,737,277
6. Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)		1,970,172	1,882,492	1,782,785	1,993,570	2,432,521	2,867,009	2,951,164	3,027,806	2,506,993	2,083,653	1,904,149	2,144,929	27,547,243
7. True-Up Provision ($)		111,821	111,821	111,821	111,821	111,821	111,821	111,821	111,821	111,821	111,821	111,821	111,820	1,341,851
8. Jurisdictional Capacity Cost Recovery Revenue (Line 6 + 7) ($)		2,081,993	1,994,313	1,894,606	2,105,391	2,544,342	2,978,830	3,062,985	3,139,627	2,618,814	2,195,474	2,015,970	2,256,749	28,889,094
9. Over/(Under) Recovery (Line 8 - 5) ($)		458,678	1,574,214	1,323,134	2,009,142	1,909,636	(645,528)	(5,170,546)	(6,147,954)	(939,929)	1,872,286	1,849,083	2,059,601	151,817
10. Interest Provision ($)		5,976	9,562	15,070	22,134	30,424	33,798	21,696	(3,812)	(19,835)	(18,367)	(10,762)	(2,733)	83,151
11. Beginning Balance True-Up & Interest Provision ($)		1,454,484	1,807,317	3,279,272	4,505,655	6,425,110	8,253,349	7,529,798	2,269,127	(3,994,460)	(5,066,045)	(3,323,947)	(1,597,447)	1,454,484
12. True-Up Collected/(Refunded) ($)		(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,821)	(111,820)	(1,341,851)
13. End of Period Total Net True-Up (Lines 9 + 10 + 11 + 12) ($)		1,807,317	3,279,272	4,505,655	6,425,110	8,253,349	7,529,798	2,269,127	(3,994,460)	(5,066,045)	(3,323,947)	(1,597,447)	347,601	347,601
Average Monthly Interest Rate		0.3671	0.3767	0.3879	0.4058	0.4154	0.4292	0.4438	0.4429	0.4388	0.4388	0.4383	0.4383	
Wall Street Annual Rate	4.30	4.51	4.53	4.78	4.96	5.01	5.29	5.36	5.27	5.26	5.27	5.25	5.27	
Average Annual Rate		4.405	4.520	4.655	4.870	4.985	5.150	5.325	5.315	5.265	5.265	5.260	5.260	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2006 - DECEMBER 2006

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	1,454,484	1,807,317	3,279,272	4,505,655	6,425,110	8,253,349	7,529,798	2,269,127	(3,994,460)	(5,066,045)	(3,323,947)	(1,597,447)	
2. Ending True-Up Amount Before Interest ($)	1,801,341	3,269,710	4,490,585	6,402,976	8,222,925	7,496,000	2,247,431	(3,990,648)	(5,046,210)	(3,305,580)	(1,586,685)	350,334	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	3,255,825	5,077,027	7,769,857	10,908,631	14,648,035	15,749,349	9,777,229	(1,721,521)	(9,040,670)	(8,371,625)	(4,910,632)	(1,247,113)	
4. Average True-Up Amount ($)	1,627,913	2,538,514	3,884,929	5,454,316	7,324,018	7,874,675	4,888,615	(860,761)	(4,520,335)	(4,185,813)	(2,455,316)	(623,557)	
5. Interest Rate - First Day of Reporting Business Month	0.043000	0.045100	0.045300	0.047800	0.049600	0.050100	0.052900	0.053600	0.052700	0.052600	0.052700	0.052500	
6. Interest Rate - First Day of Subsequent Business Month	0.045100	0.045300	0.047800	0.049600	0.050100	0.052900	0.053600	0.052700	0.052600	0.052700	0.052500	0.052700	
7. Total Interest Rate (Lines 5 + 6)	0.088100	0.090400	0.093100	0.097400	0.099700	0.103000	0.106500	0.106300	0.105300	0.105300	0.105200	0.105200	
8. Average Interest Rate	0.044050	0.045200	0.046550	0.048700	0.049850	0.051500	0.053250	0.053150	0.052650	0.052650	0.052600	0.052600	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.003671	0.003767	0.003879	0.004058	0.004154	0.004292	0.004438	0.004429	0.004388	0.004388	0.004383	0.004383	
10. Interest Provision For the Month (Lines 4 X 9) ($)	5,976	9,562	15,070	22,134	30,424	33,798	21,696	(3,812)	(19,835)	(18,367)	(10,762)	(2,733)	83,151

SCHEDULE CCA-4

GULF POWER COMPANY
2006 CAPACITY CONTRACTS

Gulf Power Company
2006 Capacity Contracts

Contract/Counterparty	Term Start	Term End (1)	Contract Type
Southern Intercompany Interchange	2/18/2000	5 Yr Notice	SES Opco
[redacted]			

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

Capacity Costs

2006	January		February		March		April		May		June		July		August		September		October		November		December		
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	Total $
Southern Intercompany Interchange	610.0	1,720,415	482.1	468,836	542.5	627,491	246.2	115,967	223.2	670,755	813.5	3,764,146	484.9	8,539,689	570.1	9,624,303	490.5	3,689,926	684.4	363,621	493.6	249,838	521.1	264,920	30,099,927
[redacted]																									(109,045)
																									(8,596)
																									(438)
																									(41,856)
																									(1,762)
																									(4,679)
																									(415)
																									(37,125)
																									(1,256)
																									(628)
																									(628)
																									(628)
																									(628)
																									(2,300)
																									(1,308)
																									(628)
																									(628)
Total		1,688,635		445,165		602,636		104,416		662,264		3,759,953		8,534,480		9,620,041		3,685,764		343,426		216,275		224,324	29,887,379

(1) Put options sold to counterparty
(2) Generator Balancing Service provides no capacity scheduling entitlements.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Docket No. 070001-EI

PREPARED DIRECT TESTIMONY AND EXHIBIT OF

RHONDA J. MARTIN

2007 ESTIMATED/ACTUAL TRUE-UP JANUARY – JUNE ACTUAL JULY – DECEMBER ESTIMATED

AUGUST 6, 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 30
COMPANY Gulf Power Co.
WITNESS R. J. Martin (RJM-2)
DATE 11-06-07

GULF POWER

A SOUTHERN COMPANY

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

BEFORE me, the undersigned authority, personally appeared Rhonda J. Martin, who being first duly sworn, deposes and says that she is the Supervisor of Rates and Regulatory Matters at Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of her knowledge, information and belief. She is personally known to me.

Rhonda J. Martin
Supervisor of Rates and Regulatory Matters

Sworn to and subscribed before me
this 3rd day of August, 2007.

Brame Nye Holsinger
Notary Public, State of Florida at Large

(SEAL)

BRAME NYE HOLSINGER
MY COMMISSION # DD 401210
EXPIRES: April 10, 2009
Bonded Thru Notary Public Underwriters

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2007 (Sch. E-1B, page 2, line 9)	($12,525,950)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2006 (EXHIBIT No.____(RJM-1)	(30,800,849)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2008 - DECEMBER 2008 (Schedule E1, Line 29)	($43,326,799)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008	11,692,537,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.3706

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	45,642,916.69	46,510,495.01	46,666,243.69	37,467,800.13	42,586,447.32	47,878,675.53	$266,752,578.37
	1a	Fuel Cost of Hedging Settlement	1,221,102.72	887,711.57	1,030,480.00	103,000.00	71,000.00	336,800.00	3,650,094.29
	2	Fuel Cost of Power Sold	(15,873,346.15)	(14,835,979.13)	(15,686,244.68)	(8,588,453.62)	(9,582,504.22)	(9,940,707.39)	(74,507,235.19)
	3	Fuel Cost of Purchased Power	405,694.57	1,342,911.69	278,323.45	1,717,545.66	1,029,004.08	2,436,454.33	7,209,933.78
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	39,136.00	168,964.00	189,130.00	242,359.00	196,722.00	196,153.00	1,032,464.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	151,845.97	122,435.11	119,563.69	123,478.84	123,605.49	214,426.07	855,355.17
	6	Adjustments to Fuel Cost *	46,645.39	(42,790.60)	7,719.62	(749.36)	9,242.48	42,101.45	62,168.98
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$31,633,995.19	$34,153,747.65	$32,605,215.77	$31,064,980.65	$34,433,517.15	$41,163,902.99	$205,055,359.40
B	1	Jurisdictional KWH Sales	889,389,209	809,445,374	793,410,439	790,980,780	985,891,266	1,118,137,500	5,387,254,568
	2	Non-Jurisdictional KWH Sales	32,723,512	30,631,297	28,310,835	27,837,845	33,632,833	38,472,538	191,608,860
	3	TOTAL SALES (Lines B1 + B2)	922,112,721	840,076,671	821,721,274	818,818,625	1,019,524,099	1,156,610,038	5,578,863,428
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.4512%	96.3537%	96.5547%	96.6002%	96.7011%	96.6737%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$34,948,511.28	$31,833,583.97	$31,188,543.79	$31,125,843.65	$38,796,651.30	$44,028,734.53	$211,921,868.52
	2	True-Up Provision	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(23,339,731.98)
	2a	Incentive Provision	70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	421,133.76
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$31,128,744.91	$28,013,817.60	$27,368,777.42	$27,306,077.28	$34,976,884.93	$40,208,968.16	$189,003,270.30
	4	Fuel & Net Power Transactions (Line A7)	$31,633,995.19	$34,153,747.65	$32,605,215.77	$31,064,980.65	$34,433,517.15	$41,163,902.99	$205,055,359.40
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	30,532,725.93	32,931,435.43	31,503,905.58	30,029,839.62	33,320,898.17	39,822,524.35	$198,141,329.08
	6	Over/(Under) Recovery (Line C3-C5)	596,018.98	(4,917,617.83)	(4,135,128.16)	(2,723,762.34)	1,655,986.76	386,443.81	($9,138,058.78)
	7	Interest Provision	(330,141.39)	(325,318.51)	(329,533.80)	(328,959.73)	(315,691.92)	(296,156.81)	($1,925,802.16)
	8	Prior Period Revenue Adjustment	0	(384,482.83)	0	0	0	0	($384,482.83)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2007 - JUNE 2007**							($11,448,343.77)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		55,298,434.00	57,919,854.00	50,242,594.00	48,957,516.00	45,964,570.00	52,450,500.00	$577,586,046.37
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	$3,650,094.29
	2	Fuel Cost of Power Sold		(17,216,000.00)	(17,360,000.00)	(16,261,000.00)	(19,206,000.00)	(18,636,000.00)	(19,415,000.00)	($182,601,235.19)
	3	Fuel Cost of Purchased Power		7,282,000.00	4,335,000.00	1,668,000.00	861,000.00	984,000.00	1,057,000.00	$23,396,933.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$1,032,464.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		220,000.00	220,000.00	214,000.00	248,000.00	240,000.00	276,000.00	$2,273,355.17
	6	Adjustments to Fuel Cost *		0.00	0.00	0.00	0.00	0.00	0.00	$62,168.98
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$45,584,434.00	$45,114,854.00	$35,863,594.00	$30,860,516.00	$28,552,570.00	$34,368,500.00	$425,399,827.40
B	1	Jurisdictional KWH Sales		1,194,601,000	1,214,089,000	1,019,077,000	873,146,000	800,511,000	897,882,000	11,386,560,568
	2	Non-Jurisdictional KWH Sales		40,894,000	41,449,000	36,413,000	32,606,000	31,023,000	34,328,000	408,321,860
	3	TOTAL SALES (Lines B1 + B2)		1,235,495,000	1,255,538,000	1,055,490,000	905,752,000	831,534,000	932,210,000	11,794,882,428
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.6901%	96.6987%	96.5501%	96.4001%	96.2692%	96.3176%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$47,009,540.51	$47,776,425.79	$40,102,378.55	$34,359,750.46	$31,501,442.14	$35,333,153.29	$448,004,559.26
	2	True-Up Provision		(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.37)	($46,679,464.00)
	2a	Incentive Provision		70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	70,189.01	$842,267.57
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$43,189,774.14	$43,956,659.42	$36,282,612.18	$30,539,984.09	$27,681,675.77	$31,513,386.92	$402,167,362.83
	4	Fuel & Net Power Transactions (Line A7)		$45,584,434.00	$45,114,854.00	$35,863,594.00	$30,860,516.00	$28,552,570.00	$34,368,500.00	$425,399,827.40
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		44,106,487.76	43,656,015.16	34,650,574.31	29,770,392.98	27,506,571.85	33,126,086.40	$410,957,457.54
	6	Over/(Under) Recovery (Line C3-C5)		(916,713.62)	300,644.26	1,632,037.87	769,591.11	175,103.92	(1,612,699.48)	($8,790,094.72)
	7	Interest Provision	(2)	(282,050.14)	(267,530.71)	(247,340.14)	(226,029.05)	(207,829.45)	(194,790.80)	($3,351,372.45)
	8	Prior Period Revenue Adjustment		0	0	0	0	0	0	($384,482.83)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2007 - DECEMBER 2007**								($12,525,950.00)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note 1: Estimated Revenues based on the 2007 Fuel Factor excluding revenue taxes of 3.9352 ¢/KWH

Note 2: Interest Calculated for July through December at June 2007 rate of 0.4400

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation	577,586,046	584,363,414	(6,777,368)	(1.16)	17,514,719,000	17,529,530,000	(14,811,000)	(0.08)	3.2977	3.3336	(0.0359)	(1.08)
1a	Fuel Cost of Hedging Settlement	3,650,094	0	3,650,094	100.00								
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
4	Other Generation	2,273,355	4,306,906	(2,033,551)	(47.22)	58,992,000	112,540,000	(53,548,000)	(47.58)	3.8537	3.8270	0.0267	0.70
5	Adjustments to Fuel Cost ***	62,169	0	62,169	100.00								
5	TOTAL COST OF GENERATED POWER	583,571,665	588,670,320	(5,098,655)	(0.87)	17,573,711,000	17,642,070,000	(68,359,000)	(0.39)	3.3207	3.3367	(0.0160)	(0.48)
6	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker)	23,396,934	31,564,000	(8,167,066)	(25.87)	583,914,117	575,829,000	8,085,117	1.40	4.0069	5.4815	(1.4746)	(26.90)
9	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities	1,032,464	0	1,032,464	100.00	27,680,669	0	27,680,669	100.00	3.7299	#N/A	#N/A	#N/A
12	TOTAL COST OF PURCHASED POWER	24,429,398	31,564,000	(7,134,602)	(22.60)	611,594,786	575,829,000	35,765,786	6.21	3.9944	5.4815	(1.4871)	(27.13)
13	Total Available KWH (Line 5 + Line 12)	608,001,063	620,234,320	(12,233,257)	(1.97)	18,185,305,786	18,217,899,000	(32,593,214)	(0.18)				
14	Fuel Cost of Economy Sales	(10,005,142)	(12,340,000)	2,334,858	18.92	(219,161,653)	(253,704,000)	34,542,347	13.62	(4.5652)	(4.8639)	0.2987	6.14
15	Gain on Economy Sales	(3,044,485)	(3,382,521)	338,036	9.99			0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales	(37,555,481)	(38,485,000)	929,519	2.42	(1,670,569,466)	(1,610,450,000)	(60,119,466)	(3.73)	(2.2481)	(2.3897)	0.1416	5.93
17	Fuel Cost of Other Power Sales	(131,996,127)	(143,688,000)	11,691,873	8.14	(3,760,653,079)	(3,645,352,000)	(115,301,079)	(3.16)	(3.5099)	(3.9417)	0.4318	10.95
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(182,601,235)	(197,895,521)	15,294,286	7.73	(5,650,384,198)	(5,509,506,000)	(140,878,198)	(2.56)	(3.2317)	(3.5919)	0.3602	10.03
19	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	425,399,828	422,338,799	3,061,029	0.72	12,534,921,588	12,708,393,000	(173,471,412)	(1.37)	3.3937	3.3233	0.0704	2.12
21	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
22	Company Use *	754,130	759,673	(5,543)	(0.73)	22,221,467	22,859,000	(637,533)	(2.79)	3.3937	3.3233	0.0704	2.12
23	T & D Losses *	24,360,579	24,577,066	(216,487)	(0.88)	717,817,693	739,538,000	(21,720,307)	(2.94)	3.3937	3.3233	0.0704	2.12
24	TERRITORIAL (SYSTEM) SALES	425,399,828	422,338,799	3,061,029	0.72	11,794,882,428	11,945,996,000	(151,113,572)	(1.26)	3.6066	3.5354	0.0712	2.01
25	Wholesale Sales	14,729,839	14,619,763	110,076	0.75	408,321,860	413,525,000	(5,203,140)	(1.26)	3.6074	3.5354	0.0720	2.04
26	Jurisdictional Sales	410,669,989	407,719,036	2,950,953	0.72	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	3.6066	3.5354	0.0712	2.01
26a	Jurisdictional Loss Multiplier	1.0007	1.0007										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0007)	410,957,458	408,004,439	2,953,019	0.72	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	3.6091	3.5379	0.0712	2.01
28	TRUE-UP **	46,679,464	46,679,464	0	0.00	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	0.4100	0.4048	0.0052	1.28
29	TOTAL JURISDICTIONAL FUEL COST	457,636,922	454,683,903	2,953,019	0.65	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	4.0191	3.9427	0.0764	1.94
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0220	3.9455	0.0765	1.94
32	GPIF Reward / (Penalty) **	(842,874)	(842,874)	0	0.00	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	(0.0074)	(0.0073)	(0.0001)	(1.37)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0146	3.9382	0.0764	1.94
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									4.0150	3.9380	0.0770	1.96

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note: Amounts Included in the Estimated/Actual Column represent 6 months actual and 6 months estimate.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

LINE	LINE DESCRIPTION	(a) JANUARY ACTUAL	(b) FEBRUARY ACTUAL	(c) MARCH ACTUAL	(d) APRIL ACTUAL	(e) MAY ACTUAL	(f) JUNE ACTUAL	(g) JULY ESTIMATED	(h) AUGUST ESTIMATED	(i) SEPTEMBER ESTIMATED	(j) OCTOBER ESTIMATED	(k) NOVEMBER ESTIMATED	(l) DECEMBER ESTIMATED	(m) TOTAL
	$													
1	Fuel Cost of System Generation	45,642,916.69	46,510,495.01	46,666,243.69	37,467,800.13	42,586,447.32	47,878,675.53	55,298,434	57,919,854	50,242,594	48,957,516	45,964,570	52,450,500	577,586,046.37
1a	Other Generation	151,845.97	122,435.11	119,563.69	123,478.84	123,605.49	214,426.07	220,000	220,000	214,000	248,000	240,000	276,000	2,273,355.17
2	Fuel Cost of Power Sold	(15,873,346.15)	(14,835,979.13)	(15,686,244.68)	(8,588,453.62)	(9,582,504.22)	(9,940,707.39)	(17,216,000)	(17,360,000)	(16,261,000)	(19,206,000)	(18,636,000)	(19,415,000)	(182,601,235.19)
3	Fuel Cost of Purchased Power	405,694.57	1,342,911.69	278,323.45	1,717,545.66	1,029,004.08	2,436,454.33	7,282,000	4,335,000	1,668,000	861,000	984,000	1,057,000	23,396,933.78
3a	Demand & Non-Fuel Cost of Pur Power	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
3b	Qualifying Facilities	39,136.00	168,964.00	189,130.00	242,359.00	196,722.00	196,153.00	0	0	0	0	0	0	1,032,464.00
4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
5	Hedging Settlement	1,221,102.72	887,711.57	1,030,480.00	103,000.00	71,000.00	336,800.00	0	0	0	0	0	0	3,650,094.29
6	Adjustment to Fuel Cost	46,645.39	(42,790.60)	7,719.62	(749.36)	9,242.48	42,101.45	0	0	0	0	0	0	62,168.98
7	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	$ 31,633,995.19	$ 34,153,747.65	$ 32,605,215.77	$ 31,064,980.65	$ 34,433,517.15	$ 41,163,902.99	$ 45,584,434.00	$ 45,114,854.00	$ 35,863,594.00	$ 30,860,516.00	$ 28,552,570.00	$ 34,368,500.00	425,399,827.40
6	System KWH Sold	922,112,721	840,076,671	821,721,274	818,818,625	1,019,524,099	1,156,610,038	1,235,495,000	1,255,538,000	1,055,490,000	905,752,000	831,534,000	932,210,000	11,794,882,428
6a	Jurisdictional % of Total Sales	96.4512	96.3537	96.5547	96.6002	96.7011	96.6737	96.6901	96.6987	96.5501	96.4001	96.2692	96.3176	96.5381
7	Cost per KWH Sold (¢/KWH)	3.4306	4.0656	3.9679	3.7939	3.3774	3.5590	3.6896	3.5933	3.3978	3.4072	3.4337	3.6868	3.6066
7a	Jurisdictional Loss Multiplier	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007
7b	Jurisdictional Cost (¢/KWH)	3.4330	4.0684	3.9707	3.7966	3.3798	3.5615	3.6922	3.5958	3.4002	3.4096	3.4361	3.6894	3.6091
8	GPIF (¢ / KWH) *	(0.0079)	(0.0087)	(0.0089)	(0.0089)	(0.0071)	(0.0063)	(0.0059)	(0.0058)	(0.0069)	(0.0080)	(0.0088)	(0.0078)	(0.0074)
9	True-Up (¢/KWH) *	0.4374	0.4806	0.4903	0.4918	0.3946	0.3479	0.3256	0.3204	0.3817	0.4455	0.4859	0.4332	0.4100
10	TOTAL	3.8625	4.5403	4.4521	4.2795	3.7673	3.9031	4.0119	3.9104	3.7750	3.8471	3.9132	4.1148	4.0117
11	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
12	Recovery Factor Adjusted for Taxes	3.8653	4.5436	4.4553	4.2826	3.7700	3.9059	4.0148	3.9132	3.7777	3.8499	3.9160	4.1178	4.0146
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	3.865	4.544	4.455	4.283	3.770	3.906	4.015	3.913	3.778	3.850	3.916	4.118	4.015

* CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	42,210	30,329	68,251	115,554	121,260	31,601	78,613	71,311	93,422	76,096	75,833	89,677	894,157
2	COAL excluding Scherer	31,588,730	27,680,814	27,774,385	23,104,179	31,571,570	32,152,149	33,743,306	35,128,202	32,335,438	27,577,633	26,060,407	30,066,642	358,783,455
3	COAL at Scherer	2,577,018	2,357,279	2,790,298	2,601,964	2,863,733	2,815,361	3,046,445	3,065,711	2,971,527	3,089,880	2,992,912	3,091,803	34,263,931
4	GAS - Generation	11,585,254	16,522,229	16,148,663	11,754,925	8,108,427	13,087,063	18,424,159	19,800,132	15,032,909	18,446,480	17,053,631	19,423,760	185,387,632
5	GAS (B.L.)	1,551	32,807	0	12,552	19,804	20,602	54,736	10,710	23,298	15,427	21,787	54,618	267,892
6	OIL - C.T.	0	9,472	4,210	2,105	25,259	(13,674)	171,175	63,788	0	0	0	0	262,335
7	TOTAL ($)	45,794,763	46,632,930	46,785,807	37,591,279	42,710,053	48,093,102	55,518,434	58,139,854	50,456,594	49,205,516	46,204,570	52,726,500	579,859,402
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	-
9	COAL excluding Scherer	1,126,075	997,826	994,582	820,113	1,114,243	1,161,051	1,261,950	1,284,900	1,192,110	1,049,320	965,340	1,113,200	13,080,710
10	COAL at Scherer	138,675	117,873	139,217	119,626	141,978	135,536	149,940	149,940	144,600	149,940	145,100	149,440	1,681,865
11	GAS	200,406	251,116	246,570	173,926	111,876	216,626	276,170	296,400	209,770	287,530	265,580	273,800	2,809,770
12	OIL - C.T.	(21)	30	3	0	(5)	49	960	350	0	0	0	0	1,366
13	TOTAL (MWH)	1,465,135	1,366,845	1,380,372	1,113,665	1,368,092	1,513,262	1,689,020	1,731,590	1,546,480	1,486,790	1,376,020	1,536,440	17,573,711
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	573	388	913	1,515	1,353	431	940	852	1,115	908	902	1,065	10,954
15	COAL excl. Scherer (TON) (1)	534,212	463,500	457,089	372,267	508,285	523,802	554,283	566,777	519,467	458,095	421,360	485,724	5,864,861
16	GAS-all (MCF) (2)	1,408,485	1,725,023	1,950,961	1,304,826	812,534	1,324,282	1,948,207	2,059,969	1,531,445	1,942,323	1,792,063	1,891,258	19,691,376
17	OIL - C.T. (BBL)	0	141	63	31	377	(204)	2,306	846	0	0	0	0	3,560
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	13,110,431	11,669,616	11,907,838	9,853,611	13,167,699	13,702,159	14,554,883	14,830,196	13,679,158	12,355,136	11,383,816	12,901,850	153,116,393
19	GAS-Generation (2)	1,454,861	1,776,967	2,007,565	1,346,327	836,910	1,366,522	1,999,326	2,120,359	1,574,359	1,998,620	1,843,289	1,942,148	20,267,253
20	OIL - C.T.	0	820	365	182	2,197	(1,193)	13,504	4,951	0	0	0	0	20,826
21	TOTAL (MMBTU)	14,565,292	13,447,403	13,915,768	11,200,120	14,006,806	15,067,488	16,567,713	16,955,506	15,253,517	14,353,756	13,227,105	14,843,998	173,404,472

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.

(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	GENERATION MIX (% MWH)													
22	LIGHTER OIL (B.L.)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
23	COAL	86.32	81.63	82.14	84.38	91.82	85.68	83.59	82.86	86.44	80.66	80.70	82.18	84.00
24	GAS-Generation	13.68	18.37	17.86	15.62	8.18	14.32	16.35	17.12	13.56	19.34	19.30	17.82	15.99
25	OIL - C.T.	0.00	0.00	0.00	#N/A	0.00	0.00	0.06	0.02	#N/A	#N/A	#N/A	#N/A	0.01
26	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
27	LIGHTER OIL ($/BBL)	73.66	78.17	74.75	76.27	89.62	73.32	83.66	83.69	83.80	83.81	84.06	84.23	81.63
28	COAL ($/TON) (1)	59.13	59.72	60.76	62.06	62.11	61.38	60.88	61.98	62.25	60.20	61.85	61.90	61.18
29	GAS + B.L. ($/MCF) (2)	8.12	9.53	8.22	8.92	9.85	9.74	9.37	9.51	9.69	9.38	9.39	10.15	9.31
30	OIL - C.T.	#N/A	67.18	66.83	67.90	67.00	67.03	74.22	75.43	#N/A	#N/A	#N/A	#N/A	73.69
	FUEL COST $ / MMBTU													
31	COAL + GAS B.L. + OIL B.L.	2.61	2.58	2.57	2.62	2.63	2.56	2.54	2.58	2.59	2.49	2.56	2.58	2.57
32	GAS-Generation (2)	7.86	9.23	7.98	8.64	9.54	9.42	9.11	9.23	9.41	9.11	9.12	9.86	9.14
33	OIL - C.T.	#N/A	11.55	11.53	11.57	11.50	11.46	12.68	12.88	#N/A	#N/A	#N/A	#N/A	12.60
34	TOTAL ($/MMBTU)	3.14	3.47	3.36	3.36	3.05	3.19	3.35	3.43	3.31	3.43	3.49	3.55	3.34
	BTU BURNED BTU / KWH													
35	COAL + GAS B.L. + OIL B.L.	10,366	10,459	10,503	10,485	10,482	10,568	10,309	10,336	10,233	10,302	10,252	10,218	10,372
36	GAS-Generation (2)	7,411	7,169	8,247	7,885	7,698	6,468	7,393	7,294	7,709	7,110	7,107	7,284	7,229
37	OIL - C.T.	#N/A	27,333	121,667	#N/A	#N/A	(24,347)	14,067	14,146	#N/A	#N/A	#N/A	#N/A	15,246
	TOTAL (BTU/KWH)	9,941	9,838	10,081	10,057	10,238	9,957	9,809	9,792	9,863	9,654	9,613	9,661	9,867
	FUEL COST CENTS / KWH													
38	COAL + GAS B.L. + OIL B.L.	2.81	2.78	2.80	2.83	2.85	2.77	2.68	2.74	2.72	2.64	2.71	2.71	2.75
39	COAL at Scherer	1.86	2.00	2.00	2.18	2.02	2.08	2.03	2.04	2.05	2.06	2.06	2.07	2.04
40	GAS-Generation	5.78	6.58	6.55	6.76	7.25	6.04	6.67	6.68	7.17	6.42	6.42	7.09	6.60
41	OIL - C.T.	#N/A	31.57	140.33	#N/A	#N/A	(27.91)	17.83	18.23	#N/A	#N/A	#N/A	#N/A	19.20
42	TOTAL (¢/KWH)	3.13	3.41	3.39	3.38	3.12	3.18	3.29	3.36	3.26	3.31	3.36	3.43	3.30

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.

(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2006	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) lbs./cf/Gal.	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
2									Gas-S	0	0	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
4									Gas-S	0	0	0	0		0.00
5	Crist 4		78.0	45,088	77.7	100.0	77.7	10,779	Coal	21,290	11,414	486,009	1,260,392	2.80	59.20
6				0					Gas-G	0	1,053	0	0	#N/A	#N/A
7									Gas-S	151	1,053	159	956		6.33
8									Oil-S	42	137,130	241	3,155		75.12
10	Crist 5		78.0	44,691	77.4	100.0	77.4	10,612	Coal	20,793	11,404	474,242	1,230,953	2.75	59.20
11				198					Gas-G	3,070	1,053	3,233	19,482	9.84	6.35
12									Gas-S	94	1,053	99	595		6.33
13									Oil-S	34	137,130	195	2,551		75.03
15	Crist 6		302.0	166,404	74.2	99.4	74.6	10,571	Coal	77,241	11,387	1,759,094	4,572,765	2.75	59.20
16				280					Gas-G	4,370	1,053	4,602	27,733	0.00	6.35
17									Gas-S	0	1,053	0	0		#N/A
18									Oil-S	0	137,130	0	0		#N/A
19	Crist 7		472.0	311,063	88.6	98.8	89.7	10,433	Coal	143,234	11,329	3,245,398	8,479,600	2.73	59.20
20				0					Gas-G	0	1,053	0	0	#N/A	#N/A
21									Gas-S	0	1,053	0	0		#N/A
22									Oil-S	18	137,130	105	1,376		76.44
23	Scherer 3	(2)	210.8	138,675	88.4	100.0	88.4	9,681	Coal	N/A	8,065	1,342,580	2,648,554	1.91	#NA
24									Oil-S	0	140,150	1	16		#N/A
25	Scholz 1		46.0	13,240	38.7	100.0	38.7	12,077	Coal	6,887	11,610	159,905	473,344	3.58	68.73
26									Oil-S	33	139,189	191	2,325		70.45
27	2		46.0	11,399	33.3	100.0	33.3	12,496	Coal	6,152	11,576	142,442	422,770	3.71	68.72
28									Oil-S	38	139,189	222	2,703		71.13
29	Smith 1		162.0	99,259	82.4	100.0	82.4	10,357	Coal	45,236	11,363	1,028,044	2,745,943	2.77	60.70
30									Oil-S	87	137,130	501	6,256		71.91
31	2		195.0	111,776	77.0	94.9	81.2	10,370	Coal	51,071	11,348	1,159,111	3,100,121	2.77	60.70
32									Oil-S	249	137,130	1,434	17,927		72.00
33	3		531.0	195,844	49.6	99.6	49.8	7,389	Gas-G	1,400,800	1,033	1,447,026	11,386,193	5.81	8.13
34	A		40.0	(21)	(0.1)	99.8	(0.1)	#N/A	Oil	0	137,918	0	0	#N/A	#N/A
35	Other Generation		0.0	4,084						0	0		151,846	3.72	#N/A
36	Daniel 1	(1)	251.5	175,356	93.7	99.5	94.2	10,262	Coal	87,718	10,257	1,799,437	4,962,442	2.83	56.57
37									Oil-S	125	139,170	731	9,961		79.69
38	Daniel 2	(1)	255.0	147,799	77.9	99.9	78.0	10,219	Coal	74,590	10,124	1,510,288	4,219,752	2.86	56.57
39									Oil-S	0	139,170	2	26		#N/A
40	Total		2,667.3	1,465,135	73.8	79.4	93.0	9,969				14,565,292	45,749,737	3.12	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and S basis only.
Smith A uses light oil; Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Adjustment - COAL	125,881	
(42)	Crist Inventory Adjustment - OIL	(3,175)	
(11)	Scherer Inventory Adjustment - OIL	(911)	
NA	Scherer Inventory Adjustment - COAL	(71,536)	
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	45,794,763	3.13

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2006	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) lbs./cf/Gal.	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	1,043	0	0	0.00	0.00
2									Gas-S	0	1,043	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	1,043	0	0	0.00	0.00
4									Gas-S	0	1,043	0	0		0.00
5	Crist 4		78.0	44,005	84.0	100.0	84.0	10,669	Coal	20,102	11,678	469,508	1,181,591	2.69	58.78
6				0					Gas-G	0	1,043	0	0	#N/A	#N/A
7									Gas-S	0	1,043	0	0		#N/A
8									Oil-S	27	137,130	157	2,048		75.85
10	Crist 5		78.0	36,689	71.1	88.7	80.2	10,751	Coal	16,907	11,665	394,437	993,767	2.71	58.78
11				585					Gas-G	474	1,043	494	9,840	1.68	20.76
12									Gas-S	7,802	1,043	8,139	161,982		20.76
13									Oil-S	35	137,130	200	2,618		74.80
15	Crist 6		302.0	154,564	76.2	94.2	80.8	10,674	Coal	70,559	11,691	1,649,812	4,147,390	2.68	58.78
16				0					Gas-G	0	1,043	0	0	0.00	#N/A
17									Gas-S	0	1,043	0	0		#N/A
18									Oil-S	0	137,130	0	0		#N/A
19	Crist 7		472.0	236,763	74.7	84.3	88.6	10,609	Coal	108,253	11,602	2,511,910	6,363,025	2.69	58.78
20				16					Gas-G	212	1,043	221	4,402	27.51	20.76
21									Gas-S	1,106	1,043	1,154	22,967		20.77
22									Oil-S	79	137,130	455	5,958		75.42
23	Scherer 3	(2)	210.8	117,873	83.2	92.6	89.9	10,138	Coal	N/A	8,651	1,195,043	2,357,279	2.00	#NA
24									Oil-S	172	140,150	1,012	14,306		83.17
25	Scholz 1		46.0	19,061	61.7	98.2	62.8	11,829	Coal	9,739	11,575	225,465	675,498	3.54	69.36
26									Oil-S	13	139,189	78	946		72.77
27	2		46.0	18,815	60.9	100.0	60.9	12,280	Coal	10,002	11,550	231,050	693,730	3.69	69.36
28									Oil-S	12	139,189	71	866		72.17
29	Smith 1		162.0	91,941	84.5	99.9	84.5	10,317	Coal	40,980	11,573	948,513	2,469,469	2.69	60.26
30									Oil-S	23	138,301	136	1,679		73.00
31	2		195.0	109,668	83.7	100.0	83.7	10,310	Coal	48,852	11,572	1,130,625	2,943,855	2.68	60.26
32									Oil-S	25	138,301	143	1,767		70.68
33	3		531.0	247,254	69.3	100.0	69.3	7,153	Gas-G	1,715,429	1,031	1,768,607	16,233,410	6.57	9.46
34	A		40.0	30	0.1	100.0	0.1	27,333	Oil	141	138,301	820	9,472	31.57	67.18
35	Other Generation		0.0	3,261						0	0		122,435	3.75	#N/A
36	Daniel 1	(1)	251.5	159,927	94.6	100.0	94.6	10,121	Coal	76,745	10,545	1,618,552	4,566,558	2.86	59.50
37									Oil-S	1	139,492	5	61		61.00
38	Daniel 2	(1)	255.0	126,393	73.8	100.0	73.8	10,213	Coal	61,361	10,518	1,290,790	3,651,164	2.89	59.50
39									Oil-S	1	139,492	6	80		80.00
40	Total		2,667.3	1,366,845	76.3	75.7	100.7	9,862				13,447,403	46,638,163	3.41	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
Smith A uses light oil; Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	46,632,930	3.41

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2006	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) lbs./cf/Gal.	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
2									Gas-S	0	0	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
4									Gas-S	0	0	0	0		0.00
5	Crist 4		78.0	48,306	83.2	99.9	83.3	10,723	Coal	22,120	11,709	518,008	1,314,906	2.72	59.44
6				5					Gas-G	57	1,053	60	440	8.80	7.72
7									Gas-S	0	1,053	0	0		#N/A
8									Oil-S	37	137,130	211	2,759		74.57
10	Crist 5		78.0	49,058	84.6	100.0	84.6	10,599	Coal	22,137	11,744	519,950	1,315,901	2.68	59.44
11				37					Gas-G	415	1,053	437	3,221	8.71	7.76
12									Gas-S	0	1,053	0	0		#N/A
13									Oil-S	24	137,130	138	1,804		75.17
15	Crist 6		302.0	177,779	79.1	100.0	79.1	10,566	Coal	80,110	11,724	1,878,432	4,762,091	2.68	59.44
16				42					Gas-G	472	1,053	498	3,670	0.00	7.78
17									Gas-S	0	1,053	0	0		#N/A
18									Oil-S	21	137,130	121	1,583		75.38
19	Crist 7		472.0	313,375	89.2	96.9	92.1	10,676	Coal	142,505	11,739	3,345,729	8,471,059	2.70	59.44
20				10					Gas-G	109	1,053	114	847	8.47	7.77
21									Gas-S	0	1,053	0	0		#N/A
22									Oil-S	6	137,130	33	430		71.67
23	Scherer 3	(2)	210.8	139,217	88.8	100.0	88.8	10,079	Coal	N/A	8,566	1,403,202	2,790,298	2.00	#NA
24									Oil-S	5	140,150	29	415		83.00
25	Scholz 1		46.0	16,414	48.0	87.0	55.1	11,874	Coal	8,423	11,570	194,906	584,053	3.56	69.34
26									Oil-S	25	139,189	148	1,802		72.08
27	2		46.0	17,862	52.2	100.0	52.2	12,548	Coal	9,668	11,591	224,135	670,422	3.75	69.34
28									Oil-S	14	139,189	80	973		69.50
29	Smith 1		162.0	28,738	23.8	29.2	81.8	10,476	Coal	12,941	11,632	301,058	791,999	2.76	61.20
30									Oil-S	44	138,301	255	3,141		71.39
31	2		195.0	108,267	74.6	90.3	82.6	10,265	Coal	47,588	11,677	1,111,360	2,912,405	2.69	61.20
32									Oil-S	333	138,301	1,933	23,846		71.61
33	3		531.0	243,323	61.6	96.7	63.7	8,246	Gas-G	1,949,908	1,029	2,006,455	16,020,921	6.58	8.22
34	A		40.0	3	0.0	100.0	0.0	121,667	Oil	63	138,301	365	4,210	140.33	66.83
35	Other Generation		0.0	3,153						0	0		119,564	3.79	#N/A
36	Daniel 1	(1)	251.5	128,968	68.9	74.7	92.3	10,269	Coal	59,627	11,105	1,324,316	3,730,861	2.89	62.57
37									Oil-S	369	139,442	2,160	28,670		77.70
38	Daniel 2	(1)	255.0	105,815	55.8	80.2	69.5	10,220	Coal	48,748	11,092	1,081,415	3,050,131	2.88	62.57
39									Oil-S	38	139,442	220	2,924		76.95
40	Total		2,667.3	1,380,372	69.6	70.0	99.3	10,104				13,915,768	46,615,346	3.38	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
Smith A uses light oil; Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
12,417	Crist Inventory Adjustment - COAL	729,872	
(9,195)	Smith Inventory Adjustment - COAL	(554,082)	
(1)	Scherer Inventory Adjustment - OIL	(96)	
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	46,785,807	3.39

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2006	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) lbs./cf/Gal.	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
2									Gas-S	0	0	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
4									Gas-S	0	0	0	0		0.00
5	Crist 4		78.0	47,370	84.4	99.7	84.7	10,748	Coal	21,214	12,000	509,144	1,255,675	2.65	59.19
6				18					Gas-G	206	1,050	216	1,640	9.11	7.96
7									Gas-S	0	1,050	0	0		#N/A
8									Oil-S	11	137,130	65	858		78.00
10	Crist 5		78.0	48,227	86.1	99.8	86.2	10,521	Coal	21,178	11,980	507,417	1,253,506	2.60	59.19
11				109					Gas-G	1,627	1,050	1,708	12,970	11.90	7.97
12									Gas-S	0	1,050	0	0		#N/A
13									Oil-S	31	137,130	176	2,299		74.16
15	Crist 6		302.0	160,455	73.8	89.6	82.5	10,504	Coal	70,298	11,988	1,685,471	4,160,953	2.59	59.19
16				124					Gas-G	1,800	1,050	1,891	14,352	0.00	7.97
17									Gas-S	723	1,050	759	5,763		7.97
18									Oil-S	26	137,130	147	1,925		74.04
19	Crist 7		472.0	171,260	50.4	55.4	91.0	10,878	Coal	78,251	11,904	1,863,004	4,631,687	2.70	59.19
20				25					Gas-G	366	1,050	385	2,919	11.68	7.98
21									Gas-S	852	1,050	894	6,789		7.97
22									Oil-S	47	137,130	269	3,518		74.85
23	Scherer 3	(2)	210.8	119,626	78.8	88.7	88.9	10,209	Coal	N/A	8,508	1,221,282	2,449,068	2.05	#NA
24									Oil-S	148	140,150	869	12,328		83.30
25	Scholz 1		46.0	19,866	60.0	100.0	60.0	11,998	Coal	9,983	11,938	238,360	692,257	3.48	69.34
26									Oil-S	15	137,408	86	1,120		74.67
27	2		46.0	17,995	54.3	93.7	58.0	12,645	Coal	9,526	11,944	227,541	660,506	3.67	69.34
28									Oil-S	23	137,408	134	1,749		76.04
29	Smith 1		162.0	(430)	(0.4)	0.0	0.0	0	Coal	0	0	0	0	#N/A	#N/A
30									Oil-S	0	138,089	0	0		#N/A
31	2		195.0	69,039	49.2	55.0	89.4	10,176	Coal	30,024	11,700	702,563	1,838,102	2.66	61.22
32									Oil-S	487	138,089	2,823	34,878		71.62
33	3		479.0	170,472	49.4	69.8	70.9	7,873	Gas-G	1,299,252	1,033	1,342,127	11,599,565	6.80	8.93
34	A		32.0	0	0.0	11.8	0.0	#N/A	Oil	31	138,089	182	2,105	#N/A	67.90
35	Other Generation		0.0	3,178						0	0		123,479	3.89	#N/A
36	Daniel 1	(1)	251.5	155,853	86.1	100.0	86.1	10,111	Coal	72,795	10,824	1,575,866	4,759,410	3.05	65.38
37									Oil-S	0	138,774	2	32		#N/A
38	Daniel 2	(1)	255.0	130,478	71.1	77.5	91.7	10,060	Coal	58,998	11,124	1,312,576	3,857,316	2.96	65.38
39									Oil-S	714	138,774	4,163	55,859		78.23
40	Total		2,607.3	1,113,665	59.3	58.4	101.5	10,086				11,200,120	37,442,628	3.36	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
Smith A uses light oil; Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
14	Smith Inventory Adjustment - Oil	988	
NA	Scherer Inventory Adjustment - Coal	152,896	
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	37,591,279	3.38

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2006	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
2									Gas-S	0	0	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
4									Gas-S	0	0	0	0		0.00
5	Crist 4		78.0	47,833	82.4	100.0	82.4	10,997	Coal	22,072	11,916	526,023	1,302,125	2.72	58.99
6				0					Gas-G	0	1,048	0	0	#N/A	#N/A
7									Gas-S	0	1,048	0	0		#N/A
8									Oil-S	15	137,130	84	1,105		73.67
10	Crist 5		78.0	48,262	83.2	100.0	83.2	10,728	Coal	21,752	11,901	517,745	1,283,248	2.66	58.99
11				0					Gas-G	0	1,048	0	0	#N/A	#N/A
12									Gas-S	0	1,048	0	0		#N/A
13									Oil-S	9	137,130	49	641		71.22
15	Crist 6		302.0	176,198	78.4	99.0	79.2	10,732	Coal	79,553	11,885	1,890,979	4,693,162	2.66	58.99
16				0					Gas-G	0	1,048	0	0	0.00	#N/A
17									Gas-S	0	1,048	0	0		#N/A
18									Oil-S	0	137,130	0	0		#N/A
19	Crist 7		472.0	288,009	82.0	93.3	88.0	10,665	Coal	129,516	11,858	3,071,610	7,640,689	2.65	58.99
20				50					Gas-G	407	1,048	426	3,407	6.81	8.37
21									Gas-S	2,365	1,048	2,479	19,804		8.37
22									Oil-S	292	137,130	1,684	22,032		75.45
23	Scherer 3	(2)	210.8	141,978	90.5	100.0	90.5	9,999	Coal	N/A	8,440	1,419,674	2,863,733	2.02	#NA
24									Oil-S	2	140,150	14	210		105.00
25	Scholz 1		46.0	19,017	55.6	100.0	55.6	12,119	Coal	9,563	12,049	230,458	644,361	3.39	67.38
26									Oil-S	12	137,408	69	1,071		89.25
27	2		46.0	17,308	50.6	99.9	50.6	12,715	Coal	9,141	12,038	220,075	615,878	3.56	67.38
28									Oil-S	15	137,408	86	1,339		89.27
29	Smith 1		162.0	72,306	60.0	68.6	87.5	10,244	Coal	31,488	11,762	740,719	1,910,270	2.64	60.67
30									Oil-S	971	138,933	5,664	91,685		94.42
31	2		195.0	129,082	89.0	100.0	89.0	10,233	Coal	55,942	11,806	1,320,901	3,393,830	2.63	60.67
32									Oil-S	18	138,933	103	1,667		92.61
33	3		479.0	108,663	30.5	79.7	38.3	7,698	Gas-G	809,762	1,033	836,484	7,981,414	7.35	9.86
34	A	(3)	32.0	(5)	(0.0)	0.0	#N/A	#N/A	Oil	377	138,933	2,197	25,258	#N/A	67.00
35	Other Generation		0.0	3,163						0	0		123,606	3.91	#N/A
36	Daniel 1	(1)	251.5	154,209	82.4	99.8	82.6	10,453	Coal	74,519	10,816	1,611,984	5,039,165	3.27	67.62
37									Oil-S	3	138,860	19	255		85.00
38	Daniel 2	(1)	255.0	162,019	85.4	99.2	86.1	9,920	Coal	74,739	10,752	1,607,187	5,054,075	3.12	67.62
39									Oil-S	16	138,860	93	1,256		78.50
40	Total		2,607.3	1,368,092	70.5	77.0	91.6	10,262				14,006,806	42,715,286	3.12	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and S basis only.
(3) Smith A uses light oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	42,710,053	3.12

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2007

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2007	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
2									Gas-S	0	0	0	0		0.00
3	Crist 3		0.0	0	0.0	0.0	0.0	#N/A	Gas-G	0	0	0	0	0.00	0.00
4									Gas-S	0	0	0	0		0.00
5	Crist 4		78.0	49,480	88.1	100.0	88.1	11,264	Coal	23,390	11,914	557,335	1,376,309	2.78	58.84
6				0					Gas-G	0	1,040	0	0	#N/A	#N/A
7									Gas-S	0	1,040	0	0		#N/A
8									Oil-S	26	140,117	154	2,042		78.54
10	Crist 5		78.0	49,993	89.0	100.0	89.0	10,809	Coal	22,682	11,912	540,380	1,334,665	2.67	58.84
11				0					Gas-G	0	1,040	0	0	#N/A	#N/A
12									Gas-S	0	1,040	0	0		#N/A
13									Oil-S	5	140,117	31	413		82.60
15	Crist 6		302.0	192,957	88.7	100.0	88.8	10,716	Coal	87,304	11,842	2,067,700	5,137,122	2.66	58.84
16				0					Gas-G	0	1,040	0	0	0.00	#N/A
17									Gas-S	0	1,040	0	0		#N/A
18									Oil-S	2	140,117	11	142		71.00
19	Crist 7		472.0	271,129	79.8	84.5	94.4	10,902	Coal	124,121	11,907	2,955,814	7,303,520	2.69	58.84
20				16					Gas-G	198	1,040	206	1,510	9.44	7.63
21									Gas-S	2,695	1,040	2,803	20,602		7.64
22									Oil-S	0	140,117	0	0		#N/A
23	Scherer 3	(2)	210.8	135,536	89.3	92.2	96.8	10,334	Coal	N/A	8,564	1,400,599	2,815,361	2.08	#NA
24									Oil-S	4	140,150	24	344		86.00
25	Scholz 1		46.0	19,517	58.9	99.9	59.0	12,185	Coal	9,992	11,900	237,807	649,924	3.33	65.04
26									Oil-S	10	137,408	59	912		91.20
27	2		46.0	17,826	53.8	100.0	53.8	12,806	Coal	9,610	11,878	228,288	625,063	3.51	65.04
28									Oil-S	12	137,408	71	1,094		91.17
29	Smith 1		162.0	107,633	92.3	100.0	92.3	10,209	Coal	46,265	11,875	1,098,805	2,800,682	2.60	60.54
30									Oil-S	13	139,245	75	(4,638)		(356.77)
31	2		195.0	122,246	87.1	95.3	91.4	10,415	Coal	53,482	11,903	1,273,195	3,237,539	2.65	60.54
32									Oil-S	213	139,245	1,245	19,808		93.00
33	3		479.0	211,257	61.3	100.0	61.3	6,468	Gas-G	1,321,389	1,034	1,366,316	12,871,127	6.09	9.74
34	A	(3)	32.0	49	0.2	11.7	1.8	(24,347)	Oil	(204)	139,245	(1,193)	(13,674)	(27.91)	67.03
35	Other Generation		0.0	5,353						0	0		214,426	4.01	#N/A
36	Daniel 1	(1)	251.5	162,651	89.8	98.8	90.9	10,091	Coal	71,848	11,422	1,641,296	4,742,112	2.92	66.00
37									Oil-S	143	138,910	833	11,243		78.62
38	Daniel 2	(1)	255.0	167,619	91.3	99.9	91.4	10,116	Coal	74,317	11,408	1,695,629	4,905,104	2.93	66.00
39									Oil-S	1	138,910	5	69		69.00
40	Total		2,607.3	1,513,262	80.6	76.6	105.2	9,992				15,067,488	48,052,821	3.18	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
2	Scherer Inventory Adjustment - OIL	172	
791	Daniel Inventory Adjustment - Coal	45,342	
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	48,093,102	3.18

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	53,500	92.2	95.4	96.6	10,638	Coal	23,969	11,872	569,116	1,349,898	2.52	56.32
4	4							Gas - G						
5	Crist 5	78.0	53,670	92.5	95.4	96.9	10,626	Coal	24,018	11,872	570,277	1,352,652	2.52	56.32
6	5							Gas - G						
7	Crist 6	302.0	199,900	89.0	93.3	95.4	10,372	Coal	87,327	11,872	2,073,460	4,918,085	2.46	56.32
8	6							Gas - G						
9	Crist 7	472.0	332,210	94.6	94.8	99.8	10,379	Coal	145,216	11,872	3,447,943	8,178,251	2.46	56.32
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,940	95.6	97.0	98.5	10,266	Coal	NA	8,586	1,539,311	3,046,445	2.03	NA
12	Scholz 1	46.0	19,280	56.3	95.4	59.0	12,430	Coal	9,979	12,008	239,653	687,010	3.56	68.85
13	Scholz 2	46.0	17,140	50.1	95.4	52.5	12,872	Coal	9,187	12,008	220,630	632,477	3.69	68.84
14	Smith 1	162.0	106,350	88.2	95.4	92.5	10,190	Coal	45,267	11,970	1,083,695	2,532,272	2.38	55.94
15	Smith 2	195.0	131,960	91.0	94.2	96.5	10,164	Coal	56,027	11,970	1,341,300	3,134,220	2.38	55.94
16	Smith 3	479.0	270,450	75.9	93.5	81.1	7,393	Gas - G	1,941,093	1,030	1,999,326	18,204,159	6.73	9.38
17	Smith A (CT)	32.0	960	4.0	90.1	4.5	14,067	Oil - G	2,306	139,400	13,504	171,175	17.83	74.22
18	Other Generation		5,720									220,000	3.85	#N/A
19	Daniel 1 (1)	251.5	172,180	92.0	94.0	97.9	9,976	Coal	76,170	11,275	1,717,585	5,445,143	3.16	71.49
20	Daniel 2 (1)	255.0	175,760	92.6	94.0	98.6	9,895	Coal	77,123	11,275	1,739,084	5,513,298	3.14	71.49
21	Gas,BL							Gas	7,114	1,030	7,327	54,736	#N/A	7.69
22	Ltr. Oil							Oil	940	139,400	5,502	78,613	#N/A	83.66
23		2,607.3	1,689,020	87.1	94.4	92.2	9,842				16,567,713	55,518,434	3.29	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	54,250	93.5	95.4	98.0	10,635	Coal	24,325	11,859	576,946	1,403,074	2.59	57.68
4	4							Gas - G						
5	Crist 5	78.0	54,340	93.6	95.4	98.1	10,638	Coal	24,373	11,859	578,087	1,405,847	2.59	57.68
6	5							Gas - G						
7	Crist 6	302.0	204,170	90.9	93.3	97.4	10,403	Coal	89,553	11,859	2,124,071	5,165,521	2.53	57.68
8	6							Gas - G						
9	Crist 7	472.0	336,940	95.9	94.8	101.3	10,389	Coal	147,580	11,859	3,500,377	8,512,556	2.53	57.68
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,940	95.6	97.0	98.5	10,266	Coal	NA	8,582	1,539,311	3,065,711	2.04	NA
12	Scholz 1	46.0	20,380	59.5	95.4	62.4	12,468	Coal	10,582	12,006	254,091	725,822	3.56	68.59
13	Scholz 2	46.0	18,910	55.3	95.3	58.0	12,668	Coal	9,977	12,006	239,548	684,279	3.62	68.59
14	Smith 1	162.0	107,290	89.0	95.4	93.3	10,511	Coal	47,310	11,919	1,127,738	2,734,725	2.55	57.80
15	Smith 2	195.0	133,850	92.3	94.2	97.9	10,176	Coal	57,143	11,919	1,362,122	3,303,097	2.47	57.80
16	Smith 3	479.0	290,680	81.6	93.5	87.2	7,294	Gas - G	2,058,601	1,030	2,120,359	19,580,132	6.74	9.51
17	Smith A (CT)	32.0	350	1.5	90.1	1.6	14,146	Oil - G	846	139,400	4,951	63,788	18.23	75.43
18	Other Generation		5,720									220,000	3.85	#N/A
19	Daniel 1 (1)	251.5	175,790	93.9	94.0	100.0	9,966	Coal	77,576	11,292	1,751,922	5,568,570	3.17	71.78
20	Daniel 2 (1)	255.0	178,980	94.3	94.0	100.4	9,887	Coal	78,358	11,292	1,769,585	5,624,711	3.14	71.78
21	Gas,BL							Gas	1,368	1,030	1,409	10,710	#N/A	7.83
22	Ltr. Oil							Oil	852	139,403	4,989	71,311	#N/A	83.69
23		2,607.3	1,731,590	89.3	94.4	94.6	9,824				16,955,506	58,139,854	3.36	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	51,680	92.0	95.4	96.4	10,604	Coal	23,082	11,872	548,033	1,340,754	2.59	58.09
4	4							Gas - G						
5	Crist 5	78.0	51,610	91.9	95.4	96.3	10,619	Coal	23,082	11,872	548,036	1,340,761	2.60	58.09
6	5							Gas - G						
7	Crist 6	302.0	192,550	88.6	93.3	94.9	10,330	Coal	83,777	11,872	1,989,127	4,866,362	2.53	58.09
8	6							Gas - G						
9	Crist 7	472.0	321,810	94.7	94.7	100.0	10,260	Coal	139,056	11,872	3,301,616	8,077,344	2.51	58.09
10	7							Gas - G						
11	Scherer 3 (2)	210.8	144,600	95.3	97.1	98.2	10,265	Coal	NA	8,581	1,484,290	2,971,527	2.05	NA
12	Scholz 1	46.0	13,360	40.3	95.4	42.3	12,574	Coal	6,998	12,004	167,991	478,718	3.58	68.41
13	Scholz 2	46.0	13,020	39.3	95.3	41.3	12,869	Coal	6,979	12,004	167,548	477,457	3.67	68.41
14	Smith 1	162.0	102,210	87.6	95.4	91.8	10,165	Coal	43,627	11,908	1,038,979	2,555,766	2.50	58.58
15	Smith 2	195.0	126,620	90.2	94.3	95.6	10,135	Coal	53,887	11,908	1,283,321	3,156,819	2.49	58.58
16	Smith 3	479.0	204,230	59.2	93.5	63.4	7,709	Gas - G	1,528,504	1,030	1,574,359	14,818,909	7.26	9.70
17	Smith A (CT)	32.0	0	0.0	90.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		5,540									214,000	3.86	#N/A
19	Daniel 1 (1)	251.5	150,330	83.0	87.8	94.6	9,944	Coal	66,154	11,299	1,494,951	4,779,723	3.18	72.25
20	Daniel 2 (1)	255.0	168,920	92.0	93.9	98.0	9,743	Coal	72,825	11,299	1,645,709	5,261,734	3.11	72.25
21	Gas,BL							Gas	2,941	1,030	3,030	23,298	#N/A	7.92
22	Ltr. Oil							Oil	1,115	139,401	6,527	93,422	#N/A	83.80
23		2,607.3	1,546,480	82.4	93.8	87.8	9,899				15,253,517	50,456,594	3.26	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	51,470	88.7	92.5	95.9	10,512	Coal	22,756	11,888	541,052	1,299,041	2.52	57.09
4	4							Gas - G						
5	Crist 5	78.0	51,480	88.7	92.5	95.9	10,539	Coal	22,818	11,888	542,534	1,302,600	2.53	57.09
6	5							Gas - G						
7	Crist 6	302.0	189,960	84.5	91.0	92.9	10,320	Coal	82,453	11,888	1,960,427	4,706,897	2.48	57.09
8	6							Gas - G						
9	Crist 7	472.0	320,010	91.1	89.8	101.5	10,368	Coal	139,540	11,888	3,317,758	7,965,788	2.49	57.09
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,940	95.6	97.0	98.5	10,265	Coal	NA	8,581	1,539,186	3,089,880	2.06	NA
12	Scholz 1	46.0	12,850	37.5	93.8	40.0	12,472	Coal	6,675	12,004	160,259	456,686	3.55	68.42
13	Scholz 2	46.0	12,390	36.2	94.2	38.4	12,920	Coal	6,668	12,004	160,082	456,179	3.68	68.41
14	Smith 1	162.0	111,410	92.4	95.8	96.5	10,160	Coal	47,527	11,908	1,131,933	2,763,035	2.48	58.14
15	Smith 2	195.0	126,440	87.2	92.2	94.5	10,149	Coal	53,878	11,908	1,283,189	3,132,249	2.48	58.14
16	Smith 3	479.0	281,090	78.9	92.5	85.3	7,110	Gas - G	1,940,408	1,030	1,998,620	18,198,480	6.47	9.38
17	Smith A (CT)	32.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		6,440									248,000	3.85	#N/A
19	Daniel 1 (1)	251.5	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
20	Daniel 2 (1)	255.0	173,310	91.4	93.8	97.4	9,875	Coal	75,780	11,292	1,711,427	5,495,158	3.17	72.51
21	Gas,BL							Gas	1,915	1,030	1,973	15,427	#N/A	8.06
22	Ltr. Oil							Oil	908	139,403	5,316	76,096	#N/A	83.81
23		2,607.3	1,486,790	76.6	83.6	91.6	9,696				14,353,756	49,205,516	3.31	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	50,100	89.2	92.5	96.4	10,499	Coal	22,168	11,863	525,982	1,271,335	2.54	57.35
4	4							Gas - G						
5	Crist 5	78.0	49,850	88.8	92.5	96.0	10,542	Coal	22,150	11,863	525,540	1,270,269	2.55	57.35
6	5							Gas - G						
7	Crist 6	302.0	55,260	25.4	27.5	92.5	10,189	Coal	23,731	11,863	563,053	1,360,940	2.46	57.35
8	6							Gas - G						
9	Crist 7	472.0	311,880	91.8	89.9	102.1	10,352	Coal	136,074	11,863	3,228,604	7,803,768	2.50	57.35
10	7							Gas - G						
11	Scherer 3 (2)	210.8	145,100	95.6	97.1	98.5	10,244	Coal	NA	8,581	1,486,446	2,992,912	2.06	#N/A
12	Scholz 1	46.0	12,430	37.5	93.9	40.0	12,477	Coal	6,461	12,003	155,095	448,642	3.61	69.44
13	Scholz 2	46.0	12,340	37.3	94.2	39.6	12,941	Coal	6,652	12,003	159,686	461,923	3.74	69.44
14	Smith 1	162.0	107,610	92.3	95.8	96.3	10,135	Coal	45,914	11,877	1,090,678	2,688,565	2.50	58.56
15	Smith 2	195.0	124,070	88.4	92.1	96.0	10,096	Coal	52,733	11,877	1,252,651	3,087,835	2.49	58.56
16	Smith 3	531.0	259,350	67.8	92.5	73.3	7,107	Gas - G	1,789,601	1,030	1,843,289	16,813,631	6.48	9.40
17	Smith A (CT)	40.0	0	0.0	93.1	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		6,230									240,000	3.85	#N/A
19	Daniel 1 (1)	251.5	72,210	39.9	43.3	92.2	9,953	Coal	31,742	11,321	718,720	2,307,335	3.20	72.69
20	Daniel 2 (1)	255.0	169,590	92.4	93.9	98.4	9,845	Coal	73,735	11,321	1,669,543	5,359,795	3.16	72.69
21	Gas,BL							Gas	2,462	1,030	2,536	21,787	#N/A	8.85
22	Ltr. Oil							Oil	902	139,402	5,282	75,833	#N/A	84.06
23		2,667.3	1,376,020	71.7	80.8	88.7	9,656				13,227,105	46,204,570	3.36	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/B	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	0.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	0.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	48,380	83.4	92.5	90.2	10,533	Coal	21,525	11,837	509,565	1,215,249	2.51	56.46
4	4							Gas - G						
5	Crist 5	78.0	48,670	83.9	92.5	90.7	10,549	Coal	21,688	11,836	513,417	1,224,438	2.52	56.46
6	5							Gas - G						
7	Crist 6	302.0	122,220	54.4	64.7	84.1	10,239	Coal	52,860	11,837	1,251,358	2,984,337	2.44	56.46
8	6							Gas - G						
9	Crist 7	472.0	315,610	89.9	89.8	100.1	10,365	Coal	138,186	11,837	3,271,268	7,801,573	2.47	56.46
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,440	95.3	96.9	98.3	10,266	Coal	NA	8,580	1,534,210	3,091,803	2.07	#N/A
12	Scholz 1	46.0	12,720	37.2	93.8	39.6	12,599	Coal	6,676	12,002	160,259	468,241	3.68	70.14
13	Scholz 2	46.0	3,100	9.1	24.3	37.2	12,876	Coal	1,663	12,002	39,915	116,623	3.76	70.13
14	Smith 1	162.0	107,060	88.8	95.8	92.7	10,070	Coal	45,511	11,844	1,078,080	2,639,574	2.47	58.00
15	Smith 2	195.0	120,780	83.3	92.2	90.3	10,090	Coal	51,446	11,844	1,218,668	2,983,790	2.47	58.00
16	Smith 3	531.0	266,650	67.5	92.5	73.0	7,284	Gas - G	1,885,581	1,030	1,942,148	19,147,760	7.18	10.15
17	Smith A (CT)	40.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		7,150									276,000	3.86	#N/A
19	Daniel 1 (1)	251.5	163,580	87.4	92.6	94.4	9,942	Coal	71,753	11,333	1,626,340	5,219,569	3.19	72.74
20	Daniel 2 (1)	255.0	171,080	90.2	93.8	96.1	9,859	Coal	74,416	11,333	1,686,688	5,413,248	3.16	72.74
21	Gas,BL							Gas	5,677	1,030	5,848	54,618	#N/A	9.62
22	Ltr. Oil							Oil	1,065	139,402	6,234	89,677	#N/A	84.23
23		2,667.3	1,536,440	77.4	88.4	87.6	9,706				14,843,998	52,726,500	3.43	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF : JANUARY 2007 - DECEMBER 2007

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	0.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	0.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	591,462	86.6	96.9	89.3	10,714	Coal	268,013	11,822	6,336,721	15,570,349	2.63	58.10
4	4		23					Gas - G	263	525	276	2,080		
5	Crist 5	78.0	586,540	85.8	95.9	89.5	10,625	Coal	263,578	11,822	6,232,062	15,308,607	2.61	58.08
6	5		929					Gas - G	5,586	526	5,872	45,513		
7	Crist 6	302.0	1,992,417	75.3	87.1	86.4	10,486	Coal	884,766	11,807	20,892,984	51,475,625	2.58	58.18
8	6		446					Gas - G	6,642	526	6,991	45,755		
9	Crist 7	472.0	3,530,059	85.4	89.0	95.9	10,499	Coal	1,571,532	11,791	37,061,031	91,228,860	2.58	58.05
10	7		117					Gas - G	1,292	0	1,352	13,085		
11	Scherer 3 (2)	210.8	1,681,865	91.1	96.4	94.5	10,170	Coal	#N/A	#N/A	17,105,134	34,182,571	2.03	#N/A
12	Scholz 1	46.0	198,135	49.2	96.0	51.2	12,235	Coal	101,958	11,888	2,424,249	6,984,556	3.53	68.50
13	Scholz 2	46.0	178,105	44.2	90.9	48.6	12,694	Coal	95,225	11,872	2,260,940	6,517,307	3.66	68.44
14	Smith 1	162.0	1,041,377	73.4	80.9	90.7	10,244	Coal	452,066	11,799	10,668,242	26,632,300	2.56	58.91
15	Smith 2	195.0	1,413,798	82.8	91.2	90.7	10,213	Coal	612,073	11,795	14,439,006	36,223,862	2.56	59.18
16	Smith 3	500.7	2,749,263	62.7	91.9	68.2	7,364	Gas - G	19,640,328	515	20,245,116	182,855,701	6.65	9.31
17	Smith A (CT)	35.3	1,366	0.4	72.7	0.6	15,246	Oil - G	3,560	2,925	20,826	262,334	19.20	73.69
18	Other Generation		58,992						0			2,273,356	3.85	#N/A
19	Daniel 1 (1)	251.5	1,671,054	75.8	81.9	92.6	10,102	Coal	766,647	11,010	16,880,969	51,120,888	3.06	66.68
20	Daniel 2 (1)	255.0	1,877,763	84.1	93.3	90.1	9,969	Coal	844,990	11,077	18,719,921	57,405,486	3.06	67.94
21	Gas,BL							Gas	37,265	518	38,609	420,034	#N/A	11.27
22	Ltr. Oil							Oil	10,995	2,918	64,171	897,180	#N/A	81.60
23		2,632.3	17,573,711	76.2	89.7	84.9	9,900				173,404,472	579,465,449	3.30	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

Inventory Adjustments		$	units
COAL	Crist	$729,872	12,417
	Scherer	81,360	N/A
	Scholz	0	-
	Smith	(554,082)	(9,195)
	Daniel	171,223	791
OIL	Crist	(3,175)	(42)
	Scherer	(835)	(10)
	Scholz	0	-
	Smith	988	14
	Daniel Railcar	(31,398)	
	Total Adjustments	$ 393,953	3,975
Total Fuel Burned Cost		**$ 579,859,402**	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS

GULF POWER COMPANY

ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	573	393	1,113	749	2,192	1,681	913	826	1,088	881	876	1,038	12,323
3	UNIT COST ($/BBL)	65.63	77.58	74.93	82.06	90.59	84.13	85.06	85.00	85.07	84.83	85.01	85.07	83.66
4	AMOUNT ($)	37,607	30,489	83,396	61,464	198,576	141,423	77,664	70,213	92,556	74,738	74,472	88,300	1,030,898
5	*BURNED :*													
6	UNITS (BBL)	681	499	1,042	1,651	1,476	509	940	852	1,115	908	902	1,065	11,640
7	UNIT COST ($/BBL)	74.41	78.11	75.11	76.65	89.53	75.17	83.63	83.70	83.79	83.81	84.07	84.20	81.60
8	AMOUNT ($)	50,675	38,975	78,260	126,555	132,144	38,262	78,613	71,311	93,422	76,096	75,833	89,677	949,823
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	7,316	7,210	7,282	6,380	7,095	8,266	8,239	8,213	8,186	8,159	8,133	8,106	
11	UNIT COST ($/BBL)	77.40	77.36	77.30	78.03	79.53	80.74	80.89	81.01	81.18	81.28	81.37	81.47	
12	AMOUNT ($)	566,267	557,781	562,917	497,826	564,258	667,419	666,470	665,372	664,506	663,148	661,787	660,410	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	515,273	523,775	453,967	459,071	429,394	552,743	568,383	555,000	546,865	512,500	445,599	452,341	6,014,911
16	UNIT COST ($/TON)	58.92	60.11	62.58	62.77	62.58	60.59	61.63	63.27	63.08	60.94	62.43	60.34	61.58
17	AMOUNT ($)	30,358,381	31,485,927	28,411,210	28,817,656	26,869,980	33,487,935	35,031,632	35,115,309	34,498,523	31,232,870	27,816,991	27,294,983	370,421,397
18	*BURNED :*													
19	UNITS (TONS)	534,212	463,500	457,089	372,267	508,285	523,802	554,283	566,777	519,467	458,095	421,360	485,724	5,864,861
20	UNIT COST ($/TON)	59.14	59.73	60.78	62.08	62.12	61.39	60.88	61.98	62.25	60.20	61.85	61.90	61.18
21	AMOUNT ($)	31,593,963	27,686,047	27,779,619	23,109,413	31,576,804	32,157,382	33,743,306	35,128,202	32,335,438	27,577,633	26,060,407	30,066,642	358,814,856
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	545,925	606,199	603,077	689,882	610,991	639,932	654,032	642,255	669,653	724,058	748,297	714,914	
24	UNIT COST ($/TON)	59.76	60.08	61.44	61.99	62.29	61.55	62.19	63.31	63.95	64.19	64.46	63.60	
25	AMOUNT ($)	32,623,410	36,423,289	37,054,879	42,763,122	38,056,299	39,386,851	40,675,177	40,662,284	42,825,369	46,480,606	48,237,190	45,465,531	
26	DAYS SUPPLY:	27	30	30	34	30	31	32	32	33	36	37	35	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	1,503,470	1,458,625	1,538,432	1,387,043	1,479,257	1,486,798	1,510,215	1,512,743	1,506,608	1,421,003	1,460,386	1,477,756	17,742,336
29	UNIT COST ($/MMBTU)	2.02	1.97	2.04	2.05	2.05	2.00	2.00	2.00	2.00	2.00	2.00	1.99	2.01
30	AMOUNT ($)	3,037,346	2,879,195	3,132,656	2,837,766	3,029,339	2,969,323	3,015,190	3,021,265	3,008,653	2,838,163	2,915,693	2,944,954	35,629,543
31	*BURNED :*													
32	UNITS (MMBTU)	1,305,912	1,195,043	1,403,203	1,298,059	1,419,674	1,400,599	1,539,311	1,539,311	1,484,290	1,539,186	1,486,446	1,534,210	17,145,244
33	UNIT COST ($/MMBTU)	1.97	1.97	1.99	2.00	2.02	2.01	1.98	1.99	2.00	2.01	2.01	2.02	2.00
34	AMOUNT ($)	2,577,018	2,357,279	2,790,298	2,601,964	2,863,733	2,815,361	3,046,445	3,065,711	2,971,527	3,089,880	2,992,912	3,091,803	34,263,931
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	3,583,234	3,846,816	3,982,045	4,071,029	4,130,612	4,216,810	4,187,714	4,161,146	4,183,464	4,065,281	4,039,221	3,982,767	
37	UNIT COST ($/MMBTU)	1.97	1.97	1.99	2.01	2.02	2.01	2.02	2.02	2.02	2.02	2.01	2.00	
38	AMOUNT ($)	7,065,711	7,587,627	7,929,985	8,165,788	8,331,394	8,485,356	8,454,101	8,409,655	8,446,781	8,195,064	8,117,845	7,970,996	
39	DAYS SUPPLY:	69	74	77	79	80	81	81	80	81	78	78	77	
	GAS (1)													
44	*BURNED :*													
45	UNITS (MMBTU)	1,455,118	1,778,614	2,007,564	1,347,980	839,389	1,369,325	2,006,653	2,121,768	1,577,389	2,000,593	1,845,825	1,947,996	20,298,214
46	UNIT COST ($/MMBTU)	7.86	9.24	7.98	8.64	9.54	9.42	9.10	9.23	9.41	9.10	9.12	9.86	9.03
47	AMOUNT ($)	11,434,959	16,432,601	16,029,099	11,643,998	8,004,625	12,893,238	18,258,895	19,590,842	14,842,207	18,213,907	16,835,418	19,202,378	183,382,167
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	0	0	0	0	0	(377)	2,306	846	0	0	0	0	2,775
55	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	67.00	84.56	84.51	#N/A	#N/A	#N/A	#N/A	86.93
56	AMOUNT ($)	0	0	0	0	0	(25,258)	194,993	71,497	0	0	0	0	241,232
57	*BURNED :*													
58	UNITS (BBL)	0	141	63	31	377	(204)	2,306	846	0	0	0	0	3,560
59	UNIT COST ($/BBL)	#N/A	67.18	66.83	67.90	67.00	67.03	74.23	75.40	#N/A	#N/A	#N/A	#N/A	73.67
60	AMOUNT ($)	0	9,472	4,210	2,105	25,258	(13,674)	171,175	63,788	0	0	0	0	262,334
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	6,388	6,247	6,184	6,153	5,776	5,603	5,603	5,603	5,603	5,603	5,603	5,603	
63	UNIT COST ($/BBL)	67.09	67.09	67.10	67.09	67.10	67.10	71.35	71.35	71.35	71.35	71.35	71.35	
64	AMOUNT ($)	428,598	419,126	414,916	412,811	387,553	375,969	399,787	399,787	399,787	399,787	399,787	399,787	
65	DAYS SUPPLY:	4	3	3	3	3	3	3	3	3	3	3	3	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007

LINE	MONTH	TYPE & SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (A) ¢ / KWH FUEL COST	(6) (B) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT	(8) TOTAL COST $
	JANUARY								
1		Other Power Sales	409,994,988	49,148,102	360,846,886	2.85	3.05	11,700,339	12,519,729
2		Unit Power Sales	132,260,956	0	132,260,956	2.32	2.45	3,069,921	3,240,718
3		Economy Sales	23,350,510	0	23,350,510	3.43	4.96	801,350	1,157,753
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	301,736	301,736
5		TOTAL ACTUAL SALES	565,606,454	49,148,102	516,458,352	2.81	3.04	15,873,346	17,219,936
	FEBRUARY								
1		Other Power Sales	365,965,715	44,265,628	321,700,087	2.76	2.98	10,107,664	10,910,971
2		Unit Power Sales	125,918,208	0	125,918,208	2.08	2.22	2,619,695	2,796,125
3		Economy Sales	39,591,969	0	39,591,969	3.53	5.71	1,397,843	2,259,551
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	710,777	710,777
5		TOTAL ACTUAL SALES	531,475,892	44,265,628	487,210,264	2.79	3.14	14,835,979	16,677,424
	MARCH								
1		Other Power Sales	394,481,896	36,647,519	357,834,377	2.99	3.22	11,805,503	12,721,108
2		Unit Power Sales	144,179,256	0	144,179,256	2.12	2.27	3,051,832	3,279,568
3		Economy Sales	16,688,245	0	16,688,245	3.47	5.31	578,250	886,717
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	250,660	250,660
5		TOTAL ACTUAL SALES	555,349,397	36,647,519	518,701,878	2.82	3.09	15,686,245	17,138,053
	APRIL								
1		Other Power Sales	190,160,387	42,738,575	147,421,812	2.56	2.78	4,875,035	5,291,992
2		Unit Power Sales	119,009,387	0	119,009,387	2.19	2.34	2,609,397	2,790,354
3		Economy Sales	20,823,088	0	20,823,088	3.71	5.53	771,778	1,152,401
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	332,244	332,244
5		TOTAL ACTUAL SALES	329,992,862	42,738,575	287,254,287	2.60	2.90	8,588,454	9,566,991
	MAY								
1		Other Power Sales	219,500,412	51,785,503	167,714,909	2.51	2.73	5,506,254	5,986,053
2		Unit Power Sales	137,760,416	0	137,760,416	2.30	2.49	3,170,087	3,425,040
3		Economy Sales	15,856,871	0	15,856,871	3.72	5.45	590,046	864,505
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	316,117	316,117
5		TOTAL ACTUAL SALES	373,117,699	51,785,503	321,332,196	2.57	2.84	9,582,504	10,591,715
	JUNE								
1		Other Power Sales	239,009,681	72,562,911	166,446,770	2.74	2.96	6,558,331	7,070,776
2		Unit Power Sales	127,175,243	0	127,175,243	2.25	2.38	2,856,549	3,030,275
3		Economy Sales	9,287,970	0	9,287,970	4.73	5.93	438,876	550,354
4		Gain on Economy Sales	0	0	0	#N/A	#N/A	86,951	86,951
5		TOTAL ACTUAL SALES	375,472,894	72,562,911	302,909,983	2.65	2.86	9,940,707	10,738,356

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JULY 2007 - DECEMBER 2007

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)		
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
MONTH		KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
JULY								
1	Other Power Sales	257,367,000	0	257,367,000	4.76	5.59	12,243,000	14,393,000
2	Unit Power Sales	148,021,000	0	148,021,000	2.28	2.38	3,379,000	3,529,000
3	Economy Sales	17,430,000	0	17,430,000	7.63	7.85	1,330,000	1,368,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	264,000	264,000
5	TOTAL ESTIMATED SALES	422,818,000	0	422,818,000	4.07	4.62	17,216,000	19,554,000
AUGUST								
1	Other Power Sales	255,725,000	0	255,725,000	4.87	5.72	12,459,000	14,638,000
2	Unit Power Sales	149,791,000	0	149,791,000	2.27	2.37	3,403,000	3,557,000
3	Economy Sales	17,613,000	0	17,613,000	7.20	7.43	1,269,000	1,308,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	229,000	229,000
5	TOTAL ESTIMATED SALES	423,129,000	0	423,129,000	4.10	4.66	17,360,000	19,732,000
SEPTEMBER								
1	Other Power Sales	294,892,000	0	294,892,000	4.23	4.97	12,471,000	14,667,000
2	Unit Power Sales	139,760,000	0	139,760,000	2.24	2.34	3,130,000	3,273,000
3	Economy Sales	10,915,000	0	10,915,000	5.43	5.59	593,000	610,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	67,000	67,000
5	TOTAL ESTIMATED SALES	445,567,000	0	445,567,000	3.65	4.18	16,261,000	18,617,000
OCTOBER								
1	Other Power Sales	387,230,000	0	387,230,000	3.94	4.63	15,242,000	17,916,000
2	Unit Power Sales	145,071,000	0	145,071,000	2.25	2.34	3,266,000	3,401,000
3	Economy Sales	12,834,000	0	12,834,000	4.83	4.90	620,000	629,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	78,000	78,000
5	TOTAL ESTIMATED SALES	545,135,000	0	545,135,000	3.52	4.04	19,206,000	22,024,000
NOVEMBER								
1	Other Power Sales	363,093,000	0	363,093,000	4.01	4.69	14,551,000	17,022,000
2	Unit Power Sales	138,955,000	0	138,955,000	2.25	2.35	3,127,000	3,263,000
3	Economy Sales	15,230,000	0	15,230,000	4.92	5.01	749,000	763,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	209,000	209,000
5	TOTAL ESTIMATED SALES	517,278,000	0	517,278,000	3.60	4.11	18,636,000	21,257,000
DECEMBER								
1	Other Power Sales	383,233,000	0	383,233,000	3.78	4.41	14,477,000	16,883,000
2	Unit Power Sales	162,668,000	0	162,668,000	2.38	2.48	3,873,000	4,042,000
3	Economy Sales	19,541,000	0	19,541,000	4.43	4.56	866,000	892,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	199,000	199,000
5	TOTAL ESTIMATED SALES	565,442,000	0	565,442,000	3.43	3.89	19,415,000	22,016,000
TOTAL								
1	Other Power Sales	3,760,653,079	297,148,238	3,463,504,841	3.51	3.99	131,996,126	150,019,629
2	Unit Power Sales	1,670,569,466	0	1,670,569,466	2.25	2.37	37,555,481	39,627,080
3	Economy Sales	219,161,653	0	219,161,653	4.57	5.68	10,005,143	12,441,281
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	3,044,485	0
5	TOTAL ESTIMATED SALES	5,650,384,198	297,148,238	5,353,235,960	3.23	3.58	182,601,235	202,087,990

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007
ESTIMATED FOR THE PERIOD OF: JULY 2007 - DECEMBER 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007/ESTIMATED FOR JULY 2007 - DECEMBER 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1	865,000	0	0	0	3.52	3.52	30,469
	Other	COG-1	251,149	0	0	0	3.45	3.45	8,667
	Total		1,116,149	0	0	0	3.51	3.51	39,136
FEBRUARY	Solutia	COG-1	536,000	0	0	0	3.70	3.70	19,829
	Other	COG-1	4,227,598	0	0	0	3.53	3.53	149,135
	Total		4,763,598	0	0	0	3.55	3.55	168,964
MARCH	Solutia	COG-1	1,090,000	0	0	0	3.56	3.56	38,772
	Other	COG-1	4,285,262	0	0	0	3.51	3.51	150,358
	Total		5,375,262	0	0	0	3.52	3.52	189,130
APRIL	Solutia	COG-1	896,000	0	0	0	4.34	4.34	38,865
	Other	COG-1	5,571,727	0	0	0	3.65	3.65	203,494
	Total		6,467,727	0	0	0	3.75	3.75	242,359
MAY	Solutia	COG-1	239,000	0	0	0	5.09	5.09	12,152
	Other	COG-1	4,782,862	0	0	0	3.86	3.86	184,570
	Total		5,021,862	0	0	0	3.92	3.92	196,722
JUNE	Solutia	COG-1	33,000	0	0	0	5.32	5.32	1,754
	Other	COG-1	4,903,071	0	0	0	3.97	3.97	194,399
	Total		4,936,071	0	0	0	3.97	3.97	196,153
JULY	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
AUGUST	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
SEPTEMBER	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
OCTOBER	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
NOVEMBER	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
DECEMBER	Solutia	COG-1	0	0	0	0	#N/A	#N/A	0
	Other	COG-1	0	0	0	0	#N/A	#N/A	0
	Total		0	0	0	0	#N/A	#N/A	0
TOTAL			27,680,669	0	0	0	3.73	3.73	1,032,464

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 2007 - JUNE 2007

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	26,339,140	3.96	1,042,797
2	Other Purchases	32,842,425	(1.94)	(637,103)
3	ACTUAL TOTAL PURCHASES	59,181,565	0.69	405,694
	FEBRUARY			
1	Southern Co. Interchange	62,648,167	4.14	2,592,797
2	Other Purchases	2,056,359	(60.78)	(1,249,885)
3	ACTUAL TOTAL PURCHASES	64,704,526	2.08	1,342,912
	MARCH			
1	Southern Co. Interchange	30,533,623	3.97	1,212,727
2	Other Purchases	10,096,984	(9.25)	(934,403)
3	ACTUAL TOTAL PURCHASES	40,630,607	0.69	278,324
	APRIL			
1	Southern Co. Interchange	55,329,913	4.25	2,353,290
2	Other Purchases	20,079,710	(3.17)	(635,745)
3	ACTUAL TOTAL PURCHASES	75,409,623	2.28	1,717,545
	MAY			
1	Southern Co. Interchange	36,425,565	4.50	1,640,584
2	Other Purchases	27,684,904	(2.21)	(611,580)
3	ACTUAL TOTAL PURCHASES	64,110,469	1.61	1,029,004
	JUNE			
1	Southern Co. Interchange	27,464,733	7.40	2,031,979
2	Other Purchases	67,408,594	0.60	404,475
3	ACTUAL TOTAL PURCHASES	94,873,327	2.57	2,436,454

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JULY 2007 - DECEMBER 2007

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	28,684,000	15.15	4,347,000
2	Other Purchases	37,904,000	7.74	2,935,000
3	TOTAL ESTIMATED PURCHASES	66,588,000	10.94	7,282,000
	AUGUST			
1	Southern Co. Interchange	14,889,000	11.27	1,678,000
2	Other Purchases	32,828,000	8.09	2,657,000
3	TOTAL ESTIMATED PURCHASES	47,717,000	9.08	4,335,000
	SEPTEMBER			
1	Southern Co. Interchange	4,030,000	7.49	302,000
2	Other Purchases	20,254,000	6.74	1,366,000
3	TOTAL ESTIMATED PURCHASES	24,284,000	6.87	1,668,000
	OCTOBER			
1	Southern Co. Interchange	5,689,000	5.22	297,000
2	Other Purchases	9,231,000	6.11	564,000
3	TOTAL ESTIMATED PURCHASES	14,920,000	5.77	861,000
	NOVEMBER			
1	Southern Co. Interchange	2,948,000	5.39	159,000
2	Other Purchases	12,836,000	6.43	825,000
3	TOTAL ESTIMATED PURCHASES	15,784,000	6.23	984,000
	DECEMBER			
1	Southern Co. Interchange	1,456,000	4.60	67,000
2	Other Purchases	14,255,000	6.94	990,000
3	TOTAL ESTIMATED PURCHASES	15,711,000	6.73	1,057,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	296,437,141	5.98	17,724,174
2	Other Purchases	287,476,976	1.97	5,672,759
3	TOTAL ACT/EST PURCHASES	583,914,117	4.01	23,396,933

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
For the Period January 2008 - December 2008

1	Estimated over/(under)-recovery, January 2007 - December 2007 (Schedule CCE-1b, Line 14 + Line 17)	$1,635,509
2	Final True-Up, January 2006 - December 2006 (Exhibit No.____(RJM-1), filed March 1, 2007	458,084
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2008 - December 2008)	$2,093,593
4	Jurisdictional KWH sales, January 2008 - December 2008	11,692,537,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0179)

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2007 - December 2007

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,149,354	379,768	578,776	217,665	576,266	3,541,079	8,699,468	10,684,337	4,151,850	340,360	270,117	395,726	30,984,766
2	Transmission Revenue	(13,223)	(43,697)	(13,111)	(19,011)	(162,875)	(33,024)	(27,000)	(27,000)	(17,000)	(20,000)	(24,000)	(30,000)	(429,941)
3	Total Capacity Payments/(Receipts)	1,136,131	336,071	565,665	198,654	413,391	3,508,055	8,672,468	10,657,337	4,134,850	320,360	246,117	365,726	30,554,825
4	Jurisdictional %	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872
5	Jurisdictional Capacity Payments/(Receipts) (Line 3 x Line 4) ($)	1,098,056	324,808	546,708	191,997	399,537	3,390,490	8,381,829	10,300,180	3,996,280	309,624	237,869	353,469	29,530,847
6	Retail KWH Sales							1,194,601,000	1,214,089,000	1,019,077,000	873,146,000	800,511,000	897,882,000	
7	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.275	0.275	0.275	0.275	0.275	0.275	
8	Capacity Cost Recovery Revenues (Line 6 x Line 7/100) ($)	2,445,741	2,236,518	2,152,312	2,150,832	2,694,534	3,097,526	3,285,153	3,338,745	2,802,462	2,401,152	2,201,405	2,469,176	31,275,556
9	Revenue Taxes (Line 8 x .00072) ($)	1,761	1,610	1,550	1,549	1,940	2,230	2,365	2,404	2,018	1,729	1,585	1,778	22,518
10	True-Up Provision ($)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(110,484)
11	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 8 - Line 9 + Line 10) ($)	2,434,773	2,225,701	2,141,555	2,140,076	2,683,387	3,086,089	3,273,581	3,327,134	2,791,237	2,390,216	2,190,613	2,458,191	31,142,554
12	Over/(Under) Recovery (Line 11 - Line 5) ($)	1,336,717	1,900,893	1,594,847	1,948,079	2,283,850	(304,401)	(5,108,248)	(6,973,046)	(1,205,043)	2,080,592	1,952,744	2,104,722	1,611,707
13	Interest Provision ($)	4,478	11,111	18,861	26,748	36,180	40,801	29,187	2,777	(15,162)	(13,262)	(4,406)	4,541	141,854
14	Total Estimated True-Up for the Period January 2007 - December 2007 (Line 12 + Line 13) ($)													1,753,561
NOTE:	Interest is Calculated for July through December at June 2007 monthly rate of		0.4400%											
15	Beginning Balance True-Up & Interest Provision ($)	347,601	1,698,003	3,501,162	5,124,077	7,108,111	9,437,348	9,182,955	4,113,101	(2,847,961)	(4,058,959)	(1,982,422)	(24,877)	347,601
16	True-Up Collected/(Refunded) ($)	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	110,484
17	2006 Revenue Adjustment		(118,052)											(118,052)
18	End of Period TOTAL Net True-Up (Lines 12 + 13 + 15 + 16 + 17) ($)	1,698,003	3,501,162	5,124,077	7,108,111	9,437,348	9,182,955	4,113,101	(2,847,961)	(4,058,959)	(1,982,422)	(24,877)	2,093,593	2,093,593

Gulf Power Company
2007 Capacity Contracts

Contract/Counterparty	Term Start	Term End (1)	Contract Type
Southern Intercompany Interchange	2/18/2000	5 Yr Notice	SES Opco
Alabama Electric Cooperative	1/1/2007	-	Other
Cargill Power Markets, LLC	4/1/2007	-	Other
Rainbow Energy Marketing Corp.	6/1/2007	-	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/31/2007	-	Other
Westar Energy, Inc.	1/1/2007	-	Other
Calpine Power Services	Varies	-	Other
Cogentrix	8/5/2003	-	Other
Coral Power, LLC	5/15/2003	-	Other
Exelon Power Team	5/1/2001	-	Other
FP&L Energy Power Marketing	6/1/2003	-	Other
KGEN, LLC	5/1/2005	-	Other
Progress Energy	Varies	-	Other
West Georgia Generating Co., LP	5/11/2000	-	Other
Williams Energy Power Marketing	5/1/2002	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

Capacity Costs

2007	January		February		March		April		May		June		*Projected* July		August		September		October		November		December		Total $
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	
Southern Intercompany Interchange	459.6	1,179,280	449.8	412,379	553.3	601,475	461.8	240,081	640.9	619,462	588.7	3,583,175	474.1	8,703,696	582.3	10,688,565	485.1	4,156,078	563.1	344,588	448.3	274,345	653.6	399,954	31,203,078
Confidential Contracts (Projected)													-	(4,228)	-	(4,228)	-	(4,228)	-	(4,228)	-	(4,228)	-	(4,228)	(25,368)
[redacted]																									(53,938)
																									(3,374)
																									(1,660)
																									(24,205)
																									(6,005)
																									(99,576)
																									(624)
																									(311)
																									(310)
																									(312)
																									(311)
																									(1,072)
																									(624)
																									(311)
																									(311)
Total		1,149,354		379,768		578,776		217,665		576,266		3,541,079		8,699,468		10,684,337		4,151,850		340,360		270,117		395,726	30,984,766

(1) Put options sold to counterparty
(2) Generator Balancing Service provides no capacity scheduling entitlements.

Before the Florida Public Service Commission

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Docket No. 070001-EI

PREPARED DIRECT TESTIMONY AND EXHIBIT OF

RHONDA J. MARTIN

PROJECTION FILING FOR THE PERIOD

January 2007 - December 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 31
COMPANY Gulf Power Co.
WITNESS R. J. Martin (RJM-3)
DATE 11-06-07

September 4, 2007

GULF POWER

A SOUTHERN COMPANY

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

BEFORE me, the undersigned authority, personally appeared Rhonda J. Martin, who being first duly sworn, deposes and says that she is the Supervisor of Rates and Regulatory Matters at Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of her knowledge, information and belief. She is personally known to me.

Rhonda J. Martin
Supervisor of Rates and Regulatory Matters

Sworn to and subscribed before me
this 30th day of August, 2007.

Linda C. Webb
Notary Public, State of Florida at Large

(SEAL)

LINDA C. WEBB
Notary Public-State of Florida
Comm. Exp. May 31, 2010
Comm. No. DD 541216

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	626,630,546	17,586,010,000	3.5632
2	Nuclear Fuel Disposal Costs		E-2			#N/A
3	Coal Car Investment					#N/A
4	Other Generation		E-3	2,920,047	75,290,000	3.8784
5	**Total Cost of Generated Power**	(Line 1 - 4)		629,550,593	17,661,300,000	3.5646
6	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
7	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
8	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	17,616,000	417,436,000	4.2200
9	Energy Cost of Schedule E Economy Purch.		E-9			#N/A
10	Capacity Cost of Schedule E Economy Purchases		E-2			#N/A
11	Energy Payments to Qualifying Facilities		E-8			#N/A
12	**Total Cost of Purchased Power**	(Line 6 - 11)		17,616,000	417,436,000	4.2200
13	**Total Available KWH**	(Line 5 + 12)			18,078,736,000	
14	Fuel Cost of Economy Sales		E-6	(10,580,000)	(177,310,000)	5.9670
15	Gain on Economy Sales		E-6	(2,218,000)	0	#N/A
16	Fuel Cost of Unit Power Sales		E-6	(36,223,000)	(1,492,381,000)	2.4272
17	Fuel Cost of Other Power Sales			(164,426,000)	(3,519,163,000)	4.6723
18	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -17)		(213,447,000)	(5,188,854,000)	4.1136
19	Net Inadvertant Interchange			0	0	#N/A
20	**Total Fuel & Net Power Trans.**	(Line 5+12+18+19)		433,719,593	12,889,882,000	3.3648
21	Net Unbilled Sales *			0	0	#N/A
22	Company Use *			852,438	25,334,000	3.3648
23	T & D Losses •			25,222,272	749,592,000	3.3648
24	**System KWH Sales**			433,719,593	12,114,956,000	3.5800
25	Wholesale KWH Sales			15,122,600	422,419,000	3.5800
26	Jurisdictional KWH Sales			418,596,993	11,692,537,000	3.5800
26a	Jurisdictional Line Loss Multiplier			1.0007		1.0007
27	Jurisdictional KWH Sales Adjusted for Line Losses			418,890,011	11,692,537,000	3.5825
28	**True-Up ****			43,326,799	11,692,537,000	0.3706
29	**Total Jurisdictional Fuel Cost**			462,216,810	11,692,537,000	3.9531
30	Revenue Tax Factor					1.00072
31	Fuel Factor Adjusted For Revenue Taxes			462,549,606	11,692,537,000	3.9559
32	GPIF Reward/(Penalty) **			(205,097)	11,692,537,000	(0.0018)
33	Fuel Factor Adjusted for GPIF			462,344,509	11,692,537,000	3.9542
34	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**3.954**

*For informational purposes only
** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2007 (Sch. E-1B, page 2, line C9)	($12,525,950)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2006 (EXHIBIT No.____(RJM-1))	(30,800,849)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2008 - DECEMBER 2008 (Schedule E1, Line 28)	($43,326,799)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008	11,692,537,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.3706

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	45,642,916.69	46,510,495.01	46,666,243.69	37,467,800.13	42,586,447.32	47,878,675.53	$266,752,578.37
	1a	Fuel Cost of Hedging Settlement	1,221,102.72	887,711.57	1,030,480.00	103,000.00	71,000.00	336,800.00	3,650,094.29
	2	Fuel Cost of Power Sold	(15,873,346.15)	(14,835,979.13)	(15,686,244.68)	(8,588,453.62)	(9,582,504.22)	(9,940,707.39)	(74,507,235.19)
	3	Fuel Cost of Purchased Power	405,694.57	1,342,911.69	278,323.45	1,717,545.66	1,029,004.08	2,436,454.33	7,209,933.78
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	39,136.00	168,964.00	189,130.00	242,359.00	196,722.00	196,153.00	1,032,464.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	151,845.97	122,435.11	119,563.69	123,478.84	123,605.49	214,426.07	855,355.17
	6	Adjustments to Fuel Cost *	46,645.39	(42,790.60)	7,719.62	(749.36)	9,242.48	42,101.45	62,168.98
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$31,633,995.19	$34,153,747.65	$32,605,215.77	$31,064,980.65	$34,433,517.15	$41,163,902.99	$205,055,359.40
B	1	Jurisdictional KWH Sales	889,389,209	809,445,374	793,410,439	790,980,780	985,891,266	1,118,137,500	5,387,254,568
	2	Non-Jurisdictional KWH Sales	32,723,512	30,631,297	28,310,835	27,837,845	33,632,833	38,472,538	191,608,860
	3	TOTAL SALES (Lines B1 + B2)	922,112,721	840,076,671	821,721,274	818,818,625	1,019,524,099	1,156,610,038	5,578,863,428
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.4512%	96.3537%	96.5547%	96.6002%	96.7011%	96.6737%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$34,948,511.28	$31,833,583.97	$31,188,543.79	$31,125,843.65	$38,796,651.30	$44,028,734.53	$211,921,868.52
	2	True-Up Provision	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(23,339,731.98)
	2a	Incentive Provision	70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	421,133.76
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$31,128,744.91	$28,013,817.60	$27,368,777.42	$27,306,077.28	$34,976,884.93	$40,208,968.16	$189,003,270.30
	4	Fuel & Net Power Transactions (Line A7)	$31,633,995.19	$34,153,747.65	$32,605,215.77	$31,064,980.65	$34,433,517.15	$41,163,902.99	$205,055,359.40
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	30,532,725.93	32,931,435.43	31,503,905.58	30,029,839.62	33,320,898.17	39,822,524.35	$198,141,329.08
	6	Over/(Under) Recovery (Line C3-C5)	596,018.98	(4,917,617.83)	(4,135,128.16)	(2,723,762.34)	1,655,986.76	386,443.81	($9,138,058.78)
	7	Interest Provision	(330,141.39)	(325,318.51)	(329,533.80)	(328,959.73)	(315,691.92)	(296,156.81)	($1,925,802.16)
	8	Prior Period Revenue Adjustment	0	(384,482.83)	0	0	0	0	($384,482.83)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2007 - JUNE 2007**							($11,448,343.77)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note 1: Estimated Revenues based on the 2007 Fuel Factor excluding revenue taxes of 3.9352 ¢/KWH

Note 2: Interest Calculated for July through December at June 2007 rate of 0.4400

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		55,298,434.00	57,919,854.00	50,242,594.00	48,957,516.00	45,964,570.00	52,450,500.00	$577,586,046.37
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	$3,650,094.29
	2	Fuel Cost of Power Sold		(17,216,000.00)	(17,360,000.00)	(16,261,000.00)	(19,206,000.00)	(18,636,000.00)	(19,415,000.00)	($182,601,235.19)
	3	Fuel Cost of Purchased Power		7,282,000.00	4,335,000.00	1,668,000.00	861,000.00	984,000.00	1,057,000.00	$23,396,933.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$1,032,464.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		220,000.00	220,000.00	214,000.00	248,000.00	240,000.00	276,000.00	$2,273,355.17
	6	Adjustments to Fuel Cost *		0.00	0.00	0.00	0.00	0.00	0.00	$62,168.98
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$45,584,434.00	$45,114,854.00	$35,863,594.00	$30,860,516.00	$28,552,570.00	$34,368,500.00	$425,399,827.40
B	1	Jurisdictional KWH Sales		1,194,601,000	1,214,089,000	1,019,077,000	873,146,000	800,511,000	897,882,000	11,386,560,568
	2	Non-Jurisdictional KWH Sales		40,894,000	41,449,000	36,413,000	32,606,000	31,023,000	34,328,000	408,321,860
	3	TOTAL SALES (Lines B1 + B2)		1,235,495,000	1,255,538,000	1,055,490,000	905,752,000	831,534,000	932,210,000	11,794,882,428
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.6901%	96.6987%	96.5501%	96.4001%	96.2692%	96.3176%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$47,009,540.51	$47,776,425.79	$40,102,378.55	$34,359,750.46	$31,501,442.14	$35,333,153.29	$448,004,559.26
	2	True-Up Provision		(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.33)	(3,889,955.37)	($46,679,464.00)
	2a	Incentive Provision		70,188.96	70,188.96	70,188.96	70,188.96	70,188.96	70,189.01	$842,267.57
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$43,189,774.14	$43,956,659.42	$36,282,612.18	$30,539,984.09	$27,681,675.77	$31,513,386.92	$402,167,362.83
	4	Fuel & Net Power Transactions (Line A7)		$45,584,434.00	$45,114,854.00	$35,863,594.00	$30,860,516.00	$28,552,570.00	$34,368,500.00	$425,399,827.40
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		44,106,487.76	43,656,015.16	34,650,574.31	29,770,392.98	27,506,571.85	33,126,086.40	$410,957,457.54
	6	Over/(Under) Recovery (Line C3-C5)		(916,713.62)	300,644.26	1,632,037.87	769,591.11	175,103.92	(1,612,699.48)	($8,790,094.72)
	7	Interest Provision	(2)	(282,050.14)	(267,530.71)	(247,340.14)	(226,029.05)	(207,829.45)	(194,790.80)	($3,351,372.45)
	8	Prior Period Revenue Adjustment		0.00	0	0	0	0	0	($384,482.83)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2007 - DECEMBER 2007**								($12,525,950.00)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note 1: Estimated Revenues based on the 2007 Fuel Factor excluding revenue taxes of 3.9352 ¢/KWH

Note 2: Interest Calculated for July through December at June 2007 rate of 0.4400

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation	577,586,046	584,363,414	(6,777,368)	(1.16)	17,514,719,000	17,529,530,000	(14,811,000)	(0.08)	3.2977	3.3336	(0.0359)	(1.08)
1a	Fuel Cost of Hedging Settlement	3,650,094	0	3,650,094	100.00								
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
4	Other Generation	2,273,355	4,306,906	(2,033,551)	(47.22)	58,992,000	112,540,000	(53,548,000)	(47.58)	3.8537	3.8270	0.0267	0.70
5	Adjustments to Fuel Cost ***	62,169	0	62,169	100.00								
6	TOTAL COST OF GENERATED POWER	583,571,665	588,670,320	(5,098,655)	(0.87)	17,573,711,000	17,642,070,000	(68,359,000)	(0.39)	3.3207	3.3367	(0.0160)	(0.48)
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
9	Energy Cost of Other Economy Purchases (Nonbroker)	23,396,934	31,564,000	(8,167,066)	(25.87)	583,914,117	575,829,000	8,085,117	1.40	4.0069	5.4815	(1.4746)	(26.90)
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
12	Energy Payments to Qualifying Facilities	1,032,464	0	1,032,464	100.00	27,680,669	0	27,680,669	100.00	3.7299	#N/A	#N/A	#N/A
13	TOTAL COST OF PURCHASED POWER	24,429,398	31,564,000	(7,134,602)	(22.60)	611,594,786	575,829,000	35,765,786	6.21	3.9944	5.4815	(1.4871)	(27.13)
14	Total Available KWH (Line 6 + Line 13)	608,001,063	620,234,320	(12,233,257)	(1.97)	18,185,305,786	18,217,899,000	(32,593,214)	(0.18)				
15	Fuel Cost of Economy Sales	(10,005,142)	(12,340,000)	2,334,858	18.92	(219,161,653)	(253,704,000)	34,542,347	13.62	(4.5652)	(4.8639)	0.2987	6.14
16	Gain on Economy Sales	(3,044,485)	(3,382,521)	338,036	9.99			0	0.00	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales	(37,555,481)	(38,485,000)	929,519	2.42	(1,670,569,466)	(1,610,450,000)	(60,119,466)	(3.73)	(2.2481)	(2.3897)	0.1416	5.93
18	Fuel Cost of Other Power Sales	(131,996,127)	(143,688,000)	11,691,873	8.14	(3,760,653,079)	(3,645,352,000)	(115,301,079)	(3.16)	(3.5099)	(3.9417)	0.4318	10.95
19	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 15+16+17+18)	(182,601,235)	(197,895,521)	15,294,286	7.73	(5,650,384,198)	(5,509,506,000)	(140,878,198)	(2.56)	(3.2317)	(3.5919)	0.3602	10.03
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
21	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 6+13+19+20)	425,399,828	422,338,799	3,061,029	0.72	12,534,921,588	12,708,393,000	(173,471,412)	(1.37)	3.3937	3.3233	0.0704	2.12
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
23	Company Use *	754,130	759,673	(5,543)	(0.73)	22,221,467	22,859,000	(637,533)	(2.79)	3.3937	3.3233	0.0704	2.12
24	T & D Losses *	24,360,579	24,577,066	(216,487)	(0.88)	717,817,693	739,538,000	(21,720,307)	(2.94)	3.3937	3.3233	0.0704	2.12
25	TERRITORIAL (SYSTEM) SALES	425,399,828	422,338,799	3,061,029	0.72	11,794,882,428	11,945,996,000	(151,113,572)	(1.26)	3.6066	3.5354	0.0712	2.01
26	Wholesale Sales	14,729,839	14,619,763	110,076	0.75	408,321,860	413,525,000	(5,203,140)	(1.26)	3.6074	3.5354	0.0720	2.04
27	Jurisdictional Sales	410,669,989	407,719,036	2,950,953	0.72	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	3.6066	3.5354	0.0712	2.01
27a	Jurisdictional Loss Multiplier	1.0007	1.0007										
28	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0007)	410,957,458	408,004,439	2,953,019	0.72	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	3.6091	3.5379	0.0712	2.01
29	TRUE-UP **	46,679,464	46,679,464	0	0.00	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	0.4100	0.4048	0.0052	1.28
30	TOTAL JURISDICTIONAL FUEL COST	457,636,922	454,683,903	2,953,019	0.65	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	4.0191	3.9427	0.0764	1.94
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									4.0220	3.9455	0.0765	1.94
33	GPIF Reward / (Penalty) **	(842,874)	(842,874)	0	0.00	11,386,560,568	11,532,471,000	(145,910,432)	(1.27)	(0.0074)	(0.0073)	(0.0001)	(1.37)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0146	3.9382	0.0764	1.94
35	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									4.0150	3.9380	0.0770	1.96

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note: Amounts Included in the Estimated/Actual Column represent 6 months actual and 6 months estimate.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	(205,097)
	B. True-Up (Over)/Under Recovered	$	43,326,799
2.	TOTAL SALES (KWH)		11,692,537,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		(0.0018)
	B. True-Up Factor		0.3706

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

		NET ENERGY FOR LOAD %
	On-Peak	29.06
	Off-Peak	70.94
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	3.5800	4.0601	3.3834
Jurisdictional Loss Factor	1.0007	1.0007	1.0007
Jurisdictional Fuel Factor	3.5825	4.0629	3.3858
GPIF	-0.0018	-0.0018	-0.0018
True-Up	0.3706	0.3706	0.3706
TOTAL	3.9513	4.4317	3.7546
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	3.9541	4.4349	3.7573
Recovery Factor Rounded to the Nearest .001 ¢/KWH	3.954	4.435	3.757

HOURS:	ON-PEAK	25.61%
	OFF-PEAK	74.39%
		100.00%

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2008 - DECEMBER 2008

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor	
A	RS, RSVP, GS, GSD, GSDT, GSTOU, OSIII, SBS (1)	3.954	1.00526	3.975	
B	LP, LPT, SBS (2)	3.954	0.98890	3.910	
C	PX, PXT, RTP, SBS (3)	3.954	0.98063	3.877	
D	OS-I/II	3.954	1.00529	3.952	*

		TOU
A	On-Peak	4.458
	Off-Peak	3.777
B	On-Peak	4.386
	Off-Peak	3.716
C	On-Peak	4.349
	Off-Peak	3.685
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	4.435	¢ / KWH	x	0.2561	=	1.136	¢ / KWH
	Off-Peak	3.757	¢ / KWH	x	0.7439	=	2.795	¢ / KWH
							3.931	¢ / KWH
			Line Loss Multiplier			x	1.00529	
							3.952	¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	51,112,416	43,486,591	54,236,013	51,387,303	47,472,531	53,722,124	59,987,069	62,739,361	55,693,392	52,076,811	42,455,520	52,261,415	626,630,546
1a	Other Generation	277,306	259,465	249,769	241,624	249,769	214,863	221,844	221,844	214,863	249,769	241,624	277,307	2,920,047
2	Fuel Cost of Power Sold	(22,654,000)	(20,478,000)	(25,471,000)	(24,289,000)	(11,444,000)	(13,862,000)	(17,966,000)	(17,158,000)	(17,958,000)	(17,756,000)	(10,866,000)	(13,545,000)	(213,447,000)
3	Fuel Cost of Purchased Power	994,000	1,574,000	775,000	625,000	1,245,000	1,843,000	2,160,000	2,615,000	961,000	1,179,000	2,281,000	1,364,000	17,616,000
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	29,729,722	24,842,056	29,789,782	27,964,927	37,523,300	41,917,987	44,402,913	48,418,205	38,911,255	35,749,580	34,112,144	40,357,722	433,719,593
6	System KWH Sold	976,077,000	847,517,000	854,082,000	867,120,000	1,071,182,000	1,188,497,000	1,251,914,000	1,279,201,000	1,074,535,000	923,424,000	836,335,000	945,072,000	12,114,956,000
6a	Jurisdictional % of Total Sales	96.3598	96.3395	96.3239	96.4818	96.7065	96.7807	96.6836	96.7110	96.5550	96.4013	96.2184	96.3016	96.5132
7	Cost per KWH Sold (¢/KWH)	3.0458	2.9312	3.4879	3.2250	3.5030	3.5270	3.5468	3.7850	3.6212	3.8714	4.0788	4.2703	3.5800
7a	Jurisdictional Loss Multiplier	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007
7b	Jurisdictional Cost (¢/KWH)	3.0479	2.9333	3.4903	3.2273	3.5055	3.5295	3.5493	3.7876	3.6237	3.8741	4.0817	4.2733	3.5825
8	GPIF (¢/KWH) *	(0.0018)	(0.0021)	(0.0021)	(0.0020)	(0.0016)	(0.0015)	(0.0014)	(0.0014)	(0.0016)	(0.0019)	(0.0021)	(0.0019)	(0.0018)
9	True-Up (¢/KWH) *	0.3839	0.4422	0.4389	0.4316	0.3485	0.3139	0.2983	0.2919	0.3480	0.4056	0.4487	0.3967	0.3706
10	TOTAL	3.4300	3.3734	3.9271	3.6569	3.8524	3.8419	3.8462	4.0781	3.9701	4.2778	4.5283	4.6681	3.9513
11	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
12	Recovery Factor Adjusted for Taxes	3.4325	3.3758	3.9299	3.6595	3.8552	3.8447	3.8490	4.0810	3.9730	4.2809	4.5316	4.6715	3.9541
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	3.433	3.376	3.930	3.660	3.855	3.845	3.849	4.081	3.973	4.281	4.532	4.672	3.954

* CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	84,410	67,684	80,435	155,907	82,918	107,519	79,979	72,605	95,111	77,315	74,833	91,099	1,069,815
2	COAL excluding Scherer	29,534,778	26,220,038	30,656,063	32,180,648	32,046,596	34,664,288	37,393,242	38,328,992	36,544,091	30,327,291	22,838,574	29,529,119	380,263,720
3	COAL at Scherer	2,980,817	2,835,131	3,018,240	2,956,308	3,091,578	3,018,369	3,136,478	3,144,908	2,651,873	0	0	2,447,857	29,281,559
4	GAS - Generation	18,698,729	14,594,284	20,700,892	16,185,262	12,458,749	16,063,959	19,483,937	21,240,410	16,590,853	21,904,595	19,760,124	20,413,222	218,095,016
5	GAS (B.L.)	90,988	28,919	30,152	150,802	42,459	82,852	62,796	12,175	26,327	17,379	23,613	57,425	625,887
6	OIL - C.T.	0	0	0	0	0	0	52,481	162,115	0	0	0	0	214,596
7	TOTAL ($)	51,389,722	43,746,056	54,485,782	51,628,927	47,722,300	53,936,987	60,208,913	62,961,205	55,908,255	52,326,580	42,697,144	52,538,722	629,550,593
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL excluding Scherer	1,173,470	1,070,310	1,114,090	1,128,580	1,119,030	1,203,600	1,274,860	1,281,650	1,201,700	1,037,680	755,220	936,670	13,296,860
10	COAL at Scherer	149,310	139,630	148,810	144,970	149,400	145,100	149,940	149,440	126,540	0	0	115,720	1,418,860
11	GAS	252,190	192,950	267,130	227,790	165,460	225,960	271,180	290,180	222,330	291,760	286,080	251,830	2,944,840
12	OIL - C.T.	0	0	0	0	0	0	420	320	0	0	0	0	740
13	TOTAL (MWH)	1,574,970	1,402,890	1,530,030	1,501,340	1,433,890	1,574,660	1,696,400	1,721,590	1,550,570	1,329,440	1,041,300	1,304,220	17,661,300
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	1,002	801	952	1,840	977	1,265	940	852	1,115	907	876	1,065	12,591
15	COAL excl. Scherer (TON) (1)	471,025	415,906	491,821	506,339	503,429	544,930	575,057	581,905	550,881	457,861	338,520	426,451	5,864,125
16	GAS-all (MCF) (2)	1,726,894	1,332,794	1,981,343	1,552,656	1,122,223	1,490,061	1,813,143	1,967,461	1,518,596	2,090,577	1,926,549	1,889,372	20,411,669
17	OIL - C.T. (BBL)	0	0	0	0	0	0	692	2,076	0	0	0	0	2,768
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	12,494,402	11,088,308	13,054,064	13,290,923	13,236,191	14,152,414	14,735,963	14,803,502	13,829,949	10,548,642	7,773,960	10,856,654	149,864,972
19	GAS-Generation (2)	1,769,330	1,369,802	2,037,612	1,581,411	1,150,817	1,524,970	1,860,210	2,025,075	1,561,125	2,151,322	1,981,810	1,940,206	20,953,690
20	OIL - C.T.	0	0	0	0	0	0	4,051	12,153	0	0	0	0	16,204
21	TOTAL (MMBTU)	14,263,732	12,458,110	15,091,676	14,872,334	14,387,008	15,677,384	16,600,224	16,840,730	15,391,074	12,699,964	9,755,770	12,796,860	170,834,866

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.

(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
GENERATION MIX (% MWH)													
22 LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23 COAL	83.99	86.25	82.54	84.83	88.46	85.65	83.99	83.12	85.66	78.05	72.53	80.69	83.33
24 GAS-Generation	16.01	13.75	17.46	15.17	11.54	14.35	15.99	16.86	14.34	21.95	27.47	19.31	16.67
25 OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.00
26 TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST $ / UNIT													
27 LIGHTER OIL ($/BBL)	84.23	84.53	84.48	84.72	84.86	85.00	85.11	85.21	85.32	85.22	85.47	85.56	84.96
28 COAL ($/TON) (1)	62.70	63.04	62.33	63.56	63.66	63.61	65.03	65.87	66.34	66.24	67.47	69.24	64.85
29 GAS + B.L. ($/MCF) (2)	10.72	10.78	10.34	10.37	10.92	10.69	10.66	10.69	10.80	10.37	10.14	10.69	10.57
30 OIL - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	75.85	78.10	#N/A	#N/A	#N/A	#N/A	77.54
FUEL COST $ / MMBTU													
31 COAL + GAS B.L. + OIL B.L.	2.62	2.63	2.59	2.67	2.66	2.68	2.76	2.81	2.84	2.88	2.95	2.96	2.74
32 GAS-Generation (2)	10.41	10.46	10.04	10.08	10.61	10.39	10.35	10.38	10.49	10.07	9.85	10.38	10.27
33 OIL - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	12.96	13.34	#N/A	#N/A	#N/A	#N/A	13.24
34 TOTAL ($/MMBTU)	3.58	3.49	3.59	3.46	3.30	3.43	3.61	3.73	3.62	4.10	4.35	4.08	3.67
BTU BURNED BTU / KWH													
35 COAL + GAS B.L. + OIL B.L.	9,446	9,164	10,337	10,436	10,435	10,493	10,342	10,344	10,412	10,166	10,294	10,316	10,184
36 GAS-Generation (2)	7,221	7,354	7,816	7,138	7,237	6,918	7,007	7,119	7,201	7,540	7,082	7,930	7,302
37 OIL - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	9,645	37,978	#N/A	#N/A	#N/A	#N/A	21,897
38 TOTAL (BTU/KWH)	9,098	8,923	9,905	9,947	10,079	9,991	9,819	9,815	9,962	9,599	9,425	9,866	9,714
FUEL COST CENTS / KWH													
39 COAL + GAS B.L. + OIL B.L.	2.53	2.46	2.76	2.88	2.87	2.90	2.94	3.00	3.05	2.93	3.04	3.17	2.87
40 COAL at Scherer	2.00	2.03	2.03	2.04	2.07	2.08	2.09	2.10	2.10	#N/A	#N/A	2.12	2.06
41 GAS-Generation	7.41	7.56	7.75	7.11	7.53	7.11	7.18	7.32	7.46	7.51	6.91	8.11	7.41
42 OIL - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	12.50	50.66	#N/A	#N/A	#N/A	#N/A	29.00
43 TOTAL (¢/KWH)	3.26	3.12	3.56	3.44	3.33	3.43	3.55	3.66	3.61	3.94	4.10	4.03	3.56

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.

(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	6,120	10.5	12.9	81.8	11,594	Coal	2,974	11,930	70,956	167,762	2.74	56.41
2	4							Gas - G						
3	Crist 5	78.0	51,070	88.0	98.8	89.1	11,042	Coal	23,635	11,930	563,923	1,333,291	2.61	56.41
4	5							Gas - G						
5	Crist 6	302.0	190,830	84.9	71.6	118.6	8,057	Coal	64,441	11,930	1,537,511	3,635,158	1.90	56.41
6	6							Gas - G						
7	Crist 7	472.0	319,120	90.9	69.8	130.2	7,662	Coal	102,481	11,930	2,445,125	5,781,042	1.81	56.41
8	7							Gas - G						
9	Scherer 3 (2)	210.8	149,310	95.2	96.6	98.6	9,731	Coal	84,798	8,567	1,452,949	2,980,817	2.00	35.15
10	Scholz 1	46.0	12,580	36.8	92.5	39.7	12,145	Coal	6,347	12,035	152,782	454,986	3.62	71.69
11	Scholz 2	46.0	12,700	37.1	94.2	39.4	12,697	Coal	6,699	12,035	161,246	480,192	3.78	71.68
12	Smith 1	162.0	108,720	90.2	98.3	91.8	10,726	Coal	48,860	11,934	1,166,149	2,829,528	2.60	57.91
13	Smith 2	195.0	130,450	89.9	94.4	95.2	10,292	Coal	56,251	11,934	1,342,570	3,257,594	2.50	57.91
14	Smith 3	531.0	245,040	62.0	92.3	67.2	7,221	Gas - G	1,717,796	1,030	1,769,330	18,421,423	7.52	10.72
15	Smith A (CT)	40.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		7,150									277,306	3.88	#N/A
17	Daniel 1 (1)	251.5	170,320	91.0	98.3	92.6	10,524	Coal	79,645	11,253	1,792,448	5,795,906	3.40	72.77
18	Daniel 2 (1)	255.0	171,560	90.4	97.0	93.2	10,454	Coal	79,692	11,253	1,793,504	5,799,319	3.38	72.77
19	Gas,BL							Gas	9,098	1,030	9,371	90,988	#N/A	10.00
20	Ltr. Oil							Oil	1,002	139,401	5,868	84,410	#N/A	84.23
21		2,667.3	1,574,970	79.4	85.8	92.5	9,098				14,263,732	51,389,722	3.26	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
2	4							Gas - G						
3	Crist 5	78.0	23,190	42.7	47.4	90.1	10,935	Coal	10,580	11,985	253,589	595,365	2.57	56.27
4	5							Gas - G						
5	Crist 6	302.0	179,280	85.3	73.3	116.4	7,978	Coal	59,671	11,985	1,430,276	3,357,938	1.87	56.27
6	6							Gas - G						
7	Crist 7	472.0	301,680	91.8	64.8	141.7	6,792	Coal	85,486	11,985	2,049,058	4,810,686	1.59	56.27
8	7							Gas - G						
9	Scherer 3 (2)	210.8	139,630	95.2	96.6	98.5	9,726	Coal	79,355	8,557	1,358,053	2,835,131	2.03	35.73
10	Scholz 1	46.0	11,690	36.5	92.7	39.4	12,384	Coal	6,020	12,024	144,766	437,715	3.74	72.71
11	Scholz 2	46.0	12,070	37.7	94.3	40.0	12,555	Coal	6,301	12,024	151,535	458,185	3.80	72.72
12	Smith 1	162.0	101,960	90.4	98.3	92.0	10,657	Coal	45,299	11,993	1,086,585	2,615,107	2.56	57.73
13	Smith 2	195.0	121,750	89.7	94.3	95.1	10,254	Coal	52,045	11,993	1,248,395	3,004,538	2.47	57.73
14	Smith 3	531.0	186,260	50.4	64.7	77.9	7,354	Gas - G	1,329,905	1,030	1,369,802	14,334,819	7.70	10.78
15	Smith A (CT)	40.0	0	0.0	93.1	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,690				0					259,465	3.88	#N/A
17	Daniel 1 (1)	251.5	158,750	90.7	98.0	92.5	10,560	Coal	75,129	11,157	1,676,453	5,461,323	3.44	72.69
18	Daniel 2 (1)	255.0	159,940	90.1	96.8	93.1	10,516	Coal	75,375	11,157	1,681,935	5,479,181	3.43	72.69
19	Gas,BL							Gas	2,889	1,030	2,975	28,919	#N/A	10.01
20	Ltr. Oil							Oil	801	139,401	4,688	67,684	#N/A	84.53
21		2,667.3	1,402,890	75.6	77.6	97.3	8,923				12,458,110	43,746,056	3.12	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	24,430	42.1	48.0	87.7	11,632	Coal	11,849	11,991	284,174	687,554	2.81	58.03
2	4							Gas - G						
3	Crist 5	78.0	26,700	46.0	50.9	90.4	11,113	Coal	12,373	11,991	296,723	717,916	2.69	58.02
4	5							Gas - G						
5	Crist 6	302.0	205,640	91.5	96.6	94.7	10,412	Coal	89,275	11,991	2,141,036	5,180,200	2.52	58.03
6	6							Gas - G						
7	Crist 7	472.0	313,170	89.2	94.1	94.8	11,111	Coal	145,096	11,991	3,479,766	8,419,235	2.69	58.03
8	7							Gas - G						
9	Scherer 3 (2)	210.8	148,810	94.9	96.5	98.3	9,746	Coal	84,831	8,548	1,450,322	3,018,240	2.03	35.58
10	Scholz 1	46.0	12,670	37.0	92.5	40.0	11,811	Coal	6,227	12,017	149,644	456,801	3.61	73.36
11	Scholz 2	46.0	12,880	37.6	94.2	40.0	12,669	Coal	6,790	12,017	163,180	498,118	3.87	73.36
12	Smith 1	162.0	111,220	92.3	98.3	93.9	10,630	Coal	49,143	12,029	1,182,306	2,831,645	2.55	57.62
13	Smith 2	195.0	135,380	93.3	76.2	0.0	8,080	Coal	45,465	12,029	1,093,826	2,619,734	1.94	57.62
14	Smith 3	531.0	260,690	66.0	92.3	71.5	7,816	Gas - G	1,978,265	1,030	2,037,612	20,451,123	7.84	10.34
15	Smith A (CT)	40.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,440									249,769	3.88	#N/A
17	Daniel 1 (1)	251.5	177,310	94.8	98.4	96.3	10,375	Coal	82,393	11,163	1,839,590	6,064,439	3.42	73.60
18	Daniel 2 (1)	255.0	94,690	49.9	53.2	93.8	10,189	Coal	43,210	11,163	964,751	3,180,421	3.36	73.60
19	Gas,BL							Gas	3,078	1,030	3,171	30,152	#N/A	9.80
20	Ltr. Oil							Oil	952	139,404	5,575	80,435	#N/A	84.48
21		2,667.3	1,530,030	77.1	87.0	88.6	9,905				15,091,676	54,485,782	3.56	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	49,000	87.3	99.2	88.0	11,211	Coal	22,921	11,983	549,330	1,363,006	2.78	59.47
2	4							Gas - G						
3	Crist 5	78.0	50,030	89.1	98.8	90.2	10,775	Coal	22,493	11,983	539,078	1,337,569	2.67	59.47
4	5							Gas - G						
5	Crist 6	302.0	188,000	86.5	96.7	89.4	10,762	Coal	84,420	11,983	2,023,274	5,020,179	2.67	59.47
6	6							Gas - G						
7	Crist 7	472.0	308,360	90.7	94.0	96.5	10,678	Coal	137,381	11,983	3,292,561	8,169,554	2.65	59.47
8	7							Gas - G						
9	Scherer 3 (2)	210.8	144,970	95.5	96.7	98.8	9,690	Coal	82,235	8,541	1,404,761	2,956,308	2.04	35.95
10	Scholz 1	46.0	12,210	36.9	92.5	39.9	12,114	Coal	6,157	12,012	147,909	454,374	3.72	73.80
11	Scholz 2	46.0	12,470	37.7	94.2	40.0	12,526	Coal	6,502	12,012	156,193	479,822	3.85	73.80
12	Smith 1	162.0	104,630	89.7	98.5	91.1	10,790	Coal	46,856	12,047	1,128,996	2,697,647	2.58	57.57
13	Smith 2	195.0	76,180	54.3	41.0	0.0	7,186	Coal	22,720	12,047	547,435	1,308,053	1.72	57.57
14	Smith 3	479.0	221,560	64.2	92.4	69.5	7,138	Gas - G	1,535,350	1,030	1,581,411	15,943,638	7.20	10.38
15	Smith A (CT)	32.0	0	0.0	93.1	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,230									241,624	3.88	#N/A
17	Daniel 1 (1)	251.5	164,240	90.7	98.3	92.3	10,543	Coal	78,224	11,068	1,731,504	5,659,241	3.45	72.35
18	Daniel 2 (1)	255.0	163,460	89.0	96.9	0.0	10,653	Coal	78,665	11,068	1,741,283	5,691,203	3.48	72.35
19	Gas,BL							Gas	17,306	1,030	17,825	150,802	#N/A	8.71
20	Ltr. Oil							Oil	1,840	139,401	10,774	155,907	#N/A	84.72
21		2,607.3	1,501,340	80.0	91.5	87.4	9,947				14,872,334	51,628,927	3.44	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	50,020	86.2	99.2	86.9	11,302	Coal	23,598	11,978	565,330	1,421,752	2.84	60.25
2	4							Gas - G						
3	Crist 5	78.0	50,860	87.6	98.8	88.7	10,928	Coal	23,201	11,978	555,816	1,397,825	2.75	60.25
4	5							Gas - G						
5	Crist 6	302.0	185,970	82.8	96.9	85.4	10,768	Coal	83,589	11,978	2,002,503	5,036,108	2.71	60.25
6	6							Gas - G						
7	Crist 7	472.0	317,180	90.3	94.4	95.7	10,245	Coal	135,640	11,978	3,249,459	8,172,086	2.58	60.25
8	7							Gas - G						
9	Scherer 3 (2)	210.8	149,400	95.3	96.9	98.3	9,744	Coal	85,281	8,535	1,455,804	3,091,578	2.07	36.25
10	Scholz 1	46.0	12,070	35.3	94.0	37.5	12,943	Coal	6,504	12,009	156,218	482,073	3.99	74.12
11	Scholz 2	46.0	12,940	37.8	95.4	39.6	12,269	Coal	6,610	12,009	158,755	489,903	3.79	74.12
12	Smith 1	162.0	110,770	91.9	98.5	93.3	10,427	Coal	47,888	12,060	1,155,029	2,755,425	2.49	57.54
13	Smith 2	195.0	52,330	36.1	39.7	90.9	10,248	Coal	22,234	12,060	536,270	1,279,320	2.44	57.54
14	Smith 3	479.0	159,020	44.6	93.7	47.6	7,237	Gas - G	1,117,298	1,030	1,150,817	12,208,980	7.68	10.93
15	Smith A (CT)	32.0	0	0.0	90.1	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,440									249,769	3.88	#N/A
17	Daniel 1 (1)	251.5	161,340	86.2	98.4	87.6	10,628	Coal	77,975	10,995	1,714,741	5,569,829	3.45	71.43
18	Daniel 2 (1)	255.0	165,550	87.3	97.0	90.0	10,121	Coal	76,190	10,995	1,675,472	5,442,275	3.29	71.43
19	Gas,BL							Gas	4,925	1,030	5,073	42,459	#N/A	8.62
20	Ltr. Oil							Oil	977	139,404	5,721	82,918	#N/A	84.86
21		2,607.3	1,433,890	73.9	91.8	80.5	10,079				14,387,008	47,722,300	3.33	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	50,830	90.5	99.4	91.1	11,335	Coal	24,148	11,929	576,134	1,477,336	2.91	61.18
2	4							Gas - G						
3	Crist 5	78.0	51,160	91.1	98.8	92.2	10,872	Coal	23,312	11,929	556,201	1,426,224	2.79	61.18
4	5							Gas - G						
5	Crist 6	302.0	189,950	87.4	96.9	90.2	10,871	Coal	86,548	11,929	2,064,932	5,294,947	2.79	61.18
6	6							Gas - G						
7	Crist 7	472.0	321,000	94.5	94.3	100.2	10,356	Coal	139,329	11,929	3,324,201	8,523,994	2.66	61.18
8	7							Gas - G						
9	Scherer 3 (2)	210.8	145,100	95.6	97.1	98.5	9,724	Coal	82,700	8,531	1,410,961	3,018,369	2.08	36.50
10	Scholz 1	46.0	13,310	40.2	94.0	42.8	12,293	Coal	6,814	12,006	163,625	506,493	3.81	74.33
11	Scholz 2	46.0	12,430	37.5	95.6	39.3	13,442	Coal	6,958	12,006	167,081	517,190	4.16	74.33
12	Smith 1	162.0	108,490	93.0	98.5	94.4	10,507	Coal	47,220	12,070	1,139,934	2,715,678	2.50	57.51
13	Smith 2	195.0	126,670	90.2	94.6	95.4	10,226	Coal	53,656	12,070	1,295,303	3,085,815	2.44	57.51
14	Smith 3	479.0	220,420	63.9	93.8	68.1	6,918	Gas - G	1,480,553	1,030	1,524,970	15,849,096	7.19	10.70
15	Smith A (CT)	32.0	0	0.0	90.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		5,540									214,863	3.88	#N/A
17	Daniel 1 (1)	251.5	162,440	89.7	98.3	91.3	10,532	Coal	78,124	10,949	1,710,794	5,533,634	3.41	70.83
18	Daniel 2 (1)	255.0	167,320	91.1	96.9	94.0	10,316	Coal	78,821	10,949	1,726,049	5,582,977	3.34	70.83
19	Gas,BL							Gas	9,508	1,030	9,793	82,852	#N/A	8.71
20	Ltr. Oil							Oil	1,265	139,402	7,406	107,519	#N/A	85.00
21		2,607.3	1,574,660	83.9	95.9	87.5	9,991				15,677,384	53,936,987	3.43	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	53,470	92.1	99.5	92.6	11,107	Coal	25,356	11,711	593,870	1,608,134	3.01	63.42
2	4							Gas - G						
3	Crist 5	78.0	53,770	92.7	98.8	93.8	10,923	Coal	25,077	11,711	587,333	1,590,432	2.96	63.42
4	5							Gas - G						
5	Crist 6	302.0	201,700	89.8	96.9	92.6	10,574	Coal	91,062	11,711	2,132,776	5,775,320	2.86	63.42
6	6							Gas - G						
7	Crist 7	472.0	335,290	95.5	94.4	101.1	10,076	Coal	144,245	11,711	3,378,374	9,148,261	2.73	63.42
8	7							Gas - G						
9	Scherer 3 (2)	210.8	149,940	95.6	97.0	98.6	9,723	Coal	85,415	8,534	1,457,873	3,136,478	2.09	36.72
10	Scholz 1	46.0	18,300	53.5	94.1	56.8	12,297	Coal	9,373	12,004	225,034	698,436	3.82	74.52
11	Scholz 2	46.0	17,350	50.7	95.4	53.1	12,774	Coal	9,231	12,004	221,626	687,856	3.96	74.52
12	Smith 1	162.0	112,810	93.6	98.5	95.0	10,501	Coal	49,588	11,945	1,184,648	2,949,805	2.61	59.49
13	Smith 2	195.0	133,220	91.8	94.6	97.1	10,106	Coal	56,356	11,945	1,346,352	3,352,453	2.52	59.49
14	Smith 3	479.0	265,460	74.5	93.7	79.5	7,007	Gas - G	1,806,029	1,030	1,860,210	19,262,093	7.26	10.67
15	Smith A (CT)	32.0	420	1.8	90.1	2.0	9,645	Oil - G	692	139,400	4,051	52,481	12.50	75.85
16	Other Generation		5,720									221,844	3.88	#N/A
17	Daniel 1 (1)	251.5	173,310	92.6	98.4	94.1	10,395	Coal	82,568	10,910	1,801,629	5,804,175	3.35	70.30
18	Daniel 2 (1)	255.0	175,640	92.6	97.0	95.4	10,212	Coal	82,201	10,910	1,793,619	5,778,370	3.29	70.30
19	Gas,BL							Gas	7,114	1,030	7,327	62,796	#N/A	8.83
20	Ltr. Oil							Oil	940	139,400	5,502	79,979	#N/A	85.11
21		2,607.3	1,696,400	87.5	95.9	91.2	9,819				16,600,224	60,208,913	3.55	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	53,780	92.7	99.5	93.1	11,295	Coal	26,174	11,604	607,443	1,689,990	3.14	64.57
2	4							Gas - G						
3	Crist 5	78.0	54,100	93.2	98.8	94.4	10,947	Coal	25,518	11,604	592,218	1,647,632	3.05	64.57
4	5							Gas - G						
5	Crist 6	302.0	203,000	90.3	96.9	93.2	10,575	Coal	92,502	11,604	2,146,766	5,972,599	2.94	64.57
6	6							Gas - G						
7	Crist 7	472.0	336,100	95.7	94.4	101.4	10,085	Coal	146,050	11,604	3,389,495	9,430,043	2.81	64.57
8	7							Gas - G						
9	Scherer 3 (2)	210.8	149,440	95.3	96.9	98.4	9,743	Coal	85,196	8,545	1,456,028	3,144,908	2.10	36.91
10	Scholz 1	46.0	18,430	53.9	94.1	57.2	11,609	Coal	8,913	12,003	213,953	665,239	3.61	74.64
11	Scholz 2	46.0	17,680	51.7	95.4	54.2	12,320	Coal	9,073	12,003	217,813	677,241	3.83	74.64
12	Smith 1	162.0	112,680	93.5	98.5	94.9	10,459	Coal	49,633	11,872	1,178,507	3,030,157	2.69	61.05
13	Smith 2	195.0	134,020	92.4	94.6	97.6	10,163	Coal	57,362	11,872	1,362,032	3,502,034	2.61	61.05
14	Smith 3	479.0	284,460	79.8	93.7	85.2	7,119	Gas - G	1,966,093	1,030	2,025,075	21,018,566	7.39	10.69
15	Smith A (CT)	32.0	320	1.3	90.1	1.5	37,978	Oil - G	2,076	139,400	12,153	162,115	50.66	78.10
16	Other Generation		5,720									221,844	3.88	#N/A
17	Daniel 1 (1)	251.5	173,810	92.9	98.4	94.4	10,449	Coal	83,330	10,898	1,816,201	5,856,308	3.37	70.28
18	Daniel 2 (1)	255.0	178,050	93.8	97.0	96.8	10,203	Coal	83,350	10,898	1,816,648	5,857,749	3.29	70.28
19	Gas,BL							Gas	1,368	1,030	1,409	12,175	#N/A	8.90
20	Ltr. Oil							Oil	852	139,403	4,989	72,605	#N/A	85.21
21		2,607.3	1,721,590	88.8	95.9	92.5	9,815				16,840,730	62,961,205	3.66	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	51,000	90.8	99.2	91.5	11,188	Coal	24,696	11,553	570,596	1,609,032	3.15	65.15
2	4							Gas - G						
3	Crist 5	78.0	50,840	90.5	98.8	91.6	11,156	Coal	24,548	11,553	567,180	1,599,399	3.15	65.15
4	5							Gas - G						
5	Crist 6	302.0	189,830	87.3	96.9	90.1	10,746	Coal	88,286	11,553	2,039,869	5,752,257	3.03	65.15
6	6							Gas - G						
7	Crist 7	472.0	319,340	94.0	94.3	99.6	10,209	Coal	141,098	11,553	3,260,113	9,193,242	2.88	65.16
8	7							Gas - G						
9	Scherer 3 (2)	210.8	126,540	83.4	84.3	98.9	9,673	Coal	71,631	8,544	1,224,035	2,651,873	2.10	37.02
10	Scholz 1	46.0	8,060	24.3	94.0	25.9	19,002	Coal	6,380	12,002	153,155	476,623	5.91	74.71
11	Scholz 2	46.0	12,440	37.6	95.4	39.4	12,451	Coal	6,453	12,002	154,896	482,041	3.87	74.70
12	Smith 1	162.0	108,540	93.1	98.5	94.5	10,411	Coal	47,731	11,837	1,129,984	2,951,009	2.72	61.83
13	Smith 2	195.0	127,020	90.5	94.6	95.6	10,145	Coal	54,430	11,837	1,288,589	3,365,214	2.65	61.83
14	Smith 3	479.0	216,790	62.9	93.8	67.0	7,201	Gas - G	1,515,655	1,030	1,561,125	16,375,990	7.55	10.80
15	Smith A (CT)	32.0	0	0.0	90.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		5,540									214,863	3.88	#N/A
17	Daniel 1 (1)	251.5	165,960	91.7	98.3	93.2	10,439	Coal	79,385	10,912	1,732,475	5,611,035	3.38	70.68
18	Daniel 2 (1)	255.0	168,670	91.9	96.9	94.8	10,076	Coal	77,874	10,912	1,699,500	5,504,239	3.26	70.68
19	Gas,BL							Gas	2,941	1,030	3,030	26,327	#N/A	8.95
20	Ltr. Oil							Oil	1,115	139,401	6,527	95,111	#N/A	85.32
21		2,607.3	1,550,570	82.6	94.9	87.1	9,962				15,391,074	55,908,255	3.61	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	50,280	86.6	99.2	87.3	11,495	Coal	25,070	11,527	577,947	1,642,747	3.27	65.53
2	4							Gas - G						
3	Crist 5	78.0	51,580	88.9	98.5	90.2	11,198	Coal	25,055	11,527	577,602	1,641,766	3.18	65.53
4	5							Gas - G						
5	Crist 6	302.0	191,740	85.3	96.6	88.3	10,629	Coal	88,402	11,527	2,037,932	5,792,583	3.02	65.53
6	6							Gas - G						
7	Crist 7	472.0	322,370	91.8	94.1	97.6	10,359	Coal	144,860	11,527	3,339,483	9,492,089	2.94	65.53
8	7							Gas - G						
9	Scherer 3 (2)	210.8	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	Scholz 1	46.0	0	0.0	59.7	0.0	#N/A	Coal	4,151	12,002	99,632	310,262	#N/A	74.74
11	Scholz 2	46.0	12,770	37.3	94.2	39.6	12,140	Coal	6,459	12,002	155,029	482,773	3.78	74.74
12	Smith 1	162.0	108,220	89.8	98.3	91.3	10,701	Coal	49,505	11,696	1,158,051	3,164,013	2.92	63.91
13	Smith 2	195.0	130,790	90.2	94.5	95.4	10,123	Coal	56,597	11,696	1,323,946	3,617,270	2.77	63.91
14	Smith 3	479.0	285,320	80.1	92.3	86.7	7,540	Gas - G	2,088,662	1,030	2,151,322	21,654,826	7.59	10.37
15	Smith A (CT)	32.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,440									249,769	3.88	#N/A
17	Daniel 1 (1)	251.5	169,930	90.8	73.0	124.4	7,484	Coal	57,762	11,008	1,271,735	4,183,788	2.46	72.43
18	Daniel 2 (1)	255.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	0	0	0	#N/A	#N/A
19	Gas,BL							Gas	1,915	1,030	1,973	17,379	#N/A	9.08
20	Ltr. Oil							Oil	907	139,402	5,312	77,315	#N/A	85.22
21		2,607.3	1,329,440	68.5	75.2	91.2	9,599				12,699,964	52,326,580	3.94	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	49,750	88.6	99.2	89.3	11,311	Coal	24,430	11,517	562,720	1,604,545	3.23	65.68
2	4							Gas - G						
3	Crist 5	78.0	50,250	89.5	85.4	104.8	9,464	Coal	20,647	11,517	475,567	1,356,036	2.70	65.68
4	5							Gas - G						
5	Crist 6	302.0	44,980	20.7	22.7	91.1	10,625	Coal	20,748	11,517	477,911	1,362,720	3.03	65.68
6	6							Gas - G						
7	Crist 7	472.0	219,330	64.5	65.7	98.2	10,395	Coal	98,982	11,517	2,279,925	6,500,999	2.96	65.68
8	7							Gas - G						
9	Scherer 3 (2)	210.8	0	0.0	0.1	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	Scholz 1	46.0	5,570	16.8	55.6	30.2	15,859	Coal	3,680	12,001	88,337	275,231	4.94	74.79
11	Scholz 2	46.0	12,410	37.5	94.2	39.8	12,648	Coal	6,539	12,001	156,962	489,045	3.94	74.79
12	Smith 1	162.0	105,640	90.6	81.8	110.7	8,868	Coal	40,309	11,620	936,773	2,643,120	2.50	65.57
13	Smith 2	195.0	128,810	91.7	94.3	97.3	10,097	Coal	55,962	11,620	1,300,536	3,669,483	2.85	65.57
14	Smith 3	531.0	279,850	73.2	92.4	79.2	7,082	Gas - G	1,924,087	1,030	1,981,810	19,518,500	6.97	10.14
15	Smith A (CT)	40.0	0	0.0	93.1	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		6,230									241,624	3.88	#N/A
17	Daniel 1 (1)	251.5	114,940	63.5	68.9	92.1	10,594	Coal	55,024	11,064	1,217,620	4,041,413	3.52	73.45
18	Daniel 2 (1)	255.0	23,540	12.8	16.2	79.1	11,468	Coal	12,199	11,064	269,947	895,982	3.81	73.45
19	Gas,BL							Gas	2,462	1,030	2,536	23,613	#N/A	9.59
20	Ltr. Oil							Oil	876	139,401	5,126	74,833	#N/A	85.47
21		2,667.3	1,041,300	54.2	61.9	87.6	9,425				9,755,770	42,697,144	4.10	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	48,680	83.9	89.5	93.7	10,172	Coal	21,509	11,511	495,189	1,415,938	2.91	65.83
2	4							Gas - G						
3	Crist 5	78.0	49,830	85.9	92.2	93.1	10,274	Coal	22,237	11,511	511,931	1,463,810	2.94	65.83
4	5							Gas - G						
5	Crist 6	302.0	141,350	62.9	75.0	83.9	10,919	Coal	67,043	11,511	1,543,453	4,413,332	3.12	65.83
6	6							Gas - G						
7	Crist 7	472.0	98,880	28.2	30.4	92.6	10,682	Coal	45,881	11,511	1,056,267	3,020,278	3.05	65.83
8	7							Gas - G						
9	Scherer 3 (2)	210.8	115,720	73.8	74.9	98.5	9,717	Coal	65,922	8,529	1,124,455	2,447,857	2.12	37.13
10	Scholz 1	46.0	12,720	37.2	92.6	40.1	12,158	Coal	6,443	12,001	154,646	482,088	3.79	74.82
11	Scholz 2	46.0	12,860	37.6	94.2	39.9	12,430	Coal	6,660	12,001	159,849	498,309	3.87	74.82
12	Smith 1	162.0	106,240	88.1	98.3	89.7	10,730	Coal	49,259	11,571	1,139,922	3,283,908	3.09	66.67
13	Smith 2	195.0	127,910	88.2	94.4	93.4	10,233	Coal	56,563	11,571	1,308,959	3,770,873	2.95	66.67
14	Smith 3	531.0	244,680	61.9	92.3	67.1	7,930	Gas - G	1,883,695	1,030	1,940,206	20,135,915	8.23	10.69
15	Smith A (CT)	40.0	0	0.0	93.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
16	Other Generation		7,150									277,307	3.88	#N/A
17	Daniel 1 (1)	251.5	167,820	89.7	98.4	91.1	10,492	Coal	79,296	11,103	1,760,845	5,876,973	3.50	74.11
18	Daniel 2 (1)	255.0	170,380	89.8	87.6	102.5	9,327	Coal	71,560	11,103	1,589,056	5,303,610	3.11	74.11
19	Gas,BL							Gas	5,677	1,030	5,848	57,425	#N/A	10.12
20	Ltr. Oil							Oil	1,065	139,402	6,234	91,099	#N/A	85.56
21		2,667.3	1,304,220	65.7	78.6	83.6	9,866				12,796,860	52,538,722	4.03	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2008 - DECEMBER 2008

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	487,360	71.1	78.9	90.2	11,190	Coal	232,725	11,717	5,453,689	14,687,796	3.01	63.11
2	4							Gas - G						
3	Crist 5	78.0	563,380	82.2	89.0	92.4	10,787	Coal	258,676	11,747	6,077,161	16,107,265	2.86	62.27
4	5							Gas - G						
5	Crist 6	302.0	2,112,270	79.6	84.9	93.8	10,216	Coal	915,987	11,779	21,578,239	56,593,341	2.68	61.78
6	6							Gas - G						
7	Crist 7	472.0	3,511,820	84.7	82.1	103.2	9,836	Coal	1,466,529	11,777	34,543,827	90,661,509	2.58	61.82
8	7							Gas - G	0					
9	Scherer 3 (2)	210.8	1,418,860	76.6	77.8	98.5	9,723	Coal	807,364	8,543	13,795,241	29,281,559	2.06	36.27
10	Scholz 1	46.0	137,610	34.1	87.4	39.0	13,442	Coal	77,009	12,010	1,849,701	5,700,321	4.14	74.02
11	Scholz 2	46.0	161,000	39.8	94.7	42.1	12,572	Coal	84,275	12,009	2,024,165	6,240,675	3.88	74.05
12	Smith 1	162.0	1,299,920	91.4	97.0	94.2	10,452	Coal	571,291	11,891	13,586,884	34,467,042	2.65	60.33
13	Smith 2	195.0	1,424,530	83.2	83.9	99.1	9,824	Coal	589,641	11,867	13,994,213	35,832,381	2.52	60.77
14	Smith 3	531.0	2,869,550	61.5	90.7	67.8	7,302	Gas - G	20,343,388	1,030	20,953,690	215,174,969	7.50	10.58
15	Smith A (CT)	35.0	740	0.2	91.8	0.3	21,897	Oil - G	2,768	139,400	16,204	214,596	29.00	77.54
16	Other Generation		75,290									2,920,047	3.88	#N/A
17	Daniel 1 (1)	251.5	1,960,170	88.7	93.8	94.6	10,237	Coal	908,855	11,039	20,066,035	65,458,064	3.34	72.02
18	Daniel 2 (1)	255.0	1,638,800	73.2	77.6	94.3	10,222	Coal	759,137	11,033	16,751,764	54,515,326	3.33	71.81
19	Gas,BL							Gas	68,281	1,030	70,331	625,887	#N/A	9.17
20	Ltr. Oil							Oil	12,591	139,402	73,722	1,069,815	#N/A	84.96
21		2,662.3	17,661,300	75.5	86.1	87.8	9,714				170,834,866	629,550,593	3.56	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	976	774	926	1,814	951	1,238	926	852	1,115	907	876	1,065	12,419
3	UNIT COST ($/BBL)	85.08	85.14	85.09	85.09	85.09	85.09	85.16	85.25	85.21	84.88	85.09	85.21	85.11
4	AMOUNT ($)	83,014	65,914	78,758	154,321	80,886	105,364	78,877	72,633	94,984	77,002	74,500	90,726	1,056,979
5	*BURNED :*													
6	UNITS (BBL)	1,002	801	952	1,840	977	1,265	940	852	1,115	907	876	1,065	12,591
7	UNIT COST ($/BBL)	84.23	84.53	84.48	84.72	84.86	85.00	85.11	85.21	85.32	85.22	85.47	85.56	84.97
8	AMOUNT ($)	84,410	67,684	80,435	155,907	82,918	107,519	79,979	72,605	95,111	77,315	74,833	91,099	1,069,815
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	8,514	8,487	8,461	8,435	8,409	8,382	8,368	8,368	8,368	8,368	8,368	8,368	
11	UNIT COST ($/BBL)	85.37	85.44	85.50	85.58	85.60	85.62	85.63	85.63	85.62	85.58	85.54	85.50	
12	AMOUNT ($)	726,876	725,106	723,429	721,843	719,811	717,656	716,554	716,582	716,455	716,142	715,809	715,436	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	392,745	418,118	492,344	509,340	505,986	546,894	581,532	584,576	549,961	511,340	381,420	361,396	5,835,652
16	UNIT COST ($/TON)	62.72	63.05	63.77	63.87	63.74	63.86	66.37	66.80	66.98	68.44	69.63	69.53	65.68
17	AMOUNT ($)	24,631,723	26,362,879	31,398,120	32,533,410	32,254,012	34,923,360	38,597,148	39,049,375	36,837,294	34,995,132	26,558,557	25,127,782	383,268,792
18	*BURNED :*													
19	UNITS (TONS)	471,025	415,906	491,821	506,339	503,429	544,930	575,057	581,905	550,881	457,861	338,520	426,451	5,864,125
20	UNIT COST ($/TON)	62.70	63.04	62.33	63.56	63.66	63.61	65.03	65.87	66.34	66.24	67.47	69.24	64.85
21	AMOUNT ($)	29,534,778	26,220,038	30,656,063	32,180,648	32,046,596	34,664,288	37,393,242	38,328,992	36,544,091	30,327,291	22,838,574	29,529,119	380,263,720
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	679,067	681,279	681,802	684,803	687,360	689,324	695,799	698,470	697,550	751,029	793,929	728,874	
24	UNIT COST ($/TON)	62.71	62.71	63.75	63.99	64.05	64.25	65.38	66.16	66.67	68.14	69.14	69.27	
25	AMOUNT ($)	42,581,915	42,724,756	43,466,813	43,819,575	44,026,991	44,286,063	45,489,969	46,210,352	46,503,555	51,171,396	54,891,379	50,490,042	
26	DAYS SUPPLY:	32	32	32	32	33	33	33	33	33	36	38	35	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	1,150,570	1,150,574	1,150,577	1,150,570	1,150,574	1,150,577	1,270,152	1,413,163	1,264,936	1,150,570	1,150,574	1,150,577	14,303,414
29	UNIT COST ($/MMBTU)	2.19	2.19	2.19	2.19	2.19	2.19	2.18	2.18	2.18	2.19	2.19	2.19	2.18
30	AMOUNT ($)	2,514,044	2,514,051	2,514,060	2,514,044	2,514,051	2,514,060	2,770,448	3,077,090	2,759,264	2,514,044	2,514,051	2,514,060	31,233,267
31	*BURNED :*													
32	UNITS (MMBTU)	1,452,949	1,358,053	1,450,322	1,404,761	1,455,804	1,410,961	1,457,873	1,456,028	1,224,035	0	0	1,124,455	13,795,241
33	UNIT COST ($/MMBTU)	2.05	2.09	2.08	2.10	2.12	2.14	2.15	2.16	2.17	#N/A	#N/A	2.18	2.12
34	AMOUNT ($)	2,980,817	2,835,131	3,018,240	2,956,308	3,091,578	3,018,369	3,136,478	3,144,908	2,651,873	0	0	2,447,857	29,281,559
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	3,815,808	3,608,329	3,308,584	3,054,393	2,749,163	2,488,779	2,301,058	2,258,193	2,299,094	3,449,664	4,600,238	4,626,360	
37	UNIT COST ($/MMBTU)	2.01	2.03	2.06	2.09	2.11	2.13	2.15	2.16	2.16	2.17	2.17	2.18	
38	AMOUNT ($)	7,652,766	7,331,686	6,827,506	6,385,242	5,807,715	5,303,406	4,937,376	4,869,558	4,976,949	7,490,993	10,005,044	10,071,247	
39	DAYS SUPPLY:	74	70	64	59	53	48	44	44	44	67	89	89	
	GAS (1)													
44	*BURNED :*													
45	UNITS (MMBTU)	1,778,701	1,372,777	2,040,783	1,599,236	1,155,890	1,534,763	1,867,537	2,026,484	1,564,155	2,153,295	1,984,346	1,946,054	21,024,021
46	UNIT COST ($/MMBTU)	10.41	10.46	10.04	10.06	10.60	10.38	10.35	10.38	10.49	10.06	9.85	10.38	10.26
47	AMOUNT ($)	18,512,411	14,363,738	20,481,275	16,094,440	12,251,439	15,931,948	19,324,889	21,030,741	16,402,317	21,672,205	19,542,113	20,193,340	215,800,856
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	0	0	0	0	0	0	692	2,076	0	0	0	0	2,768
55	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	84.60	84.60	#N/A	#N/A	#N/A	#N/A	84.59
56	AMOUNT ($)	0	0	0	0	0	0	58,538	175,615	0	0	0	0	234,153
57	*BURNED :*													
58	UNITS (BBL)	0	0	0	0	0	0	692	2,076	0	0	0	0	2,768
59	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	75.85	78.10	#N/A	#N/A	#N/A	#N/A	77.53
60	AMOUNT ($)	0	0	0	0	0	0	52,481	162,115	0	0	0	0	214,596
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	
63	UNIT COST ($/BBL)	75.36	75.36	75.36	75.36	75.36	75.36	76.21	78.10	78.10	78.10	78.10	78.10	
64	AMOUNT ($)	538,287	538,287	538,287	538,287	538,287	538,287	544,344	557,844	557,844	557,844	557,844	557,844	
65	DAYS SUPPLY:	4	4	4	4	4	4	4	4	4	4	4	4	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)		
		TOTAL	KWH WHEELED	KWH	¢ / KWH		TOTAL $	
LINE	MONTH TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JANUARY							
1	Southern Co. Interchange	384,746,000	0	384,746,000	4.59	4.80	17,642,000	18,485,000
2	Unit Power Sales	163,167,000	0	163,167,000	2.51	2.62	4,091,000	4,273,000
3	Economy Sales	12,511,000	0	12,511,000	5.48	5.55	686,000	694,000
4	Gain on Economy Sales						235,000	235,000
5	TOTAL ESTIMATED SALES	560,424,000	0	560,424,000	4.04	4.23	22,654,000	23,687,000
	FEBRUARY							
1	Southern Co. Interchange	369,656,000	0	369,656,000	4.12	4.36	15,247,000	16,106,000
2	Unit Power Sales	158,838,000	0	158,838,000	2.52	2.63	4,003,000	4,175,000
3	Economy Sales	18,904,000	0	18,904,000	5.45	5.48	1,030,000	1,036,000
4	Gain on Economy Sales						198,000	198,000
5	TOTAL ESTIMATED SALES	547,398,000	0	547,398,000	3.74	3.93	20,478,000	21,515,000
	MARCH							
1	Southern Co. Interchange	470,948,000	0	470,948,000	4.32	4.54	20,366,000	21,375,000
2	Unit Power Sales	167,088,000	0	167,088,000	2.53	2.64	4,233,000	4,409,000
3	Economy Sales	12,331,000	0	12,331,000	5.73	5.71	706,000	704,000
4	Gain on Economy Sales						166,000	166,000
5	TOTAL ESTIMATED SALES	650,367,000	0	650,367,000	3.92	4.10	25,471,000	26,654,000
	APRIL							
1	Southern Co. Interchange	452,252,000	0	452,252,000	4.48	4.66	20,244,000	21,081,000
2	Unit Power Sales	142,394,000	0	142,394,000	2.32	2.43	3,302,000	3,464,000
3	Economy Sales	11,580,000	0	11,580,000	5.22	5.22	604,000	604,000
4	Gain on Economy Sales						139,000	139,000
5	TOTAL ESTIMATED SALES	606,226,000	0	606,226,000	4.01	4.17	24,289,000	25,288,000
	MAY							
1	Southern Co. Interchange	175,705,000	0	175,705,000	4.18	4.41	7,342,000	7,752,000
2	Unit Power Sales	144,205,000	0	144,205,000	2.21	2.33	3,193,000	3,363,000
3	Economy Sales	14,269,000	0	14,269,000	5.04	5.05	719,000	720,000
4	Gain on Economy Sales						190,000	190,000
5	TOTAL ESTIMATED SALES	334,179,000	0	334,179,000	3.42	3.60	11,444,000	12,025,000
	JUNE							
1	Southern Co. Interchange	183,914,000	0	183,914,000	5.17	5.39	9,517,000	9,914,000
2	Unit Power Sales	142,065,000	0	142,065,000	2.24	2.35	3,178,000	3,345,000
3	Economy Sales	14,085,000	0	14,085,000	6.55	6.60	923,000	930,000
4	Gain on Economy Sales						244,000	244,000
5	TOTAL ESTIMATED SALES	340,064,000	0	340,064,000	4.08	4.24	13,862,000	14,433,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)		
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
	MONTH	KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JULY							
1	Southern Co. Interchange	221,245,000	0	221,245,000	5.82	6.05	12,883,000	13,387,000
2	Unit Power Sales	148,939,000	0	148,939,000	2.27	2.39	3,376,000	3,553,000
3	Economy Sales	17,367,000	0	17,367,000	8.31	8.35	1,443,000	1,451,000
4	Gain on Economy Sales						264,000	264,000
5	TOTAL ESTIMATED SALES	387,551,000	0	387,551,000	4.64	4.81	17,966,000	18,655,000
	AUGUST							
1	Southern Co. Interchange	219,112,000	0	219,112,000	5.56	5.78	12,178,000	12,671,000
2	Unit Power Sales	149,041,000	0	149,041,000	2.27	2.39	3,384,000	3,560,000
3	Economy Sales	17,639,000	0	17,639,000	7.75	7.81	1,367,000	1,377,000
4	Gain on Economy Sales						229,000	229,000
5	TOTAL ESTIMATED SALES	385,792,000	0	385,792,000	4.45	4.62	17,158,000	17,837,000
	SEPTEMBER							
1	Southern Co. Interchange	292,410,000	0	292,410,000	4.94	5.14	14,437,000	15,023,000
2	Unit Power Sales	123,554,000	0	123,554,000	2.28	2.40	2,816,000	2,961,000
3	Economy Sales	10,936,000	0	10,936,000	5.83	5.87	638,000	642,000
4	Gain on Economy Sales						67,000	67,000
5	TOTAL ESTIMATED SALES	426,900,000	0	426,900,000	4.21	4.38	17,958,000	18,693,000
	OCTOBER							
1	Southern Co. Interchange	351,755,000	0	351,755,000	4.55	4.76	16,001,000	16,746,000
2	Unit Power Sales	19,126,000	0	19,126,000	5.15	5.17	985,000	988,000
3	Economy Sales	12,921,000	0	12,921,000	5.36	5.39	692,000	696,000
4	Gain on Economy Sales						78,000	78,000
5	TOTAL ESTIMATED SALES	383,802,000	0	383,802,000	4.63	4.82	17,756,000	18,508,000
	NOVEMBER							
1	Southern Co. Interchange	190,761,000	0	190,761,000	4.66	4.85	8,899,000	9,247,000
2	Unit Power Sales	18,283,000	0	18,283,000	5.17	5.20	946,000	950,000
3	Economy Sales	15,127,000	0	15,127,000	5.37	5.41	812,000	818,000
4	Gain on Economy Sales						209,000	209,000
5	TOTAL ESTIMATED SALES	224,171,000	0	224,171,000	4.85	5.01	10,866,000	11,224,000
	DECEMBER							
1	Southern Co. Interchange	206,659,000	0	206,659,000	4.68	4.89	9,670,000	10,115,000
2	Unit Power Sales	115,681,000	0	115,681,000	2.35	2.46	2,716,000	2,849,000
3	Economy Sales	19,640,000	0	19,640,000	4.89	4.98	960,000	979,000
4	Gain on Economy Sales						199,000	199,000
5	TOTAL ESTIMATED SALES	341,980,000	0	341,980,000	3.96	4.14	13,545,000	14,142,000
	TOTAL							
1	Southern Co. Interchange	3,519,163,000	0	3,519,163,000	4.67	4.88	164,426,000	171,902,000
2	Unit Power Sales	1,492,381,000	0	1,492,381,000	2.43	2.54	36,223,000	37,890,000
3	Economy Sales	177,310,000	0	177,310,000	5.97	6.01	10,580,000	10,651,000
4	Gain on Economy Sales						2,218,000	2,218,000
5	TOTAL ESTIMATED SALES	5,188,854,000	0	5,188,854,000	4.11	4.29	213,447,000	222,661,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY		COG-1				None			
FEBRUARY		COG-1				None			
MARCH		COG-1				None			
APRIL		COG-1				None			
MAY		COG-1				None			
JUNE		COG-1				None			
JULY		COG-1				None			
AUGUST		COG-1				None			
SEPTEMBER		COG-1				None			
OCTOBER		COG-1				None			
NOVEMBER		COG-1				None			
DECEMBER		COG-1				None			
TOTAL			0			-			0

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	368,000	4.08	15,000
2	Unit Power Sales	5,758,000	5.64	325,000
3	*Economy Energy*	5,201,000	4.00	208,000
4	Other Purchases	9,080,000	4.91	446,000
5	TOTAL ESTIMATED PURCHASES	20,407,000	4.87	994,000
	FEBRUARY			
1	Southern Co. Interchange	14,853,000	4.09	607,000
2	Unit Power Sales	6,299,000	4.89	308,000
3	Economy Energy	6,803,000	3.95	269,000
4	Other Purchases	8,020,000	4.86	390,000
5	TOTAL ESTIMATED PURCHASES	35,975,000	4.38	1,574,000
	MARCH			
1	Southern Co. Interchange	1,383,000	4.05	56,000
2	Unit Power Sales	6,589,000	4.20	277,000
3	Economy Energy	5,719,000	3.22	184,000
4	Other Purchases	5,530,000	4.67	258,000
5	TOTAL ESTIMATED PURCHASES	19,221,000	4.03	775,000
	APRIL			
1	Southern Co. Interchange	5,168,000	2.98	154,000
2	Unit Power Sales	1,705,000	4.11	70,000
3	Economy Energy	5,479,000	3.32	182,000
4	Other Purchases	5,460,000	3.32	219,000
5	TOTAL ESTIMATED PURCHASES	17,812,000	3.51	625,000
	MAY			
1	Southern Co. Interchange	26,717,000	2.49	666,000
2	Unit Power Sales	954,000	4.19	40,000
3	Economy Energy	5,308,000	3.05	162,000
4	Other Purchases	9,490,000	3.97	377,000
5	TOTAL ESTIMATED PURCHASES	42,469,000	2.93	1,245,000
	JUNE			
1	Southern Co. Interchange	16,897,000	4.05	685,000
2	Unit Power Sales	1,161,000	7.24	84,000
3	Economy Energy	9,365,000	4.72	442,000
4	Other Purchases	14,380,000	4.39	632,000
5	TOTAL ESTIMATED PURCHASES	41,803,000	4.41	1,843,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY				
1		Southern Co. Interchange	7,119,000	5.44	387,000
2		Unit Power Sales	1,402,000	8.63	121,000
3		Economy Energy	12,831,000	5.94	762,000
4		Other Purchases	20,040,000	4.44	890,000
5		TOTAL ESTIMATED PURCHASES	41,392,000	5.22	2,160,000
	AUGUST				
1		Southern Co. Interchange	14,153,000	6.80	962,000
2		Unit Power Sales	1,480,000	9.19	136,000
3		Economy Energy	11,329,000	5.78	655,000
4		Other Purchases	19,280,000	4.47	862,000
5		TOTAL ESTIMATED PURCHASES	46,242,000	5.66	2,615,000
	SEPTEMBER				
1		Southern Co. Interchange	3,560,000	4.16	148,000
2		Unit Power Sales	1,668,000	5.76	96,000
3		Economy Energy	6,489,000	4.08	265,000
4		Other Purchases	10,300,000	4.39	452,000
5		TOTAL ESTIMATED PURCHASES	22,017,000	4.36	961,000
	OCTOBER				
1		Southern Co. Interchange	10,456,000	3.40	356,000
2		Unit Power Sales	4,616,000	5.24	242,000
3		Economy Energy	6,122,000	3.64	223,000
4		Other Purchases	8,650,000	4.14	358,000
5		TOTAL ESTIMATED PURCHASES	29,844,000	3.95	1,179,000
	NOVEMBER				
1		Southern Co. Interchange	41,017,000	3.33	1,367,000
2		Unit Power Sales	6,033,000	5.15	311,000
3		Economy Energy	7,007,000	3.57	250,000
4		Other Purchases	8,100,000	4.36	353,000
5		TOTAL ESTIMATED PURCHASES	62,157,000	3.67	2,281,000
	DECEMBER				
1		Southern Co. Interchange	22,055,000	2.89	638,000
2		Unit Power Sales	1,757,000	6.15	108,000
3		Economy Energy	6,105,000	3.95	241,000
4		Other Purchases	8,180,000	4.61	377,000
5		TOTAL ESTIMATED PURCHASES	38,097,000	3.58	1,364,000
	TOTAL FOR PERIOD				
1		Southern Co. Interchange	163,746,000	3.69	6,041,000
2		Unit Power Sales	39,422,000	5.37	2,118,000
3		Economy Energy	87,758,000	4.38	3,843,000
4		Other Purchases	126,510,000	4.44	5,614,000
5		TOTAL ESTIMATED PURCHASES	417,436,000	4.22	17,616,000

GULF POWER COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

	Actual Jan. 07 - Dec. 07 ($/1000 kWh)	Proposed Jan. 08 - Dec. 08 ($/1000 kWh)	Difference from Current $	Difference from Current %
Base Rate	$ 49.30	$ 49.30	$ -	0.0%
Fuel Cost Recovery	39.59	39.75	0.16	0.4%
Capacity Cost Recovery	3.11	2.71	(0.40)	-12.9%
Energy Conservation Cost Recovery *	0.88	0.88	-	0.0%
Environmental Cost Recovery	3.87	4.36	0.49	12.7%
Storm Surcharge	2.57	2.57	-	0.0%
Subtotal	$ 99.32	$ 99.57	$ 0.25	0.3%
Gross Receipts Tax	2.55	2.55	-	0.0%
Total	$ 101.87	$ 102.12	$ 0.25	0.2%

** For purposes of this comparison, the Energy Conservation factor has not yet been updated. The proposed 2008 Energy Conservation factor will be updated and filed with the FPSC on September 14, 2007.*

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

		TOTAL ¢ / KWH
2008	JANUARY	4.098
	FEBRUARY	4.098
	MARCH	4.098
	APRIL	5.063
	MAY	5.063
	JUNE	5.063
	JULY	5.063
	AUGUST	5.063
	SEPTEMBER	5.063
	OCTOBER	5.063
	NOVEMBER	4.527
	DECEMBER	4.527
2009	JANUARY	4.527
	FEBRUARY	4.527
	MARCH	4.527
	APRIL	5.422
	MAY	5.422
	JUNE	5.422
	JULY	5.422
	AUGUST	5.422
	SEPTEMBER	5.422
	OCTOBER	5.422
	NOVEMBER	4.754
	DECEMBER	4.754

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2008 - DECEMBER 2008

LINE	LINE DESCRIPTION	2005	2006	2007	2008	% Change 2005 to 2006	% Change 2006 to 2007	% Change 2007 to 2008
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	LIGHTER OIL (B.L.)	580,586	932,818	1,191,575	1,069,815	60.67	27.74	(10.22)
2	COAL	222,004,811	304,864,767	408,147,689	380,263,720	37.32	33.88	(6.83)
2a	COAL at Scherer	30,885,672	29,925,268	36,188,584	29,281,559	(3.11)	20.93	(19.09)
3	GAS	139,525,114	186,750,701	138,136,699	215,174,969	33.85	(26.03)	55.77
3a	GAS (B.L.)	424,440	590,160	650,220	625,887	39.04	10.18	(3.74)
4	OTHER - C.T.	22,145	0	48,647	214,596	(100.00)	100.00	341.13
4a	OTHER GENERATION	2,795,957	2,020,429	4,306,906	2,920,047	(27.74)	113.17	(32.20)
5	TOTAL ($)	396,238,725	525,084,143	588,670,320	629,550,593	32.52	12.11	6.94
	SYSTEM NET GENERATION (MWH)							
6	COAL	13,119,070	15,389,180	15,849,960	14,715,720	17.30	2.99	(7.16)
7	GAS	2,609,370	2,421,680	1,679,290	2,869,550	(7.19)	(30.66)	70.88
8	OTHER - C.T.	220	0	280	740	(100.00)	100.00	164.29
8a	OTHER GENERATION	101,010	67,370	112,540	75,290	(33.30)	67.05	(33.10)
9	TOTAL (MWH)	15,829,670	17,878,230	17,642,070	17,661,300	12.94	(1.32)	0.11
	UNITS OF FUEL BURNED							
10	LIGHTER OIL (BBL)	13,523	14,165	13,791	12,591	4.75	(2.64)	(8.70)
11	COAL excl. Scherer (TON)	5,109,413	6,235,260	6,249,582	5,864,125	22.03	0.23	(6.17)
12	GAS (MCF)	17,719,614	16,977,015	12,206,589	20,411,669	(4.19)	(28.10)	67.22
13	OTHER - C.T. (BBL)	534	0	692	2,768	(100.00)	100.00	300.00
	BTU'S BURNED (MMBTU)							
14	COAL + GAS B.L. + OIL B.L.	134,687,669	158,502,546	162,746,967	149,864,972	17.68	2.68	(7.92)
15	GAS - Generation	18,186,921	17,415,995	12,502,331	20,953,690	(4.24)	(28.21)	67.60
16	OTHER - C.T.	3,151	0	4,051	16,204	(100.00)	100.00	300.00
17	TOTAL (MMBTU)	152,877,741	175,918,541	175,253,349	170,834,866	15.07	(0.38)	(2.52)
	GENERATION MIX (% MWH)							
18	COAL + GAS B.L. + OIL B.L.	82.88	86.07	89.84	83.32	3.85	4.38	(7.26)
19	GAS - Generation	16.48	13.55	9.52	16.25	(17.78)	(29.74)	70.69
20	OTHER - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20a	OTHER GENERATION	0.64	0.38	0.64	0.43	(40.63)	68.42	(32.81)
21	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
22	LIGHTER OIL B.L. ($/BBL)	42.93	65.85	86.40	84.96	53.39	31.21	(1.67)
23	COAL ($/TON)	43.45	48.89	65.31	64.85	12.52	33.59	(0.70)
24	GAS +B.L. ($/MCF)	7.90	11.03	11.37	10.57	39.62	3.08	(7.04)
25	OTHER - C.T.	41.47	#N/A	70.31	77.54	#N/A	#N/A	10.28
	FUEL COST ($) / MMBTU							
26	COAL + GAS B.L. + OIL B.L.	1.89	2.12	2.74	2.74	12.17	29.25	0.00
27	GAS - Generation	7.67	10.72	11.05	10.27	39.77	3.08	(7.06)
28	OTHER - C.T.	7.03	#N/A	12.01	13.24	#N/A	#N/A	10.24
29	TOTAL ($/MMBTU)	2.57	2.97	3.33	3.67	15.56	12.12	10.21
	BTU BURNED / KWH							
30	COAL + GAS B.L. + OIL B.L.	10,267	10,300	10,268	10,184	0.32	(0.31)	(0.82)
31	GAS - Generation	6,970	7,192	7,445	7,302	3.19	3.52	(1.92)
32	OTHER - C.T.	14,323	#N/A	14,468	21,897	#N/A	#N/A	51.35
33	TOTAL (BTU/KWH)	9,720	9,877	9,998	9,714	1.62	1.23	(2.84)
	FUEL COST (¢ / KWH)							
34	COAL + GAS B.L. + OIL B.L.	1.93	2.18	2.81	2.79	12.95	28.90	(0.71)
35	GAS - Generation	5.35	7.71	8.23	7.50	44.11	6.74	(8.87)
36	OTHER - C.T.	10.07	#N/A	17.37	29.00	#N/A	#N/A	66.95
36a	OTHER GENERATION	2.77	3.00	3.83	3.88	8.30	27.67	1.31
37	TOTAL (¢ / KWH)	2.50	2.94	3.34	3.56	17.60	13.61	6.59

Schedule CCE-1

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2008 - December 2008

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) & Market Sales ($)	1,071,779	545.583	590,999	275,427	648.222	3,499,385	8,459,002	10,052,378	4,144,283	391,011	293,660	271,916	30,243,645
2	Projected Transmission Revenue	(14,000)	(21,000)	(14,000)	(13,000)	(16,000)	(16,000)	(20,000)	(20,000)	(12,000)	(15,000)	(17,000)	(22,000)	(200,000)
3	Total Projected Capacity Payments/(Receipts) (Line 1 + 2) ($)	1,057,779	524.583	576,999	262,427	632,222	3,483,385	8,439,002	10,032,378	4,132,283	376,011	276,660	249,916	30,043,645
4	Jurisdictional %	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160
5	Projected Jurisdictional Capacity Payments/(Receipts) (Line 3 x Line 4) ($)	1,019,927	505.811	556,352	253,036	609,599	3,358,736	8,137,021	9,673,380	3,984,413	362,556	266,760	240,973	28,968,564
6	True-Up ($)													(2,093,593)
7	Total Jurisdictional Amount to be Recovered (Line 5 + Line 6) ($)													26,874,971
8	Revenue Tax Multiplier													1.00072
9	Total Recoverable Capacity Payments/(Receipts) (Line 7 x Line 8) ($)													26,894,321

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,883,605.48	96.42160%
FERC	69,904.37	3.57840%
Total	1,953,509.85	100.00000%

* Based on 2006 Actual Data

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
For the Period January 2008 - December 2008

1	Estimated over/(under)-recovery, January 2007 - December 2007 (Schedule CCE-1b, Line 14 + Line 17)	$1,635,509
2	Final True-Up, January 2006 - December 2006 (Exhibit No.____(RJM-1), filed March 1, 2007	458,084
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2008 - December 2008)	$2,093,593
4	Jurisdictional KWH sales, January 2008 - December 2008	11,692,537,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0179)

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2007 - December 2007

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,149,354	379,768	578,776	217,665	576,266	3,541,079	8,699,468	10,684,337	4,151,850	340,360	270,117	395,726	30,984,766
2	Transmission Revenue	(13,223)	(43,697)	(13,111)	(19,011)	(162,875)	(33,024)	(27,000)	(27,000)	(17,000)	(20,000)	(24,000)	(30,000)	(429,941)
3	Total Capacity Payments/(Receipts)	1,136,131	336,071	565,665	198,654	413,391	3,508,055	8,672,468	10,657,337	4,134,850	320,360	246,117	365,726	30,554,825
4	Jurisdictional %	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872
5	Jurisdictional Capacity Payments/(Receipts) (Line 3 x Line 4) ($)	1,098,056	324,808	546,708	191,997	399,537	3,390,490	8,381,829	10,300,180	3,996,280	309,624	237,869	353,469	29,530,847
6	Retail KWH Sales							1,194,601,000	1,214,089,000	1,019,077,000	873,146,000	800,511,000	897,882,000	
7	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.275	0.275	0.275	0.275	0.275	0.275	
8	Capacity Cost Recovery Revenues (Line 6 x Line 7/100) ($)	2,445,741	2,236,518	2,152,312	2,150,832	2,694,534	3,097,526	3,285,153	3,338,745	2,802,462	2,401,152	2,201,405	2,469,176	31,275,556
9	Revenue Taxes (Line 8 x .00072) ($)	1,761	1,610	1,550	1,549	1,940	2,230	2,365	2,404	2,018	1,729	1,585	1,778	22,518
10	True-Up Provision ($)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(9,207)	(110,484)
11	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 8 - Line 9 + Line 10) ($)	2,434,773	2,225,701	2,141,555	2,140,076	2,683,387	3,086,089	3,273,581	3,327,134	2,791,237	2,390,216	2,190,613	2,458,191	31,142,554
12	Over/(Under) Recovery (Line 11 - Line 5) ($)	1,336,717	1,900,893	1,594,847	1,948,079	2,283,850	(304,401)	(5,108,248)	(6,973,046)	(1,205,043)	2,080,592	1,952,744	2,104,722	1,611,707
13	Interest Provision ($)	4,478	11,111	18,861	26,748	36,180	40,801	29,187	2,777	(15,162)	(13,262)	(4,406)	4,541	141,854
14	Total Estimated True-Up for the Period January 2007 - December 2007 (Line 12 + Line 13) ($)													1,753,561
NOTE:	Interest is Calculated for July through December at June 2007 monthly rate of		44.0000%											
15	Beginning Balance True-Up & Interest Provision ($)	347,601	1,698,003	3,501,162	5,124,077	7,108,111	9,437,348	9,182,955	4,113,101	(2,847,961)	(4,058,959)	(1,982,422)	(24,877)	347,601
16	True-Up Collected/(Refunded) ($)	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	9,207	110,484
17	2006 Revenue Adjustment	0	(118,052)	0	0	0	0	0	0	0	0	0	0	(118,052)
18	End of Period TOTAL Net True-Up (Lines 12 + 13 + 15 + 16 + 17) ($)	1,698,003	3,501,162	5,124,077	7,108,111	9,437,348	9,182,955	4,113,101	(2,847,961)	(4,058,959)	(1,982,422)	(24,877)	2,093,593	2,093,593

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2008 - December 2008

	A	B	C	D	E	F	G	H	I
Rate Class	Average 12 CP Load Factor at Meter	Jan - Dec 08 Projected KWH Sales at Meter	Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Jan - Dec 08 Projected KWH Sales at Generation Col B x Col E	Projected Avg 12 CP KW at Generation Col C x Col D	Percentage of KWH Sales at Generation Col F / Total Col F	Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	58.020395%	5,632,024,000	1,108,101.93	1.00486476	1.00530097	5,661,879,190	1,113,492.58	48.40517%	57.53202%
GS	63.781436%	314,778,000	56,338.59	1.00485887	1.00529775	316,445,615	56,612.33	2.70539%	2.92505%
GSD, GSDT, GSTOU	75.860452%	2,615,948,000	393,649.38	1.00470565	1.00516604	2,629,462,092	395,501.76	22.48009%	20.43481%
LP, LPT	86.886296%	1,945,899,000	255,661.25	0.98422595	0.98911989	1,924,727,405	251,628.44	16.45509%	13.00115%
PX, PXT, RTP, SBS	104.683592%	1,044,432,000	113,893.11	0.97443817	0.98057253	1,024,141,329	110,981.79	8.75570%	5.73421%
OS - I / II	321.885641%	111,185,000	3,943.12	1.00468934	1.00529485	111,773,708	3,961.61	0.95559%	0.20469%
OS-III	99.718369%	28,271,000	3,236.40	1.00511513	1.00526827	28,419,939	3,252.95	0.24297%	0.16807%
TOTAL		11,692,537,000	1,934,823.78			11,696,849,278	1,935,431.46	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2006 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2008 - December 2008

Rate Class	A Jan - Dec 08 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 08 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RSVP	48.40517%	57.53202%	1,001,403	14,282,628	15,284,031	5,632,024,000	0.271
GS	2.70539%	2.92505%	55,969	726,159	782,128	314,778,000	0.248
GSD, GSDT, GSTOU	22.48009%	20.43481%	465,067	5,073,049	5,538,116	2,615,948,000	0.212
LP, LPT	16.45509%	13.00115%	340,422	3,227,604	3,568,026	1,945,899,000	0.183
PX, PXT, RTP, SBS	8.75570%	5.73421%	181,137	1,423,548	1,604,685	1,044,432,000	0.154
OS - I / II	0.95559%	0.20469%	19,769	50,815	70,584	111,185,000	0.063
OS-III	0.24297%	0.16807%	5,027	41,724	46,751	28,271,000	0.165
TOTAL	100.00000%	100.00000%	$2,068,794	$24,825,527	$26,894,321	11,692,537,000	0.230

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 9) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 9) x 12 / 13 x Col B

GULF POWER COMPANY
2008 CAPACITY CONTRACTS

Gulf Power Company
2008 Capacity Contracts

Contract/Counterparty	Term Start	Term End (1)	Contract Type
Southern Intercompany Interchange	2/18/2000	5 Yr Notice	SES Opco
South Carolina PSA	9/1/2003	-	Other
Broadway Generating Company	5/1/2007	-	Other
Calpine Power Services	Varies	-	Other
Cogentrix	7/1/2003	-	Other
Coral Power, LLC	5/1/2003	-	Other
Effingham County Power, LLC	6/11/2007	-	Other
Exelon Power Team	1/1/2000	-	Other
FP&L Energy Power Marketing	6/1/2003	-	Other
KGEN, LLC	5/1/2005	-	Other
MPC Generating, LLC	6/11/2007	-	Other
Williams Energy Power Marketing	5/1/2002	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

Capacity Costs

2008	January		February		March		April		May		June		July		August		September		October		November		December		
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	Total $
Southern Intercompany Interchange	437.5	1,075,955	547.7	549,863	606.6	595,279	564.8	279,707	637.1	652,502	607.4	3,503,665	534.0	8,463,282	644.1	10,056,658	612.2	4,148,563	806.9	395,291	621.5	297,940	574.0	276,196	30,294,901
South Carolina PSA																									
Broadway Generating Company (1)																									
Calpine Power Services (1)																									
Cogentrix (1)																									
Coral Power, LLC (1)																									
Effingham County Power, LLC (1)																									
Exelon Power Team (1)																									
FP&L Energy Power Marketing (1)																									
KGEN, LLC (1)																									
MPC Generating, LLC (1)																									
Williams Energy Power Marketing (1)																									
Total		1,071,779		545,583		590,999		275,427		648,222		3,499,385		8,459,002		10,052,378		4,144,283		391,011		293,660		271,916	30,243,645

(1) Generator Balancing Service provides no capacity scheduling entitlements.

GULF POWER COMPANY
TESTIMONY AND EXHIBITS OF
L. S. NOACK

GENERATING PERFORMANCE INCENTIVE FACTOR

RESULTS FOR

JANUARY 2006 - DECEMBER 2006

Before

THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

GULF POWER

A SOUTHERN COMPANY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 32
COMPANY Gulf Power Co.
WITNESS L.S. Noack (LSN-1)
DATE 11-06-07

Florida Public Service Commission
Docket No. 070001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No. ___ (LSN-1)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 070001-EI

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2006 - DECEMBER 2006 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2006 - December 2006 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
02/24/06	Crist 4	Event Type	MO	208.0	78.0	Change MO to PO
05/04/06	Crist 5	Event Type	PFO	0.5	23.0	Change PFO to NC
05/08/06	Crist 5	Event Type	PFO	15.3	15.0	Change PFO to PMO
05/29/06	Crist 5	Event Type	PFO	23.0	20.0	Change PFO to NC
12/27/06	Crist 6	MW Affected	PFO	2.6	37.0	Change 37.0 to 66.0
03/27/06	Crist 7	Event Hours &	PFO	86.2	77.0	Change 86.2 to 114.0
"	"	MW Affected	"	"	"	Change 77.0 to 59.8
03/31/06	Crist 7	Event Added	PFO	0.8	394.0	Force Draft Fan Problem
05/10/06	Crist 7	Event Type	PFO	41.7	17.0	Change PFO to PMO
05/24/06	Crist 7	Event Type	PFO	12.7	13.0	Change PFO to PMO
06/22/06	Crist 7	Event Type	PFO	1.7	13.0	Change PFO to PMO
06/23/06	Crist 7	Event Type	PFO	9.3	22.0	Change PFO to PMO
06/24/06	Crist 7	Event Type	PFO	9.2	13.0	Change PFO to PMO
06/24/06	Crist 7	Event Type	PFO	3.6	23.0	Change PFO to PMO
06/24/06	Crist 7	Event Type	PFO	6.5	41.0	Change PFO to PMO
06/25/06	Crist 7	Event Type	PFO	11.8	3.0	Change PFO to PMO
07/01/06	Crist 7	Event Type	PFO	15.7	19.0	Change PFO to PMO
07/04/06	Crist 7	Event Type	PFO	17.7	37.0	Change PFO to PMO
07/05/06	Crist 7	Event Type	PFO	14.8	27.0	Change PFO to PMO
07/11/06	Crist 7	Event Type	PFO	4.8	23.0	Change PFO to PMO
07/11/06	Crist 7	Event Type	PFO	4.3	23.0	Change PFO to PMO
07/14/06	Crist 7	Event Type	PFO	8.8	22.0	Change PFO to PMO
08/07/06	Crist 7	Event Hours &	PMO	251.0	22.0	Change 251.0 to 589.2
"	"	MW Affected	"	"	"	Change 22.0 to 19.5
08/19/06	Crist 7	MW Affected	PMO	2.7	249.0	Change 249.0 to 228.7
08/24/06	Crist 7	MW Affected	PMO	8.5	32.0	Change 32.0 to 12.0
03/03/06	Smith 1	Event Added	PMO	3.3	27.0	Pulverizer Mill Inspection
01/01/06	Smith 2	MW Affected	PFO	11.3	58.0	Change 58.0 to 64.0
01/21/06	Smith 2	MW Affected	PFO	0.0	188.0	Change 188.0 to 215.7
11/21/06	Smith 2	Event Added	PFO	15.1	20.0	Wet Coal Problem

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2006 - December 2006

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 4	1	01/28/06 - 03/12/06	1056.0	02/24/06 - 03/05/06	208.0
		-	-	10/06/06 - 10/28/06	521.4
Crist 5	2	01/28/06 - 02/19/06	552.0	02/25/06 - 03/05/06	193.7
		-	-	10/06/06 - 10/27/06	491.5
Crist 6	3	-	-	03/18/06 - 05/15/06	1406.4
Crist 7	4	03/18/06 - 04/16/06	719.0	11/04/06 - 12/01/06	667.1
Smith 2	5	09/30/06 - 10/22/06	552.0	09/30/06 - 10/19/06	450.1
Daniel 1	6	04/15/06 - 04/23/06	216.0	-	-
Daniel 2	7	03/13/06 - 05/07/06	1343.0	03/12/06 - 04/28/06	1116.3

• Planned outage hours in the January 2006 - December 2006 period only.

Notes:
1. The outage date was changed subsequent to the target filing.
2. The outage date was changed subsequent to the target filing.
3. The outage date was added subsequent to the target filing.
4. The outage date was changed subsequent to the target filing.
5. This outage proceeded as scheduled and was completed ahead of schedule.
6. The outage date was changed subsequent to the target filing.
7. This outage proceeded as scheduled and was completed ahead of schedule.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Crist 4

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	1.0	0.0	0.0	0.0	0.0	1.0
EFOH	0.0	2.1	0.0	0.0	0.0	0.0	
	9.7	6.3	0.7	0.0	0.0	0.0	18.8
MOH	45.9	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	15.0	0.0	60.9
EMOH	0.0	0.0	0.0	0.0	2.5	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	2.5
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	97.4	110.6	0.0	0.0	0.0	
	0.0	0.0	0.0	521.4	0.0	0.0	729.4
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	240.4	240.4

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(1.0 + 18.8 + 60.9 + 2.5)}{(8760.0 - 729.4 - 240.4)}$$

EUOR = 0.0107

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1056.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1056.0 + 0.0107\ (8760.0 - 1056.0 - 0.0))}{8760.0} \right] \times 100 = 87.0\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Crist 5

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EFOH	0.0	1.3	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1.3
MOH	0.0	0.0	0.0	0.0	0.0	34.8	
	0.0	0.0	0.0	0.0	0.0	0.0	34.8
EMOH	0.0	0.0	0.0	0.0	2.9	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	2.9
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	95.7	98.1	0.0	0.0	0.0	
	0.0	0.0	0.0	491.5	0.0	0.0	685.3
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	168.7	168.7

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 1.3 + 34.8 + 2.9)}{(8760.0 - 685.3 - 168.7)}$$

$$EUOR = 0.0049$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 552.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(552.0 + 0.0049\ (8760.0 - 552.0 - 0.0))}{8760.0} \right] \times 100 = 93.2\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	30.5	0.0	4.3	0.0	
	0.0	34.7	38.6	10.9	0.0	0.0	119.0
EFOH	15.1	0.1	1.3	0.0	0.0	0.0	
	4.0	0.0	0.7	10.6	15.9	12.1	59.8
MOH	0.0	27.9	0.0	0.0	0.0	0.0	
	0.0	0.0	23.5	73.5	0.0	157.0	281.9
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.6	0.0	0.0	0.0	51.0	51.6
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	335.7	719.0	351.7	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1406.4
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(119.0 + 59.8 + 281.9 + 51.6)}{(8760.0 - 1406.4 - 0.0)}$$

$$EUOR = 0.0697$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0697\ (8760.0 - 0.0 - 0.0))}{8760.0} \right] \times 100 = 93.0\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	4.4	0.0	0.0	0.0	0.0	
	37.0	0.0	0.0	33.8	0.0	0.0	75.2
EFOH	0.3	7.4	19.1	22.2	2.2	4.2	
	0.2	0.0	0.5	16.7	0.0	3.5	76.3
MOH	0.0	90.8	27.8	26.4	72.3	58.4	
	8.0	93.7	0.0	0.0	0.0	0.0	377.4
EMOH	0.4	0.0	0.0	5.3	1.8	1.8	
	25.5	25.5	30.1	6.9	0.0	0.0	97.3
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	645.6	21.5	667.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(75.2 + 76.3 + 377.4 + 97.3)}{(8760.0 - 667.1 - 0.0)}$$

$$EUOR = 0.0774$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$\text{Target } POH^* = 719.0$$

$$\text{Target } RSH^* = 0.0$$

$$EA = \left[1 - \frac{(719.0 + 0.0774\ (8760.0 - 719.0 - 0.0))}{8760.0} \right] \times 100 = 84.7\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	227.6	0.0	0.0	0.0	227.6
EFOH	2.1	0.0	4.4	0.1	0.9	0.8	
	2.0	0.1	6.7	50.5	8.5	0.0	76.1
MOH	0.0	0.0	0.0	0.0	96.5	0.0	
	31.2	0.0	0.0	0.0	77.0	0.0	204.7
EMOH	0.0	1.5	3.2	0.0	1.2	0.0	
	0.8	0.8	0.0	0.0	0.0	0.0	7.5
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(227.6 + 76.1 + 204.7 + 7.5)}{(8760.0 - 0.0 - 0.0)}$$

$$EUOR = 0.0589$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0589\ (8760.0 - 0.0 - 0.0))}{8760.0} \right] \times 100 = 94.1\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	7.5	7.1	
	0.0	0.0	207.9	0.0	9.9	0.0	232.4
EFOH	4.3	1.5	0.4	0.2	63.0	0.0	
	56.1	0.3	3.5	0.0	7.3	0.1	136.7
MOH	0.0	39.8	0.0	103.5	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	143.3
EMOH	0.0	2.8	0.0	0.0	0.0	0.0	
	2.0	0.0	0.0	0.0	0.0	0.0	4.8
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	24.0	426.1	0.0	0.0	450.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(232.4 + 136.7 + 143.3 + 4.8)}{(8760.0 - 450.1 - 0.0)}$$

$$EUOR = 0.0622$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 552.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(552.0 + 0.0622\ (8760.0 - 552.0 - 0.0))}{8760.0} \right] \times 100 = 87.9\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	9.1	0.0	18.0	0.0	0.0	27.1
EFOH	7.1	3.4	3.0	3.4	0.8	4.1	
	4.2	1.3	0.1	6.1	0.9	0.2	34.6
MOH	0.0	0.0	0.0	129.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	129.0
EMOH	3.8	1.1	0.8	1.1	0.0	1.1	
	1.1	0.0	0.0	9.2	0.0	0.0	18.2
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(27.1 + 34.6 + 129.0 + 18.2)}{(8760.0 - 0.0 - 0.0)}$$

$$EUOR = 0.0238$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(216.0 + 0.0238\ (8760.0 - 216.0 - 0.0))}{8760.0} \right] \times 100 = 95.2\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2006 - December 2006
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	54.9	209.6	3.9	
	0.0	0.0	0.0	4.7	0.0	0.0	273.1
EFOH	0.9	10.3	1.6	0.0	8.7	6.9	
	1.1	0.2	0.7	8.7	2.1	2.1	43.3
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	28.6	28.6
EMOH	2.3	0.1	0.0	0.0	0.0	0.0	
	0.5	0.0	0.0	3.8	0.2	0.4	7.3
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	456.5	659.8	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1116.3
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(273.1 + 43.3 + 28.6 + 7.3)}{(8760.0 - 1116.3 - 0.0)}$$

EUOR = 0.0461

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1343.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1343.0 + 0.0461\ (8760.0 - 1343.0 - 0.0))}{8760.0} \right] \times 100 = 80.8\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2006 - December 2006

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 4	87.1	87.0	86.7	-2.50
Crist 5	92.4	93.2	92.8	10.00
Crist 6	90.2	93.0	93.1	9.66
Crist 7	80.8	84.7	84.1	10.00
Smith 1	98.1	94.1	97.2	-10.00
Smith 2	84.1	87.9	87.0	10.00
Daniel 1	93.6	95.2	94.8	10.00
Daniel 2	81.5	80.8	80.0	-4.67

* As appropriate from page 5, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Refer to pages 3 through 10 of this Schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Crist 4

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	43937.6	37897.6	42474.0	49334.9	48063.8	48859.6	
	49646.4	51374.3	45967.3	13797.1	44970.2	31178.5	507501.3
BTU/Lb*	11389.2	11478.3	11621.7	11393.4	11299.9	11559.3	
	11616.0	11351.6	11292.5	11344.4	11413.3	11626.8	11448.8
Coal, MMBTU	500414.1	435000.0	493620.1	562092.2	543116.1	564782.8	
	576692.6	583180.5	519085.7	156519.8	513258.4	362506.2	5810268.5
Oil, MMBTU	558.7	248.3	151.6	33.5	142.1	305.5	
	398.9	484.5	367.7	528.8	1216.4	108.8	4544.8
Gas, MMBTU	65.0	0.0	699.0	0.0	5.0	0.0	
	0.0	221.0	1634.0	898.0	2192.0	0.0	5714.0
Startup, MMBTU **	-400.0	0.0	-400.0	0.0	0.0	0.0	
	0.0	0.0	0.0	-400.0	0.0	0.0	-1200.0
Total Fuel Consumption, MMBTU	500637.8	435248.3	494070.7	562125.7	543263.2	565088.3	
	577091.5	583886.0	521087.4	157546.6	516666.8	362615.0	5819327.3
Net MWH Generation***	47736	41511	46620	53326	50608	51756	
	52497	52023	46223	14099	47701	33401	537501
Average Net Operating Heat Rate	10488	10485	10598	10541	10735	10918	
	10993	11224	11273	11174	10831	10856	10827

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Crist 5

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	46306.8	35698.5	42503.0	47052.5	46309.0	44812.8	
	47648.9	49731.6	45522.2	15449.5	44214.9	34707.7	499957.4
BTU/Lb*	11383.1	11483.3	11567.7	11402.5	11343.3	11591.3	
	11601.9	11368.8	11333.8	11334.5	11413.5	11569.8	11451.8
Coal, MMBTU	527114.9	409936.6	491662.0	536516.1	525296.9	519438.6	
	552817.8	565388.6	515939.5	175112.4	504646.8	401561.1	5725431.3
Oil, MMBTU	474.1	360.2	584.4	284.8	362.3	162.7	
	860.6	583.3	256.1	460.5	784.5	50.6	5224.1
Gas, MMBTU	771.0	133.0	1324.0	2387.0	3134.0	534.0	
	11246.0	5239.0	2714.0	2692.0	7554.0	0.0	37728.0
Startup, MMBTU **	0.0	0.0	-400.0	0.0	0.0	-400.0	
	0.0	0.0	0.0	-400.0	0.0	0.0	-1200.0
Total Fuel Consumption, MMBTU	528360.0	410429.8	493170.4	539187.9	528793.2	519735.3	
	564924.4	571210.9	518909.6	177864.9	512985.3	401611.7	5767183.4
Net MWH Generation***	50081	39593	46649	51618	49360	47525	
	52109	51648	45651	15938	48837	37921	536930
Average Net Operating Heat Rate	10550	10366	10572	10446	10713	10936	
	10841	11060	11367	11160	10504	10591	10741

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	169168.4	158189.2	94187.7	0.0	82238.3	187206.0	
	194328.3	188202.3	165904.2	163107.0	180340.9	121357.7	1704230.0
BTU/Lb*	11425.4	11530.1	11514.0	0.0	11500.0	11649.5	
	11581.5	11386.5	11314.5	11370.6	11308.7	11528.5	11460.7
Coal, MMBTU	1932816.6	1823937.3	1084477.2	0.0	945740.5	2180856.3	
	2250613.2	2142965.5	1877123.1	1854624.5	2039421.1	1399072.2	19531647.5
Oil, MMBTU	728.0	319.5	32.2	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1079.7
Gas, MMBTU	1555.0	1125.0	1869.0	0.0	16394.0	0.0	
	0.0	4466.0	5006.0	2853.0	0.0	11785.0	45053.0
Startup, MMBTU **	0.0	-4040.0	-4040.0	0.0	-4040.0	0.0	
	0.0	-4040.0	-8080.0	-4040.0	0.0	-4040.0	-32320.0
Total Fuel Consumption, MMBTU	1935099.6	1821341.8	1082338.4	0.0	958094.5	2180856.3	
	2250613.2	2143391.5	1874049.1	1853437.5	2039421.1	1406817.2	19545460.2
Net MWH Generation***	191120	176354	105121	0	90624	207333	
	214642	204960	177063	179605	196667	129630	1873119
Average Net Operating Heat Rate	10125	10328	10296	---	10572	10519	
	10485	10458	10584	10320	10370	10853	10435

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	294306.5	235463.6	290004.3	280006.1	277233.0	266667.9	
	275122.2	264170.3	287580.9	279876.6	30913.5	276429.3	3057774.2
BTU/Lb*	11411.4	11504.8	11644.3	11436.2	11418.9	11626.5	
	11560.4	11428.7	11274.5	11388.3	11296.0	11487.1	11468.0
Coal, MMBTU	3358449.2	2708961.6	3376897.1	3202205.8	3165695.9	3100414.3	
	3180522.7	3019123.1	3242330.9	3187318.7	349198.9	3175371.0	35066489.2
Oil, MMBTU	31.6	336.4	578.8	157.1	89.9	363.9	
	194.0	539.9	126.7	714.4	0.0	1227.3	4360.0
Gas, MMBTU	0.0	3460.0	1817.0	926.0	3271.0	1242.0	
	0.0	4712.0	345.0	3149.0	2899.0	1607.0	23428.0
Startup, MMBTU **	0.0	-2256.0	-2256.0	-2256.0	-2256.0	-2256.0	
	0.0	-4512.0	0.0	-2256.0	0.0	0.0	-18048.0
Total Fuel Consumption, MMBTU	3358480.8	2710502.0	3377036.9	3201032.9	3166800.8	3099764.2	
	3180716.7	3019863.0	3242802.6	3188926.1	352097.9	3178205.3	35076229.2
Net MWH Generation***	331585	261391	320786	307437	299371	293365	
	301002	279797	306534	304180	32829	306330	3344607
Average Net Operating Heat Rate	10129	10370	10527	10412	10578	10566	
	10567	10793	10579	10484	10725	10375	10487

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Smith 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	101304.1	93880.7	101784.2	98936.7	86736.2	99286.8	
	95025.7	102967.0	64407.7	95001.6	87189.1	94110.9	1120630.7
BTU/Lb*	11411.0	11405.1	11567.4	11450.2	11293.3	11539.3	
	11708.9	11308.7	11341.4	11327.2	11380.3	11454.9	11436.5
Coal, MMBTU	1155981.1	1070718.8	1177378.6	1132845.0	979537.9	1145700.2	
	1112646.4	1164422.9	730473.5	1076102.1	992238.1	1078030.9	12816075.5
Oil, MMBTU	180.0	282.8	671.4	210.4	2060.7	1007.5	
	1816.5	560.1	3431.4	167.5	1319.0	97.6	11804.9
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	0.0	-964.0	0.0	
	-964.0	0.0	-1928.0	0.0	-964.0	0.0	-4820.0
Total Fuel Consumption, MMBTU	1156161.1	1071001.6	1178050.0	1133055.4	980634.6	1146707.7	
	1113498.9	1164983.0	731976.9	1076269.6	992593.1	1078128.5	12823060.4
Net MWH Generation***	112215	104480	115997	111425	96017	109536	
	106617	113232	70880	104653	96599	105002	1246653
Average Net Operating Heat Rate	10303	10251	10156	10169	10213	10469	
	10444	10288	10327	10284	10275	10268	10286

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Smith 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	120523.5	104193.6	124323.6	100787.8	108718.3	114260.0	
	110353.3	120896.2	76058.9	52247.4	114722.8	109208.2	1256293.6
BTU/Lb*	11404.9	11459.9	11564.5	11481.7	11269.9	11499.2	
	11709.6	11312.4	11356.5	11205.5	11357.5	11418.4	11431.8
Coal, MMBTU	1374558.5	1194048.2	1437740.3	1157215.3	1225244.4	1313898.6	
	1292193.0	1367626.2	863762.9	585458.2	1302964.2	1246982.9	14361692.7
Oil, MMBTU	91.9	2601.6	111.6	1824.9	583.9	804.5	
	382.1	1141.4	1292.9	2119.3	920.6	221.1	12095.8
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-1190.0	0.0	-1190.0	0.0	0.0	
	0.0	0.0	-1190.0	-1190.0	0.0	0.0	-4760.0
Total Fuel Consumption, MMBTU	1374650.4	1195459.8	1437851.9	1157850.2	1225828.3	1314703.1	
	1292575.1	1368767.6	863865.8	586387.5	1303884.8	1247204.0	14369028.5
Net MWH Generation***	132283	115412	139483	111477	119292	125891	
	123272	132121	83544	57323	127119	121613	1388830
Average Net Operating Heat Rate	10392	10358	10308	10386	10276	10443	
	10486	10360	10340	10230	10257	10256	10346

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	330886.0	333232.0	357612.0	250052.0	312542.0	335078.0	
	351964.0	352032.0	346178.0	338644.0	341270.0	352088.0	4001578.0
BTU/Lb*	10085.6	10070.3	10049.8	10779.3	10450.3	10381.6	
	10379.4	10331.1	10457.1	10416.0	10352.0	10488.7	10343.5
Coal, MMBTU	3337183.8	3355746.2	3593929.1	2695385.5	3266157.7	3478645.8	
	3653175.1	3636877.8	3620018.0	3527315.9	3532827.0	3692945.4	41390207.3
Oil, MMBTU	7.0	10.4	1542.1	6982.6	8.6	9.4	
	9.0	2538.4	40.9	4548.8	10.8	24.7	15732.7
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-2388.7	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	-2388.7
Total Fuel Consumption, MMBTU	3337190.8	3355756.6	3595471.2	2699979.4	3266166.3	3478655.2	
	3653184.1	3639416.2	3620058.9	3531864.7	3532837.8	3692970.1	41403551.3
Net MWH Generation***	328710	330423	358773	266568	320440	341250	
	367717	360851	356414	348896	353897	361788	4095727
Average Net Operating Heat Rate	10152	10156	10022	10129	10193	10194	
	9935	10086	10157	10123	9983	10208	10109

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2006 - December 2006

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	335470.0	318264.0	123552.0	5030.0	213814.0	309170.0	
	333580.0	341094.0	302502.0	321832.0	325212.0	306902.0	3236422.0
BTU/Lb*	10015.2	10213.7	10529.2	10717.0	10339.1	10380.5	
	10382.2	10321.2	10357.5	10451.6	10386.4	10497.6	10340.2
Coal, MMBTU	3359799.1	3250653.0	1300903.7	53906.5	2210644.3	3209339.2	
	3463294.3	3520499.4	3133164.5	3363659.3	3377781.9	3221734.4	33465379.6
Oil, MMBTU	42.7	2184.4	510.9	8227.7	7237.0	1418.5	
	2.1	137.4	7.2	1408.8	240.0	2482.5	23899.2
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-2388.7	-4777.4	0.0	
	0.0	0.0	0.0	0.0	0.0	-2388.7	-9554.8
Total Fuel Consumption, MMBTU	3359841.8	3252837.4	1301414.6	59745.5	2213103.9	3210757.7	
	3463296.4	3520636.8	3133171.7	3365068.1	3378021.9	3221828.2	33479724.0
Net MWH Generation***	332654	324547	137642	529	226785	325586	
	342529	347441	304202	330743	330974	313327	3316959
Average Net Operating Heat Rate	10100	10023	9455	112940	9759	9861	
	10111	10133	10300	10174	10206	10283	10093

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Crist 4

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10338	0	10502	10509	10527	10502	
		10501	10501	10504	10509	10509	10510	
2.	Target Heat Rate	10365	10390	10499	10463	10560	10497	
	at Actual Conditions**	10503	10488	10601	10610	10554	10600	
3.	Adjustment to Actual	-27	103	3	46	-33	5	
	Heat Rate (1-2)	-2	13	-97	-101	-45	-90	
4.	Actual Heat Rate	10488	10485	10598	10541	10735	10918	
	(Page 2 of Sched. 3)	10993	11224	11273	11174	10831	10856	
5.	Adjusted Actual	10461	10588	10601	10587	10702	10923	
	Heat Rate (4+3)	10991	11237	11176	11073	10786	10766	
6.	Net MWH Generation	47736	41511	46620	53326	50608	51756	
		52497	52023	46223	14099	47701	33401	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							10815

* From pages 20 & 21, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Crist 5

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10225	10427	10416	10426	10451	10416	
		10416	10236	10420	10427	10220	10428	
2.	Target Heat Rate	10327	10528	10513	10423	10603	10505	
	at Actual Conditions**	10479	10273	10618	10660	10298	10640	
3.	Adjustment to Actual	-102	-101	-97	3	-152	-89	
	Heat Rate (1-2)	-63	-37	-198	-233	-78	-212	
4.	Actual Heat Rate	10550	10366	10572	10446	10713	10936	
	(Page 3 of Sched. 3)	10841	11060	11367	11160	10504	10591	
5.	Adjusted Actual	10448	10265	10475	10449	10561	10847	
	Heat Rate (4+3)	10778	11023	11169	10927	10426	10379	
6.	Net MWH Generation	50081	39593	46649	51618	49360	47525	
		52109	51648	45651	15938	48837	37921	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							10639

* From pages 22 & 23, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10176	10175	10165	10167	10200	10164	
		10164	10163	10167	10170	10167	10176	
2.	Target Heat Rate	10343	10268	10250	10167	10465	10211	
	at Actual Conditions**	10209	10207	10288	10276	10271	10542	
3.	Adjustment to Actual	-167	-93	-85	0	-265	-47	
	Heat Rate (1-2)	-45	-44	-121	-106	-104	-366	
4.	Actual Heat Rate	10125	10328	10296	0	10572	10519	
	(Page 4 of Sched. 3)	10485	10458	10584	10320	10370	10853	
5.	Adjusted Actual	9958	10235	10211	0	10307	10472	
	Heat Rate (4+3)	10440	10414	10463	10214	10266	10487	
6.	Net MWH Generation	191120	176354	105121	0	90624	207333	
		214642	204960	177063	179605	196667	129630	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							10318

* From pages 24 & 25, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10796	10796	10802	10170	10169	10164	
		10160	10160	10162	10171	10172	10166	
2.	Target Heat Rate	10235	10216	10229	10240	10235	10241	
	at Actual Conditions**	10275	10276	10289	10283	10246	10294	
3.	Adjustment to Actual	561	580	573	-70	-66	-77	
	Heat Rate (1-2)	-115	-116	-127	-112	-74	-128	
4.	Actual Heat Rate	10129	10370	10527	10412	10578	10566	
	(Page 5 of Sched. 3)	10567	10793	10579	10484	10725	10375	
5.	Adjusted Actual	10690	10950	11100	10342	10512	10489	
	Heat Rate (4+3)	10452	10677	10452	10372	10651	10247	
6.	Net MWH Generation	331585	261391	320786	307437	299371	293365	
		301002	279797	306534	304180	32829	306330	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							10570

* From pages 26 & 27, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Smith 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10236	10229	9828	10477	10244	10229	
		10229	10230	10230	10237	10232	10232	
2.	Target Heat Rate	10263	10248	9828	10511	10321	10267	
	at Actual Conditions**	10307	10264	10286	10257	10259	10315	
3.	Adjustment to Actual	-27	-19	0	-34	-77	-38	
	Heat Rate (1-2)	-78	-34	-56	-20	-27	-83	
4.	Actual Heat Rate	10392	10358	10308	10386	10276	10443	
	(Page 7 of Sched. 3)	10486	10360	10340	10230	10257	10256	
5.	Adjusted Actual	10365	10339	10308	10352	10199	10405	
	Heat Rate (4+3)	10408	10326	10284	10210	10230	10173	
6.	Net MWH Generation	132283	115412	139483	111477	119292	125891	
		123272	132121	83544	57323	127119	121613	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							10305

* From pages 30 & 31, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10200	10194	10216	10335	10099	10195	
		10188	10017	10194	10201	10191	10201	
2.	Target Heat Rate	10411	10281	10301	10335	10199	10240	
	at Actual Conditions**	10207	10051	10194	10283	10211	10180	
3.	Adjustment to Actual	-211	-87	-85	0	-100	-45	
	Heat Rate (1-2)	-19	-34	0	-82	-20	21	
4.	Actual Heat Rate***	10152	10156	10022	10129	10193	10194	
	(Page 8 of Sched. 3)	9935	10086	10157	10123	9983	10208	
5.	Adjusted Actual	9941	10069	9937	10129	10093	10149	
	Heat Rate (4+3)	9916	10052	10157	10041	9963	10229	
6.	Net MWH Generation	328710	330423	358773	266568	320440	341250	
		367717	360851	356414	348896	353897	361788	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 =(Σ (5*6) / Σ 6)							10055

* From pages 32 & 33, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2006 - December 2006
Adjusted to Target Basis Using Heat Rate
Equations Filed September 16, 2005

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10001	9993	10024	0	10021	10115	
		10153	9830	9993	10174	9990	10004	
2.	Target Heat Rate	10332	10154	10070	13697	10306	10325	
	at Actual Conditions**	10356	9991	10307	10384	10171	10204	
3.	Adjustment to Actual	-331	-161	-46	-3670	-285	-210	
	Heat Rate (1-2)	-203	-161	-314	-210	-181	-200	
4.	Actual Heat Rate***	10100	10023	9455	112940	9759	9861	
	(Page 9 of Sched. 3)	10111	10133	10300	10174	10206	10283	
5.	Adjusted Actual	9769	9862	9409	109270	9474	9651	
	Heat Rate (4+3)	9908	9972	9986	9964	10025	10083	
6.	Net MWH Generation	332654	324547	137642	529	226785	325586	
		342529	347441	304202	330743	330974	313327	
7.	Adjusted Actual Heat Rate for January 2006 - December 2006 $=(\Sigma(5*6)/\Sigma 6)$							9877

* From pages 34 & 35, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2006 - December 2006

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 4						
$AKW * 10^{+3}$	68.4	72.2	73.6	74.2	68.0	71.9
	70.6	70.0	64.2	63.1	67.7	66.3
$LSRF \bullet 10^{+6}$	4790.6	5284.8	5467.8	5525.4	4741.3	5234.7
	5060.7	4969.0	4244.4	4098.4	4696.4	4532.3
Crist 5						
$AKW * 10^{+3}$	67.3	68.7	72.2	71.8	66.3	69.4
	70.0	69.4	63.4	62.9	67.8	65.9
$LSRF \bullet 10^{+6}$	4636.3	4815.4	5295.3	5184.6	4522.6	4899.6
	4967.9	4884.9	4124.1	4076.1	4695.8	4487.1
Crist 6						
$AKW \bullet 10^{+3}$	256.9	273.8	278.2	0.0	233.6	288.0
	288.5	289.0	269.1	271.9	273.1	220.8
$LSRF \bullet 10^{+6}$	71419.9	76379.7	78619.9	0.0	58217.4	83291.6
	83818.7	83999.1	74227.8	75474.4	75407.1	53008.7
Crist 7						
$AKW \bullet 10^{+3}$	445.7	453.2	447.9	443.9	445.7	443.4
	430.6	430.3	425.7	427.7	441.3	424.0
$LSRF * 10^{+6}$	201111.7	206818.2	203211.8	198962.0	202190.0	199910.9
	190100.9	188995.9	184532.7	187199.4	195873.2	179398.1
Smith 1						
$AKW * 10^{+3}$	150.8	155.5	155.9	155.0	148.3	152.1
	149.6	152.2	143.9	140.5	150.2	141.1
$LSRF * 10^{+6}$	23201.0	24385.5	24553.5	24435.0	22704.3	23540.8
	22821.1	23499.1	21581.6	20463.8	22927.0	20257.3
Smith 2						
$AKW * 10^{+3}$	177.8	182.6	187.5	181.1	162.0	176.6
	165.7	177.6	171.2	179.8	179.0	163.5
$LSRF \bullet 10^{+6}$	32288.0	33621.9	35452.1	33740.0	27403.8	32138.0
	28466.3	32311.7	30477.2	32838.3	32542.4	27529.4

Actual Values of
Target Heat Rate Equation Parameters
for January 2006 - December 2006

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Daniel 1						
$AKW * 10^{+3}$	441.8	491.7	482.2	451.8	430.7	474.0
	494.2	491.0	495.0	479.9	491.5	486.3
$LSRF * 10^{+6}$	207503.9	243283.0	236030.6	213847.3	199040.0	230185.0
	245379.2	243505.7	246306.2	237711.8	242974.9	238744.0
Daniel 2						
$AKW * 10^{+3}$	447.1	483.0	478.8	123.0	424.4	454.7
	460.4	467.0	422.5	446.8	459.7	438.0
$LSRF * 10^{+6}$	209229.4	238535.7	232546.1	16033.4	194251.3	215897.9
	218688.9	222184.8	191444.3	210631.7	219746.8	203459.9

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [498.36 - 12.78 * JAN - 8.72 * FEB]

-4347 + 0.10869 * LSRF / AKW

Crist 5 ANOHR = 10^6 / AKW * [563.97 - 15.45 * JAN - 14.34 * AUG - 16.27 * NOV]

-5954 + 0.11802 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * [313.41]

+ 9,123

Crist 7 ANOHR = 10^6 / AKW * [512.95]

+ 9,084

Smith 1 ANOHR = 10^6 / AKW * [117.29 - 12.42 * AUG - 14.59 * OCT]

+ 9,462

Smith 2 ANOHR = 10^6 / AKW * [105.64 - 75.81 * MAR + 46.86 * APR]

+ 9,669

Daniel 1 ANOHR = 10^6 / AKW * [2810.38 + 68.52 * APR - 58.18 * MAY - 90.02 * AUG]

+ 2,265 + 10^6 / AKW * [-0.1179 * BTU/LB] + 0.00953 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [2174.94 + 62.25 * JUN + 85.53 * JUL - 82.98 * AUG + 86.31 * OCT]

+ 8,739 + 10^6 / AKW * [-0.1460 * BTU/LB]

Where:		
	ANOHR	Average Net Operating Heat Rate, BTU/KWH
	AKW	Average Kilowatt Load, KW
	LSRF	Load Square Range Factor, KW^2
	JAN	January, 0 if not January, 1 if January
	FEB	February, 0 if not February, 1 if February
	MAR	March, 0 if not March, 1 if March
	APR	April, 0 if not April, 1 if April
	MAY	May, 0 if not May, 1 if May
	JUN	June, 0 if not June, 1 if June
	JUL	July, 0 if not July, 1 if July
	AUG	August, 0 if not August, 1 if August
	SEP	September, 0 if not September, 1 if September
	OCT	October, 0 if not October, 1 if October
	NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2006 - December 2006

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 4	10493	10815	10178	-10.00
Crist 5	10375	10639	10064	-8.01
Crist 6	10171	10318	9866	-3.13
Crist 7	10268	10570	9960	-9.74
Smith 1	10176	10232	9871	0.00
Smith 2	10222	10305	9915	-0.34
Daniel 1	10181	10055	9876	2.22
Daniel 2	10027	9877	9726	3.32

* From page 5, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

** Refer to pages 10 through 17 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

$$\text{If } [\,(2) - (3) - 75\,] > 0 \text{ then points} = \frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$$

$$\text{If } [\,(2) - (3) + 75\,] < 0 \text{ then points} = \frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$$

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2006 - December 2006

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 4	-2.50	0.000	-10.00	0.034
Crist 5	10.00	0.001	-8.01	0.037
Crist 6	9.66	0.017	-3.13	0.122
Crist 7	10.00	0.080	-9.74	0.197
Smith 1	-10.00	0.003	0.00	0.067
Smith 2	10.00	0.027	-0.34	0.064
Daniel 1	10.00	0.024	2.22	0.160
Daniel 2	-4.67	0.029	3.32	0.138

Company GPIF Points = - 2.50 * 0.000 - 10.00 * 0.034
+ 10.00 * 0.001 - 8.01 * 0.037
+ 9.66 • 0.017 - 3.13 * 0.122
+ 10.00 • 0.080 - 9.74 * 0.197
- 10.00 * 0.003 + 0.00 • 0.067
+ 10.00 * 0.027 - 0.34 * 0.064
+ 10.00 * 0.024 + 2.22 * 0.160
- 4.67 • 0.029 + 3.32 • 0.138

= -0.84

Company reward/penalty = -0.84 points • $244163 per point

= ($205,097)

• From page 5, Schedule 3 of Exhibit to L. S. Noack's September 16, 2005 GPIF Testimony in Docket 050001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2006 - DECEMBER 2006 PERIOD

CONTENTS

	SCHEDULE 5 PAGE
GPIF Reward/Penalty Table (Actual)	3
GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)	4
Calculation of System Actual GPIF Points	5
Generating Performance Incentive Points Table	6 - 13
GPIF Unit Performance Summary	14
Actual Unit Performance Data	15
Historic Unit Performance Data	16 - 31
Planned Outage Schedules (Actual)	32

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2006 - December 2006

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	8250	2442
+ 9	7425	2197
+ 8	6600	1953
+ 7	5775	1709
+ 6	4950	1465
+ 5	4125	1221
+ 4	3300	977
+ 3	2475	732
+ 2	1650	488
+ 1	825	244
0	0	0
- 1	-924	-244
- 2	-1849	-488
- 3	-2773	-732
- 4	-3698	-977
- 5	-4622	-1221
- 6	-5546	-1465
- 7	-6471	-1709
- 8	-7395	-1953
- 9	-8320	-2197
- 10	-9244	-2442
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2006 - December 2006

Line 1	Beginning of Period Balance of Common Equity	$602,541,000
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '06	$610,503,000
Line 3	Month of Feb '06	$616,843,000
Line 4	Month of Mar '06	$619,188,000
Line 5	Month of Apr '06	$605,807,000
Line 6	Month of May '06	$612,914,000
Line 7	Month of Jun '06	$623,743,000
Line 8	Month of Jul '06	$617,640,000
Line 9	Month of Aug '06	$630,239,000
Line 10	Month of Sep '06	$638,852,000
Line 11	Month of Oct '06	$626,349,000
Line 12	Month of Nov '06	$629,458,000
Line 13	Month of Dec '06	$632,909,000
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$620,537,385
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.3808%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,527,408
Line 18	Jurisdictional Sales (KWH)	11,428,880,000
Line 19	Total Territorial Sales (KWH)	11,830,383,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.6062%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$2,441,632

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2006 - December 2006

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 4	EAF1	0.0%	-2.50	0.000
Crist 4	ANOHR1	3.4%	-10.00	-0.341
Crist 5	EAF2	0.1%	10.00	0.006
Crist 5	ANOHR2	3.7%	-8.01	-0.299
Crist 6	EAF3	1.7%	9.66	0.166
Crist 6	ANOHR3	12.2%	-3.13	-0.382
Crist 7	EAF4	8.0%	10.00	0.799
Crist 7	ANOHR4	19.7%	-9.74	-1.921
Smith 1	EAF5	0.3%	-10.00	-0.034
Smith 1	ANOHR5	6.7%	0.00	0.000
Smith 2	EAF6	2.7%	10.00	0.270
Smith 2	ANOHR6	6.4%	-0.34	-0.022
Daniel 1	EAF7	2.4%	10.00	0.242
Daniel 1	ANOHR7	16.0%	2.22	0.354
Daniel 2	EAF8	2.9%	-4.67	-0.135
Daniel 2	ANOHR8	13.8%	3.32	0.458
Gulf Power GPIF Total		100.0%		-0.84

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	0	87.30	+ 10	281	10,178
+ 9	0	87.28	+ 9	253	10,202
+ 8	0	87.26	+ 8	225	10,226
+ 7	0	87.24	+ 7	197	10,250
+ 6	0	87.22	+ 6	169	10,274
+ 5	0	87.20	+ 5	141	10,298
+ 4	0	87.18	+ 4	112	10,322
+ 3	0	87.16	+ 3	84	10,346
+ 2	0	87.14	+ 2	56	10,370
+ 1	0	87.12	+ 1	28	10,394
				0	10,418
0	0	87.10	0	0	10,493
				0	10,568
- 1	(1)	87.06	- 1	(28)	10,592
- 2	(3)	87.02	- 2	(56)	10,616
- 3	(4)	86.98	- 3	(84)	10,640
- 4	(5)	86.94	- 4	(112)	10,664
- 5	(7)	86.90	- 5	(141)	10,688
- 6	(8)	86.86	- 6	(169)	10,712
- 7	(9)	86.82	- 7	(197)	10,736
- 8	(10)	86.78	- 8	(225)	10,760
- 9	(12)	86.74	- 9	(253)	10,784
- 10	(13)	86.70	- 10	(281)	10,808
Weighting Factor:		0.000	Weighting Factor:		0.034

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	5	92.80	+ 10	308	10,064
+ 9	5	92.76	+ 9	277	10,088
+ 8	4	92.72	+ 8	246	10,111
+ 7	4	92.68	+ 7	216	10,135
+ 6	3	92.64	+ 6	185	10,158
+ 5	3	92.60	+ 5	154	10,182
+ 4	2	92.56	+ 4	123	10,206
+ 3	2	92.52	+ 3	92	10,229
+ 2	1	92.48	+ 2	62	10,253
+ 1	1	92.44	+ 1	31	10,276
				0	10,300
0	0	92.40	0	0	10,375
				0	10,450
- 1	(1)	92.33	- 1	(31)	10,474
- 2	(3)	92.26	- 2	(62)	10,497
- 3	(4)	92.19	- 3	(92)	10,521
- 4	(5)	92.12	- 4	(123)	10,544
- 5	(7)	92.05	- 5	(154)	10,568
- 6	(8)	91.98	- 6	(185)	10,592
- 7	(9)	91.91	- 7	(216)	10,615
- 8	(10)	91.84	- 8	(246)	10,639
- 9	(12)	91.77	- 9	(277)	10,662
- 10	(13)	91.70	- 10	(308)	10,686
Weighting Factor:		0.001	Weighting Factor:		0.037

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	142	93.10	+ 10	1,008	9,866
+ 9	128	92.81	+ 9	907	9,889
+ 8	114	92.52	+ 8	806	9,912
+ 7	99	92.23	+ 7	706	9,935
+ 6	85	91.94	+ 6	605	9,958
+ 5	71	91.65	+ 5	504	9,981
+ 4	57	91.36	+ 4	403	10,004
+ 3	43	91.07	+ 3	302	10,027
+ 2	28	90.78	+ 2	202	10,050
+ 1	14	90.49	+ 1	101	10,073
				0	10,096
0	0	90.20	0	0	10,171
				0	10,246
- 1	(27)	89.76	- 1	(101)	10,269
- 2	(55)	89.32	- 2	(202)	10,292
- 3	(82)	88.88	- 3	(302)	10,315
- 4	(110)	88.44	- 4	(403)	10,338
- 5	(137)	88.00	- 5	(504)	10,361
- 6	(164)	87.56	- 6	(605)	10,384
- 7	(192)	87.12	- 7	(706)	10,407
- 8	(219)	86.68	- 8	(806)	10,430
- 9	(247)	86.24	- 9	(907)	10,453
- 10	(274)	85.80	- 10	(1,008)	10,476
Weighting Factor:		0.017	Weighting Factor:		0.122

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	659	84.10	+ 10	1,627	9,960
+ 9	593	83.77	+ 9	1,464	9,983
+ 8	527	83.44	+ 8	1,302	10,007
+ 7	461	83.11	+ 7	1,139	10,030
+ 6	395	82.78	+ 6	976	10,053
+ 5	330	82.45	+ 5	814	10,077
+ 4	264	82.12	+ 4	651	10,100
+ 3	198	81.79	+ 3	488	10,123
+ 2	132	81.46	+ 2	325	10,146
+ 1	66	81.13	+ 1	163	10,170
				0	10,193
0	0	80.80	0	0	10,268
				0	10,343
- 1	(113)	80.31	- 1	(163)	10,366
- 2	(225)	79.82	- 2	(325)	10,390
- 3	(338)	79.33	- 3	(488)	10,413
- 4	(450)	78.84	- 4	(651)	10,436
- 5	(563)	78.35	- 5	(814)	10,460
- 6	(676)	77.86	- 6	(976)	10,483
- 7	(788)	77.37	- 7	(1,139)	10,506
- 8	(901)	76.88	- 8	(1,302)	10,529
- 9	(1,013)	76.39	- 9	(1,464)	10,553
- 10	(1,126)	75.90	- 10	(1,627)	10,576
Weighting Factor:		0.080	Weighting Factor:		0.197

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	28	98.70	+ 10	549	9,871
+ 9	25	98.64	+ 9	494	9,894
+ 8	22	98.58	+ 8	439	9,917
+ 7	20	98.52	+ 7	384	9,940
+ 6	17	98.46	+ 6	329	9,963
+ 5	14	98.40	+ 5	275	9,986
+ 4	11	98.34	+ 4	220	10,009
+ 3	8	98.28	+ 3	165	10,032
+ 2	6	98.22	+ 2	110	10,055
+ 1	3	98.16	+ 1	55	10,078
				0	10,101
0	0	98.10	0	0	10,176
				0	10,251
- 1	(3)	98.01	- 1	(55)	10,274
- 2	(6)	97.92	- 2	(110)	10,297
- 3	(10)	97.83	- 3	(165)	10,320
- 4	(13)	97.74	- 4	(220)	10,343
- 5	(16)	97.65	- 5	(275)	10,366
- 6	(19)	97.56	- 6	(329)	10,389
- 7	(22)	97.47	- 7	(384)	10,412
- 8	(26)	97.38	- 8	(439)	10,435
- 9	(29)	97.29	- 9	(494)	10,458
- 10	(32)	97.20	- 10	(549)	10,481
Weighting Factor:		0.003	Weighting Factor:		0.067

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	223	87.00	+ 10	526	9,915
+ 9	201	86.71	+ 9	473	9,938
+ 8	178	86.42	+ 8	421	9,961
+ 7	156	86.13	+ 7	368	9,985
+ 6	134	85.84	+ 6	316	10,008
+ 5	112	85.55	+ 5	263	10,031
+ 4	89	85.26	+ 4	210	10,054
+ 3	67	84.97	+ 3	158	10,077
+ 2	45	84.68	+ 2	105	10,101
+ 1	22	84.39	+ 1	53	10,124
				0	10,147
0	0	84.10	0	0	10,222
				0	10,297
- 1	(31)	83.67	- 1	(53)	10,320
- 2	(62)	83.24	- 2	(105)	10,343
- 3	(93)	82.81	- 3	(158)	10,367
- 4	(124)	82.38	- 4	(210)	10,390
- 5	(156)	81.95	- 5	(263)	10,413
- 6	(187)	81.52	- 6	(316)	10,436
- 7	(218)	81.09	- 7	(368)	10,459
- 8	(249)	80.66	- 8	(421)	10,483
- 9	(280)	80.23	- 9	(473)	10,506
- 10	(311)	79.80	- 10	(526)	10,529
Weighting Factor:		0.027	Weighting Factor:		0.064

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	200	94.80	+ 10	1,317	9,876
+ 9	180	94.68	+ 9	1,185	9,899
+ 8	160	94.56	+ 8	1,054	9,922
+ 7	140	94.44	+ 7	922	9,945
+ 6	120	94.32	+ 6	790	9,968
+ 5	100	94.20	+ 5	659	9,991
+ 4	80	94.08	+ 4	527	10,014
+ 3	60	93.96	+ 3	395	10,037
+ 2	40	93.84	+ 2	263	10,060
+ 1	20	93.72	+ 1	132	10,083
				0	10,106
0	0	93.60	0	0	10,181
				0	10,256
- 1	(31)	93.42	- 1	(132)	10,279
- 2	(62)	93.24	- 2	(263)	10,302
- 3	(93)	93.06	- 3	(395)	10,325
- 4	(124)	92.88	- 4	(527)	10,348
- 5	(155)	92.70	- 5	(659)	10,371
- 6	(186)	92.52	- 6	(790)	10,394
- 7	(217)	92.34	- 7	(922)	10,417
- 8	(248)	92.16	- 8	(1,054)	10,440
- 9	(279)	91.98	- 9	(1,185)	10,463
- 10	(310)	91.80	- 10	(1,317)	10,486
Weighting Factor:		0.024	Weighting Factor:		0.160

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2006 - December 2006

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	238	82.40	+ 10	1,139	9,726
+ 9	214	82.31	+ 9	1,025	9,749
+ 8	190	82.22	+ 8	911	9,771
+ 7	167	82.13	+ 7	797	9,794
+ 6	143	82.04	+ 6	683	9,816
+ 5	119	81.95	+ 5	570	9,839
+ 4	95	81.86	+ 4	456	9,862
+ 3	71	81.77	+ 3	342	9,884
+ 2	48	81.68	+ 2	228	9,907
+ 1	24	81.59	+ 1	114	9,929
				0	9,952
0	0	81.50	0	0	10,027
				0	10,102
- 1	(41)	81.35	- 1	(114)	10,125
- 2	(82)	81.20	- 2	(228)	10,147
- 3	(123)	81.05	- 3	(342)	10,170
- 4	(164)	80.90	- 4	(456)	10,192
- 5	(205)	80.75	- 5	(570)	10,215
- 6	(246)	80.60	- 6	(683)	10,238
- 7	(287)	80.45	- 7	(797)	10,260
- 8	(328)	80.30	- 8	(911)	10,283
- 9	(369)	80.15	- 9	(1,025)	10,305
- 10	(410)	80.00	- 10	(1,139)	10,328
Weighting Factor:		0.029	Weighting Factor:		0.138

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2006 - December 2006

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 4	0.0	87.1	87.3	86.7	$0	($13)	87.0	($3)
Crist 5	0.1	92.4	92.8	91.7	$5	($13)	93.2	$5
Crist 6	1.7	90.2	93.1	85.8	$142	($274)	93.0	$137
Crist 7	8.0	80.8	84.1	75.9	$659	($1,126)	84.7	$659
Smith 1	0.3	98.1	98.7	97.2	$28	($32)	94.1	($32)
Smith 2	2.7	84.1	87.0	79.8	$223	($311)	87.9	$223
Daniel 1	2.4	93.6	94.8	91.8	$200	($310)	95.2	$200
Daniel 2	2.9	81.5	82.4	80.0	$238	($410)	80.8	($191)
Total:	18.1							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 4	3.4	10,493	97.8	10,808	10,178	$281	($281)	10,815	($281)
Crist 5	3.7	10,375	98.7	10,686	10,064	$308	($308)	10,639	($247)
Crist 6	12.2	10,171	99.0	10,476	9,866	$1,008	($1,008)	10,318	($316)
Crist 7	19.7	10,268	90.8	10,576	9,960	$1,627	($1,627)	10,570	($1,585)
Smith 1	6.7	10,176	99.4	10,481	9,871	$549	($549)	10,232	$0
Smith 2	6.4	10,222	99.3	10,529	9,915	$526	($526)	10,305	($18)
Daniel 1	16.0	10,181	99.7	10,486	9,876	$1,317	($1,317)	10,055	$292
Daniel 2	13.8	10,027	99.7	10,328	9,726	$1,139	($1,139)	9,877	$378
Total:	81.9								

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Actual Unit Performance Data

Gulf Power Company

Period of: January 2006 - December 2006

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 4	90.7	-3.7	87.0
Crist 5	91.7	1.5	93.2
Crist 6	78.1	14.9	93.0
Crist 7	85.2	-0.5	84.7
Smith 1	94.1	0.0	94.1
Smith 2	89.0	-1.1	87.9
Daniel 1	97.6	-2.4	95.2
Daniel 2	83.2	-2.4	80.8

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 4	10,827	-12	10,815
Crist 5	10,741	-102	10,639
Crist 6	10,435	-117	10,318
Crist 7	10,487	83	10,570
Smith 1	10,286	-54	10,232
Smith 2	10,346	-41	10,305
Daniel 1	10,109	-54	10,055
Daniel 2	10,093	-216	9,877

* Refer to pages 3 through 10, Schedule 2.

** Refer to pages 10 through 17, Schedule 3.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 4	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	93.8	85.2	85.1	100.0	99.7	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	698.1	574.6	633.4	719.0	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	45.9	97.4	110.6	0.0	0.0	0.0	
6.	POH	0.0	97.4	110.6	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	45.9	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	5.2	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	31.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	15.3	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	13.0	0.0	
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	
14.	Oper MBtu	500638	435248	494071	562126	543263	565088	
15.	Net Gen (MWH)	47736	41511	46620	53326	50608	51756	
16.	ANOHR (Btu/KWH)	10488	10485	10598	10541	10735	10918	
17.	NOF %	87.7	92.6	94.4	95.1	87.2	92.2	
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	
19.	ANOHR Equation	10^6 / AKW * [498.36 - 12.78 * JAN - 8.72 * FEB] -4347 + 0.10869 * LSRF / AKW						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 4	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	98.7	99.0	99.9	30.0	97.9	100.0	90.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	743.0	720.0	223.6	705.0	503.6	7728.3
4.	RSH	0.0	0.0	0.0	0.0	0.0	240.4	240.4
5.	UH	0.0	1.0	0.0	521.4	15.0	0.0	791.3
6.	POH	0.0	0.0	0.0	521.4	0.0	0.0	729.4
7.	FOH	0.0	1.0	0.0	0.0	0.0	0.0	1.0
8.	MOH	0.0	0.0	0.0	0.0	15.0	0.0	60.9
9.	PFOH	27.0	18.4	4.0	0.0	0.0	0.0	54.6
10.	LR pf (MW)	28.0	26.7	13.0	0.0	0.0	0.0	26.7
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	15.3
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	13.0
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0
14.	Oper MBtu	577091	583886	521087	157547	516667	362615	5819327
15.	Net Gen (MWH)	52497	52023	46223	14099	47701	33401	537501
16.	ANOHR (Btu/KWH)	10993	11224	11273	11174	10831	10856	10827
17.	NOF %	90.5	89.8	82.3	80.8	86.7	85.0	89.2
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [498.36 - 12.78 * JAN - 8.72 * FEB] -4347 + 0.10869 * LSRF / AKW

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 5	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	100.0	85.6	86.8	100.0	99.6	95.2	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	576.3	645.9	719.0	744.0	685.2	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	95.7	98.1	0.0	0.0	34.8	
6.	POH	0.0	95.7	98.1	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	34.8	
9.	PFOH	0.0	7.5	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	14.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	15.3	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	15.0	0.0	
13.	NSC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	
14.	Oper MBtu	528360	410430	493170	539188	528793	519735	
15.	Net Gen (MWH)	50081	39593	46649	51618	49360	47525	
16.	ANOHR (Btu/KWH)	10550	10366	10572	10446	10713	10936	
17.	NOF %	84.1	85.9	90.3	89.7	82.9	86.7	
18.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	

19.	ANOHR Equation	10^6 / AKW * [563.97 - 15.45 * JAN - 14.34 * AUG - 16.27 * NOV] -5954 + 0.11802 * LSRF / AKW

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 5	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	100.0	100.0	100.0	34.0	100.0	100.0	91.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	253.5	720.0	575.3	7871.2
4.	RSH	0.0	0.0	0.0	0.0	0.0	168.7	168.7
5.	UH	0.0	0.0	0.0	491.5	0.0	0.0	720.1
6.	POH	0.0	0.0	0.0	491.5	0.0	0.0	685.3
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	34.8
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	7.5
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	14.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	15.3
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	15.0
13.	NSC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0
14.	Oper MBtu	564924	571211	518910	177865	512985	401612	5767183
15.	Net Gen (MWH)	52109	51648	45651	15938	48837	37921	536930
16.	ANOHR (Btu/KWH)	10841	11060	11367	11160	10504	10591	10741
17.	NOF %	87.5	86.8	79.3	78.6	84.8	82.4	85.3
18.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0
19.	ANOHR Equation	10^6 / AKW * [563.97 - 15.45 * JAN - 14.34 * AUG - 16.27 * NOV] -5954 + 0.11802 * LSRF / AKW						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 6	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	98.0	95.8	50.6	0.0	52.2	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	644.1	377.8	0.0	388.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	27.9	366.2	719.0	356.0	0.0	
6.	POH	0.0	0.0	335.7	719.0	351.7	0.0	
7.	FOH	0.0	0.0	30.5	0.0	4.3	0.0	
8.	MOH	0.0	27.9	0.0	0.0	0.0	0.0	
9.	PFOH	22.9	2.7	8.3	0.0	0.0	0.0	
10.	LR pf (MW)	198.9	8.0	48.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	
14.	Oper MBtu	1935100	1821342	1082338	0	958094	2180856	
15.	Net Gen (MWH)	191120	176354	105121	0	90624	207333	
16.	ANOHR (Btu/KWH)	10125	10328	10296	0	10572	10519	
17.	NOF %	85.1	90.7	92.1	0.0	77.3	95.4	
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [313.41] + 9,123

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 6	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	99.5	95.3	91.3	87.3	97.8	70.4	78.1
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	709.3	657.9	660.6	720.0	587.0	6952.7
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	34.7	62.1	84.4	0.0	157.0	1807.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1406.4
7.	FOH	0.0	34.7	38.6	10.9	0.0	0.0	119.0
8.	MOH	0.0	0.0	23.5	73.5	0.0	157.0	281.9
9.	PFOH	23.8	0.0	2.6	112.0	278.1	46.1	496.5
10.	LR pf (MW)	51.2	0.0	80.8	28.5	17.3	79.2	36.4
11.	PMOH	0.0	8.5	0.0	0.0	0.0	87.0	95.5
12.	LR pm (MW)	0.0	20.0	0.0	0.0	0.0	177.0	163.0
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
14.	Oper MBtu	2250613	2143391	1874049	1853437	2039421	1406817	19545458
15.	Net Gen (MWH)	214642	204960	177063	179605	196667	129630	1873119
16.	ANOHR (Btu/KWH)	10485	10458	10584	10320	10370	10853	10435
17.	NOF %	95.5	95.7	89.1	90.0	90.4	73.1	89.2
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [313.41] + 9,123

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 7	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	99.9	84.7	93.7	92.5	89.7	91.1	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	576.8	716.2	692.6	671.7	661.6	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	95.2	27.8	26.4	72.3	58.4	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	4.4	0.0	0.0	0.0	0.0	
8.	MOH	0.0	90.8	27.8	26.4	72.3	58.4	
9.	PFOH	2.6	96.9	162.1	136.7	71.1	24.2	
10.	LR pf (MW)	61.0	36.6	56.3	77.5	15.0	82.4	
11.	PMOH	2.7	0.0	0.0	32.9	54.3	49.5	
12.	LR pm (MW)	70.0	0.0	0.0	77.0	16.1	17.6	
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	
14.	Oper MBtu	3358481	2710502	3377037	3201033	3166801	3099764	
15.	Net Gen (MWH)	331585	261391	320786	307437	299371	293365	
16.	ANOHR (Btu/KWH)	10129	10370	10527	10412	10578	10566	
17.	NOF %	93.4	95.0	93.9	93.1	93.4	93.0	
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [512.95] + 9,084

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	CRIST 7	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	90.5	84.0	95.8	92.3	10.3	96.6	85.2
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	699.0	650.3	720.0	711.2	74.4	722.5	7640.3
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	45.0	93.7	0.0	33.8	645.6	21.5	1119.7
6.	POH	0.0	0.0	0.0	0.0	645.6	21.5	667.1
7.	FOH	37.0	0.0	0.0	33.8	0.0	0.0	75.2
8.	MOH	8.0	93.7	0.0	0.0	0.0	0.0	377.4
9.	PFOH	10.8	0.0	5.1	124.8	0.0	36.1	670.4
10.	LR pf (MW)	9.3	0.0	45.4	63.7	0.0	46.5	54.4
11.	PMOH	121.7	600.3	717.9	164.7	0.0	0.0	1744.0
12.	LR pm (MW)	100.0	20.3	20.0	20.0	0.0	0.0	26.6
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
14.	Oper MBtu	3180717	3019863	3242803	3188926	352098	3178205	35076230
15.	Net Gen (MWH)	301002	279797	306534	304180	32829	306330	3344607
16.	ANOHR (Btu/KWH)	10567	10793	10579	10484	10725	10375	10487
17.	NOF %	90.3	90.2	89.3	89.7	92.5	88.9	91.8
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
19.	ANOHR Equation	10^6 / AKW * [512.95] + 9,084						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	SMITH 1	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	99.7	99.8	99.0	100.0	86.7	99.9	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	672.0	744.0	719.0	647.5	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	0.0	0.0	96.5	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	96.5	0.0	
9.	PFOH	3.0	0.4	15.8	0.4	4.9	4.2	
10.	LR pf (MW)	112.0	16.2	44.8	30.0	29.0	31.7	
11.	PMOH	0.0	9.3	15.0	0.0	3.3	0.0	
12.	LR pm (MW)	0.0	26.2	34.7	0.0	61.0	0.0	
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
14.	Oper MBtu	1156161	1071002	1178050	1133055	980635	1146708	
15.	Net Gen (MWH)	112215	104480	115997	111425	96017	109536	
16.	ANOHR (Btu/KWH)	10303	10251	10156	10169	10213	10469	
17.	NOF %	93.1	96.0	96.2	95.7	91.5	93.9	
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
19.	ANOHR Equation	10^6 / AKW * [117.29 - 12.42 * AUG - 14.59 * OCT] + 9,462						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	SMITH 1	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	95.4	99.9	67.5	93.2	88.1	100.0	94.1
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	712.8	744.0	492.4	745.0	643.0	744.0	8327.7
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	31.2	0.0	227.6	0.0	77.0	0.0	432.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	227.6	0.0	0.0	0.0	227.6
8.	MOH	31.2	0.0	0.0	0.0	77.0	0.0	204.7
9.	PFOH	7.9	1.0	13.8	193.1	23.4	0.0	267.9
10.	LR pf (MW)	40.0	24.0	78.3	42.4	59.0	0.0	46.0
11.	PMOH	8.0	3.3	0.0	0.0	0.0	0.0	38.9
12.	LR pm (MW)	17.0	40.0	0.0	0.0	0.0	0.0	31.7
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
14.	Oper MBtu	1113499	1164983	731977	1076270	992593	1078129	12823062
15.	Net Gen (MWH)	106617	113232	70880	104653	96599	105002	1246653
16.	ANOHR (Btu/KWH)	10444	10288	10327	10284	10275	10268	10286
17.	NOF %	92.3	93.9	88.9	86.7	92.7	87.1	92.4
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
19.	ANOHR Equation	10^6 / AKW * [117.29 - 12.42 * AUG - 14.59 * OCT] + 9,462						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	SMITH 2	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	99.4	93.4	99.9	85.6	90.5	99.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	632.2	744.0	615.5	736.5	712.9	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	39.8	0.0	103.5	7.5	7.1	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	7.5	7.1	
8.	MOH	0.0	39.8	0.0	103.5	0.0	0.0	
9.	PFOH	13.8	10.3	1.5	2.3	224.6	0.4	
10.	LR pf (MW)	61.2	28.9	51.7	17.0	54.7	19.0	
11.	PMOH	0.0	32.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	17.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	
14.	Oper MBtu	1374650	1195460	1437852	1157850	1225828	1314703	
15.	Net Gen (MWH)	132283	115412	139483	111477	119292	125891	
16.	ANOHR (Btu/KWH)	10392	10358	10308	10386	10276	10443	
17.	NOF %	91.2	93.6	96.1	92.9	83.1	90.6	
18.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	

19.	ANOHR Equation	10^6 / AKW * [105.64 - 75.81 * MAR + 46.86 * APR] + 9,669

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	SMITH 2	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	92.2	100.0	67.3	42.8	97.6	100.0	89.0
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	488.1	318.9	710.1	744.0	7934.2
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	231.9	426.1	9.9	0.0	825.8
6.	POH	0.0	0.0	24.0	426.1	0.0	0.0	450.1
7.	FOH	0.0	0.0	207.9	0.0	9.9	0.0	232.4
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	143.3
9.	PFOH	170.8	2.9	12.3	0.0	43.5	0.2	482.6
10.	LR pf (MW)	64.0	22.6	56.2	0.0	32.5	145.0	55.3
11.	PMOH	6.1	0.0	0.0	0.0	0.0	0.0	38.1
12.	LR pm (MW)	64.0	0.0	0.0	0.0	0.0	0.0	24.5
13.	NSC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0
14.	Oper MBtu	1292575	1368768	863866	586388	1303885	1247204	14369029
15.	Net Gen (MWH)	123272	132121	83544	57323	127119	121613	1388830
16.	ANOHR (Btu/KWH)	10486	10360	10340	10230	10257	10256	10346
17.	NOF %	85.0	91.1	87.8	92.2	91.8	83.8	89.8
18.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0
19.	ANOHR Equation	10^6 / AKW * [105.64 - 75.81 * MAR + 46.86 * APR] + 9,669						

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	DANIEL 1	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	
1.	EAF (%)	98.5	99.3	99.5	81.4	99.9	99.3	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	672.0	744.0	590.0	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	0.0	129.0	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	129.0	0.0	0.0	
9.	PFOH	11.4	31.7	8.9	8.4	8.6	20.9	
10.	LR pf (MW)	319.2	55.9	175.9	206.8	47.5	100.2	
11.	PMOH	9.3	4.6	3.0	2.4	0.0	6.5	
12.	LR pm (MW)	208.5	126.1	134.0	245.8	0.0	87.0	
13.	NSC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	
14.	Oper MBtu	3337191	3355757	3595471	2699979	3266166	3478655	
15.	Net Gen (MWH)	328710	330423	358773	266568	320440	341250	
16.	ANOHR (Btu/KWH)	10152	10156	10022	10129	10193	10194	
17.	NOF %	86.0	95.7	93.8	87.9	83.8	92.2	
18.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	

19.	ANOHR Equation	10^6 / AKW * [2810.38 + 68.52 * APR - 58.18 * MAY - 90.02 * AUG] + 2,265 + 10^6 / AKW * [-0.1179 * BTU/LB] + 0.00953 * LSRF / AKW

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	DANIEL 1	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	99.3	98.6	100.0	95.5	99.9	100.0	97.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	734.9	720.0	727.0	720.0	744.0	8603.9
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	9.1	0.0	18.0	0.0	0.0	156.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	9.1	0.0	18.0	0.0	0.0	27.1
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	129.0
9.	PFOH	34.8	8.2	0.3	9.5	7.3	1.1	151.1
10.	LR pf (MW)	61.6	81.1	174.0	329.0	64.2	101.4	117.7
11.	PMOH	9.6	0.0	0.0	20.9	0.0	0.0	56.3
12.	LR pm (MW)	57.3	0.0	0.0	227.2	0.0	0.0	166.5
13.	NSC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0
14.	Oper MBtu	3653184	3639416	3620059	3531865	3532838	3692970	41403552
15.	Net Gen (MWH)	367717	360851	356414	348896	353897	361788	4095727
16.	ANOHR (Btu/KWH)	9935	10086	10157	10123	9983	10208	10109
17.	NOF %	96.2	95.5	96.3	93.4	95.6	94.6	92.6
18.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0

19.	ANOHR Equation	10^6 / AKW * [2810.38 + 68.52 * APR - 58.18 * MAY - 90.02 * AUG] + 2,265 + 10^6 / AKW * [-0.1179 * BTU/LB] + 0.00953 * LSRF / AKW

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2006 - December 2006

	DANIEL 2	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Total
1.	EAF (%)	99.8	100.0	99.9	97.7	99.7	95.8	83.2
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	740.3	720.0	715.4	7342.0
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	0.0	4.7	0.0	28.6	1418.0
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1116.3
7.	FOH	0.0	0.0	0.0	4.7	0.0	0.0	273.1
8.	MOH	0.0	0.0	0.0	0.0	0.0	28.6	28.6
9.	PFOH	6.6	4.7	1.9	18.2	6.3	17.4	270.7
10.	LR pf (MW)	84.4	20.9	172.9	238.0	163.9	59.0	79.8
11.	PMOH	2.8	0.0	0.0	8.6	5.0	1.5	36.3
12.	LR pm (MW)	88.1	0.0	0.0	219.0	19.9	130.0	98.7
13.	NSC (MW)	500.0	500.0	500.0	500.0	500.0	500.0	500.0
14.	Oper MBtu	3463296	3520637	3133172	3365068	3378022	3221828	33479724
15.	Net Gen (MWH)	342529	347441	304202	330743	330974	313327	3316959
16.	ANOHR (Btu/KWH)	10111	10133	10300	10174	10206	10283	10093
17.	NOF %	92.1	93.4	84.5	89.4	91.9	87.6	90.4
18.	NPC (MW)	500.0	500.0	500.0	500.0	500.0	500.0	500.0

19.	ANOHR Equation	10^6 / AKW * [2174.94 + 62.25 * JUN + 85.53 * JUL - 82.98 * AUG + 86.31 * OCT] + 8,739 + 10^6 / AKW * [-0.1460 * BTU/LB]

Issued by: S. N. Story

Filed: April 05, 2007
Suspended:
Effective: April 05, 2007
Docket No.: 070001-EI
Order No.:

Planned Outage Schedules (Actual)

Period of: January 2006 - December 2006

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

Before me, the undersigned authority, personally appeared Lonzelle S. Noack, who being first duly sworn, deposes, and says that she is the Power Generation Specialist, Senior for Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

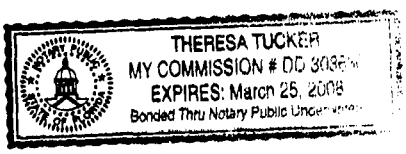
Lonzelle S. Noack
Power Generation Specialist, Senior

Sworn to and subscribed before me this 2nd day of April, 2007.

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:



GULF POWER COMPANY
TESTIMONY AND EXHIBITS OF
L. S. NOACK

GENERATING PERFORMANCE INCENTIVE FACTOR

TARGETS FOR

JANUARY 2008 - DECEMBER 2008

Before

THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

GULF POWER

A SOUTHERN COMPANY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 33
COMPANY Gulf Power Co.
WITNESS L. S. Noack (LSN-2)
DATE 11-06-07

Florida Public Service Commission
Docket No. 070001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No.___(LSN-2)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 070001-EI

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [-508.01 + 11.33 * MAR + 21.63 * MAY + 36.12 * JUN + 26.37 * JUL + 39.93 * AUG + 26.37 * SEP + 18.89 * OCT + 12.20 * NOV]

+ 28,136 - 0.14571 * LSRF / AKW

Crist 5 ANOHR = 10^6 / AKW * [107.79 - 10.84 * APR + 13.62 * MAY + 14.07 * JUN + 22.79 * JUL + 23.21 * AUG + 28.04 * SEP + 23.17 * OCT]

+ 8,943

Crist 6 ANOHR = 10^6 / AKW * [457.20 - 54.35 * FEB - 64.08 * MAR + 52.17 * JUN - 50.16 * OCT]

+ 8,761

Crist 7 ANOHR = 10^6 / AKW * [575.62 - 136.35 * FEB + 117.15 * MAR + 87.68 * APR + 104.03 * JUN]

+ 9,081

Smith 1 ANOHR = 10^6 / AKW * [96.28 + 12.10 * JUN + 11.27 * JUL - 11.78 * OCT]

+ 9,613

Smith 2 ANOHR = 10^6 / AKW * [275.87 - 16.87 * MAY - 11.84 * JUL - 10.07 * SEP]

+ 7,294 + 0.00822 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [695.23]

+ 8,686

Daniel 2 ANOHR = 10^6 / AKW * [398.00 - 123.89 * MAR - 108.06 * MAY - 96.34 * SEP]

+ 9,262

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
JAN = January, 0 if not January, 1 if January
FEB = February, 0 if not February, 1 if February
MAR = March, 0 if not March, 1 if March
APR = April, 0 if not April, 1 if April
MAY = May, 0 if not May, 1 if May
JUN = June, 0 if not June, 1 if June
JUL = July, 0 if not July, 1 if July
AUG = August, 0 if not August, 1 if August
SEP = September, 0 if not September, 1 if September
OCT = October, 0 if not October, 1 if October
NOV = November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10576	168	65.9	4504	0	0	0	0	0	0	1	0	0	0	0	0	2004
10726	168	66.5	4576	0	0	0	0	0	0	1	0	0	0	0	0	2004
10664	168	66.3	4571	0	0	0	0	0	0	1	0	0	0	0	0	2004
10740	168	67.9	4767	0	0	0	0	0	0	1	0	0	0	0	0	2004
10703	168	69.6	4974	0	0	0	0	0	0	0	1	0	0	0	0	2004
10768	168	67.7	4747	0	0	0	0	0	0	0	1	0	0	0	0	2004
10524	168	65.9	4502	0	0	0	0	0	0	0	1	0	0	0	0	2004
10576	168	68.4	4796	0	0	0	0	0	0	0	1	0	0	0	0	2004
10620	168	69.8	4959	0	0	0	0	0	0	0	1	0	0	0	0	2004
10553	168	63.3	4195	0	0	0	0	0	0	0	0	1	0	0	0	2004
10763	168	62.3	4104	0	0	0	0	0	0	0	0	1	0	0	0	2004
11010	105	54.9	3239	0	0	0	0	0	0	0	0	1	0	0	1	2004
10564	168	69.0	4870	0	0	0	0	0	0	0	0	1	0	0	0	2004
10724	168	70.0	5027	0	0	0	0	0	0	0	0	0	1	0	0	2004
10636	168	69.7	4966	0	0	0	0	0	0	0	0	0	1	0	0	2004
10536	168	69.9	5009	0	0	0	0	0	0	0	0	0	1	0	0	2004
10609	168	71.6	5223	0	0	0	0	0	0	0	0	0	1	0	0	2004
10632	169	72.9	5391	0	0	0	0	0	0	0	0	0	1	0	0	2004
10667	168	67.4	4732	0	0	0	0	0	0	0	0	0	0	1	0	2004
10635	168	73.0	5386	0	0	0	0	0	0	0	0	0	0	1	0	2004
10661	168	70.4	5076	0	0	0	0	0	0	0	0	0	0	1	0	2004
10860	168	60.4	3759	0	0	0	0	0	0	0	0	0	0	1	0	2004
10362	168	69.3	4898	0	0	0	0	0	0	0	0	0	0	0	0	2004
10433	168	65.0	4315	0	0	0	0	0	0	0	0	0	0	0	0	2004
10530	128	64.0	4310	0	0	0	0	0	0	0	0	0	0	0	1	2004
10538	168	65.3	4375	0	0	0	0	0	0	0	0	0	0	0	0	2004
10662	24	59.2	3676	0	0	0	0	0	0	0	0	0	0	0	0	2004
9884	82	53.8	3048	1	0	0	0	0	0	0	0	0	0	0	0	2005
10143	166	57.7	3493	1	0	0	0	0	0	0	0	0	0	0	1	2005
10454	168	66.7	4609	1	0	0	0	0	0	0	0	0	0	0	0	2005
9876	168	72.0	5219	0	1	0	0	0	0	0	0	0	0	0	0	2005
10472	168	60.7	3828	0	1	0	0	0	0	0	0	0	0	0	0	2005
10417	168	57.8	3477	0	1	0	0	0	0	0	0	0	0	0	0	2005
10569	168	59.8	3740	0	1	0	0	0	0	0	0	0	0	0	0	2005
11368	168	56.4	3279	0	0	1	0	0	0	0	0	0	0	0	0	2005
10538	168	67.3	4633	0	0	1	0	0	0	0	0	0	0	0	0	2005
10540	168	71.4	5183	0	0	1	0	0	0	0	0	0	0	0	0	2005
10549	168	68.2	4772	0	0	1	0	0	0	0	0	0	0	0	0	2005
10575	168	67.6	4736	0	0	1	0	0	0	0	0	0	0	0	0	2005
10445	167	66.4	4458	0	0	0	1	0	0	0	0	0	0	0	0	2005
10485	168	68.9	4799	0	0	0	1	0	0	0	0	0	0	0	0	2005
10588	168	65.8	4470	0	0	0	1	0	0	0	0	0	0	0	0	2005
*12495	95	53.0	3047	0	0	0	1	0	0	0	0	0	0	0	1	2005
10872	168	67.1	4624	0	0	0	0	1	0	0	0	0	0	0	0	2005
10755	168	68.4	4835	0	0	0	0	1	0	0	0	0	0	0	0	2005
10683	168	70.4	5079	0	0	0	0	1	0	0	0	0	0	0	0	2005
10849	168	70.8	5102	0	0	0	0	1	0	0	0	0	0	0	0	2005

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10842	168	66.0	4471	0	0	0	0	1	0	0	0	0	0	0	0	2005
10871	168	68.4	4784	0	0	0	0	0	1	0	0	0	0	0	0	2005
10766	168	68.4	4787	0	0	0	0	0	1	0	0	0	0	0	0	2005
10886	168	67.6	4714	0	0	0	0	0	1	0	0	0	0	0	0	2005
10791	144	72.4	5304	0	0	0	0	0	1	0	0	0	0	0	0	2005
10860	168	72.7	5342	0	0	0	0	0	0	1	0	0	0	0	0	2005
10992	168	61.5	3965	0	0	0	0	0	0	1	0	0	0	0	0	2005
11051	168	65.4	4396	0	0	0	0	0	0	1	0	0	0	0	0	2005
10859	168	73.2	5369	0	0	0	0	0	0	1	0	0	0	0	0	2005
11133	142	64.8	4370	0	0	0	0	0	0	0	1	0	0	0	0	2005
11040	135	70.8	5127	0	0	0	0	0	0	0	1	0	0	0	1	2005
10660	168	73.7	5453	0	0	0	0	0	0	0	1	0	0	0	0	2005
11050	168	73.5	5422	0	0	0	0	0	0	0	1	0	0	0	0	2005
11059	168	71.6	5143	0	0	0	0	0	0	0	1	0	0	0	0	2005
10930	168	68.8	4851	0	0	0	0	0	0	0	0	1	0	0	0	2005
10524	168	71.6	5205	0	0	0	0	0	0	0	0	1	0	0	0	2005
10809	168	71.6	5167	0	0	0	0	0	0	0	0	1	0	0	0	2005
11014	168	63.4	4139	0	0	0	0	0	0	0	0	1	0	0	0	2005
10906	168	66.1	4466	0	0	0	0	0	0	0	0	0	1	0	0	2005
10689	168	70.4	5065	0	0	0	0	0	0	0	0	0	1	0	0	2005
10457	168	68.1	4766	0	0	0	0	0	0	0	0	0	1	0	0	2005
10543	168	70.7	5101	0	0	0	0	0	0	0	0	0	1	0	0	2005
10723	169	72.2	5254	0	0	0	0	0	0	0	0	0	1	0	0	2005
10823	168	66.3	4415	0	0	0	0	0	0	0	0	0	0	1	0	2005
10948	168	59.2	3532	0	0	0	0	0	0	0	0	0	0	1	0	2005
10770	168	61.8	3845	0	0	0	0	0	0	0	0	0	0	1	0	2005
10813	168	61.4	3825	0	0	0	0	0	0	0	0	0	0	1	0	2005
10803	168	66.4	4528	0	0	0	0	0	0	0	0	0	0	0	0	2005
10827	168	66.3	4476	0	0	0	0	0	0	0	0	0	0	0	0	2005
10098	168	69.7	4871	0	0	0	0	0	0	0	0	0	0	0	0	2005
10032	168	64.3	4281	0	0	0	0	0	0	0	0	0	0	0	0	2005
9974	24	69.7	4966	0	0	0	0	0	0	0	0	0	0	0	0	2005
11054	168	67.1	4613	1	0	0	0	0	0	0	0	0	0	0	0	2006
10247	168	71.2	5136	1	0	0	0	0	0	0	0	0	0	0	0	2006
10415	123	66.8	4632	1	0	0	0	0	0	0	0	0	0	0	1	2006
10330	168	68.2	4792	1	0	0	0	0	0	0	0	0	0	0	0	2006
10451	168	70.2	5035	0	1	0	0	0	0	0	0	0	0	0	0	2006
10553	168	71.9	5250	0	1	0	0	0	0	0	0	0	0	0	0	2006
10489	168	71.6	5208	0	1	0	0	0	0	0	0	0	0	0	0	2006
10374	143	73.0	5399	0	1	0	0	0	0	0	0	0	0	0	0	2006
10498	154	68.6	4850	0	0	1	0	0	0	0	0	0	0	0	1	2006
10246	168	73.7	5477	0	0	1	0	0	0	0	0	0	0	0	0	2006
10831	168	75.9	5772	0	0	1	0	0	0	0	0	0	0	0	0	2006
10784	168	75.9	5766	0	0	1	0	0	0	0	0	0	0	0	0	2006
10436	167	75.5	5701	0	0	0	1	0	0	0	0	0	0	0	0	2006
10456	168	74.8	5613	0	0	0	1	0	0	0	0	0	0	0	0	2006
10551	168	74.4	5570	0	0	0	1	0	0	0	0	0	0	0	0	2006

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10749	168	72.4	5273	0	0	0	1	0	0	0	0	0	0	0	0	2006
10347	168	69.8	4944	0	0	0	0	1	0	0	0	0	0	0	0	2006
10770	168	67.6	4690	0	0	0	0	1	0	0	0	0	0	0	0	2006
10693	168	66.3	4518	0	0	0	0	1	0	0	0	0	0	0	0	2006
11000	168	68.0	4752	0	0	0	0	1	0	0	0	0	0	0	0	2006
10931	168	70.9	5102	0	0	0	0	1	0	0	0	0	0	0	0	2006
10802	168	69.7	4975	0	0	0	0	0	1	0	0	0	0	0	0	2006
10935	168	72.5	5295	0	0	0	0	0	1	0	0	0	0	0	0	2006
11014	168	72.8	5359	0	0	0	0	0	1	0	0	0	0	0	0	2006
10918	144	72.0	5246	0	0	0	0	0	1	0	0	0	0	0	0	2006
10316	168	72.5	5294	0	0	0	0	0	0	1	0	0	0	0	0	2006
10915	168	68.5	4837	0	0	0	0	0	0	1	0	0	0	0	0	2006
11293	168	71.0	5125	0	0	0	0	0	0	1	0	0	0	0	0	2006
11346	168	70.4	5018	0	0	0	0	0	0	1	0	0	0	0	0	2006
11724	168	69.8	4956	0	0	0	0	0	0	0	1	0	0	0	0	2006
11903	168	71.9	5209	0	0	0	0	0	0	0	1	0	0	0	0	2006
11756	168	70.7	5056	0	0	0	0	0	0	0	1	0	0	0	0	2006
* 9573	168	69.0	4871	0	0	0	0	0	0	0	1	0	0	0	0	2006
11317	168	68.5	4774	0	0	0	0	0	0	0	1	0	0	0	0	2006
11682	168	67.3	4607	0	0	0	0	0	0	0	0	1	0	0	0	2006
11204	168	65.1	4342	0	0	0	0	0	0	0	0	1	0	0	0	2006
11027	168	64.2	4254	0	0	0	0	0	0	0	0	1	0	0	0	2006
10955	168	60.1	3761	0	0	0	0	0	0	0	0	1	0	0	0	2006
11254	168	61.6	3958	0	0	0	0	0	0	0	0	0	1	0	0	2006
11186	139	64.3	4352	0	0	0	0	0	0	0	0	0	1	0	1	2006
10747	168	67.5	4696	0	0	0	0	0	0	0	0	0	0	1	0	2006
10852	168	67.1	4569	0	0	0	0	0	0	0	0	0	0	1	0	2006
10712	168	69.6	4945	0	0	0	0	0	0	0	0	0	0	1	0	2006
10856	168	66.4	4579	0	0	0	0	0	0	0	0	0	0	1	0	2006
10803	168	68.0	4736	0	0	0	0	0	0	0	0	0	0	0	0	2006
10872	168	66.9	4603	0	0	0	0	0	0	0	0	0	0	0	0	2006
10923	144	63.9	4244	0	0	0	0	0	0	0	0	0	0	0	0	2006
10593	140	58.4	3561	1	0	0	0	0	0	0	0	0	0	0	1	2007
10641	168	60.1	3752	1	0	0	0	0	0	0	0	0	0	0	0	2007
11016	168	65.9	4438	1	0	0	0	0	0	0	0	0	0	0	0	2007
10754	168	65.5	4405	1	0	0	0	0	0	0	0	0	0	0	0	2007
10675	168	67.8	4674	0	1	0	0	0	0	0	0	0	0	0	0	2007
10619	168	64.8	4313	0	1	0	0	0	0	0	0	0	0	0	0	2007
10707	168	69.4	4907	0	1	0	0	0	0	0	0	0	0	0	0	2007
10754	168	63.6	4137	0	1	0	0	0	0	0	0	0	0	0	0	2007
10740	168	60.6	3761	0	0	1	0	0	0	0	0	0	0	0	0	2007
10784	167	64.5	4265	0	0	1	0	0	0	0	0	0	0	0	0	2007
10720	168	64.9	4323	0	0	1	0	0	0	0	0	0	0	0	0	2007
10683	168	64.9	4363	0	0	1	0	0	0	0	0	0	0	0	0	2007
10716	168	67.3	4635	0	0	1	0	0	0	0	0	0	0	0	0	2007
10961	168	62.2	3996	0	0	0	1	0	0	0	0	0	0	0	0	2007
10471	168	69.0	4830	0	0	0	1	0	0	0	0	0	0	0	0	2007

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10679	168	66.7	4536	0	0	0	1	0	0	0	0	0	0	0	0	2007
10890	168	65.8	4434	0	0	0	1	0	0	0	0	0	0	0	0	2007
10869	168	65.7	4410	0	0	0	0	1	0	0	0	0	0	0	0	2007
11058	168	64.8	4314	0	0	0	0	1	0	0	0	0	0	0	0	2007
11133	168	62.7	4087	0	0	0	0	1	0	0	0	0	0	0	0	2007
10919	168	63.3	4176	0	0	0	0	1	0	0	0	0	0	0	0	2007
11095	168	66.5	4565	0	0	0	0	0	1	0	0	0	0	0	0	2007
11148	168	70.5	5023	0	0	0	0	0	1	0	0	0	0	0	0	2007
11378	168	67.5	4666	0	0	0	0	0	1	0	0	0	0	0	0	2007
11331	168	67.8	4663	0	0	0	0	0	1	0	0	0	0	0	0	2007
11359	120	69.9	4939	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 4 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10653	168	65.0	4403	0	0	0	0	0	0	1	0	0	0	0	0	2004
10758	168	65.6	4463	0	0	0	0	0	0	1	0	0	0	0	0	2004
10625	168	65.9	4529	0	0	0	0	0	0	1	0	0	0	0	0	2004
10702	168	67.6	4757	0	0	0	0	0	0	1	0	0	0	0	0	2004
10551	168	68.5	4843	0	0	0	0	0	0	0	1	0	0	0	0	2004
10665	168	67.3	4697	0	0	0	0	0	0	0	1	0	0	0	0	2004
10538	168	67.9	4774	0	0	0	0	0	0	0	1	0	0	0	0	2004
10466	168	71.0	5139	0	0	0	0	0	0	0	1	0	0	0	0	2004
10681	141	71.6	5250	0	0	0	0	0	0	0	1	0	0	0	1	2004
10796	168	63.1	4169	0	0	0	0	0	0	0	0	1	0	0	0	2004
10905	168	63.8	4288	0	0	0	0	0	0	0	0	1	0	0	0	2004
11208	114	53.9	3096	0	0	0	0	0	0	0	0	1	0	0	1	2004
10722	168	67.3	4630	0	0	0	0	0	0	0	0	1	0	0	0	2004
10891	168	69.5	4959	0	0	0	0	0	0	0	0	0	1	0	0	2004
10906	168	70.0	5011	0	0	0	0	0	0	0	0	0	1	0	0	2004
10829	168	69.9	5023	0	0	0	0	0	0	0	0	0	1	0	0	2004
10862	168	71.6	5221	0	0	0	0	0	0	0	0	0	1	0	0	2004
10753	169	73.7	5486	0	0	0	0	0	0	0	0	0	1	0	0	2004
11002	168	66.2	4582	0	0	0	0	0	0	0	0	0	0	1	0	2004
10677	168	70.4	5046	0	0	0	0	0	0	0	0	0	0	1	0	2004
10690	168	69.2	4905	0	0	0	0	0	0	0	0	0	0	1	0	2004
10878	168	59.7	3665	0	0	0	0	0	0	0	0	0	0	1	0	2004
10616	168	68.0	4703	0	0	0	0	0	0	0	0	0	0	0	0	2004
10739	168	65.3	4351	0	0	0	0	0	0	0	0	0	0	0	0	2004
10602	168	65.4	4413	0	0	0	0	0	0	0	0	0	0	0	0	2004
10984	168	62.4	4058	0	0	0	0	0	0	0	0	0	0	0	0	2004
11461	24	46.0	2135	0	0	0	0	0	0	0	0	0	0	0	0	2004
10471	67	48.4	2389	1	0	0	0	0	0	0	0	0	0	0	0	2005
11147	164	59.0	3688	1	0	0	0	0	0	0	0	0	0	0	1	2005
* 9451	168	71.1	5156	1	0	0	0	0	0	0	0	0	0	0	0	2005
9985	168	74.6	5571	0	1	0	0	0	0	0	0	0	0	0	0	2005
10379	168	62.5	4051	0	1	0	0	0	0	0	0	0	0	0	0	2005
11271	168	56.7	3351	0	1	0	0	0	0	0	0	0	0	0	0	2005
• 9499	138	61.5	3960	0	1	0	0	0	0	0	0	0	0	0	1	2005
10605	168	68.8	4820	0	0	1	0	0	0	0	0	0	0	0	0	2005
10706	168	69.1	4872	0	0	1	0	0	0	0	0	0	0	0	0	2005
9846	168	72.7	5335	0	0	1	0	0	0	0	0	0	0	0	0	2005
10750	168	69.5	4934	0	0	1	0	0	0	0	0	0	0	0	0	2005
10646	168	67.8	4744	0	0	1	0	0	0	0	0	0	0	0	0	2005
10047	167	63.5	4117	0	0	0	1	0	0	0	0	0	0	0	0	2005
10014	168	68.2	4676	0	0	0	1	0	0	0	0	0	0	0	0	2005
10039	168	67.8	4702	0	0	0	1	0	0	0	0	0	0	0	0	2005
*11754	125	65.7	4362	0	0	0	1	0	0	0	0	0	0	0	0	2005
11973	147	63.5	4178	0	0	0	0	1	0	0	0	0	0	0	1	2005
10564	168	67.5	4698	0	0	0	0	1	0	0	0	0	0	0	0	2005
10675	150	69.1	4956	0	0	0	0	1	0	0	0	0	0	0	0	2005
10577	168	70.9	5120	0	0	0	0	1	0	0	0	0	0	0	0	2005

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10747	168	66.9	4593	0	0	0	0	1	0	0	0	0	0	0	0	2005
10876	168	67.3	4619	0	0	0	0	0	1	0	0	0	0	0	0	2005
10601	168	69.1	4893	0	0	0	0	0	1	0	0	0	0	0	0	2005
10677	168	67.6	4725	0	0	0	0	0	1	0	0	0	0	0	0	2005
10663	144	72.4	5312	0	0	0	0	0	1	0	0	0	0	0	0	2005
10714	168	72.5	5300	0	0	0	0	0	0	1	0	0	0	0	0	2005
11268	142	63.9	4290	0	0	0	0	0	0	1	0	0	0	0	1	2005
11112	168	65.7	4427	0	0	0	0	0	0	1	0	0	0	0	0	2005
11013	168	73.1	5356	0	0	0	0	0	0	1	0	0	0	0	0	2005
10666	168	72.2	5268	0	0	0	0	0	0	0	1	0	0	0	0	2005
10568	168	72.2	5263	0	0	0	0	0	0	0	1	0	0	0	0	2005
10836	168	72.1	5228	0	0	0	0	0	0	0	1	0	0	0	0	2005
10902	168	73.7	5442	0	0	0	0	0	0	0	1	0	0	0	0	2005
11289	166	66.0	4575	0	0	0	0	0	0	0	1	0	0	0	0	2005
11238	168	65.1	4408	0	0	0	0	0	0	0	0	1	0	0	0	2005
10564	168	70.4	5057	0	0	0	0	0	0	0	0	1	0	0	0	2005
10781	168	73.0	5353	0	0	0	0	0	0	0	0	1	0	0	0	2005
11020	168	66.8	4539	0	0	0	0	0	0	0	0	1	0	0	0	2005
10612	168	74.4	5552	0	0	0	0	0	0	0	0	0	1	0	0	2005
10526	168	72.0	5280	0	0	0	0	0	0	0	0	0	1	0	0	2005
10306	168	69.1	4918	0	0	0	0	0	0	0	0	0	1	0	0	2005
10276	168	72.5	5336	0	0	0	0	0	0	0	0	0	1	0	0	2005
11856	111	71.6	5267	0	0	0	0	0	0	0	0	0	1	0	1	2005
10386	168	72.8	5318	0	0	0	0	0	0	0	0	0	0	1	0	2005
10274	168	73.2	5388	0	0	0	0	0	0	0	0	0	0	1	0	2005
10812	168	70.8	5091	0	0	0	0	0	0	0	0	0	0	1	0	2005
10010	168	70.7	5069	0	0	0	0	0	0	0	0	0	0	1	0	2005
10483	12	67.8	4592	0	0	0	0	0	0	0	0	0	0	0	0	2005
*13096	60	65.2	4489	0	0	0	0	0	0	0	0	0	0	0	1	2005
10050	168	64.9	4327	0	0	0	0	0	0	0	0	0	0	0	0	2005
10058	24	69.0	4872	0	0	0	0	0	0	0	0	0	0	0	0	2005
11016	168	66.3	4503	1	0	0	0	0	0	0	0	0	0	0	0	2006
10353	168	67.3	4615	1	0	0	0	0	0	0	0	0	0	0	0	2006
10359	168	69.9	4957	1	0	0	0	0	0	0	0	0	0	0	0	2006
10514	168	66.8	4591	1	0	0	0	0	0	0	0	0	0	0	0	2006
10385	168	67.6	4704	0	1	0	0	0	0	0	0	0	0	0	0	2006
10337	168	70.8	5086	0	1	0	0	0	0	0	0	0	0	0	0	2006
10523	168	68.9	4836	0	1	0	0	0	0	0	0	0	0	0	0	2006
10247	145	65.1	4378	0	1	0	0	0	0	0	0	0	0	0	0	2006
10462	165	67.8	4754	0	0	1	0	0	0	0	0	0	0	0	1	2006
10124	168	71.9	5208	0	0	1	0	0	0	0	0	0	0	0	0	2006
10863	168	74.2	5517	0	0	1	0	0	0	0	0	0	0	0	0	2006
10808	168	75.8	5746	0	0	1	0	0	0	0	0	0	0	0	0	2006
10422	167	72.8	5315	0	0	0	1	0	0	0	0	0	0	0	0	2006
10375	168	71.3	5101	0	0	0	1	0	0	0	0	0	0	0	0	2006
10440	168	72.4	5286	0	0	0	1	0	0	0	0	0	0	0	0	2006
10542	168	71.1	5081	0	0	0	1	0	0	0	0	0	0	0	0	2006

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10575	168	67.5	4651	0	0	0	0	1	0	0	0	0	0	0	0	2006
10723	168	64.9	4339	0	0	0	0	1	0	0	0	0	0	0	0	2006
11047	168	63.7	4192	0	0	0	0	1	0	0	0	0	0	0	0	2006
10638	168	68.6	4813	0	0	0	0	1	0	0	0	0	0	0	0	2006
10443	168	69.2	4869	0	0	0	0	1	0	0	0	0	0	0	0	2006
10440	168	68.3	4782	0	0	0	0	0	1	0	0	0	0	0	0	2006
*12763	133	67.6	4685	0	0	0	0	0	1	0	0	0	0	0	1	2006
10732	168	70.8	5062	0	0	0	0	0	1	0	0	0	0	0	0	2006
10430	144	69.6	4922	0	0	0	0	0	1	0	0	0	0	0	0	2006
10836	168	69.9	4933	0	0	0	0	0	0	1	0	0	0	0	0	2006
10858	168	70.1	4970	0	0	0	0	0	0	1	0	0	0	0	0	2006
10909	168	70.3	5016	0	0	0	0	0	0	1	0	0	0	0	0	2006
10870	168	69.8	4948	0	0	0	0	0	0	1	0	0	0	0	0	2006
10772	168	70.0	4959	0	0	0	0	0	0	0	1	0	0	0	0	2006
11124	168	70.0	4950	0	0	0	0	0	0	0	1	0	0	0	0	2006
11167	168	69.0	4817	0	0	0	0	0	0	0	1	0	0	0	0	2006
10984	168	69.1	4870	0	0	0	0	0	0	0	1	0	0	0	0	2006
11087	168	69.3	4871	0	0	0	0	0	0	0	1	0	0	0	0	2006
11301	168	68.0	4676	0	0	0	0	0	0	0	0	1	0	0	0	2006
11458	168	63.3	4112	0	0	0	0	0	0	0	0	1	0	0	0	2006
11356	168	61.8	3924	0	0	0	0	0	0	0	0	1	0	0	0	2006
11339	168	60.4	3764	0	0	0	0	0	0	0	0	1	0	0	0	2006
11351	167	60.8	3853	0	0	0	0	0	0	0	0	0	1	0	0	2006
*14390	14	44.3	2126	0	0	0	0	0	0	0	0	0	1	0	1	2006
10660	169	67.6	4635	0	0	0	0	0	0	0	0	0	1	0	0	2006
10453	168	67.3	4640	0	0	0	0	0	0	0	0	0	0	1	0	2006
10668	168	64.8	4258	0	0	0	0	0	0	0	0	0	0	1	0	2006
10498	168	70.7	5057	0	0	0	0	0	0	0	0	0	0	1	0	2006
10344	168	68.0	4771	0	0	0	0	0	0	0	0	0	0	1	0	2006
10608	168	68.2	4760	0	0	0	0	0	0	0	0	0	0	0	0	2006
10613	168	68.8	4853	0	0	0	0	0	0	0	0	0	0	0	0	2006
10526	168	65.2	4415	0	0	0	0	0	0	0	0	0	0	0	0	2006
10838	48	50.4	2621	0	0	0	0	0	0	0	0	0	0	0	0	2006
10606	145	56.1	3277	1	0	0	0	0	0	0	0	0	0	0	1	2007
10425	168	57.9	3482	1	0	0	0	0	0	0	0	0	0	0	0	2007
10741	168	66.6	4540	1	0	0	0	0	0	0	0	0	0	0	0	2007
10807	168	63.8	4173	1	0	0	0	0	0	0	0	0	0	0	0	2007
10080	168	71.5	5181	0	1	0	0	0	0	0	0	0	0	0	0	2007
10812	168	64.0	4184	0	1	0	0	0	0	0	0	0	0	0	0	2007
11816	86	61.1	3905	0	1	0	0	0	0	0	0	0	0	0	1	2007
10717	163	62.6	4029	0	1	0	0	0	0	0	0	0	0	0	0	2007
10526	168	62.0	3944	0	0	1	0	0	0	0	0	0	0	0	0	2007
10644	167	64.7	4295	0	0	1	0	0	0	0	0	0	0	0	0	2007
10649	168	66.6	4553	0	0	1	0	0	0	0	0	0	0	0	0	2007
10527	168	66.6	4582	0	0	1	0	0	0	0	0	0	0	0	0	2007
10561	168	67.7	4697	0	0	1	0	0	0	0	0	0	0	0	0	2007
10731	168	64.8	4302	0	0	0	1	0	0	0	0	0	0	0	0	2007

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10327	168	70.5	5039	0	0	0	1	0	0	0	0	0	0	0	0	2007
10427	168	68.2	4759	0	0	0	1	0	0	0	0	0	0	0	0	2007
10500	168	66.0	4474	0	0	0	1	0	0	0	0	0	0	0	0	2007
10638	168	65.7	4418	0	0	0	0	1	0	0	0	0	0	0	0	2007
10725	168	65.7	4428	0	0	0	0	1	0	0	0	0	0	0	0	2007
10818	168	63.2	4155	0	0	0	0	1	0	0	0	0	0	0	0	2007
10790	168	63.9	4265	0	0	0	0	1	0	0	0	0	0	0	0	2007
10742	168	67.1	4631	0	0	0	0	0	1	0	0	0	0	0	0	2007
10697	168	70.9	5088	0	0	0	0	0	1	0	0	0	0	0	0	2007
10900	168	68.8	4851	0	0	0	0	0	1	0	0	0	0	0	0	2007
10985	168	68.2	4738	0	0	0	0	0	1	0	0	0	0	0	0	2007
10704	120	70.9	5071	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 5 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10405	168	241.7	63812	0	0	0	0	0	0	1	0	0	0	0	0	2004
10323	168	250.9	2260	0	0	0	0	0	0	1	0	0	0	0	0	2004
10536	121	248.1	1016	0	0	0	0	0	0	1	0	0	0	0	1	2004
10492	168	250.7	2086	0	0	0	0	0	0	1	0	0	0	0	0	2004
10457	161	235.5	62236	0	0	0	0	0	0	0	1	0	0	0	0	2004
10348	168	259.5	5978	0	0	0	0	0	0	0	1	0	0	0	0	2004
10381	168	257.0	5018	0	0	0	0	0	0	0	1	0	0	0	0	2004
10564	168	274.8	12325	0	0	0	0	0	0	0	1	0	0	0	0	2004
10633	168	282.8	16216	0	0	0	0	0	0	0	1	0	0	0	0	2004
10657	168	240.7	63485	0	0	0	0	0	0	0	0	1	0	0	0	2004
10434	168	233.0	60185	0	0	0	0	0	0	0	0	1	0	0	0	2004
*11310	20	89.3	10447	0	0	0	0	0	0	0	0	1	0	0	1	2004
*10333	168	195.1	44119	0	0	0	0	0	0	0	0	1	0	0	0	2004
9957	168	282.2	16147	0	0	0	0	0	0	0	0	0	1	0	0	2004
9897	152	288.2	18984	0	0	0	0	0	0	0	0	0	1	0	0	2004
10234	148	257.0	5891	0	0	0	0	0	0	0	0	0	1	0	1	2004
10558	166	287.4	18301	0	0	0	0	0	0	0	0	0	1	0	0	2004
10266	131	291.9	21278	0	0	0	0	0	0	0	0	0	1	0	1	2004
10296	168	280.0	14758	0	0	0	0	0	0	0	0	0	0	1	0	2004
* 9643	139	232.9	62546	0	0	0	0	0	0	0	0	0	0	1	1	2004
9623	168	278.2	14601	0	0	0	0	0	0	0	0	0	0	1	0	2004
11173	168	243.2	64217	0	0	0	0	0	0	0	0	0	0	1	0	2004
9850	45	298.9	24346	0	0	0	0	0	0	0	0	0	0	0	0	2004
10615	143	272.3	12156	0	0	0	0	0	0	0	0	0	0	0	1	2004
10506	166	286.3	18246	0	0	0	0	0	0	0	0	0	0	0	0	2004
11312	24	236.3	59120	0	0	0	0	0	0	0	0	0	0	0	0	2004
* 8644	168	250.8	1572	1	0	0	0	0	0	0	0	0	0	0	0	2005
* 8266	168	285.0	16877	1	0	0	0	0	0	0	0	0	0	0	0	2005
* 8308	168	276.3	12709	1	0	0	0	0	0	0	0	0	0	0	0	2005
*16833	152	265.8	7601	1	0	0	0	0	0	0	0	0	0	0	0	2005
* 8086	167	289.6	19818	0	1	0	0	0	0	0	0	0	0	0	0	2005
10879	168	247.5	64878	0	1	0	0	0	0	0	0	0	0	0	0	2005
9957	168	235.5	58384	0	1	0	0	0	0	0	0	0	0	0	0	2005
10228	168	253.4	2246	0	1	0	0	0	0	0	0	0	0	0	0	2005
10781	168	268.8	8772	0	0	1	0	0	0	0	0	0	0	0	0	2005
* 9349	168	283.7	16270	0	0	1	0	0	0	0	0	0	0	0	0	2005
*11950	137	277.1	13710	0	0	1	0	0	0	0	0	0	0	0	1	2005
9532	168	274.0	11524	0	0	1	0	0	0	0	0	0	0	0	0	2005
10952	168	248.6	64741	0	0	1	0	0	0	0	0	0	0	0	0	2005
* 8634	167	286.4	18101	0	0	0	1	0	0	0	0	0	0	0	0	2005
* 8759	168	291.2	20106	0	0	0	1	0	0	0	0	0	0	0	0	2005
* 8925	167	263.9	7681	0	0	0	1	0	0	0	0	0	0	0	0	2005
*20445	97	249.3	2895	0	0	0	1	0	0	0	0	0	0	0	3	2005
10365	168	275.9	12688	0	0	0	0	1	0	0	0	0	0	0	0	2005
10584	168	265.1	8120	0	0	0	0	1	0	0	0	0	0	0	0	2005
10541	168	272.8	11652	0	0	0	0	1	0	0	0	0	0	0	0	2005
10629	168	284.8	17037	0	0	0	0	1	0	0	0	0	0	0	0	2005

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10629	168	253.4	2115	0	0	0	0	1	0	0	0	0	0	0	0	2005
10722	168	279.1	13970	0	0	0	0	0	1	0	0	0	0	0	0	2005
10776	139	261.2	4198	0	0	0	0	0	1	0	0	0	0	0	0	2005
10587	135	264.8	8582	0	0	0	0	0	1	0	0	0	0	0	1	2005
10445	144	274.2	12256	0	0	0	0	0	1	0	0	0	0	0	0	2005
10477	168	239.4	63010	0	0	0	0	0	0	1	0	0	0	0	0	2005
10958	160	252.7	4867	0	0	0	0	0	0	1	0	0	0	0	0	2005
10617	168	286.8	17926	0	0	0	0	0	0	1	0	0	0	0	0	2005
10714	168	290.3	19916	0	0	0	0	0	0	1	0	0	0	0	0	2005
9848	168	285.9	17619	0	0	0	0	0	0	0	1	0	0	0	0	2005
* 9057	166	276.6	13725	0	0	0	0	0	0	0	1	0	0	0	0	2005
* 9076	168	277.2	13856	0	0	0	0	0	0	0	1	0	0	0	0	2005
* 9199	168	285.6	17341	0	0	0	0	0	0	0	1	0	0	0	0	2005
*18340	133	269.0	11056	0	0	0	0	0	0	0	1	0	0	0	0	2005
* 8971	168	281.4	15203	0	0	0	0	0	0	0	0	1	0	0	0	2005
*11998	146	276.7	13996	0	0	0	0	0	0	0	0	1	0	0	0	2005
*13219	28	270.4	11736	0	0	0	0	0	0	0	0	1	0	0	0	2005
16439	30	88.0	8549	0	0	0	0	0	0	0	0	0	0	1	1	2005
*19524	140	175.1	35083	0	0	0	0	0	0	0	0	0	0	1	0	2005
*11898	138	254.0	2600	0	0	0	0	0	0	0	0	0	0	0	1	2005
9770	136	262.9	7895	0	0	0	0	0	0	0	0	0	0	0	1	2005
* 6647	168	294.7	21426	0	0	0	0	0	0	0	0	0	0	0	0	2005
10341	168	254.7	2701	0	0	0	0	0	0	0	0	0	0	0	0	2005
* 6389	24	258.8	3121	0	0	0	0	0	0	0	0	0	0	0	0	2005
* 7503	153	254.8	3673	1	0	0	0	0	0	0	0	0	0	0	0	2006
10788	168	279.3	13395	1	0	0	0	0	0	0	0	0	0	0	0	2006
10729	168	267.9	8415	1	0	0	0	0	0	0	0	0	0	0	0	2006
10870	168	252.8	720	1	0	0	0	0	0	0	0	0	0	0	0	2006
10520	168	263.8	6602	0	1	0	0	0	0	0	0	0	0	0	0	2006
10383	168	274.5	11076	0	1	0	0	0	0	0	0	0	0	0	0	2006
10364	168	276.9	12448	0	1	0	0	0	0	0	0	0	0	0	0	2006
10204	140	256.1	2005	0	1	0	0	0	0	0	0	0	0	0	1	2006
*11968	139	281.8	15718	0	0	1	0	0	0	0	0	0	0	0	1	2006
9727	168	280.5	14512	0	0	1	0	0	0	0	0	0	0	0	0	2006
9562	145	276.7	13330	0	0	1	0	0	0	0	0	0	0	0	0	2006
*10257	124	201.5	44671	0	0	0	0	1	0	0	0	0	0	0	1	2006
11344	168	240.3	60470	0	0	0	0	1	0	0	0	0	0	0	0	2006
10066	168	267.2	7727	0	0	0	0	1	0	0	0	0	0	0	0	2006
10498	168	288.6	17895	0	0	0	0	0	1	0	0	0	0	0	0	2006
10637	168	290.1	18754	0	0	0	0	0	1	0	0	0	0	0	0	2006
10514	168	287.3	17650	0	0	0	0	0	1	0	0	0	0	0	0	2006
10469	144	293.3	20572	0	0	0	0	0	1	0	0	0	0	0	0	2006
10607	168	290.0	18975	0	0	0	0	0	0	1	0	0	0	0	0	2006
10493	168	291.9	19942	0	0	0	0	0	0	1	0	0	0	0	0	2006
10545	168	279.2	14117	0	0	0	0	0	0	1	0	0	0	0	0	2006
10329	168	291.8	19716	0	0	0	0	0	0	1	0	0	0	0	0	2006
10322	168	290.3	18792	0	0	0	0	0	0	0	1	0	0	0	0	2006

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10820	134	271.7	11193	0	0	0	0	0	0	0	1	0	0	0	1	2006
10423	168	295.9	22058	0	0	0	0	0	0	0	1	0	0	0	0	2006
10400	168	291.9	19747	0	0	0	0	0	0	0	1	0	0	0	0	2006
10534	168	290.9	19215	0	0	0	0	0	0	0	1	0	0	0	0	2006
10879	105	266.3	9346	0	0	0	0	0	0	0	0	1	0	0	2	2006
10677	168	280.3	13798	0	0	0	0	0	0	0	0	1	0	0	0	2006
10503	168	259.5	3112	0	0	0	0	0	0	0	0	1	0	0	0	2006
10515	168	266.8	7001	0	0	0	0	0	0	0	0	1	0	0	0	2006
10406	168	281.3	13746	0	0	0	0	0	0	0	0	0	1	0	0	2006
10268	168	277.4	11948	0	0	0	0	0	0	0	0	0	1	0	0	2006
10408	168	275.6	10793	0	0	0	0	0	0	0	0	0	1	0	0	2006
10273	157	262.1	6195	0	0	0	0	0	0	0	0	0	1	0	0	2006
10453	95	260.8	5803	0	0	0	0	0	0	0	0	0	1	0	1	2006
10529	168	278.6	12720	0	0	0	0	0	0	0	0	0	0	1	0	2006
10263	168	259.5	2766	0	0	0	0	0	0	0	0	0	0	1	0	2006
10380	168	281.1	13751	0	0	0	0	0	0	0	0	0	0	1	0	2006
10275	168	271.4	9087	0	0	0	0	0	0	0	0	0	0	1	0	2006
10420	168	273.8	10354	0	0	0	0	0	0	0	0	0	0	0	0	2006
10346	118	259.9	3846	0	0	0	0	0	0	0	0	0	0	0	0	2006
*16417	62	120.0	14784	0	0	0	0	0	0	0	0	0	0	0	1	2006
11148	168	185.3	36836	0	0	0	0	0	0	0	0	0	0	0	0	2006
* 9881	24	176.2	32896	0	0	0	0	0	0	0	0	0	0	0	0	2006
10465	168	204.2	44974	1	0	0	0	0	0	0	0	0	0	0	0	2007
10532	168	193.4	39419	1	0	0	0	0	0	0	0	0	0	0	0	2007
10423	168	239.3	59467	1	0	0	0	0	0	0	0	0	0	0	0	2007
10643	168	250.2	65107	1	0	0	0	0	0	0	0	0	0	0	0	2007
*12129	126	256.4	3291	0	1	0	0	0	0	0	0	0	0	0	1	2007
10392	168	234.8	58029	0	1	0	0	0	0	0	0	0	0	0	0	2007
10234	168	263.8	6783	0	1	0	0	0	0	0	0	0	0	0	0	2007
10373	168	239.4	59224	0	1	0	0	0	0	0	0	0	0	0	0	2007
10523	168	228.5	53847	0	0	1	0	0	0	0	0	0	0	0	0	2007
10479	167	239.1	60368	0	0	1	0	0	0	0	0	0	0	0	0	2007
10524	168	238.8	60353	0	0	1	0	0	0	0	0	0	0	0	0	2007
10502	168	242.4	62769	0	0	1	0	0	0	0	0	0	0	0	0	2007
10745	168	243.8	63142	0	0	1	0	0	0	0	0	0	0	0	0	2007
10741	168	237.5	59399	0	0	0	1	0	0	0	0	0	0	0	0	2007
10141	168	265.6	6719	0	0	0	1	0	0	0	0	0	0	0	0	2007
10222	168	252.5	382	0	0	0	1	0	0	0	0	0	0	0	0	2007
11057	95	239.6	60606	0	0	0	1	0	0	0	0	0	0	0	0	2007
10931	167	235.5	59031	0	0	0	0	1	0	0	0	0	0	0	1	2007
10648	168	241.6	62389	0	0	0	0	1	0	0	0	0	0	0	0	2007
10784	168	230.2	57342	0	0	0	0	1	0	0	0	0	0	0	0	2007
10667	168	233.9	58658	0	0	0	0	1	0	0	0	0	0	0	0	2007
10784	168	250.8	1451	0	0	0	0	0	1	0	0	0	0	0	0	2007
10676	168	275.2	11700	0	0	0	0	0	1	0	0	0	0	0	0	2007
10782	168	266.5	8063	0	0	0	0	0	1	0	0	0	0	0	0	2007
10791	168	262.3	5393	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10478	120	278.3	12931	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 6 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10406	139	377.9	26238	0	0	0	0	0	0	1	0	0	0	0	1	2004
10399	168	406.5	44776	0	0	0	0	0	0	1	0	0	0	0	0	2004
10450	136	372.8	24340	0	0	0	0	0	0	1	0	0	0	0	1	2004
10319	168	413.9	49849	0	0	0	0	0	0	1	0	0	0	0	0	2004
10688	162	359.8	14783	0	0	0	0	0	0	0	1	0	0	0	0	2004
10879	168	296.0	24387	0	0	0	0	0	0	0	1	0	0	0	0	2004
10410	168	413.3	49499	0	0	0	0	0	0	0	1	0	0	0	0	2004
10338	168	448.8	8948	0	0	0	0	0	0	0	1	0	0	0	0	2004
10383	147	429.3	62430	0	0	0	0	0	0	0	1	0	0	0	0	2004
10334	168	387.6	32273	0	0	0	0	0	0	0	0	1	0	0	0	2004
10478	168	384.0	30326	0	0	0	0	0	0	0	0	1	0	0	0	2004
*15913	4	30.0	2630	0	0	0	0	0	0	0	0	1	0	0	0	2004
10774	91	397.8	38711	0	0	0	0	0	0	0	0	1	0	0	1	2004
10366	168	441.4	4042	0	0	0	0	0	0	0	0	0	1	0	0	2004
10525	168	369.8	21088	0	0	0	0	0	0	0	0	0	1	0	0	2004
10317	168	436.3	649	0	0	0	0	0	0	0	0	0	1	0	0	2004
10459	168	468.4	23070	0	0	0	0	0	0	0	0	0	1	0	0	2004
10493	137	447.4	8803	0	0	0	0	0	0	0	0	0	1	0	1	2004
10223	168	450.7	10122	0	0	0	0	0	0	0	0	0	0	1	0	2004
10214	168	463.7	19382	0	0	0	0	0	0	0	0	0	0	1	0	2004
10281	168	442.1	4651	0	0	0	0	0	0	0	0	0	0	1	0	2004
10357	168	410.4	47081	0	0	0	0	0	0	0	0	0	0	1	0	2004
10165	168	461.8	18458	0	0	0	0	0	0	0	0	0	0	0	0	2004
10187	168	431.9	62199	0	0	0	0	0	0	0	0	0	0	0	0	2004
10179	168	451.6	10664	0	0	0	0	0	0	0	0	0	0	0	0	2004
10448	168	457.8	15997	0	0	0	0	0	0	0	0	0	0	0	0	2004
10006	24	400.8	35669	0	0	0	0	0	0	0	0	0	0	0	0	2004
11377	168	409.0	44831	1	0	0	0	0	0	0	0	0	0	0	0	2005
* 8439	168	462.4	18274	1	0	0	0	0	0	0	0	0	0	0	0	2005
10390	168	457.6	14197	1	0	0	0	0	0	0	0	0	0	0	0	2005
10474	167	456.2	13598	1	0	0	0	0	0	0	0	0	0	0	0	2005
* 5180	47	215.2	49335	0	0	0	1	0	0	0	0	0	0	0	1	2005
*16597	156	202.5	42371	0	0	0	1	0	0	0	0	0	0	0	0	2005
12816	113	213.8	46622	0	0	0	1	0	0	0	0	0	0	0	1	2005
*10701	168	203.3	42704	0	0	0	0	1	0	0	0	0	0	0	0	2005
11455	168	178.5	32498	0	0	0	0	1	0	0	0	0	0	0	0	2005
11492	144	183.5	33896	0	0	0	0	1	0	0	0	0	0	0	0	2005
*15081	9	207.4	53436	0	0	0	0	1	0	0	0	0	0	0	1	2005
12472	124	253.9	840	0	0	0	0	1	0	0	0	0	0	0	1	2005
10893	168	277.3	11386	0	0	0	0	0	1	0	0	0	0	0	0	2005
10891	99	274.2	11943	0	0	0	0	0	1	0	0	0	0	0	1	2005
11026	168	273.1	9515	0	0	0	0	0	1	0	0	0	0	0	0	2005
11265	144	255.3	769	0	0	0	0	0	1	0	0	0	0	0	0	2005
10962	168	281.6	13822	0	0	0	0	0	0	1	0	0	0	0	0	2005
10965	58	255.6	1875	0	0	0	0	0	0	1	0	0	0	0	0	2005
12778	138	156.1	28846	0	0	0	0	0	0	1	0	0	0	0	1	2005
11144	168	278.5	12014	0	0	0	0	0	0	0	1	0	0	0	0	2005

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11190	168	278.4	11955	0	0	0	0	0	0	0	1	0	0	0	0	2005
11106	168	275.6	10569	0	0	0	0	0	0	0	1	0	0	0	0	2005
10992	168	277.6	11504	0	0	0	0	0	0	0	1	0	0	0	0	2005
10958	168	276.6	11034	0	0	0	0	0	0	0	1	0	0	0	0	2005
12434	143	267.9	7278	0	0	0	0	0	0	0	0	1	0	0	0	2005
9788	66	443.2	4160	0	0	0	0	0	0	0	0	1	0	0	1	2005
9902	168	437.8	873	0	0	0	0	0	0	0	0	1	0	0	0	2005
*11801	129	452.5	12315	0	0	0	0	0	0	0	0	1	0	0	1	2005
11090	164	378.6	22266	0	0	0	0	0	0	0	0	0	1	0	0	2005
10245	157	452.6	11950	0	0	0	0	0	0	0	0	0	1	0	0	2005
10300	150	438.7	1059	0	0	0	0	0	0	0	0	0	1	0	0	2005
10299	168	462.1	18247	0	0	0	0	0	0	0	0	0	1	0	0	2005
* 9188	169	455.7	14435	0	0	0	0	0	0	0	0	0	1	0	0	2005
*21874	109	413.6	51114	0	0	0	0	0	0	0	0	0	0	1	1	2005
* 7814	168	462.2	18698	0	0	0	0	0	0	0	0	0	0	1	0	2005
* 7759	168	461.6	17839	0	0	0	0	0	0	0	0	0	0	1	0	2005
* 9370	168	442.6	3529	0	0	0	0	0	0	0	0	0	0	1	0	2005
10952	168	426.9	57542	0	0	0	0	0	0	0	0	0	0	0	0	2005
10368	168	466.8	21562	0	0	0	0	0	0	0	0	0	0	0	0	2005
10353	168	458.6	16090	0	0	0	0	0	0	0	0	0	0	0	0	2005
10324	168	437.9	65497	0	0	0	0	0	0	0	0	0	0	0	0	2005
10287	24	438.0	65125	0	0	0	0	0	0	0	0	0	0	0	0	2005
10061	168	433.3	61617	1	0	0	0	0	0	0	0	0	0	0	0	2006
10088	168	455.9	12042	1	0	0	0	0	0	0	0	0	0	0	0	2006
10124	168	458.1	14385	1	0	0	0	0	0	0	0	0	0	0	0	2006
10206	168	442.0	1179	1	0	0	0	0	0	0	0	0	0	0	0	2006
10278	96	432.4	60120	0	1	0	0	0	0	0	0	0	0	0	0	2006
10477	146	425.0	54423	0	1	0	0	0	0	0	0	0	0	0	1	2006
10343	168	464.8	19881	0	1	0	0	0	0	0	0	0	0	0	0	2006
10367	168	459.3	15325	0	1	0	0	0	0	0	0	0	0	0	0	2006
10404	168	466.4	21012	0	0	1	0	0	0	0	0	0	0	0	0	2006
10512	168	459.2	15233	0	0	1	0	0	0	0	0	0	0	0	0	2006
10475	168	457.9	13811	0	0	1	0	0	0	0	0	0	0	0	0	2006
10562	168	463.5	18877	0	0	1	0	0	0	0	0	0	0	0	0	2006
10946	140	388.6	25562	0	0	1	0	0	0	0	0	0	0	0	1	2006
11428	144	401.8	32380	0	0	0	1	0	0	0	0	0	0	0	0	2006
10003	165	442.7	2955	0	0	0	1	0	0	0	0	0	0	0	1	2006
10161	168	465.5	20138	0	0	0	1	0	0	0	0	0	0	0	0	2006
10121	168	459.9	15693	0	0	0	1	0	0	0	0	0	0	0	0	2006
9849	168	445.0	3855	0	0	0	0	1	0	0	0	0	0	0	0	2006
9867	168	450.2	7480	0	0	0	0	1	0	0	0	0	0	0	0	2006
9813	168	463.3	18438	0	0	0	0	1	0	0	0	0	0	0	0	2006
*11598	145	449.3	8015	0	0	0	0	1	0	0	0	0	0	0	0	2006
11022	119	407.7	47986	0	0	0	0	1	0	0	0	0	0	0	1	2006
10533	168	450.1	8498	0	0	0	0	0	1	0	0	0	0	0	0	2006
10485	168	464.4	19753	0	0	0	0	0	1	0	0	0	0	0	0	2006
10712	168	453.7	10649	0	0	0	0	0	1	0	0	0	0	0	0	2006

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10745	86	368.7	12867	0	0	0	0	0	1	0	0	0	0	0	1	2006
10669	168	372.4	14413	0	0	0	0	0	0	1	0	0	0	0	0	2006
10450	168	450.7	7635	0	0	0	0	0	0	1	0	0	0	0	0	2006
10551	168	458.5	14160	0	0	0	0	0	0	1	0	0	0	0	0	2006
10633	168	438.4	1040	0	0	0	0	0	0	1	0	0	0	0	0	2006
10968	60	396.2	36741	0	0	0	0	0	0	0	1	0	0	0	1	2006
10754	168	436.7	61663	0	0	0	0	0	0	0	1	0	0	0	0	2006
10783	142	442.2	300	0	0	0	0	0	0	0	1	0	0	0	0	2006
10850	163	420.0	52090	0	0	0	0	0	0	0	1	0	0	0	1	2006
10709	168	441.4	64603	0	0	0	0	0	0	0	1	0	0	0	0	2006
10564	168	436.1	60883	0	0	0	0	0	0	0	0	1	0	0	0	2006
10639	168	427.0	54335	0	0	0	0	0	0	0	0	1	0	0	0	2006
10613	168	421.5	50310	0	0	0	0	0	0	0	0	1	0	0	0	2006
10507	168	420.8	50044	0	0	0	0	0	0	0	0	1	0	0	0	2006
10694	134	378.2	23697	0	0	0	0	0	0	0	0	0	1	0	1	2006
10369	168	442.2	1523	0	0	0	0	0	0	0	0	0	1	0	0	2006
10678	168	411.5	40771	0	0	0	0	0	0	0	0	0	1	0	0	2006
10379	168	453.5	9657	0	0	0	0	0	0	0	0	0	1	0	0	2006
10485	169	446.2	3691	0	0	0	0	0	0	0	0	0	1	0	0	2006
*10575	3	208.7	60203	0	0	0	0	0	0	0	0	0	0	1	0	2006
14937	18	131.6	19802	0	0	0	0	0	0	0	0	0	0	1	0	2006
10397	168	425.0	55548	0	0	0	0	0	0	0	0	0	0	0	0	2006
10387	168	442.3	1293	0	0	0	0	0	0	0	0	0	0	0	0	2006
10292	168	427.6	57379	0	0	0	0	0	0	0	0	0	0	0	0	2006
10318	168	410.0	42591	0	0	0	0	0	0	0	0	0	0	0	0	2006
10231	24	397.2	30005	0	0	0	0	0	0	0	0	0	0	0	0	2006
10538	168	390.5	26847	1	0	0	0	0	0	0	0	0	0	0	0	2007
10495	168	415.2	46610	1	0	0	0	0	0	0	0	0	0	0	0	2007
10281	168	425.3	53672	1	0	0	0	0	0	0	0	0	0	0	0	2007
10666	168	429.2	58239	1	0	0	0	0	0	0	0	0	0	0	0	2007
10007	168	442.2	1278	0	1	0	0	0	0	0	0	0	0	0	0	2007
9439	168	438.5	63323	0	1	0	0	0	0	0	0	0	0	0	0	2007
9809	63	374.5	20798	0	1	0	0	0	0	0	0	0	0	0	1	2007
*11746	168	422.3	50997	0	1	0	0	0	0	0	0	0	0	0	0	2007
11325	168	404.6	39145	0	0	1	0	0	0	0	0	0	0	0	0	2007
10552	167	428.9	56816	0	0	1	0	0	0	0	0	0	0	0	0	2007
10661	168	426.5	55519	0	0	1	0	0	0	0	0	0	0	0	0	2007
10752	168	412.7	43266	0	0	1	0	0	0	0	0	0	0	0	0	2007
10819	168	413.9	41459	0	0	1	0	0	0	0	0	0	0	0	0	2007
10880	168	389.3	22195	0	0	0	1	0	0	0	0	0	0	0	0	2007
11309	48	377.2	15296	0	0	0	1	0	0	0	0	0	0	0	0	2007
10657	156	434.1	62723	0	0	0	1	0	0	0	0	0	0	0	1	2007
10549	136	440.6	49	0	0	0	0	1	0	0	0	0	0	0	0	2007
10780	161	402.3	38824	0	0	0	0	1	0	0	0	0	0	0	1	2007
10730	168	410.7	43380	0	0	0	0	1	0	0	0	0	0	0	0	2007
10666	164	397.9	36491	0	0	0	0	1	0	0	0	0	0	0	0	2007
10848	168	432.0	60288	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11198	168	437.3	63944	0	0	0	0	0	1	0	0	0	0	0	0	2007
11017	168	443.5	3296	0	0	0	0	0	1	0	0	0	0	0	0	2007
11123	168	446.7	5409	0	0	0	0	0	1	0	0	0	0	0	0	2007
* 1502	14	448.6	7103	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
•	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10344	168	125.2	17493	0	0	0	0	0	0	1	0	0	0	0	0	2004
10178	168	134.1	19565	0	0	0	0	0	0	1	0	0	0	0	0	2004
10172	168	130.2	18570	0	0	0	0	0	0	1	0	0	0	0	0	2004
10013	168	138.3	20555	0	0	0	0	0	0	1	0	0	0	0	0	2004
9873	168	140.1	20952	0	0	0	0	0	0	0	1	0	0	0	0	2004
9928	168	136.5	19970	0	0	0	0	0	0	0	1	0	0	0	0	2004
9925	168	136.9	20126	0	0	0	0	0	0	0	1	0	0	0	0	2004
10183	168	150.1	23160	0	0	0	0	0	0	0	1	0	0	0	0	2004
10267	168	152.8	23870	0	0	0	0	0	0	0	1	0	0	0	0	2004
10310	168	124.2	17238	0	0	0	0	0	0	0	0	1	0	0	0	2004
10336	168	125.0	17445	0	0	0	0	0	0	0	0	1	0	0	0	2004
10360	168	121.8	16755	0	0	0	0	0	0	0	0	1	0	0	0	2004
10079	166	140.0	20897	0	0	0	0	0	0	0	0	1	0	0	0	2004
10082	168	151.4	23550	0	0	0	0	0	0	0	0	0	1	0	0	2004
9929	168	156.9	24857	0	0	0	0	0	0	0	0	0	1	0	0	2004
10007	168	146.4	22220	0	0	0	0	0	0	0	0	0	1	0	0	2004
9919	168	149.8	23157	0	0	0	0	0	0	0	0	0	1	0	0	2004
9795	169	152.8	24007	0	0	0	0	0	0	0	0	0	1	0	0	2004
9852	47	148.8	22986	0	0	0	0	0	0	0	0	0	0	1	0	2004
10622	104	137.6	20429	0	0	0	0	0	0	0	0	0	0	1	1	2004
10393	168	140.9	20712	0	0	0	0	0	0	0	0	0	0	1	0	2004
10224	168	153.2	24007	0	0	0	0	0	0	0	0	0	0	0	0	2004
10409	168	136.8	20185	0	0	0	0	0	0	0	0	0	0	0	0	2004
10283	168	153.1	23813	0	0	0	0	0	0	0	0	0	0	0	0	2004
10414	168	152.6	23712	0	0	0	0	0	0	0	0	0	0	0	0	2004
10131	24	131.0	17776	0	0	0	0	0	0	0	0	0	0	0	0	2004
10375	168	137.2	20076	1	0	0	0	0	0	0	0	0	0	0	0	2005
10196	168	155.4	24395	1	0	0	0	0	0	0	0	0	0	0	0	2005
10330	168	154.6	24241	1	0	0	0	0	0	0	0	0	0	0	0	2005
10285	168	153.2	23730	1	0	0	0	0	0	0	0	0	0	0	0	2005
10326	168	158.0	25090	0	1	0	0	0	0	0	0	0	0	0	0	2005
10332	168	130.9	18186	0	1	0	0	0	0	0	0	0	0	0	0	2005
10320	168	123.2	16063	0	1	0	0	0	0	0	0	0	0	0	0	2005
10217	168	128.4	17567	0	1	0	0	0	0	0	0	0	0	0	0	2005
10194	168	150.4	23138	0	0	1	0	0	0	0	0	0	0	0	0	2005
10258	168	151.7	23605	0	0	1	0	0	0	0	0	0	0	0	0	2005
10176	168	156.3	24648	0	0	1	0	0	0	0	0	0	0	0	0	2005
10210	168	149.8	23068	0	0	1	0	0	0	0	0	0	0	0	0	2005
10281	93	141.1	20866	0	0	1	0	0	0	0	0	0	0	0	0	2005
10559	159	139.3	21117	0	0	0	1	0	0	0	0	0	0	0	1	2005
10259	168	154.2	24128	0	0	0	1	0	0	0	0	0	0	0	0	2005
10233	168	153.4	23948	0	0	0	1	0	0	0	0	0	0	0	0	2005
10267	168	157.4	24948	0	0	0	1	0	0	0	0	0	0	0	0	2005
10280	168	148.1	22542	0	0	0	0	1	0	0	0	0	0	0	0	2005
10255	168	144.3	21791	0	0	0	0	1	0	0	0	0	0	0	0	2005
10243	168	145.6	22114	0	0	0	0	1	0	0	0	0	0	0	0	2005
10334	168	150.5	23310	0	0	0	0	1	0	0	0	0	0	0	0	2005

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10266	168	141.1	21014	0	0	0	0	1	0	0	0	0	0	0	0	2005
10253	168	149.4	22910	0	0	0	0	0	1	0	0	0	0	0	0	2005
10369	168	150.7	23337	0	0	0	0	0	1	0	0	0	0	0	0	2005
10363	168	143.5	21699	0	0	0	0	0	1	0	0	0	0	0	0	2005
10306	144	151.5	23552	0	0	0	0	0	1	0	0	0	0	0	0	2005
10274	168	154.3	24152	0	0	0	0	0	0	1	0	0	0	0	0	2005
10468	168	145.9	22211	0	0	0	0	0	0	1	0	0	0	0	0	2005
10510	168	140.6	21022	0	0	0	0	0	0	1	0	0	0	0	0	2005
10545	168	137.4	20270	0	0	0	0	0	0	1	0	0	0	0	0	2005
10484	168	148.3	22834	0	0	0	0	0	0	0	1	0	0	0	0	2005
10380	168	142.3	21449	0	0	0	0	0	0	0	1	0	0	0	0	2005
10503	168	148.3	22831	0	0	0	0	0	0	0	1	0	0	0	0	2005
10436	168	151.8	23594	0	0	0	0	0	0	0	1	0	0	0	0	2005
10382	168	149.9	23154	0	0	0	0	0	0	0	1	0	0	0	0	2005
10443	168	143.4	21559	0	0	0	0	0	0	0	0	1	0	0	0	2005
10418	168	137.4	20311	0	0	0	0	0	0	0	0	1	0	0	0	2005
10629	168	139.9	20780	0	0	0	0	0	0	0	0	1	0	0	0	2005
10500	168	144.2	21895	0	0	0	0	0	0	0	0	1	0	0	0	2005
10285	168	158.3	25281	0	0	0	0	0	0	0	0	0	1	0	0	2005
10414	168	158.9	25401	0	0	0	0	0	0	0	0	0	1	0	0	2005
10496	168	154.8	24368	0	0	0	0	0	0	0	0	0	1	0	0	2005
10163	24	147.4	23067	0	0	0	0	0	0	0	0	0	1	0	0	2005
10366	135	155.9	24827	0	0	0	0	0	0	0	0	0	0	1	1	2005
10178	168	155.9	24528	0	0	0	0	0	0	0	0	0	0	1	0	2005
10224	168	157.0	24751	0	0	0	0	0	0	0	0	0	0	1	0	2005
10043	168	157.7	25018	0	0	0	0	0	0	0	0	0	0	0	0	2005
10106	168	159.3	25449	0	0	0	0	0	0	0	0	0	0	0	0	2005
10113	168	155.0	24326	0	0	0	0	0	0	0	0	0	0	0	0	2005
10305	168	149.7	22940	0	0	0	0	0	0	0	0	0	0	0	0	2005
10186	24	159.4	25430	0	0	0	0	0	0	0	0	0	0	0	0	2005
10379	168	148.2	22622	1	0	0	0	0	0	0	0	0	0	0	0	2006
10208	168	153.9	23993	1	0	0	0	0	0	0	0	0	0	0	0	2006
10299	168	155.4	24408	1	0	0	0	0	0	0	0	0	0	0	0	2006
10309	168	150.2	22936	1	0	0	0	0	0	0	0	0	0	0	0	2006
10263	168	147.3	22290	0	1	0	0	0	0	0	0	0	0	0	0	2006
10314	168	154.0	23943	0	1	0	0	0	0	0	0	0	0	0	0	2006
10264	168	158.7	25227	0	1	0	0	0	0	0	0	0	0	0	0	2006
10241	168	155.3	24367	0	1	0	0	0	0	0	0	0	0	0	0	2006
10152	168	153.2	23768	0	0	1	0	0	0	0	0	0	0	0	0	2006
10248	168	154.0	23992	0	0	1	0	0	0	0	0	0	0	0	0	2006
10159	168	156.5	24712	0	0	1	0	0	0	0	0	0	0	0	0	2006
10153	168	159.6	25548	0	0	1	0	0	0	0	0	0	0	0	0	2006
10073	168	156.6	24816	0	0	1	0	0	0	0	0	0	0	0	0	2006
10178	167	158.3	25368	0	0	0	1	0	0	0	0	0	0	0	0	2006
10194	168	147.5	22687	0	0	0	1	0	0	0	0	0	0	0	0	2006
10334	168	156.7	24791	0	0	0	1	0	0	0	0	0	0	0	0	2006
10012	168	158.4	25192	0	0	0	1	0	0	0	0	0	0	0	0	2006

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9955	145	148.6	22863	0	0	0	0	1	0	0	0	0	0	0	0	2006
10142	94	139.2	20719	0	0	0	0	1	0	0	0	0	0	0	1	2006
10253	168	149.2	22798	0	0	0	0	1	0	0	0	0	0	0	0	2006
10309	168	150.2	23052	0	0	0	0	1	0	0	0	0	0	0	0	2006
10362	168	154.8	24216	0	0	0	0	1	0	0	0	0	0	0	0	2006
10433	168	149.8	22924	0	0	0	0	0	1	0	0	0	0	0	0	2006
10559	168	152.5	23618	0	0	0	0	0	1	0	0	0	0	0	0	2006
10497	168	148.5	22625	0	0	0	0	0	1	0	0	0	0	0	0	2006
10460	144	155.3	24340	0	0	0	0	0	1	0	0	0	0	0	0	2006
10469	168	152.9	23717	0	0	0	0	0	0	1	0	0	0	0	0	2006
10548	168	146.9	22181	0	0	0	0	0	0	1	0	0	0	0	0	2006
10426	168	152.0	23390	0	0	0	0	0	0	1	0	0	0	0	0	2006
10518	137	142.4	21064	0	0	0	0	0	0	1	0	0	0	0	1	2006
10300	168	155.9	24422	0	0	0	0	0	0	0	1	0	0	0	0	2006
10370	168	150.2	22947	0	0	0	0	0	0	0	1	0	0	0	0	2006
10224	168	153.6	23900	0	0	0	0	0	0	0	1	0	0	0	0	2006
10361	168	148.0	22351	0	0	0	0	0	0	0	1	0	0	0	0	2006
10127	168	154.8	24242	0	0	0	0	0	0	0	1	0	0	0	0	2006
10255	168	152.2	23509	0	0	0	0	0	0	0	0	1	0	0	0	2006
10277	168	145.9	22145	0	0	0	0	0	0	0	0	1	0	0	0	2006
10506	112	137.8	20320	0	0	0	0	0	0	0	0	1	0	0	1	2006
11037	20	80.3	7079	0	0	0	0	0	0	0	0	1	0	0	0	2006
10360	146	143.3	21267	0	0	0	0	0	0	0	0	0	1	0	1	2006
10276	168	151.2	23315	0	0	0	0	0	0	0	0	0	1	0	0	2006
10264	168	146.4	22068	0	0	0	0	0	0	0	0	0	1	0	0	2006
10196	168	138.4	19927	0	0	0	0	0	0	0	0	0	1	0	0	2006
10572	121	106.5	11688	0	0	0	0	0	0	0	0	0	1	0	0	2006
10439	140	146.7	22082	0	0	0	0	0	0	0	0	0	0	1	1	2006
10249	168	150.4	22946	0	0	0	0	0	0	0	0	0	0	1	0	2006
10199	168	156.7	24743	0	0	0	0	0	0	0	0	0	0	1	0	2006
10243	168	150.4	22891	0	0	0	0	0	0	0	0	0	0	1	0	2006
10215	168	145.0	21326	0	0	0	0	0	0	0	0	0	0	0	0	2006
10229	168	144.4	21141	0	0	0	0	0	0	0	0	0	0	0	0	2006
10308	168	146.5	21828	0	0	0	0	0	0	0	0	0	0	0	0	2006
10330	168	134.6	18396	0	0	0	0	0	0	0	0	0	0	0	0	2006
10308	24	128.0	16576	0	0	0	0	0	0	0	0	0	0	0	0	2006
10263	168	133.8	18206	1	0	0	0	0	0	0	0	0	0	0	0	2007
10365	168	125.1	15779	1	0	0	0	0	0	0	0	0	0	0	0	2007
10410	168	132.9	17911	1	0	0	0	0	0	0	0	0	0	0	0	2007
10402	168	137.4	19325	1	0	0	0	0	0	0	0	0	0	0	0	2007
10322	168	143.1	20800	0	1	0	0	0	0	0	0	0	0	0	0	2007
10334	168	138.9	19662	0	1	0	0	0	0	0	0	0	0	0	0	2007
10297	168	144.7	21275	0	1	0	0	0	0	0	0	0	0	0	0	2007
10300	168	127.8	16908	0	1	0	0	0	0	0	0	0	0	0	0	2007
10437	168	125.1	16207	0	0	1	0	0	0	0	0	0	0	0	0	2007
10307	121	142.4	20630	0	0	1	0	0	0	0	0	0	0	0	0	2007
11053	99	112.9	16908	0	0	0	0	1	0	0	0	0	0	0	1	2007

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10182	168	143.9	21100	0	0	0	0	1	0	0	0	0	0	0	0	2007
10146	168	139.5	19960	0	0	0	0	1	0	0	0	0	0	0	0	2007
10222	168	144.2	21308	0	0	0	0	0	1	0	0	0	0	0	0	2007
10192	168	153.4	23787	0	0	0	0	0	1	0	0	0	0	0	0	2007
10176	168	149.1	22635	0	0	0	0	0	1	0	0	0	0	0	0	2007
10203	168	147.8	22281	0	0	0	0	0	1	0	0	0	0	0	0	2007
10341	120	148.8	22531	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
•	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10432	168	141.0	22500	0	0	0	0	0	0	1	0	0	0	0	0	2004
10360	168	150.6	25021	0	0	0	0	0	0	1	0	0	0	0	0	2004
10435	168	145.9	23827	0	0	0	0	0	0	1	0	0	0	0	0	2004
10395	168	154.9	26008	0	0	0	0	0	0	1	0	0	0	0	0	2004
10431	168	157.9	26785	0	0	0	0	0	0	0	1	0	0	0	0	2004
10498	168	154.9	25860	0	0	0	0	0	0	0	1	0	0	0	0	2004
10550	168	154.2	25720	0	0	0	0	0	0	0	1	0	0	0	0	2004
10345	168	172.2	30424	0	0	0	0	0	0	0	1	0	0	0	0	2004
10414	168	172.4	30364	0	0	0	0	0	0	0	1	0	0	0	0	2004
10351	168	139.0	21964	0	0	0	0	0	0	0	0	1	0	0	0	2004
10574	168	141.5	22579	0	0	0	0	0	0	0	0	1	0	0	0	2004
10648	168	133.7	20841	0	0	0	0	0	0	0	0	1	0	0	0	2004
10422	167	161.0	27523	0	0	0	0	0	0	0	0	1	0	0	0	2004
10418	168	172.7	30663	0	0	0	0	0	0	0	0	0	1	0	0	2004
10376	168	178.2	32127	0	0	0	0	0	0	0	0	0	1	0	0	2004
10436	168	169.3	29676	0	0	0	0	0	0	0	0	0	1	0	0	2004
10404	168	172.6	30605	0	0	0	0	0	0	0	0	0	1	0	0	2004
10409	169	173.9	31149	0	0	0	0	0	0	0	0	0	1	0	0	2004
10622	139	169.7	29937	0	0	0	0	0	0	0	0	0	0	1	1	2004
10537	168	179.9	32579	0	0	0	0	0	0	0	0	0	0	1	0	2004
10466	168	168.6	29692	0	0	0	0	0	0	0	0	0	0	1	0	2004
10590	168	156.2	25744	0	0	0	0	0	0	0	0	0	0	1	0	2004
10504	168	176.9	31868	0	0	0	0	0	0	0	0	0	0	0	0	2004
10564	168	163.5	28049	0	0	0	0	0	0	0	0	0	0	0	0	2004
10542	168	173.6	30685	0	0	0	0	0	0	0	0	0	0	0	0	2004
10620	168	173.8	30690	0	0	0	0	0	0	0	0	0	0	0	0	2004
10492	24	142.1	21342	0	0	0	0	0	0	0	0	0	0	0	0	2004
10580	168	154.9	25792	1	0	0	0	0	0	0	0	0	0	0	0	2005
10430	168	176.6	31521	1	0	0	0	0	0	0	0	0	0	0	0	2005
10407	168	176.5	31524	1	0	0	0	0	0	0	0	0	0	0	0	2005
10417	168	170.1	29673	1	0	0	0	0	0	0	0	0	0	0	0	2005
10394	168	177.6	31876	0	1	0	0	0	0	0	0	0	0	0	0	2005
10600	168	149.7	23814	0	1	0	0	0	0	0	0	0	0	0	0	2005
10523	157	141.5	21501	0	1	0	0	0	0	0	0	0	0	0	0	2005
12474	20	114.9	17713	0	0	0	1	0	0	0	0	0	0	0	1	2005
10488	107	175.1	31910	0	0	0	0	1	0	0	0	0	0	0	1	2005
10294	168	175.5	32103	0	0	0	0	1	0	0	0	0	0	0	0	2005
10241	168	179.1	33152	0	0	0	0	1	0	0	0	0	0	0	0	2005
10205	168	163.6	28557	0	0	0	0	1	0	0	0	0	0	0	0	2005
10144	168	177.1	32239	0	0	0	0	0	1	0	0	0	0	0	0	2005
10287	168	177.2	32406	0	0	0	0	0	1	0	0	0	0	0	0	2005
10361	168	166.5	29840	0	0	0	0	0	1	0	0	0	0	0	0	2005
10340	135	177.0	32486	0	0	0	0	0	1	0	0	0	0	0	0	2005
10264	168	180.1	33492	0	0	0	0	0	0	1	0	0	0	0	0	2005
10218	168	172.5	31280	0	0	0	0	0	0	1	0	0	0	0	0	2005
10349	168	163.1	28827	0	0	0	0	0	0	1	0	0	0	0	0	2005
10224	168	157.3	27257	0	0	0	0	0	0	1	0	0	0	0	0	2005

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10310	168	173.7	31616	0	0	0	0	0	0	0	1	0	0	0	0	2005
10282	168	167.3	29986	0	0	0	0	0	0	0	1	0	0	0	0	2005
10221	168	173.6	31693	0	0	0	0	0	0	0	1	0	0	0	0	2005
10263	168	183.4	34172	0	0	0	0	0	0	0	1	0	0	0	0	2005
10431	168	175.4	31945	0	0	0	0	0	0	0	1	0	0	0	0	2005
10383	168	174.5	31585	0	0	0	0	0	0	0	0	1	0	0	0	2005
10275	168	161.7	28634	0	0	0	0	0	0	0	0	1	0	0	0	2005
10412	168	165.6	29468	0	0	0	0	0	0	0	0	1	0	0	0	2005
10351	168	172.1	31431	0	0	0	0	0	0	0	0	1	0	0	0	2005
10258	168	189.8	36147	0	0	0	0	0	0	0	0	0	1	0	0	2005
10334	168	176.6	32566	0	0	0	0	0	0	0	0	0	1	0	0	2005
10340	168	180.2	33545	0	0	0	0	0	0	0	0	0	1	0	0	2005
10345	168	187.4	35460	0	0	0	0	0	0	0	0	0	1	0	0	2005
10171	122	188.5	35994	0	0	0	0	0	0	0	0	0	1	0	0	2005
10556	58	175.3	32022	0	0	0	0	0	0	0	0	0	0	1	1	2005
10297	168	190.8	36434	0	0	0	0	0	0	0	0	0	0	1	0	2005
10287	168	186.1	34927	0	0	0	0	0	0	0	0	0	0	1	0	2005
10407	168	185.9	34724	0	0	0	0	0	0	0	0	0	0	1	0	2005
10207	168	186.9	35151	0	0	0	0	0	0	0	0	0	0	0	0	2005
10224	168	188.7	35677	0	0	0	0	0	0	0	0	0	0	0	0	2005
10380	168	183.5	33922	0	0	0	0	0	0	0	0	0	0	0	0	2005
10587	168	134.5	20478	0	0	0	0	0	0	0	0	0	0	0	0	2005
10268	24	156.3	26634	0	0	0	0	0	0	0	0	0	0	0	0	2005
10264	168	180.1	33492	0	0	0	0	0	0	1	0	0	0	0	0	2005
10218	168	172.5	31280	0	0	0	0	0	0	1	0	0	0	0	0	2005
10349	168	163.1	28827	0	0	0	0	0	0	1	0	0	0	0	0	2005
10224	168	157.3	27257	0	0	0	0	0	0	1	0	0	0	0	0	2005
10310	168	173.7	31616	0	0	0	0	0	0	0	1	0	0	0	0	2005
10282	168	167.3	29986	0	0	0	0	0	0	0	1	0	0	0	0	2005
10221	168	173.6	31693	0	0	0	0	0	0	0	1	0	0	0	0	2005
10263	168	183.4	34172	0	0	0	0	0	0	0	1	0	0	0	0	2005
10431	168	175.4	31945	0	0	0	0	0	0	0	1	0	0	0	0	2005
10383	168	174.5	31585	0	0	0	0	0	0	0	0	1	0	0	0	2005
10275	168	161.7	28634	0	0	0	0	0	0	0	0	1	0	0	0	2005
10412	168	165.6	29468	0	0	0	0	0	0	0	0	1	0	0	0	2005
10351	168	172.1	31431	0	0	0	0	0	0	0	0	1	0	0	0	2005
10258	168	189.8	36147	0	0	0	0	0	0	0	0	0	1	0	0	2005
10334	168	176.6	32566	0	0	0	0	0	0	0	0	0	1	0	0	2005
10340	168	180.2	33545	0	0	0	0	0	0	0	0	0	1	0	0	2005
10345	168	187.4	35460	0	0	0	0	0	0	0	0	0	1	0	0	2005
10171	122	188.5	35994	0	0	0	0	0	0	0	0	0	1	0	0	2005
10556	58	175.3	32022	0	0	0	0	0	0	0	0	0	0	1	1	2005
10297	168	190.8	36434	0	0	0	0	0	0	0	0	0	0	1	0	2005
10287	168	186.1	34927	0	0	0	0	0	0	0	0	0	0	1	0	2005
10407	168	185.9	34724	0	0	0	0	0	0	0	0	0	0	1	0	2005
10207	168	186.9	35151	0	0	0	0	0	0	0	0	0	0	0	0	2005
10224	168	188.7	35677	0	0	0	0	0	0	0	0	0	0	0	0	2005

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10380	168	183.5	33922	0	0	0	0	0	0	0	0	0	0	0	0	2005
10587	168	134.5	20478	0	0	0	0	0	0	0	0	0	0	0	0	2005
10268	24	156.3	26634	0	0	0	0	0	0	0	0	0	0	0	0	2005
10468	168	170.4	30113	1	0	0	0	0	0	0	0	0	0	0	0	2006
10329	168	182.7	33736	1	0	0	0	0	0	0	0	0	0	0	0	2006
10311	168	184.8	34572	1	0	0	0	0	0	0	0	0	0	0	0	2006
10417	168	178.4	32318	1	0	0	0	0	0	0	0	0	0	0	0	2006
10513	168	173.1	30754	0	1	0	0	0	0	0	0	0	0	0	0	2006
10435	144	175.6	31679	0	1	0	0	0	0	0	0	0	0	0	0	2006
10325	155	185.3	34837	0	1	0	0	0	0	0	0	0	0	0	1	2006
10306	168	181.4	33493	0	1	0	0	0	0	0	0	0	0	0	0	2006
10258	168	189.2	35956	0	0	1	0	0	0	0	0	0	0	0	0	2006
10395	168	185.2	34578	0	0	1	0	0	0	0	0	0	0	0	0	2006
10318	168	186.0	34992	0	0	1	0	0	0	0	0	0	0	0	0	2006
10351	168	190.4	36339	0	0	1	0	0	0	0	0	0	0	0	0	2006
10226	168	188.2	35883	0	0	1	0	0	0	0	0	0	0	0	0	2006
10325	167	187.2	35541	0	0	0	1	0	0	0	0	0	0	0	0	2006
10362	168	172.3	31389	0	0	0	1	0	0	0	0	0	0	0	0	2006
10516	168	186.1	34996	0	0	0	1	0	0	0	0	0	0	0	0	2006
10303	71	180.1	33503	0	0	0	1	0	0	0	0	0	0	0	0	2006
10248	162	176.8	32344	0	0	0	0	1	0	0	0	0	0	0	1	2006
10318	161	134.2	18975	0	0	0	0	1	0	0	0	0	0	0	0	2006
10238	168	147.9	22782	0	0	0	0	1	0	0	0	0	0	0	0	2006
10303	168	177.6	32320	0	0	0	0	1	0	0	0	0	0	0	0	2006
10365	168	180.9	33447	0	0	0	0	1	0	0	0	0	0	0	0	2006
10487	168	176.6	32031	0	0	0	0	0	1	0	0	0	0	0	0	2006
10457	168	179.4	32898	0	0	0	0	0	1	0	0	0	0	0	0	2006
10409	168	172.2	30940	0	0	0	0	0	1	0	0	0	0	0	0	2006
10445	137	174.5	31526	0	0	0	0	0	1	0	0	0	0	0	0	2006
10420	168	178.6	32615	0	0	0	0	0	0	1	0	0	0	0	0	2006
10490	168	167.0	29231	0	0	0	0	0	0	1	0	0	0	0	0	2006
10506	168	130.8	17194	0	0	0	0	0	0	1	0	0	0	0	0	2006
10503	168	179.6	32742	0	0	0	0	0	0	1	0	0	0	0	0	2006
10450	168	183.5	33883	0	0	0	0	0	0	0	1	0	0	0	0	2006
10474	168	172.7	30897	0	0	0	0	0	0	0	1	0	0	0	0	2006
10320	168	177.9	32462	0	0	0	0	0	0	0	1	0	0	0	0	2006
10401	168	173.0	30893	0	0	0	0	0	0	0	1	0	0	0	0	2006
10228	168	184.1	34330	0	0	0	0	0	0	0	1	0	0	0	0	2006
10373	168	177.5	32284	0	0	0	0	0	0	0	0	1	0	0	0	2006
10291	168	179.7	32965	0	0	0	0	0	0	0	0	1	0	0	0	2006
10357	97	165.7	28480	0	0	0	0	0	0	0	0	1	0	0	0	2006
10975	32	91.2	10126	0	0	0	0	0	0	0	0	1	0	0	1	2006
10558	55	165.7	30075	0	0	0	0	0	0	0	0	0	1	0	1	2006
10205	168	180.3	32862	0	0	0	0	0	0	0	0	0	1	0	0	2006
10188	169	183.5	33954	0	0	0	0	0	0	0	0	0	1	0	0	2006
10311	168	176.2	31628	0	0	0	0	0	0	0	0	0	0	1	0	2006
10241	168	179.5	32705	0	0	0	0	0	0	0	0	0	0	1	0	2006

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10195	168	180.1	32833	0	0	0	0	0	0	0	0	0	0	1	0	2006
10306	159	178.6	32786	0	0	0	0	0	0	0	0	0	0	1	0	2006
10218	168	170.1	29578	0	0	0	0	0	0	0	0	0	0	0	0	2006
10195	168	167.5	28762	0	0	0	0	0	0	0	0	0	0	0	0	2006
10274	168	168.7	29386	0	0	0	0	0	0	0	0	0	0	0	0	2006
10329	168	153.0	24078	0	0	0	0	0	0	0	0	0	0	0	0	2006
10245	24	140.8	20474	0	0	0	0	0	0	0	0	0	0	0	0	2006
10279	168	155.6	24994	1	0	0	0	0	0	0	0	0	0	0	0	2007
10502	130	151.2	24276	1	0	0	0	0	0	0	0	0	0	0	1	2007
10392	168	158.7	25664	1	0	0	0	0	0	0	0	0	0	0	0	2007
10392	168	162.6	27195	1	0	0	0	0	0	0	0	0	0	0	0	2007
10284	168	168.8	29130	0	1	0	0	0	0	0	0	0	0	0	0	2007
10332	168	163.0	27385	0	1	0	0	0	0	0	0	0	0	0	0	2007
10282	168	173.4	30698	0	1	0	0	0	0	0	0	0	0	0	0	2007
10332	168	157.9	25798	0	1	0	0	0	0	0	0	0	0	0	0	2007
10313	168	147.6	22734	0	0	1	0	0	0	0	0	0	0	0	0	2007
10251	167	165.5	28051	0	0	1	0	0	0	0	0	0	0	0	0	2007
10260	168	161.0	26786	0	0	1	0	0	0	0	0	0	0	0	0	2007
10296	168	163.9	27879	0	0	1	0	0	0	0	0	0	0	0	0	2007
10238	72	163.4	27708	0	0	1	0	0	0	0	0	0	0	0	0	2007
10224	87	164.5	28662	0	0	0	1	0	0	0	0	0	0	0	1	2007
10114	118	175.6	31951	0	0	0	1	0	0	0	0	0	0	0	1	2007
10154	168	178.6	32530	0	0	0	1	0	0	0	0	0	0	0	0	2007
10279	168	181.3	33257	0	0	0	0	1	0	0	0	0	0	0	0	2007
10185	168	179.2	32642	0	0	0	0	1	0	0	0	0	0	0	0	2007
10222	168	169.5	29596	0	0	0	0	1	0	0	0	0	0	0	0	2007
10229	168	167.5	29050	0	0	0	0	1	0	0	0	0	0	0	0	2007
10308	148	168.5	29798	0	0	0	0	0	1	0	0	0	0	0	0	2007
10432	154	181.7	33815	0	0	0	0	0	1	0	0	0	0	0	1	2007
10381	168	179.9	33043	0	0	0	0	0	1	0	0	0	0	0	0	2007
10392	168	177.1	32141	0	0	0	0	0	1	0	0	0	0	0	0	2007
10536	120	180.3	33128	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for SMITH 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10232	168	503.3	56900	0	0	0	0	0	0	1	0	0	0	0	0	2004
10325	135	478.5	39799	0	0	0	0	0	0	1	0	0	0	0	1	2004
10240	168	461.1	25434	0	0	0	0	0	0	1	0	0	0	0	0	2004
10090	168	492.0	47847	0	0	0	0	0	0	1	0	0	0	0	0	2004
9944	168	461.1	22988	0	0	0	0	0	0	0	1	0	0	0	0	2004
10223	168	387.8	29796	0	0	0	0	0	0	0	1	0	0	0	0	2004
9786	168	468.0	31146	0	0	0	0	0	0	0	1	0	0	0	0	2004
9900	168	495.3	51440	0	0	0	0	0	0	0	1	0	0	0	0	2004
10142	168	499.7	54317	0	0	0	0	0	0	0	1	0	0	0	0	2004
10565	168	433.0	7692	0	0	0	0	0	0	0	0	1	0	0	0	2004
10603	165	423.4	2524	0	0	0	0	0	0	0	0	1	0	0	0	2004
10782	164	359.5	23617	0	0	0	0	0	0	0	0	1	0	0	0	2004
10393	168	471.4	33145	0	0	0	0	0	0	0	0	1	0	0	0	2004
* 8387	48	440.4	12147	0	0	0	0	0	0	0	0	0	1	0	0	2004
12872	113	226.8	4832	0	0	0	0	0	0	0	0	0	0	1	1	2004
9811	168	426.2	61187	0	0	0	0	0	0	0	0	0	0	1	0	2004
9765	99	434.1	11982	0	0	0	0	0	0	0	0	0	0	0	1	2004
10131	168	475.9	36056	0	0	0	0	0	0	0	0	0	0	0	0	2004
10259	129	484.8	44926	0	0	0	0	0	0	0	0	0	0	0	1	2004
10367	168	490.7	47477	0	0	0	0	0	0	0	0	0	0	0	0	2004
9734	24	501.7	55527	0	0	0	0	0	0	0	0	0	0	0	0	2004
10039	168	474.6	33197	1	0	0	0	0	0	0	0	0	0	0	0	2005
10175	168	503.5	57810	1	0	0	0	0	0	0	0	0	0	0	0	2005
10149	168	504.0	57961	1	0	0	0	0	0	0	0	0	0	0	0	2005
9924	168	502.3	56077	1	0	0	0	0	0	0	0	0	0	0	0	2005
10057	168	498.8	53713	0	1	0	0	0	0	0	0	0	0	0	0	2005
9993	168	491.0	46378	0	1	0	0	0	0	0	0	0	0	0	0	2005
10059	168	503.2	56909	0	1	0	0	0	0	0	0	0	0	0	0	2005
10267	167	491.8	48669	0	1	0	0	0	0	0	0	0	0	0	0	2005
10292	168	501.5	56012	0	0	1	0	0	0	0	0	0	0	0	0	2005
10198	164	464.6	29128	0	0	1	0	0	0	0	0	0	0	0	0	2005
10194	157	483.5	44244	0	0	1	0	0	0	0	0	0	0	0	0	2005
10123	168	499.1	54292	0	0	1	0	0	0	0	0	0	0	0	0	2005
10147	165	464.4	29337	0	0	1	0	0	0	0	0	0	0	0	0	2005
10667	137	481.4	41283	0	0	0	1	0	0	0	0	0	0	0	1	2005
10613	168	492.8	49485	0	0	0	1	0	0	0	0	0	0	0	0	2005
10313	168	489.3	45313	0	0	0	1	0	0	0	0	0	0	0	0	2005
10487	168	500.5	54887	0	0	0	1	0	0	0	0	0	0	0	0	2005
10230	168	468.5	30343	0	0	0	0	1	0	0	0	0	0	0	0	2005
10129	168	436.3	2587	0	0	0	0	1	0	0	0	0	0	0	0	2005
10080	168	465.9	26511	0	0	0	0	1	0	0	0	0	0	0	0	2005
10072	168	489.3	46951	0	0	0	0	1	0	0	0	0	0	0	0	2005
10217	142	463.2	27048	0	0	0	0	1	0	0	0	0	0	0	0	2005
10244	127	480.2	40556	0	0	0	0	0	1	0	0	0	0	0	1	2005
9933	168	501.9	55708	0	0	0	0	0	1	0	0	0	0	0	0	2005
10148	168	470.4	31763	0	0	0	0	0	1	0	0	0	0	0	0	2005
9856	144	494.7	50403	0	0	0	0	0	1	0	0	0	0	0	0	2005

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10316	125	464.4	30879	0	0	0	0	0	0	1	0	0	0	0	1	2005
10383	164	441.2	16747	0	0	0	0	0	0	1	0	0	0	0	0	2005
10156	168	500.8	54828	0	0	0	0	0	0	1	0	0	0	0	0	2005
10124	168	503.2	56739	0	0	0	0	0	0	1	0	0	0	0	0	2005
10348	168	495.7	51120	0	0	0	0	0	0	0	1	0	0	0	0	2005
10363	167	484.7	42456	0	0	0	0	0	0	0	1	0	0	0	0	2005
10235	168	496.8	51087	0	0	0	0	0	0	0	1	0	0	0	0	2005
10274	168	489.4	44508	0	0	0	0	0	0	0	1	0	0	0	0	2005
11121	76	468.1	28604	0	0	0	0	0	0	0	1	0	0	0	0	2005
11595	87	388.4	27794	0	0	0	0	0	0	0	0	1	0	0	1	2005
9685	132	380.1	34243	0	0	0	0	0	0	0	0	1	0	0	1	2005
9496	109	445.3	8805	0	0	0	0	0	0	0	0	1	0	0	1	2005
9905	168	492.9	47013	0	0	0	0	0	0	0	0	1	0	0	0	2005
9896	168	481.7	37767	0	0	0	0	0	0	0	0	0	1	0	0	2005
9946	168	460.9	20457	0	0	0	0	0	0	0	0	0	1	0	0	2005
10222	140	443.3	9911	0	0	0	0	0	0	0	0	0	1	0	1	2005
10029	168	486.8	41674	0	0	0	0	0	0	0	0	0	1	0	0	2005
9935	28	416.0	143	0	0	0	0	0	0	0	0	0	1	0	0	2005
10764	121	416.5	55388	0	0	0	0	0	0	0	0	0	0	0	1	2005
10429	168	399.0	44143	0	0	0	0	0	0	0	0	0	0	0	0	2005
10511	24	454.4	16430	0	0	0	0	0	0	0	0	0	0	0	0	2005
10016	168	416.0	57837	1	0	0	0	0	0	0	0	0	0	0	0	2006
10135	168	460.2	23603	1	0	0	0	0	0	0	0	0	0	0	0	2006
9674	168	467.4	29669	1	0	0	0	0	0	0	0	0	0	0	0	2006
10776	168	446.2	13572	1	0	0	0	0	0	0	0	0	0	0	0	2006
10200	168	445.5	13904	0	1	0	0	0	0	0	0	0	0	0	0	2006
10084	168	487.0	42619	0	1	0	0	0	0	0	0	0	0	0	0	2006
10189	168	493.0	48027	0	1	0	0	0	0	0	0	0	0	0	0	2006
10220	168	496.9	50632	0	1	0	0	0	0	0	0	0	0	0	0	2006
10054	168	489.3	45056	0	0	1	0	0	0	0	0	0	0	0	0	2006
10035	168	474.8	36138	0	0	1	0	0	0	0	0	0	0	0	0	2006
9948	168	496.2	50251	0	0	1	0	0	0	0	0	0	0	0	0	2006
10095	168	480.3	37156	0	0	1	0	0	0	0	0	0	0	0	0	2006
10059	168	473.5	30944	0	0	1	0	0	0	0	0	0	0	0	0	2006
10093	95	465.6	24985	0	0	0	1	0	0	0	0	0	0	0	0	2006
10224	110	404.9	50662	0	0	0	1	0	0	0	0	0	0	0	1	2006
9907	168	465.0	26357	0	0	0	1	0	0	0	0	0	0	0	0	2006
10286	168	460.5	22604	0	0	0	1	0	0	0	0	0	0	0	0	2006
10214	168	447.0	14666	0	0	0	0	1	0	0	0	0	0	0	0	2006
10388	168	421.7	62928	0	0	0	0	1	0	0	0	0	0	0	0	2006
10294	168	425.7	63431	0	0	0	0	1	0	0	0	0	0	0	0	2006
9986	168	433.3	3158	0	0	0	0	1	0	0	0	0	0	0	0	2006
10053	168	447.6	13450	0	0	0	0	1	0	0	0	0	0	0	0	2006
10379	168	432.3	4326	0	0	0	0	0	1	0	0	0	0	0	0	2006
10244	168	481.0	38510	0	0	0	0	0	1	0	0	0	0	0	0	2006
10086	168	496.2	50030	0	0	0	0	0	1	0	0	0	0	0	0	2006
10111	144	489.0	44339	0	0	0	0	0	1	0	0	0	0	0	0	2006

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9781	168	495.6	49898	0	0	0	0	0	0	1	0	0	0	0	0	2006
9904	168	488.4	44478	0	0	0	0	0	0	1	0	0	0	0	0	2006
9970	168	493.5	47712	0	0	0	0	0	0	1	0	0	0	0	0	2006
10035	168	500.1	53541	0	0	0	0	0	0	1	0	0	0	0	0	2006
10109	168	497.4	51440	0	0	0	0	0	0	0	1	0	0	0	0	2006
10169	168	491.7	46982	0	0	0	0	0	0	0	1	0	0	0	0	2006
10110	159	480.1	39302	0	0	0	0	0	0	0	1	0	0	0	0	2006
10019	168	496.3	50955	0	0	0	0	0	0	0	1	0	0	0	0	2006
9975	168	490.8	46678	0	0	0	0	0	0	0	1	0	0	0	0	2006
10141	168	498.3	52344	0	0	0	0	0	0	0	0	1	0	0	0	2006
10251	168	493.7	49367	0	0	0	0	0	0	0	0	1	0	0	0	2006
10241	168	498.3	52662	0	0	0	0	0	0	0	0	1	0	0	0	2006
10033	168	494.5	48638	0	0	0	0	0	0	0	0	1	0	0	0	2006
10279	149	440.1	12364	0	0	0	0	0	0	0	0	0	1	0	0	2006
10024	168	466.5	31949	0	0	0	0	0	0	0	0	0	1	0	0	2006
10046	168	499.3	53634	0	0	0	0	0	0	0	0	0	1	0	0	2006
10165	168	499.0	53499	0	0	0	0	0	0	0	0	0	1	0	0	2006
10109	169	498.9	53223	0	0	0	0	0	0	0	0	0	1	0	0	2006
9949	168	480.5	36996	0	0	0	0	0	0	0	0	0	0	1	0	2006
9891	168	497.6	52417	0	0	0	0	0	0	0	0	0	0	1	0	2006
10115	168	495.9	50133	0	0	0	0	0	0	0	0	0	0	1	0	2006
9936	168	484.6	39217	0	0	0	0	0	0	0	0	0	0	1	0	2006
10220	168	497.6	51651	0	0	0	0	0	0	0	0	0	0	0	0	2006
10242	168	469.5	28502	0	0	0	0	0	0	0	0	0	0	0	0	2006
10179	168	482.0	37553	0	0	0	0	0	0	0	0	0	0	0	0	2006
10208	168	498.2	52859	0	0	0	0	0	0	0	0	0	0	0	0	2006
10326	24	502.6	56028	0	0	0	0	0	0	0	0	0	0	0	0	2006
10188	168	458.5	16532	1	0	0	0	0	0	0	0	0	0	0	0	2007
10229	168	468.8	24625	1	0	0	0	0	0	0	0	0	0	0	0	2007
10277	168	490.1	44650	1	0	0	0	0	0	0	0	0	0	0	0	2007
10312	168	480.4	34877	1	0	0	0	0	0	0	0	0	0	0	0	2007
10249	165	468.6	27396	0	1	0	0	0	0	0	0	0	0	0	0	2007
10127	168	471.7	28123	0	1	0	0	0	0	0	0	0	0	0	0	2007
10215	168	484.9	39199	0	1	0	0	0	0	0	0	0	0	0	0	2007
10059	168	475.3	29985	0	1	0	0	0	0	0	0	0	0	0	0	2007
10095	168	466.2	21163	0	0	1	0	0	0	0	0	0	0	0	0	2007
10207	167	476.0	30544	0	0	1	0	0	0	0	0	0	0	0	0	2007
10145	120	484.1	40678	0	0	1	0	0	0	0	0	0	0	0	0	2007
11227	29	369.1	20594	0	0	1	0	0	0	0	0	0	0	0	1	2007
10130	168	463.5	23402	0	0	1	0	0	0	0	0	0	0	0	0	2007
10127	168	416.2	53044	0	0	0	1	0	0	0	0	0	0	0	0	2007
10035	168	452.9	14258	0	0	0	1	0	0	0	0	0	0	0	0	2007
10168	168	425.7	56888	0	0	0	1	0	0	0	0	0	0	0	0	2007
10167	168	434.2	64930	0	0	0	1	0	0	0	0	0	0	0	0	2007
10129	168	431.3	61070	0	0	0	0	1	0	0	0	0	0	0	0	2007
10438	168	428.2	62469	0	0	0	0	1	0	0	0	0	0	0	0	2007
10458	168	401.4	43680	0	0	0	0	1	0	0	0	0	0	0	0	2007

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10475	168	405.3	48813	0	0	0	0	1	0	0	0	0	0	0	0	2007
10282	168	425.5	64388	0	0	0	0	0	1	0	0	0	0	0	0	2007
9948	168	466.6	26372	0	0	0	0	0	1	0	0	0	0	0	0	2007
10219	168	451.3	15572	0	0	0	0	0	1	0	0	0	0	0	0	2007
10141	165	436.0	4560	0	0	0	0	0	1	0	0	0	0	0	0	2007
9940	120	469.2	27452	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for DANIEL 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10332	168	444.2	13865	0	0	0	0	0	0	1	0	0	0	0	0	2004
10066	168	471.8	32298	0	0	0	0	0	0	1	0	0	0	0	0	2004
10141	168	461.3	23750	0	0	0	0	0	0	1	0	0	0	0	0	2004
10111	168	475.0	34409	0	0	0	0	0	0	1	0	0	0	0	0	2004
10126	135	470.1	31117	0	0	0	0	0	0	0	1	0	0	0	1	2004
9806	168	445.3	15246	0	0	0	0	0	0	0	1	0	0	0	0	2004
* 9516	124	453.8	22586	0	0	0	0	0	0	0	1	0	0	0	1	2004
9625	168	496.0	50332	0	0	0	0	0	0	0	1	0	0	0	0	2004
9755	168	495.2	49589	0	0	0	0	0	0	0	1	0	0	0	0	2004
10035	168	436.2	7910	0	0	0	0	0	0	0	0	1	0	0	0	2004
10028	168	432.7	4415	0	0	0	0	0	0	0	0	1	0	0	0	2004
*10234	168	361.6	22704	0	0	0	0	0	0	0	0	1	0	0	0	2004
9651	168	482.5	40444	0	0	0	0	0	0	0	0	1	0	0	0	2004
10311	168	471.3	31775	0	0	0	0	0	0	0	0	0	1	0	0	2004
9954	168	503.8	57205	0	0	0	0	0	0	0	0	0	1	0	0	2004
10086	164	479.2	40827	0	0	0	0	0	0	0	0	0	1	0	0	2004
*10574	140	405.9	65066	0	0	0	0	0	0	0	0	0	1	0	1	2004
10487	169	456.3	22383	0	0	0	0	0	0	0	0	0	1	0	0	2004
9979	168	489.7	46126	0	0	0	0	0	0	0	0	0	0	1	0	2004
10121	168	504.5	57965	0	0	0	0	0	0	0	0	0	0	1	0	2004
9958	168	484.6	42988	0	0	0	0	0	0	0	0	0	0	1	0	2004
10207	168	451.2	18914	0	0	0	0	0	0	0	0	0	0	1	0	2004
9759	168	485.2	43977	0	0	0	0	0	0	0	0	0	0	0	0	2004
9885	168	475.0	35927	0	0	0	0	0	0	0	0	0	0	0	0	2004
10001	168	496.1	51545	0	0	0	0	0	0	0	0	0	0	0	0	2004
10320	168	494.9	49824	0	0	0	0	0	0	0	0	0	0	0	0	2004
9982	24	404.4	45296	0	0	0	0	0	0	0	0	0	0	0	0	2004
10348	168	460.1	20212	1	0	0	0	0	0	0	0	0	0	0	0	2005
*10732	168	457.1	13423	1	0	0	0	0	0	0	0	0	0	0	0	2005
10357	168	484.6	41633	1	0	0	0	0	0	0	0	0	0	0	0	2005
10028	168	498.4	52212	1	0	0	0	0	0	0	0	0	0	0	0	2005
10236	168	495.9	50629	0	1	0	0	0	0	0	0	0	0	0	0	2005
10158	168	487.0	42928	0	1	0	0	0	0	0	0	0	0	0	0	2005
10190	168	495.4	49830	0	1	0	0	0	0	0	0	0	0	0	0	2005
10271	168	500.2	53687	0	1	0	0	0	0	0	0	0	0	0	0	2005
10395	163	481.7	42281	0	0	1	0	0	0	0	0	0	0	0	0	2005
*11000	167	278.2	16230	0	0	0	1	0	0	0	0	0	0	0	0	2005
*10742	166	316.5	41661	0	0	0	1	0	0	0	0	0	0	0	0	2005
*10028	166	474.6	34729	0	0	0	1	0	0	0	0	0	0	0	0	2005
*10203	168	493.4	47649	0	0	0	1	0	0	0	0	0	0	0	0	2005
10028	168	476.3	36115	0	0	0	0	1	0	0	0	0	0	0	0	2005
10056	168	458.3	23851	0	0	0	0	1	0	0	0	0	0	0	0	2005
10158	168	471.3	31701	0	0	0	0	1	0	0	0	0	0	0	0	2005
10074	168	486.0	43129	0	0	0	0	1	0	0	0	0	0	0	0	2005
*10345	168	450.4	15524	0	0	0	0	1	0	0	0	0	0	0	0	2005
10405	147	462.2	27948	0	0	0	0	0	1	0	0	0	0	0	0	2005
10194	168	494.6	48312	0	0	0	0	0	1	0	0	0	0	0	0	2005

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10345	168	465.7	26662	0	0	0	0	0	1	0	0	0	0	0	0	2005
10101	144	489.5	44744	0	0	0	0	0	1	0	0	0	0	0	0	2005
10285	168	487.3	42024	0	0	0	0	0	0	1	0	0	0	0	0	2005
10339	168	445.3	12988	0	0	0	0	0	0	1	0	0	0	0	0	2005
10296	168	495.1	48623	0	0	0	0	0	0	1	0	0	0	0	0	2005
10248	168	488.6	43297	0	0	0	0	0	0	1	0	0	0	0	0	2005
10420	168	462.1	25055	0	0	0	0	0	0	0	1	0	0	0	0	2005
10180	168	485.3	41809	0	0	0	0	0	0	0	1	0	0	0	0	2005
10128	168	492.2	46820	0	0	0	0	0	0	0	1	0	0	0	0	2005
10165	168	489.9	44596	0	0	0	0	0	0	0	1	0	0	0	0	2005
10401	85	401.1	44761	0	0	0	0	0	0	0	1	0	0	0	0	2005
*11272	62	316.4	40241	0	0	0	0	0	0	0	0	1	0	0	1	2005
9315	168	464.6	24276	0	0	0	0	0	0	0	0	1	0	0	0	2005
9457	168	491.5	45583	0	0	0	0	0	0	0	0	1	0	0	0	2005
9731	168	495.0	48523	0	0	0	0	0	0	0	0	1	0	0	0	2005
9914	168	485.3	39701	0	0	0	0	0	0	0	0	0	1	0	0	2005
9926	168	471.3	28214	0	0	0	0	0	0	0	0	0	1	0	0	2005
10122	168	443.5	6614	0	0	0	0	0	0	0	0	0	1	0	0	2005
10033	168	482.2	38388	0	0	0	0	0	0	0	0	0	1	0	0	2005
10244	169	493.6	48192	0	0	0	0	0	0	0	0	0	1	0	0	2005
10114	168	493.1	47800	0	0	0	0	0	0	0	0	0	0	1	0	2005
9821	168	493.6	48223	0	0	0	0	0	0	0	0	0	0	1	0	2005
9937	168	475.4	35069	0	0	0	0	0	0	0	0	0	0	1	0	2005
10031	168	471.9	32622	0	0	0	0	0	0	0	0	0	0	1	0	2005
9967	168	487.6	43942	0	0	0	0	0	0	0	0	0	0	0	0	2005
10053	168	480.9	39831	0	0	0	0	0	0	0	0	0	0	0	0	2005
10068	168	491.0	45722	0	0	0	0	0	0	0	0	0	0	0	0	2005
10083	168	410.4	49861	0	0	0	0	0	0	0	0	0	0	0	0	2005
10413	24	456.7	17000	0	0	0	0	0	0	0	0	0	0	0	0	2005
9999	168	416.7	56873	1	0	0	0	0	0	0	0	0	0	0	0	2006
10220	168	462.4	23560	1	0	0	0	0	0	0	0	0	0	0	0	2006
10102	168	458.5	20551	1	0	0	0	0	0	0	0	0	0	0	0	2006
10064	168	452.5	17268	1	0	0	0	0	0	0	0	0	0	0	0	2006
10101	168	468.5	27293	0	1	0	0	0	0	0	0	0	0	0	0	2006
9952	168	478.8	35031	0	1	0	0	0	0	0	0	0	0	0	0	2006
10052	168	496.8	50404	0	1	0	0	0	0	0	0	0	0	0	0	2006
10123	165	472.5	35273	0	1	0	0	0	0	0	0	0	0	0	0	2006
9683	168	494.0	48950	0	0	1	0	0	0	0	0	0	0	0	0	2006
9402	168	475.7	34014	0	0	1	0	0	0	0	0	0	0	0	0	2006
9434	24	442.3	9901	0	0	1	0	0	0	0	0	0	0	0	0	2006
*117280	5	105.8	16033	0	0	0	1	0	0	0	0	0	0	0	1	2006
*38935	5	50.4	3873	0	0	0	0	1	0	0	0	0	0	0	1	2006
9733	96	395.5	40865	0	0	0	0	1	0	0	0	0	0	0	1	2006
9833	168	438.1	6072	0	0	0	0	1	0	0	0	0	0	0	0	2006
9714	168	438.7	6213	0	0	0	0	1	0	0	0	0	0	0	0	2006
9691	168	452.1	16169	0	0	0	0	1	0	0	0	0	0	0	0	2006
9921	168	436.9	6448	0	0	0	0	0	1	0	0	0	0	0	0	2006

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9770	168	458.2	21061	0	0	0	0	0	1	0	0	0	0	0	0	2006
9951	168	458.6	22045	0	0	0	0	0	1	0	0	0	0	0	0	2006
9873	140	453.6	19873	0	0	0	0	0	1	0	0	0	0	0	0	2006
9937	168	485.2	41055	0	0	0	0	0	0	1	0	0	0	0	0	2006
10111	168	472.3	31556	0	0	0	0	0	0	1	0	0	0	0	0	2006
10188	168	441.7	9001	0	0	0	0	0	0	1	0	0	0	0	0	2006
10220	168	438.7	4615	0	0	0	0	0	0	1	0	0	0	0	0	2006
*10159	168	467.2	25167	0	0	0	0	0	0	0	1	0	0	0	0	2006
10139	168	472.9	31855	0	0	0	0	0	0	0	1	0	0	0	0	2006
10123	168	479.5	35611	0	0	0	0	0	0	0	1	0	0	0	0	2006
10120	168	457.2	17546	0	0	0	0	0	0	0	1	0	0	0	0	2006
10100	168	452.8	13731	0	0	0	0	0	0	0	1	0	0	0	0	2006
10306	168	469.4	28216	0	0	0	0	0	0	0	0	1	0	0	0	2006
10381	168	456.1	19518	0	0	0	0	0	0	0	0	1	0	0	0	2006
10416	168	420.2	59363	0	0	0	0	0	0	0	0	1	0	0	0	2006
10157	168	362.6	16638	0	0	0	0	0	0	0	0	1	0	0	0	2006
10225	164	388.8	37659	0	0	0	0	0	0	0	0	0	1	0	0	2006
10203	168	421.6	61870	0	0	0	0	0	0	0	0	0	1	0	0	2006
10068	168	468.3	29809	0	0	0	0	0	0	0	0	0	1	0	0	2006
10192	168	471.2	32467	0	0	0	0	0	0	0	0	0	1	0	0	2006
10165	169	462.6	24743	0	0	0	0	0	0	0	0	0	1	0	0	2006
10292	168	428.7	353	0	0	0	0	0	0	0	0	0	0	1	0	2006
10097	168	474.3	34889	0	0	0	0	0	0	0	0	0	0	1	0	2006
10287	168	471.8	32024	0	0	0	0	0	0	0	0	0	0	1	0	2006
10123	168	468.9	29347	0	0	0	0	0	0	0	0	0	0	1	0	2006
10207	168	483.0	41117	0	0	0	0	0	0	0	0	0	0	0	0	2006
10121	168	467.4	27608	0	0	0	0	0	0	0	0	0	0	0	0	2006
10336	168	434.3	5240	0	0	0	0	0	0	0	0	0	0	0	0	2006
10484	167	385.7	30794	0	0	0	0	0	0	0	0	0	0	0	0	2006
10370	168	344.7	2690	1	0	0	0	0	0	0	0	0	0	0	0	2007
10097	168	419.1	59699	1	0	0	0	0	0	0	0	0	0	0	0	2007
10136	168	431.1	64197	1	0	0	0	0	0	0	0	0	0	0	0	2007
10195	168	394.0	40873	1	0	0	0	0	0	0	0	0	0	0	0	2007
10269	168	394.1	42642	0	1	0	0	0	0	0	0	0	0	0	0	2007
10271	168	377.6	32903	0	1	0	0	0	0	0	0	0	0	0	0	2007
10239	168	401.9	47599	0	1	0	0	0	0	0	0	0	0	0	0	2007
10355	168	319.6	49458	0	1	0	0	0	0	0	0	0	0	0	0	2007
9975	168	381.8	31475	0	0	1	0	0	0	0	0	0	0	0	0	2007
10367	167	330.7	56457	0	0	1	0	0	0	0	0	0	0	0	0	2007
10229	168	341.1	64681	0	0	1	0	0	0	0	0	0	0	0	0	2007
10104	168	392.6	38237	0	0	1	0	0	0	0	0	0	0	0	0	2007
10159	153	396.7	39727	0	0	0	1	0	0	0	0	0	0	0	1	2007
*10023	168	369.2	6066	0	0	0	1	0	0	0	0	0	0	0	0	2007
*10055	163	360.1	884	0	0	0	1	0	0	0	0	0	0	0	0	2007
*10132	168	412.2	45515	0	0	0	1	0	0	0	0	0	0	0	0	2007
9788	168	453.8	14174	0	0	0	0	1	0	0	0	0	0	0	0	2007
9979	168	448.7	12355	0	0	0	0	1	0	0	0	0	0	0	0	2007

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10076	168	419.9	56964	0	0	0	0	1	0	0	0	0	0	0	0	2007
9802	168	426.3	62712	0	0	0	0	1	0	0	0	0	0	0	0	2007
10103	168	440.8	9000	0	0	0	0	0	1	0	0	0	0	0	0	2007
10053	168	470.8	29873	0	0	0	0	0	1	0	0	0	0	0	0	2007
10120	168	476.5	33749	0	0	0	0	0	1	0	0	0	0	0	0	2007
10158	168	455.7	17621	0	0	0	0	0	1	0	0	0	0	0	0	2007
10029	120	466.4	25846	0	0	0	0	0	1	0	0	0	0	0	0	2007

Data Base for DANIEL 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2008 - December 2008

Unit	Month	(1) Forecast AKW • 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 4	Jan '08	70.5	5,054	10,484	6,768	
	Feb '08	0.0	0	0	0	
	Mar '08	75.5	5,712	10,534	26,964	
	Apr '08	73.6	5,459	10,426	52,704	
	May '08	70.9	5,106	10,782	52,433	
	Jun '08	73.7	5,473	10,914	52,789	
	Jul '08	74.6	5,592	10,758	55,203	
	Aug '08	75.1	5,658	10,925	55,601	
	Sep '08	74.0	5,512	10,774	52,961	
	Oct '08	73.0	5,380	10,697	54,019	
	Nov '08	74.2	5,539	10,577	53,212	
	Dec '08	70.7	5,080	10,480	47,251	10,696
CRIST 5	Jan '08	73.7	5,461	10,406	54,192	
	Feb '08	73.4	5,422	10,412	24,356	
	Mar '08	75.5	5,695	10,371	28,603	
	Apr '08	74.0	5,500	10,253	52,588	
	May '08	71.0	5,114	10,653	52,175	
	Jun '08	73.9	5,487	10,592	52,511	
	Jul '08	74.8	5,604	10,689	54,947	
	Aug '08	75.4	5,682	10,680	55,451	
	Sep '08	74.0	5,500	10,779	52,619	
	Oct '08	73.2	5,396	10,732	53,806	
	Nov '08	74.0	5,500	10,400	45,736	
	Dec '08	71.2	5,139	10,457	48,956	10,552
CRIST 6	Jan '08	275.8	77,902	10,419	147,568	
	Feb '08	272.9	76,502	10,237	139,716	
	Mar '08	294.5	87,169	10,096	212,026	
	Apr '08	278.7	79,312	10,401	194,564	
	May '08	264.8	72,642	10,488	190,933	
	Jun '08	279.5	79,703	10,583	195,118	
	Jul '08	285.4	82,608	10,363	205,807	
	Aug '08	287.7	83,752	10,350	207,417	
	Sep '08	281.4	80,634	10,386	196,406	
	Oct '08	276.1	78,047	10,235	199,075	
	Nov '08	280.8	80,340	10,389	46,046	
	Dec '08	263.6	72,077	10,495	147,066	10,365

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2008 - December 2008

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 7	Jan '08	453.4	208,614	10,351	236,221	
	Feb '08	449.7	205,525	10,058	203,724	
	Mar '08	470.3	222,964	10,554	329,648	
	Apr '08	461.0	215,018	10,520	313,041	
	May '08	446.4	202,786	10,370	313,352	
	Jun '08	464.3	217,824	10,545	315,240	
	Jul '08	466.6	219,788	10,315	327,521	
	Aug '08	468.3	221,245	10,310	328,758	
	Sep '08	465.3	218,677	10,318	315,964	
	Oct '08	460.4	214,509	10,331	323,186	
	Nov '08	464.2	217,738	10,321	220,944	
	Dec '08	449.0	204,943	10,363	101,927	10,375
SMITH 1	Jan '08	155.5	24,457	10,232	113,971	
	Feb '08	154.8	24,276	10,235	106,164	
	Mar '08	158.0	25,107	10,222	115,652	
	Apr '08	155.6	24,483	10,232	110,340	
	May '08	153.9	24,044	10,239	112,807	
	Jun '08	156.0	24,587	10,308	110,587	
	Jul '08	156.9	24,821	10,298	115,037	
	Aug '08	157.2	24,899	10,225	115,257	
	Sep '08	155.8	24,535	10,231	110,447	
	Oct '08	155.5	24,457	10,156	114,015	
	Nov '08	154.6	24,225	10,236	91,526	
	Dec '08	151.8	23,505	10,247	111,245	10,238
SMITH 2	Jan '08	184.7	34,579	10,327	130,006	
	Feb '08	183.7	34,264	10,329	120,863	
	Mar '08	186.9	35,277	10,322	105,970	
	Apr '08	179.5	32,952	10,340	52,954	
	May '08	177.3	32,274	10,251	52,314	
	Jun '08	184.2	34,421	10,328	125,417	
	Jul '08	186.4	35,118	10,259	131,236	
	Aug '08	187.5	35,469	10,320	131,980	
	Sep '08	184.2	34,421	10,273	125,435	
	Oct '08	182.0	33,730	10,333	128,116	
	Nov '08	184.7	34,579	10,327	125,948	
	Dec '08	179.8	33,045	10,339	126,604	10,314

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2008 - December 2008

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 1	Jan '08	483.8	237,652	10,123	354,134	
	Feb '08	484.3	238,042	10,122	331,249	
	Mar '08	499.3	249,871	10,078	364,998	
	Apr '08	483.2	237,184	10,125	342,093	
	May '08	459.4	218,912	10,199	336,257	
	Jun '08	476.4	231,905	10,145	337,268	
	Jul '08	486.7	239,920	10,114	356,264	
	Aug '08	491.3	243,534	10,101	359,608	
	Sep '08	483.4	237,340	10,124	342,251	
	Oct '08	459.2	218,761	10,200	249,360	
	Nov '08	484.2	237,964	10,122	240,660	
	Dec '08	473.9	229,976	10,153	346,862	10,132
DANIEL 2	Jan '08	493.4	244,597	10,069	356,243	
	Feb '08	495.1	245,874	10,066	334,181	
	Mar '08	497.7	247,828	9,813	196,607	
	Apr '08	495.8	246,400	10,065	346,042	
	May '08	469.8	226,900	9,879	339,199	
	Jun '08	491.0	242,794	10,073	342,708	
	Jul '08	493.5	244,672	10,068	356,301	
	Aug '08	500.4	249,859	10,057	361,270	
	Sep '08	493.2	244,446	9,874	344,237	
	Oct '08	0.0	0	-	0	
	Nov '08	455.6	216,285	10,136	53,307	
	Dec '08	483.3	237,014	10,086	315,101	10,016

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4))) / (\Sigma (4))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2008 - December 2008

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 4	10,696	10,375	11,017
CRIST 5	10,552	10,235	10,869
CRIST 6	10,365	10,054	10,676
CRIST 7	10,375	10,064	10,686
SMITH 1	10,238	9,931	10,545
SMITH 2	10,314	10,005	10,623
DANIEL 1	10,132	9,828	10,436
DANIEL 2	10,016	9,716	10,316

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2008 - December 2008

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '08 - Dec '08	Reserve Shutdown Hours for Jan '08 - Dec '08	Target Equivalent Availability **
Crist 4	0.0173	1,728	0	78.9
Crist 5	0.0307	720	0	89.0
Crist 6	0.0753	720	0	84.9
Crist 7	0.1059	720	0	82.1
Smith 1	0.0297	0	0	97.0
Smith 2	0.0862	720	0	83.9
Daniel 1	0.0387	216	0	93.8
Daniel 2	0.0400	1,680	0	77.6

* For Period July 2002 through June 2007.

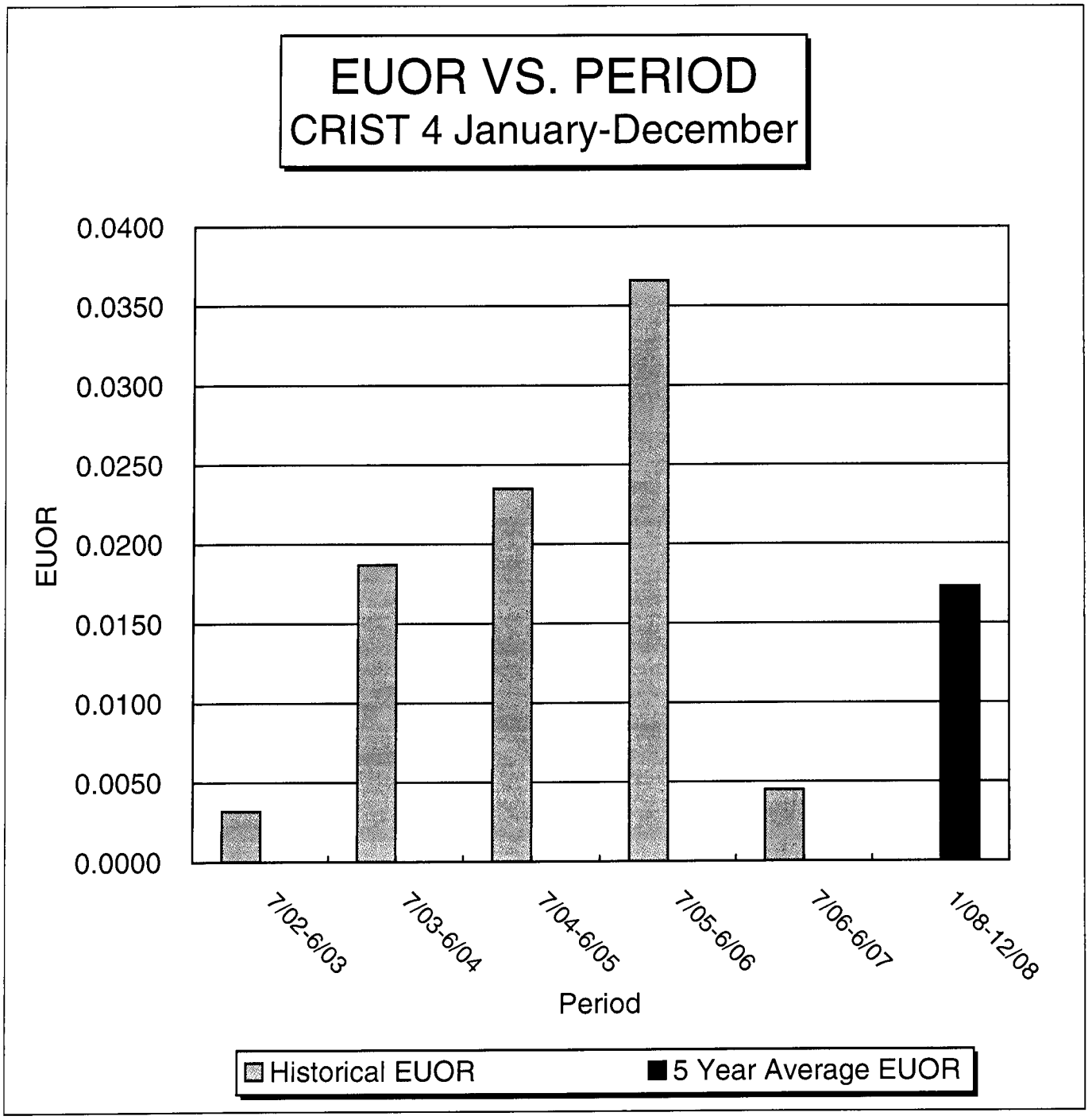
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

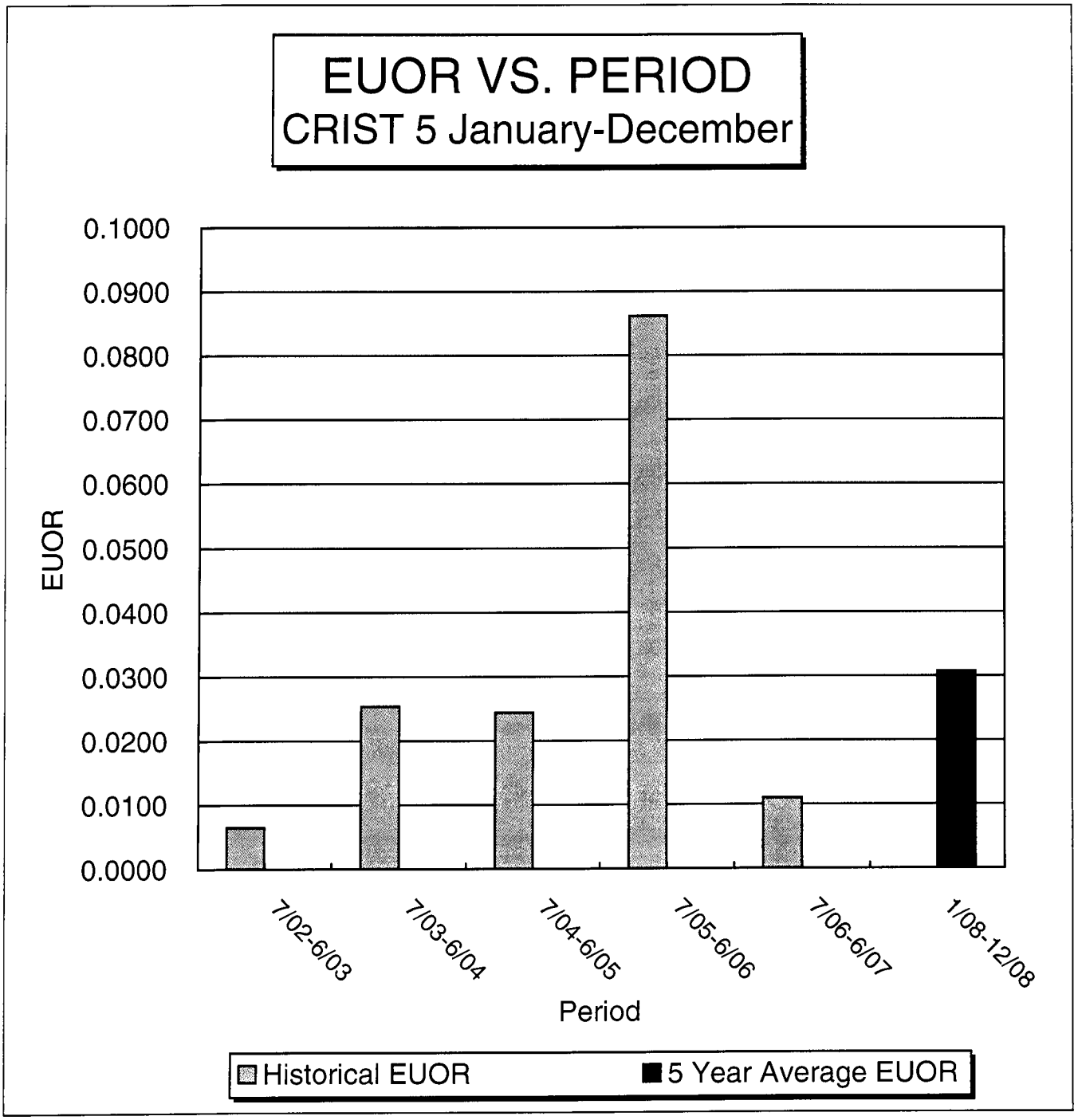
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2008 - December 2008

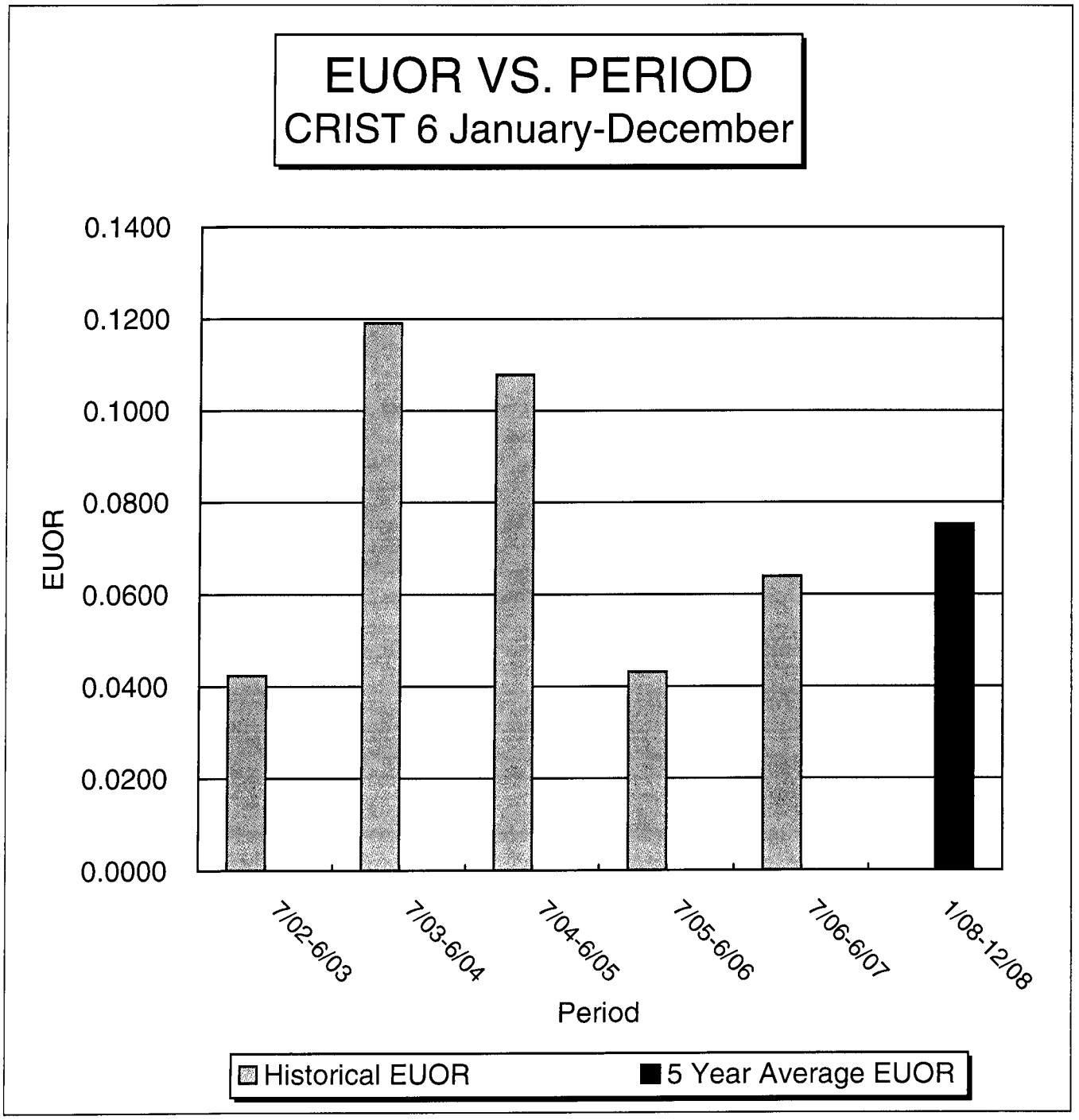
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 4	0.0173	0.0121	79.4	0.0251	78.3
Crist 5	0.0307	0.0215	89.8	0.0445	87.7
Crist 6	0.0753	0.0527	87.0	0.1092	81.8
Crist 7	0.1059	0.0741	85.0	0.1536	77.7
Smith 1	0.0297	0.0208	97.9	0.0431	95.7
Smith 2	0.0862	0.0603	86.3	0.1250	80.3
Daniel 1	0.0387	0.0271	94.9	0.0561	92.1
Daniel 2	0.0400	0.0280	78.6	0.0580	76.2

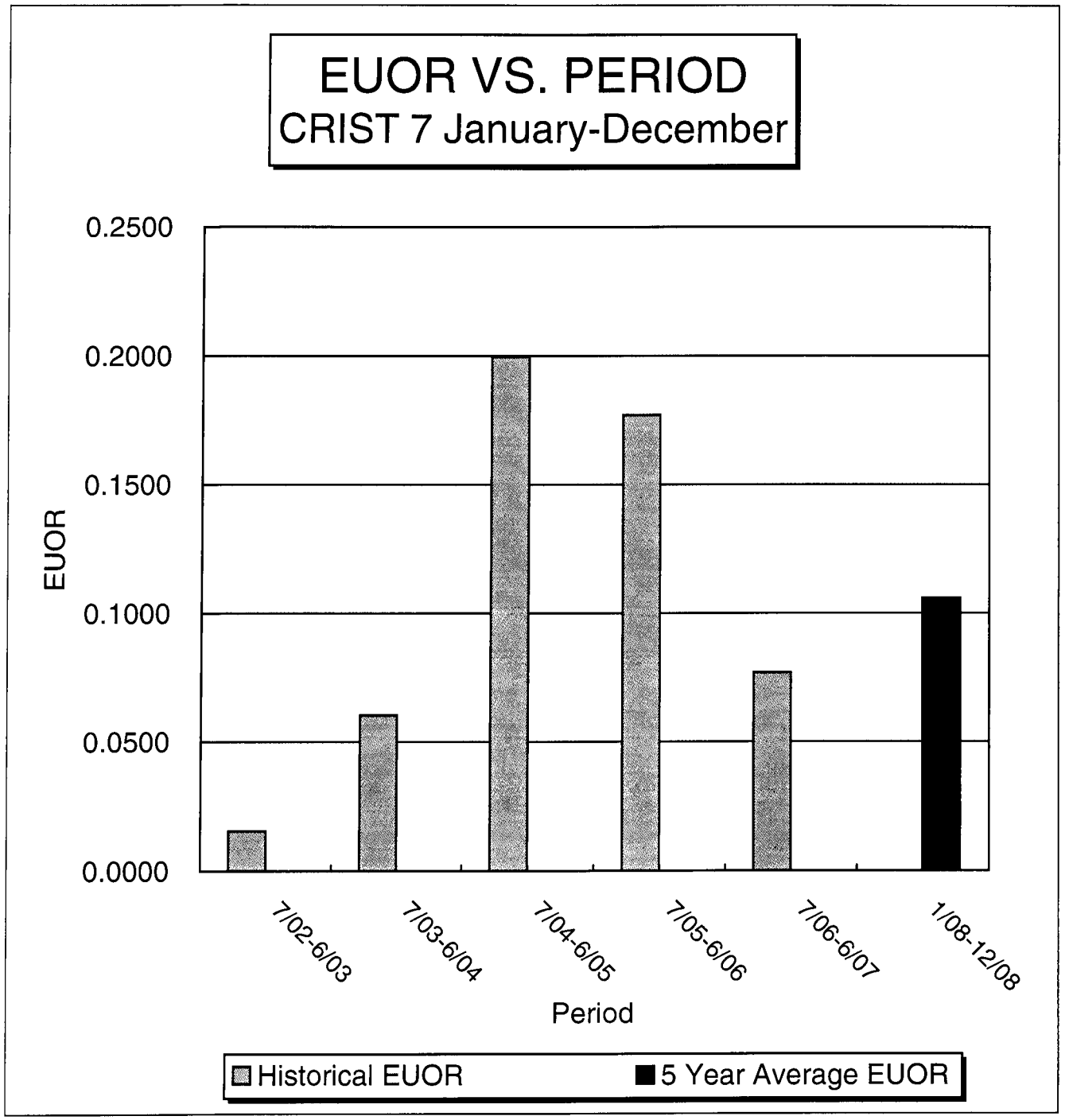
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2008 - December 2008

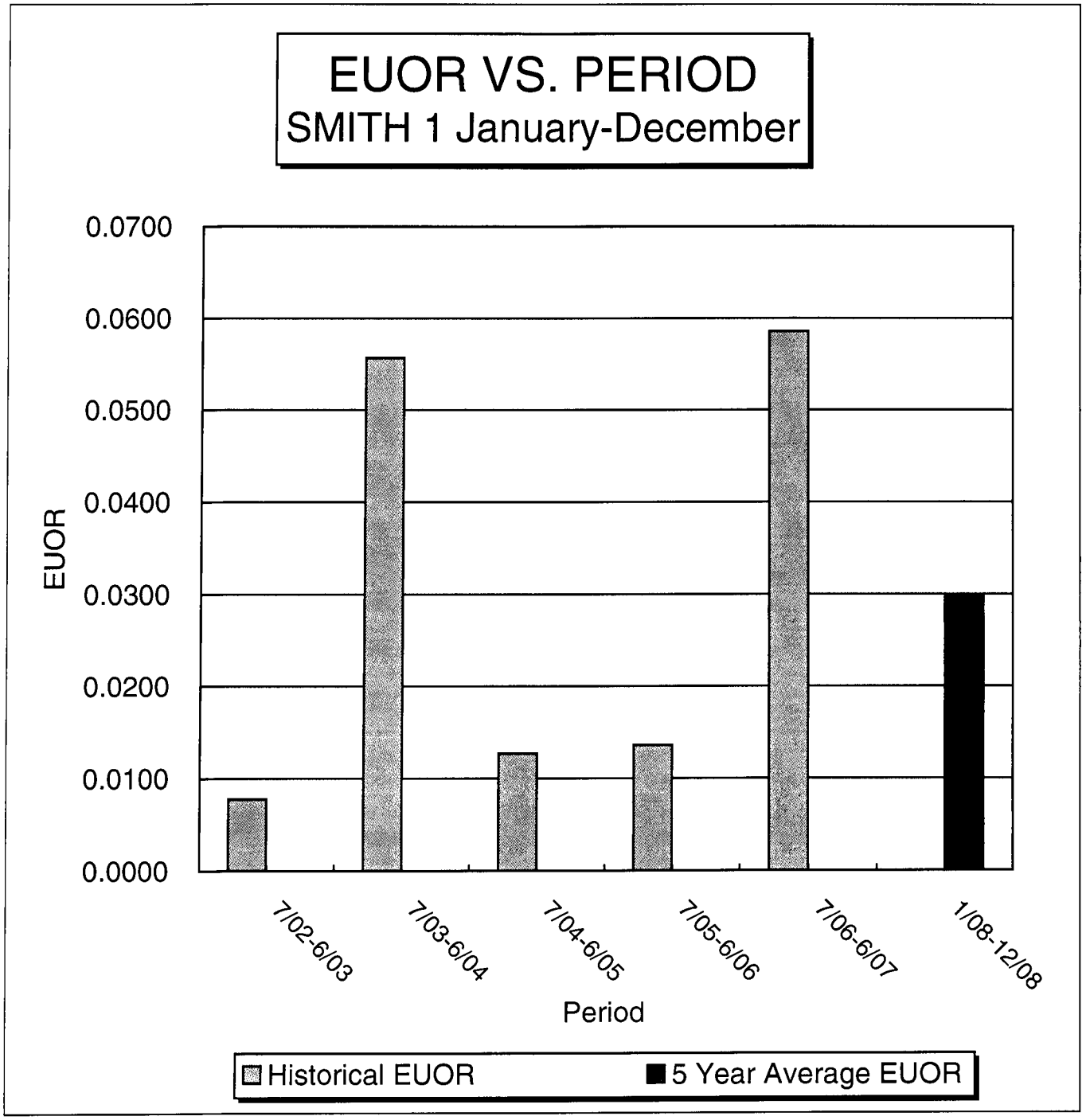
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 4	78.9	79.4	78.3
Crist 5	89.0	89.8	87.7
Crist 6	84.9	87.0	81.8
Crist 7	82.1	85.0	77.7
Smith 1	97.0	97.9	95.7
Smith 2	83.9	86.3	80.3
Daniel 1	93.8	94.9	92.1
Daniel 2	77.6	78.6	76.2

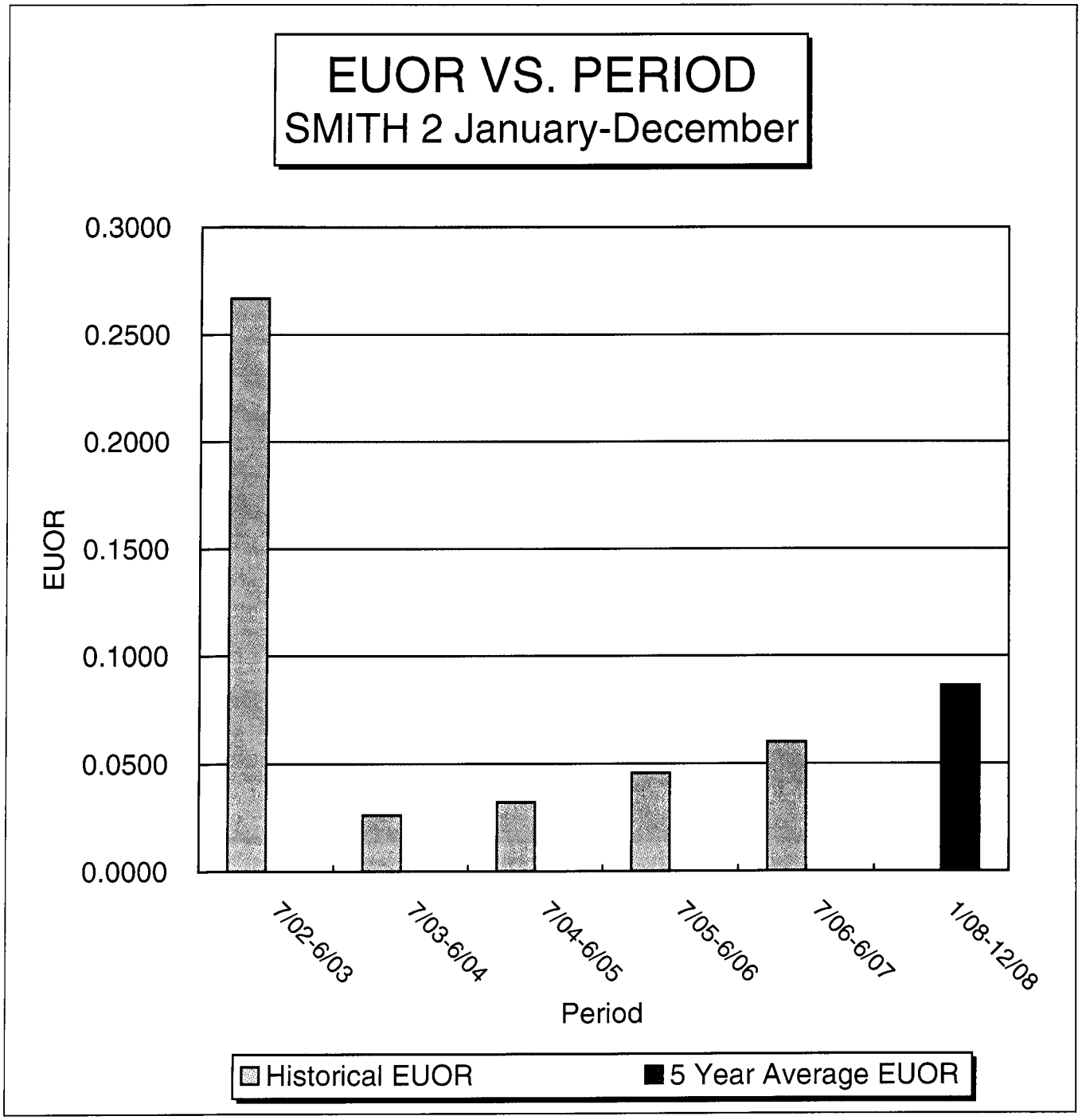

EUOR VS. PERIOD
CRIST 4 January-December
0.0400
0.0350
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR

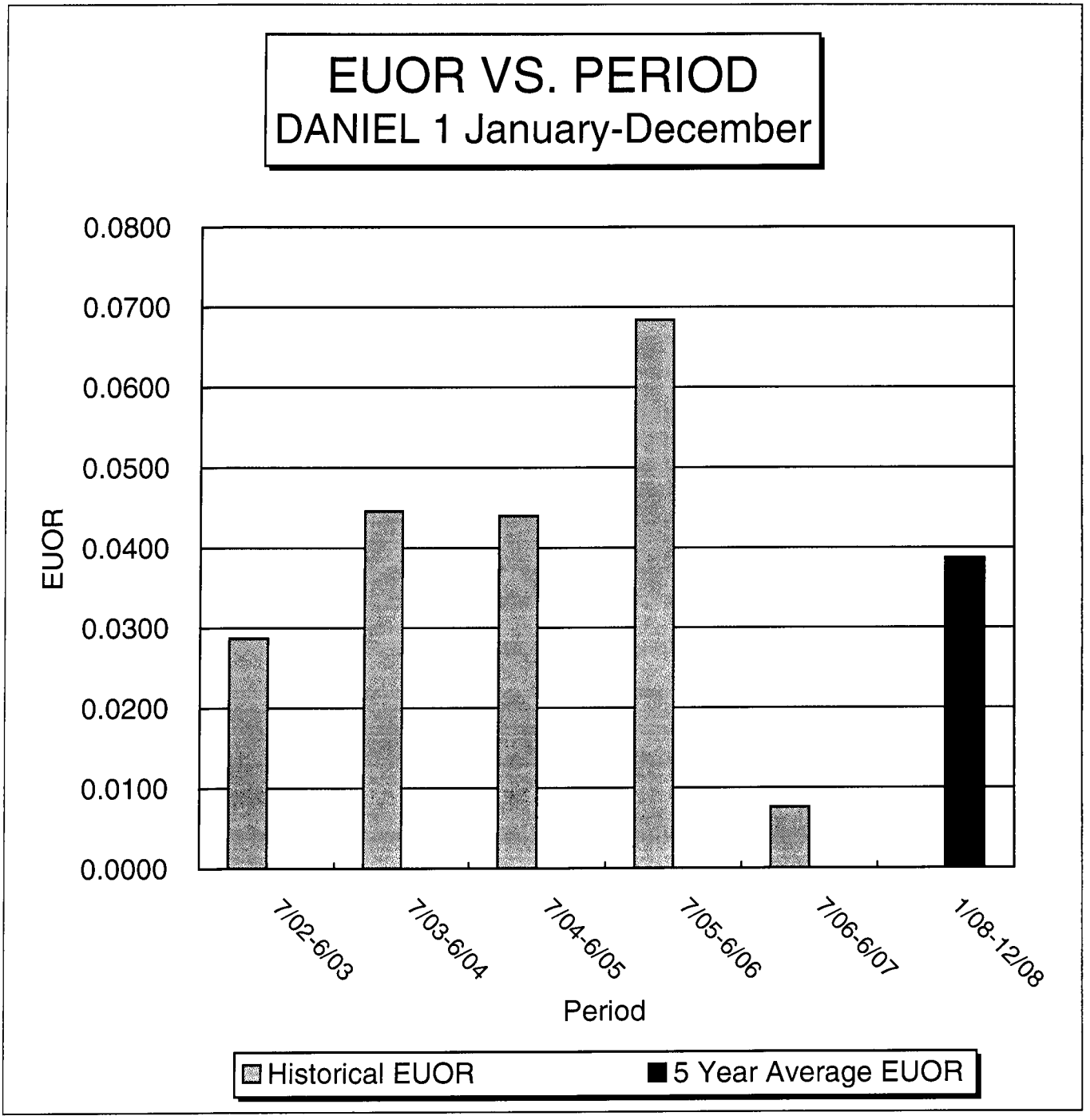

EUOR VS. PERIOD
CRIST 5 January-December
0.1000
0.0900
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR

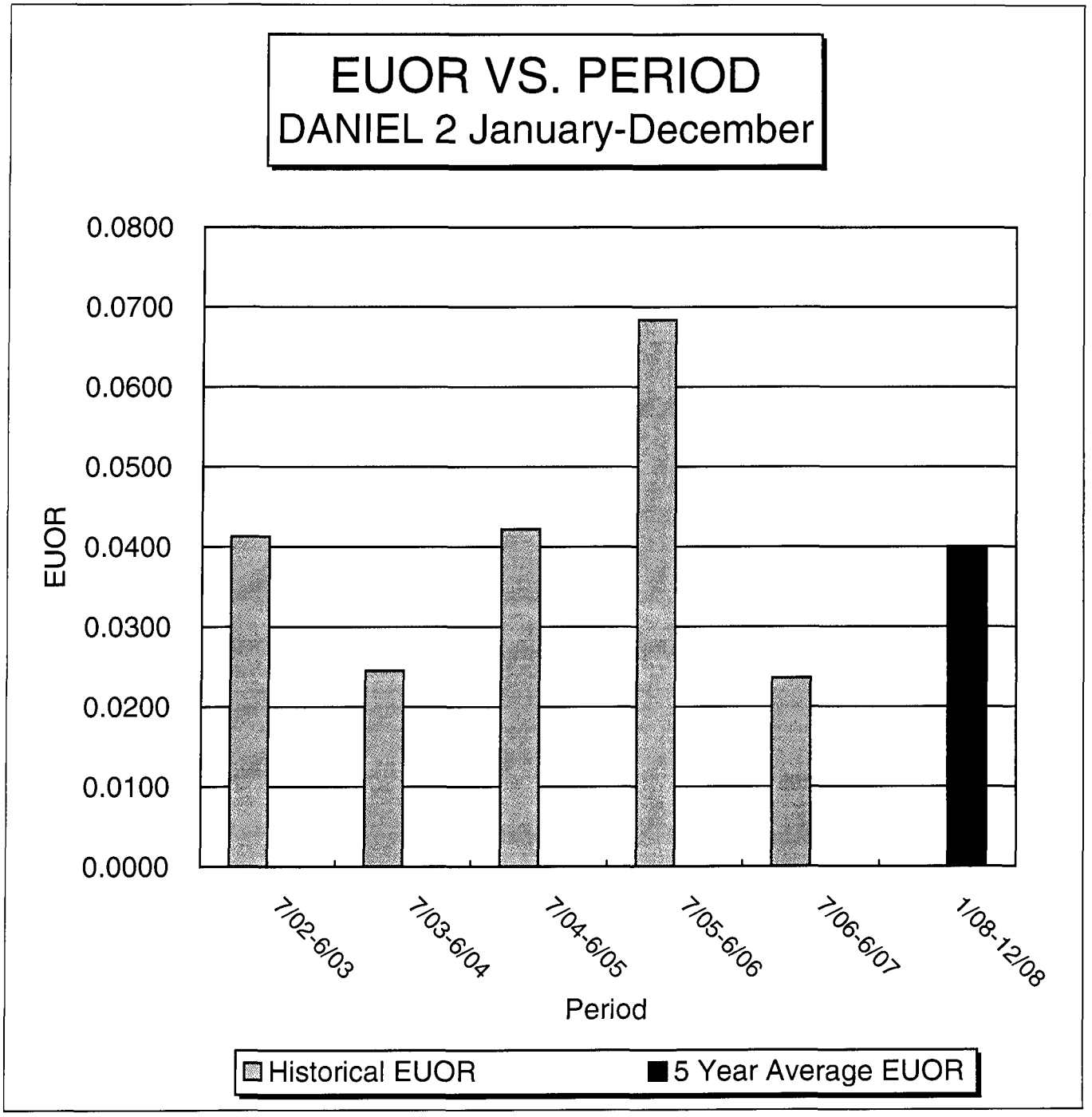

EUOR VS. PERIOD
CRIST 6 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January-December
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January-December
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/02-6/03
7/03-6/04
7/04-6/05
7/05-6/06
7/06-6/07
1/08-12/08
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE
PERIOD JANUARY 2008 - DECEMBER 2008

CONTENTS	SCHEDULE 3 PAGE
GPIF Reward/Penalty Table (Estimated)	3
GPIF Calculation of Maximum Allowed Incentive Dollars	4
GPIF Target and Range Summary	5
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for Availability	6 - 7
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for ANOHR	8
Example Calculation of Prior Season ANOHR	9
Derivation of Weighting Factors	10
GPIF Unit Point Tables	11 - 18
Estimated Unit Performance Data	19 - 35
Planned Outage Schedules	36 - 37

Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2008 - December 2008

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	10482	3354
+ 9	9434	3019
+ 8	8386	2683
+ 7	7337	2348
+ 6	6289	2012
+ 5	5241	1677
+ 4	4193	1342
+ 3	3145	1006
+ 2	2096	671
+ 1	1048	335
0	0	0
- 1	-1159	-335
- 2	-2318	-671
- 3	-3476	-1006
- 4	-4635	-1342
- 5	-5794	-1677
- 6	-6953	-2012
- 7	-8112	-2348
- 8	-9270	-2683
- 9	-10429	-3019
- 10	-11588	-3354
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2008 - December 2008

Line 1	Beginning of Period Balance of Common Equity	$734,235,973
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '08	$845,465,950
Line 3	Month of Feb '08	$853,472,138
Line 4	Month of Mar '08	$858,787,896
Line 5	Month of Apr '08	$842,724,574
Line 6	Month of May '08	$851,968,408
Line 7	Month of Jun '08	$864,148,545
Line 8	Month of Jul '08	$858,216,408
Line 9	Month of Aug '08	$873,702,795
Line 10	Month of Sep '08	$884,117,131
Line 11	Month of Oct '08	$868,581,377
Line 12	Month of Nov '08	$871,796,261
Line 13	Month of Dec '08	$888,243,260
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$853,496,978
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.3808%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$3,476,239
Line 18	Jurisdictional Sales (KWH)	11,587,237,105
Line 19	Total Territorial Sales (KWH)	12,009,655,811
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.4827%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$3,353,968

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	0.1%	78.9	79.4	78.3	$12	($30)
Crist 5	0.2%	89.0	89.8	87.7	$23	($34)
Crist 6	2.0%	84.9	87.0	81.8	$209	($442)
Crist 7	8.5%	82.1	85.0	77.7	$896	($1,317)
Smith 1	1.2%	97.0	97.9	95.7	$125	($164)
Smith 2	3.7%	83.9	86.3	80.3	$392	($574)
Daniel 1	0.7%	93.8	94.9	92.1	$73	($205)
Daniel 2	2.0%	77.6	78.6	76.2	$210	($280)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	3.3%	10,696	94.1	10,375	11,017	$350	($350)
Crist 5	3.7%	10,552	94.4	10,235	10,869	$385	($385)
Crist 6	11.1%	10,365	92.3	10,054	10,676	$1,165	($1,165)
Crist 7	21.3%	10,375	97.7	10,064	10,686	$2,230	($2,230)
Smith 1	9.0%	10,238	96.0	9,931	10,545	$948	($948)
Smith 2	8.5%	10,314	94.3	10,005	10,623	$892	($892)
Daniel 1	12.9%	10,132	95.6	9,828	10,436	$1,357	($1,357)
Daniel 2	11.6%	10,016	96.2	9,716	10,316	$1,215	($1,215)

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '06 - Jun '07			Actual Performance 2nd Prior Period Jul '05 - Jun '06		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.1%	0.6%	0.1967	0.0139	0.0173	0.0595	0.0041	0.0045	0.0000	0.0366	0.0366
Crist 5	0.2%	1.2%	0.0820	0.0282	0.0307	0.0561	0.0101	0.0110	0.0000	0.0860	0.0862
Crist 6	2.0%	10.8%	0.0820	0.0691	0.0753	0.0000	0.0639	0.0639	0.3459	0.0281	0.0432
Crist 7	8.5%	46.2%	0.0820	0.0972	0.1059	0.1105	0.0685	0.0770	0.0000	0.1765	0.1771
Smith 1	1.2%	6.4%	0.0000	0.0297	0.0297	0.1665	0.0488	0.0586	0.0588	0.0128	0.0136
Smith 2	3.7%	20.2%	0.0820	0.0791	0.0862	0.0826	0.0550	0.0600	0.0000	0.0457	0.0457
Daniel 1	0.7%	3.8%	0.0246	0.0378	0.0387	0.0213	0.0074	0.0076	0.1366	0.0590	0.0684
Daniel 2	2.0%	10.8%	0.1913	0.0323	0.0400	0.0191	0.0232	0.0236	0.1274	0.0596	0.0684
Weighted GPIF System Average			0.0871	0.0756	0.0826	0.0824	0.0557	0.0613	0.0600	0.1045	0.1078

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '04 - Jun '05			Actual Performance 4th Prior Period Jul '03 - Jun '04			Actual Performance 5th Prior Period Jul '02 - Jun '03		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.1%	0.6%	0.0222	0.0228	0.0235	0.0598	0.0176	0.0187	0.0581	0.0030	0.0032
Crist 5	0.2%	1.2%	0.0219	0.0236	0.0244	0.0571	0.0239	0.0254	0.0598	0.0061	0.0065
Crist 6	2.0%	10.8%	0.0000	0.1079	0.1079	0.0650	0.1112	0.1191	0.0589	0.0399	0.0424
Crist 7	8.5%	46.2%	0.2054	0.1587	0.1997	0.2192	0.0472	0.0604	0.1199	0.0136	0.0155
Smith 1	1.2%	6.4%	0.0403	0.0122	0.0127	0.0798	0.0512	0.0557	0.1019	0.0070	0.0078
Smith 2	3.7%	20.2%	0.1962	0.0259	0.0322	0.0388	0.0252	0.0262	0.3159	0.1825	0.2668
Daniel 1	0.7%	3.8%	0.1343	0.0381	0.0440	0.0870	0.0407	0.0446	0.2250	0.0222	0.0287
Daniel 2	2.0%	10.8%	0.0743	0.0390	0.0422	0.1328	0.0212	0.0245	0.0526	0.0391	0.0413
Weighted GPIF System Average			0.1506	0.0970	0.1178	0.1399	0.0464	0.0544	0.1473	0.0531	0.0718

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '06 - Jun '07	2nd Prior Period Heat Rate Jul '05 - Jun '06	3rd Prior Period Heat Rate Jul '04 - Jun '05
Crist 4	3.3%	4.1%	10,696	10,868	10,642	10,605
Crist 5	3.7%	4.5%	10,552	10,626	10,589	10,514
Crist 6	11.1%	13.6%	10,365	10,420	10,405	10,261
Crist 7	21.3%	26.1%	10,375	10,542	10,349	10,316
Smith 1	9.0%	11.1%	10,238	10,253	10,293	10,169
Smith 2	8.5%	10.4%	10,314	10,291	10,312	10,408
Daniel 1	12.9%	15.9%	10,132	10,107	10,117	9,922
Daniel 2	11.6%	14.2%	10,016	10,029	20,325	10,063
Weighted GPIF System Average:			10,284	10,342	11,751	10,224

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '05 - Jun '06

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun	
1. Target Heat Rate*	10363.0 10419.0	10350.0 10237.0	10386.0 10096.0	10235.0 10401.0	10389.0 10488.0	10495.0 10583.0	
2. Target Heat Rate at Actual Conditions**	10399.0 10541.0	10403.0 10232.0	10393.0 10174.0	0.0 0.0	11829.0 10718.0	10478.0 10530.0	
3. Adjustments to Actual Heat Rate (1-2)	-36.0 -122.0	-53.0 5.0	-7.0 -78.0	10235.0 10401.0	-1440.0 -230.0	17.0 53.0	
4. Actual Heat Rate for Prior Period	10699.0 10125.0	10808.0 10328.0	10468.0 10296.0	0.0 0.0	11615.0 10572.0	10369.0 10519.0	
5. Adjusted actual Heat Rate (4+3)	10663.0 10003.0	10755.0 10333.0	10461.0 10218.0	10235.0 10401.0	10175.0 10342.0	10386.0 10572.0	
6. Forecast Net MWH Generation*	205806.8 147568.0	207417.0 139716.3	196405.6 212025.7	199075.1 194564.3	46046.0 190932.8	147065.6 195117.8	
7. Adjusted Actual Heat Rate for Jul '05 - Jun '06 = (Σ ((5) * (6))) / (Σ (6))							10,405

* For the January 2008 - December 2008 time period.

** Based on the target heat rate equation from Page 2 of Schedule 1 using actual rather than forecast variable values.

Derivation of Weighting Factors

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 4	EA-1	$566,468	$566,456	$12	0.1%
Crist 4	ANOHR-1	$566,468	$566,118	$350	3.3%
Crist 5	EA-2	$566,468	$566,445	$23	0.2%
Crist 5	ANOHR-2	$566,468	$566,083	$385	3.7%
Crist 6	EA-3	$566,468	$566,259	$209	2.0%
Crist 6	ANOHR-3	$566,468	$565,303	$1,165	11.1%
Crist 7	EA-4	$566,468	$565,572	$896	8.5%
Crist 7	ANOHR-4	$566,468	$564,238	$2,230	21.3%
Smith 1	EA-5	$566,468	$566,343	$125	1.2%
Smith 1	ANOHR-5	$566,468	$565,520	$948	9.0%
Smith 2	EA-6	$566,468	$566,076	$392	3.7%
Smith 2	ANOHR-6	$566,468	$565,576	$892	8.5%
Daniel 1	EA-7	$566,468	$566,395	$73	0.7%
Daniel 1	ANOHR-7	$566,468	$565,111	$1,357	12.9%
Daniel 2	EA-8	$566,468	$566,258	$210	2.0%
Daniel 2	ANOHR-8	$566,468	$565,253	$1,215	11.6%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	12	79.40	+ 10	350	10,375
+ 9	11	79.35	+ 9	315	10,400
+ 8	10	79.30	+ 8	280	10,424
+ 7	8	79.25	+ 7	245	10,449
+ 6	7	79.20	+ 6	210	10,473
+ 5	6	79.15	+ 5	175	10,498
+ 4	5	79.10	+ 4	140	10,523
+ 3	4	79.05	+ 3	105	10,547
+ 2	2	79.00	+ 2	70	10,572
+ 1	1	78.95	+ 1	35	10,596
				0	10,621
0	0	78.90	0	0	10,696
				0	10,771
- 1	(3)	78.84	- 1	(35)	10,796
- 2	(6)	78.78	- 2	(70)	10,820
- 3	(9)	78.72	- 3	(105)	10,845
- 4	(12)	78.66	- 4	(140)	10,869
- 5	(15)	78.60	- 5	(175)	10,894
- 6	(18)	78.54	- 6	(210)	10,919
- 7	(21)	78.48	- 7	(245)	10,943
- 8	(24)	78.42	- 8	(280)	10,968
- 9	(27)	78.36	- 9	(315)	10,992
- 10	(30)	78.30	- 10	(350)	11,017
Weighting Factor:		0.001	Weighting Factor:		0.033

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	23	89.80	+ 10	385	10,235
+ 9	21	89.72	+ 9	347	10,259
+ 8	18	89.64	+ 8	308	10,283
+ 7	16	89.56	+ 7	270	10,308
+ 6	14	89.48	+ 6	231	10,332
+ 5	12	89.40	+ 5	193	10,356
+ 4	9	89.32	+ 4	154	10,380
+ 3	7	89.24	+ 3	116	10,404
+ 2	5	89.16	+ 2	77	10,429
+ 1	2	89.08	+ 1	39	10,453
				0	10,477
0	0	89.00	0	0	10,552
				0	10,627
- 1	(3)	88.87	- 1	(39)	10,651
- 2	(7)	88.74	- 2	(77)	10,675
- 3	(10)	88.61	- 3	(116)	10,700
- 4	(14)	88.48	- 4	(154)	10,724
- 5	(17)	88.35	- 5	(193)	10,748
- 6	(20)	88.22	- 6	(231)	10,772
- 7	(24)	88.09	- 7	(270)	10,796
- 8	(27)	87.96	- 8	(308)	10,821
- 9	(31)	87.83	- 9	(347)	10,845
- 10	(34)	87.70	- 10	(385)	10,869
Weighting Factor:		0.002	Weighting Factor:		0.037

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	209	87.00	+ 10	1,165	10,054
+ 9	188	86.79	+ 9	1,049	10,078
+ 8	167	86.58	+ 8	932	10,101
+ 7	146	86.37	+ 7	816	10,125
+ 6	125	86.16	+ 6	699	10,148
+ 5	105	85.95	+ 5	583	10,172
+ 4	84	85.74	+ 4	466	10,196
+ 3	63	85.53	+ 3	350	10,219
+ 2	42	85.32	+ 2	233	10,243
+ 1	21	85.11	+ 1	117	10,266
				0	10,290
0	0	84.90	0	0	10,365
				0	10,440
- 1	(44)	84.59	- 1	(117)	10,464
- 2	(88)	84.28	- 2	(233)	10,487
- 3	(133)	83.97	- 3	(350)	10,511
- 4	(177)	83.66	- 4	(466)	10,534
- 5	(221)	83.35	- 5	(583)	10,558
- 6	(265)	83.04	- 6	(699)	10,582
- 7	(309)	82.73	- 7	(816)	10,605
- 8	(354)	82.42	- 8	(932)	10,629
- 9	(398)	82.11	- 9	(1,049)	10,652
- 10	(442)	81.80	- 10	(1,165)	10,676
Weighting Factor:		0.020	Weighting Factor:		0.111

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	896	85.00	+ 10	2,230	10,064
+ 9	806	84.71	+ 9	2,007	10,088
+ 8	717	84.42	+ 8	1,784	10,111
+ 7	627	84.13	+ 7	1,561	10,135
+ 6	538	83.84	+ 6	1,338	10,158
+ 5	448	83.55	+ 5	1,115	10,182
+ 4	358	83.26	+ 4	892	10,206
+ 3	269	82.97	+ 3	669	10,229
+ 2	179	82.68	+ 2	446	10,253
+ 1	90	82.39	+ 1	223	10,276
				0	10,300
0	0	82.10	0	0	10,375
				0	10,450
- 1	(132)	81.66	- 1	(223)	10,474
- 2	(263)	81.22	- 2	(446)	10,497
- 3	(395)	80.78	- 3	(669)	10,521
- 4	(527)	80.34	- 4	(892)	10,544
- 5	(659)	79.90	- 5	(1,115)	10,568
- 6	(790)	79.46	- 6	(1,338)	10,592
- 7	(922)	79.02	- 7	(1,561)	10,615
- 8	(1,054)	78.58	- 8	(1,784)	10,639
- 9	(1,185)	78.14	- 9	(2,007)	10,662
- 10	(1,317)	77.70	- 10	(2,230)	10,686
Weighting Factor:		0.085	Weighting Factor:		0.213

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	125	97.90	+ 10	948	9,931
+ 9	113	97.81	+ 9	853	9,954
+ 8	100	97.72	+ 8	758	9,977
+ 7	88	97.63	+ 7	664	10,001
+ 6	75	97.54	+ 6	569	10,024
+ 5	63	97.45	+ 5	474	10,047
+ 4	50	97.36	+ 4	379	10,070
+ 3	38	97.27	+ 3	284	10,093
+ 2	25	97.18	+ 2	190	10,117
+ 1	13	97.09	+ 1	95	10,140
				0	10,163
0	0	97.00	0	0	10,238
				0	10,313
- 1	(16)	96.87	- 1	(95)	10,336
- 2	(33)	96.74	- 2	(190)	10,359
- 3	(49)	96.61	- 3	(284)	10,383
- 4	(66)	96.48	- 4	(379)	10,406
- 5	(82)	96.35	- 5	(474)	10,429
- 6	(98)	96.22	- 6	(569)	10,452
- 7	(115)	96.09	- 7	(664)	10,475
- 8	(131)	95.96	- 8	(758)	10,499
- 9	(148)	95.83	- 9	(853)	10,522
- 10	(164)	95.70	- 10	(948)	10,545
Weighting Factor:		0.012	Weighting Factor:		0.090

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	392	86.30	+ 10	892	10,005
+ 9	353	86.06	+ 9	803	10,028
+ 8	314	85.82	+ 8	714	10,052
+ 7	274	85.58	+ 7	624	10,075
+ 6	235	85.34	+ 6	535	10,099
+ 5	196	85.10	+ 5	446	10,122
+ 4	157	84.86	+ 4	357	10,145
+ 3	118	84.62	+ 3	268	10,169
+ 2	78	84.38	+ 2	178	10,192
+ 1	39	84.14	+ 1	89	10,216
				0	10,239
0	0	83.90	0	0	10,314
				0	10,389
- 1	(57)	83.54	- 1	(89)	10,412
- 2	(115)	83.18	- 2	(178)	10,436
- 3	(172)	82.82	- 3	(268)	10,459
- 4	(230)	82.46	- 4	(357)	10,483
- 5	(287)	82.10	- 5	(446)	10,506
- 6	(344)	81.74	- 6	(535)	10,529
- 7	(402)	81.38	- 7	(624)	10,553
- 8	(459)	81.02	- 8	(714)	10,576
- 9	(517)	80.66	- 9	(803)	10,600
- 10	(574)	80.30	- 10	(892)	10,623
Weighting Factor:		0.037	Weighting Factor:		0.085

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	73	94.90	+ 10	1,357	9,828
+ 9	66	94.79	+ 9	1,221	9,851
+ 8	58	94.68	+ 8	1,086	9,874
+ 7	51	94.57	+ 7	950	9,897
+ 6	44	94.46	+ 6	814	9,920
+ 5	37	94.35	+ 5	679	9,943
+ 4	29	94.24	+ 4	543	9,965
+ 3	22	94.13	+ 3	407	9,988
+ 2	15	94.02	+ 2	271	10,011
+ 1	7	93.91	+ 1	136	10,034
				0	10,057
0	0	93.80	0	0	10,132
				0	10,207
- 1	(21)	93.63	- 1	(136)	10,230
- 2	(41)	93.46	- 2	(271)	10,253
- 3	(62)	93.29	- 3	(407)	10,276
- 4	(82)	93.12	- 4	(543)	10,299
- 5	(103)	92.95	- 5	(679)	10,322
- 6	(123)	92.78	- 6	(814)	10,344
- 7	(144)	92.61	- 7	(950)	10,367
- 8	(164)	92.44	- 8	(1,086)	10,390
- 9	(185)	92.27	- 9	(1,221)	10,413
- 10	(205)	92.10	- 10	(1,357)	10,436
Weighting Factor:		0.007	Weighting Factor:		0.129

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2008 - December 2008

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	210	78.60	+ 10	1,215	9,716
+ 9	189	78.50	+ 9	1,094	9,739
+ 8	168	78.40	+ 8	972	9,761
+ 7	147	78.30	+ 7	851	9,784
+ 6	126	78.20	+ 6	729	9,806
+ 5	105	78.10	+ 5	608	9,829
+ 4	84	78.00	+ 4	486	9,851
+ 3	63	77.90	+ 3	365	9,874
+ 2	42	77.80	+ 2	243	9,896
+ 1	21	77.70	+ 1	122	9,919
				0	9,941
0	0	77.60	0	0	10,016
				0	10,091
- 1	(28)	77.46	- 1	(122)	10,114
- 2	(56)	77.32	- 2	(243)	10,136
- 3	(84)	77.18	- 3	(365)	10,159
- 4	(112)	77.04	- 4	(486)	10,181
- 5	(140)	76.90	- 5	(608)	10,204
- 6	(168)	76.76	- 6	(729)	10,226
- 7	(196)	76.62	- 7	(851)	10,249
- 8	(224)	76.48	- 8	(972)	10,271
- 9	(252)	76.34	- 9	(1,094)	10,294
- 10	(280)	76.20	- 10	(1,215)	10,316
Weighting Factor:		0.020	Weighting Factor:		0.116

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 4	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	12.9	0.0	48.0	99.2	99.2	99.4	
2.	POF (%)	87.1	100.0	51.7	0.0	0.0	0.0	
3.	EUOF (%)	0.0	0.0	0.3	0.8	0.8	0.6	
4.	EUOR (%)	0.0	0.0	0.6	0.8	0.8	0.6	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	96.0	0.0	357.0	716.0	740.0	716.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	648.0	696.0	386.0	4.0	4.0	4.0	
9.	POH	648.0	696.0	384.0	0.0	0.0	0.0	
10.	FOH & EFOH	0.0	0.0	2.0	6.0	6.0	4.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	70956.0	0.0	284039.0	549488.0	565330.0	576134.0	
13.	Net Gen (MWH)	6768.0	0.0	26964.0	52703.6	52432.8	52788.5	
14.	ANOHR (Btu/KWH)	10484.0	-	10534.0	10426.0	10782.0	10914.0	
15.	NOF %	90.4	0.0	96.8	94.4	90.8	94.5	
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [-508.01 + 11.33 * MAR + 21.63 * MAY + 36.12 * JUN + 26.37 * JUL + 39.93 * AUG + 26.37 * SEP + 18.89 * OCT + 12.20 * NOV] + 28,136 - 0.14571 * LSRF / AKW

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 4	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	99.5	99.5	99.2	99.2	99.2	89.5	78.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	19.7
3.	EUOF (%)	0.5	0.5	0.8	0.8	0.8	10.5	1.4
4.	EUOR (%)	0.5	0.5	0.8	0.8	0.8	10.5	1.7
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	740.0	740.0	716.0	740.0	717.0	668.0	6946.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	4.0	4.0	4.0	4.0	4.0	76.0	1838.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1728.0
10.	FOH & EFOH	4.0	4.0	6.0	6.0	6.0	6.0	50.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	72.0	72.0
12.	Oper MBtu	593870.0	607443.0	570596.0	577839.0	562826.0	495189.0	5453710.0
13.	Net Gen (MWH)	55202.6	55601.2	52960.5	54018.8	53212.3	47250.9	509903.2
14.	ANOHR (Btu/KWH)	10758.0	10925.0	10774.0	10697.0	10577.0	10480.0	10696.0
15.	NOF %	95.6	96.3	94.8	93.6	95.1	90.7	94.1
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [-508.01 + 11.33 * MAR + 21.63 * MAY + 36.12 * JUN + 26.37 * JUL + 39.93 * AUG + 26.37 * SEP + 18.89 * OCT + 12.20 * NOV] + 28,136 - 0.14571 * LSRF / AKW

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 5	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	98.8	47.4	50.9	98.8	98.8	98.8	
2.	POF (%)	0.0	51.7	48.5	0.0	0.0	0.0	
3.	EUOF (%)	1.2	0.9	0.6	1.2	1.2	1.2	
4.	EUOR (%)	1.2	1.8	1.3	1.3	1.2	1.3	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	735.0	332.0	379.0	711.0	735.0	711.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	9.0	364.0	364.0	9.0	9.0	9.0	
9.	POH	0.0	360.0	360.0	0.0	0.0	0.0	
10.	FOH & EFOH	9.0	6.0	5.0	9.0	9.0	9.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	563923.0	253589.0	296638.0	539183.0	555816.0	556201.0	
13.	Net Gen (MWH)	54192.1	24355.5	28602.6	52587.8	52174.6	52511.4	
14.	ANOHR (Btu/KWH)	10406.0	10412.0	10371.0	10253.0	10653.0	10592.0	
15.	NOF %	94.5	94.1	96.8	94.8	91.0	94.7	
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [107.79 - 10.84 * APR + 13.62 * MAY + 14.07 * JUN + 22.79 * JUL + 23.21 * AUG + 28.04 * SEP + 23.17 * OCT] + 8,943

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 5	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	98.8	98.8	98.8	98.5	85.4	92.2	89.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	1.2	1.2	1.2	1.5	14.6	7.8	2.8
4.	EUOR (%)	1.2	1.2	1.3	1.5	14.6	7.8	3.1
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	735.0	735.0	711.0	735.0	618.0	688.0	7825.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	9.0	9.0	9.0	9.0	103.0	56.0	959.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	9.0	9.0	9.0	11.0	9.0	10.0	104.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	96.0	48.0	144.0
12.	Oper MBtu	587333.0	592218.0	567180.0	577441.0	475659.0	511931.0	6077112.0
13.	Net Gen (MWH)	54947.4	55451.1	52619.0	53805.5	45736.4	48955.8	575939.2
14.	ANOHR (Btu/KWH)	10689.0	10680.0	10779.0	10732.0	10400.0	10457.0	10552.0
15.	NOF %	95.8	96.7	94.9	93.9	94.9	91.2	94.4
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [107.79 - 10.84 * APR + 13.62 * MAY + 14.07 * JUN + 22.79 * JUL + 23.21 * AUG + 28.04 * SEP + 23.17 * OCT] + 8,943

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 6	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	71.6	73.3	96.6	96.7	96.9	96.9	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	28.4	26.7	3.4	3.3	3.1	3.1	
4.	EUOR (%)	28.4	26.7	3.4	3.3	3.1	3.1	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	535.0	512.0	720.0	698.0	721.0	698.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	209.0	184.0	23.0	22.0	23.0	22.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	19.0	18.0	25.0	24.0	23.0	22.0	
11.	MOH & EMOH	192.0	168.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1537511.0	1430276.0	2140611.0	2023663.0	2002503.0	2064932.0	
13.	Net Gen (MWH)	147568.0	139716.3	212025.7	194564.3	190932.8	195117.8	
14.	ANOHR (Btu/KWH)	10419.0	10237.0	10096.0	10401.0	10488.0	10583.0	
15.	NOF %	91.3	90.4	97.5	92.3	87.7	92.6	
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [457.20 - 54.35 * FEB - 64.08 * MAR + 52.17 * JUN - 50.16 * OCT] + 8,761

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 6	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	96.9	96.9	96.9	96.6	22.7	75.0	84.9
2.	POF (%)	0.0	0.0	0.0	0.0	76.6	22.6	8.2
3.	EUOF (%)	3.1	3.1	3.1	3.4	0.7	2.4	6.9
4.	EUOR (%)	3.1	3.1	3.1	3.4	3.0	3.1	7.5
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	721.0	721.0	698.0	721.0	164.0	558.0	7467.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	23.0	23.0	22.0	23.0	557.0	186.0	1317.0
9.	POH	0.0	0.0	0.0	0.0	552.0	168.0	720.0
10.	FOH & EFOH	23.0	23.0	22.0	25.0	5.0	18.0	247.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	360.0
12.	Oper MBtu	2132776.0	2146766.0	2039869.0	2037534.0	478372.0	1543453.0	21578266.0
13.	Net Gen (MWH)	205806.8	207417.0	196405.6	199075.1	46046.0	147065.6	2081741.0
14.	ANOHR (Btu/KWH)	10363.0	10350.0	10386.0	10235.0	10389.0	10495.0	10365.0
15.	NOF %	94.5	95.3	93.2	91.4	93.0	87.3	92.3
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [457.20 - 54.35 * FEB - 64.08 * MAR + 52.17 * JUN - 50.16 * OCT] + 8,761

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 7	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	69.8	64.8	94.1	94.0	94.4	94.3	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	30.2	35.2	5.9	6.0	5.6	5.7	
4.	EUOR (%)	30.2	35.2	5.9	6.0	5.6	5.7	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	521.0	453.0	701.0	679.0	702.0	679.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	223.0	243.0	42.0	41.0	42.0	41.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	33.0	29.0	44.0	43.0	42.0	41.0	
11.	MOH & EMOH	192.0	216.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	2445125.0	2049058.0	3479107.0	3293187.0	3249459.0	3324201.0	
13.	Net Gen (MWH)	236221.1	203724.2	329648.2	313040.6	313351.9	315239.5	
14.	ANOHR (Btu/KWH)	10351.0	10058.0	10554.0	10520.0	10370.0	10545.0	
15.	NOF %	96.1	95.3	99.6	97.7	94.6	98.4	
16.	NPC (MW)	472.0	472.0	472.0	472.0	472.0	472.0	

19.	ANOHR Equation	10^6 / AKW * [575.62 - 136.35 * FEB + 117.15 * MAR + 87.68 * APR + 104.03 * JUN] + 9,081

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	CRIST 7	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	94.4	94.4	94.3	94.1	65.7	30.4	82.1
2.	POF (%)	0.0	0.0	0.0	0.0	30.0	67.7	8.2
3.	EUOF (%)	5.6	5.6	5.7	5.9	4.3	1.9	9.7
4.	EUOR (%)	5.6	5.6	5.7	5.9	6.1	5.8	10.6
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	702.0	702.0	679.0	702.0	476.0	227.0	7223.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	42.0	42.0	41.0	42.0	245.0	517.0	1561.0
9.	POH	0.0	0.0	0.0	0.0	216.0	504.0	720.0
10.	FOH & EFOH	42.0	42.0	41.0	44.0	31.0	14.0	446.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	408.0
12.	Oper MBtu	3378374.0	3389495.0	3260113.0	3338837.0	2280367.0	1056267.0	34543590.0
13.	Net Gen (MWH)	327520.5	328758.0	315963.7	323186.2	220944.4	101926.8	3329525.1
14.	ANOHR (Btu/KWH)	10315.0	10310.0	10318.0	10331.0	10321.0	10363.0	10375.0
15.	NOF %	98.8	99.2	98.6	97.5	98.3	95.1	97.7
16.	NPC (MW)	472.0	472.0	472.0	472.0	472.0	472.0	472.0

19.	ANOHR Equation	10^6 / AKW * [575.62 - 136.35 * FEB + 117.15 * MAR + 87.68 * APR + 104.03 * JUN] + 9,081

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	SMITH 1	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	98.3	98.3	98.3	98.5	98.5	98.5	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.7	1.7	1.7	1.5	1.5	1.5	
4.	EUOR (%)	1.7	1.7	1.7	1.5	1.5	1.5	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	733.0	686.0	732.0	709.0	733.0	709.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	11.0	10.0	11.0	11.0	11.0	11.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	13.0	12.0	13.0	11.0	11.0	11.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1166149.0	1086585.0	1182191.0	1128996.0	1155029.0	1139934.0	
13.	Net Gen (MWH)	113970.8	106163.7	115651.6	110339.7	112806.8	110587.3	
14.	ANOHR (Btu/KWH)	10232.0	10235.0	10222.0	10232.0	10239.0	10308.0	
15.	NOF %	96.0	95.5	97.5	96.1	95.0	96.3	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [96.28 + 12.10 * JUN + 11.27 * JUL - 11.78 * OCT] + 9,613

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	SMITH 1	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	98.5	98.5	98.5	98.3	81.8	98.3	97.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	1.5	1.5	1.5	1.7	18.2	1.7	3.0
4.	EUOR (%)	1.5	1.5	1.5	1.7	18.2	1.7	3.0
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	733.0	733.0	709.0	733.0	592.0	733.0	8535.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	11.0	11.0	11.0	11.0	129.0	11.0	249.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	11.0	11.0	11.0	13.0	11.0	13.0	141.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	120.0	0.0	120.0
12.	Oper MBtu	1184648.0	1178507.0	1129984.0	1157937.0	936864.0	1139922.0	13586746.0
13.	Net Gen (MWH)	115036.7	115257.4	110447.1	114015.1	91526.4	111244.5	1327047.1
14.	ANOHR (Btu/KWH)	10298.0	10225.0	10231.0	10156.0	10236.0	10247.0	10238.0
15.	NOF %	96.9	97.1	96.2	96.0	95.4	93.7	96.0
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [96.28 + 12.10 * JUN + 11.27 * JUL - 11.78 * OCT] + 9,613

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	SMITH 2	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	94.4	94.3	76.2	41.0	39.7	94.6	
2.	POF (%)	0.0	0.0	0.0	40.0	58.1	0.0	
3.	EUOF (%)	5.6	5.7	23.8	19.0	2.2	5.4	
4.	EUOR (%)	5.6	5.7	23.8	31.7	5.4	5.4	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	704.0	658.0	567.0	295.0	295.0	681.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	40.0	38.0	176.0	425.0	449.0	39.0	
9.	POH	0.0	0.0	0.0	288.0	432.0	0.0	
10.	FOH & EFOH	42.0	40.0	33.0	17.0	17.0	39.0	
11.	MOH & EMOH	0.0	0.0	144.0	120.0	0.0	0.0	
12.	Oper MBtu	1342570.0	1248395.0	1093826.0	547541.0	536270.0	1295303.0	
13.	Net Gen (MWH)	130005.8	120863.1	105970.4	52953.7	52313.9	125416.6	
14.	ANOHR (Btu/KWH)	10327.0	10329.0	10322.0	10340.0	10251.0	10328.0	
15.	NOF %	94.7	94.2	95.8	92.1	90.9	94.4	
16.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	

19.	ANOHR Equation	10^6 / AKW * [275.87 - 16.87 * MAY - 11.84 * JUL - 10.07 * SEP] + 7.294 + 0.00822 * LSRF / AKW

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	SMITH 2	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	94.6	94.6	94.6	94.5	94.3	94.4	83.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	5.4	5.4	5.4	5.5	5.7	5.6	7.9
4.	EUOR (%)	5.4	5.4	5.4	5.5	5.7	5.6	8.6
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	704.0	704.0	681.0	704.0	682.0	704.0	7379.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	40.0	40.0	39.0	40.0	39.0	40.0	1405.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	40.0	40.0	39.0	41.0	41.0	42.0	431.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	264.0
12.	Oper MBtu	1346352.0	1362032.0	1288589.0	1323817.0	1300662.0	1308959.0	13994316.0
13.	Net Gen (MWH)	131236.2	131979.8	125434.5	128115.5	125947.7	126604.0	1356841.2
14.	ANOHR (Btu/KWH)	10259.0	10320.0	10273.0	10333.0	10327.0	10339.0	10314.0
15.	NOF %	95.6	96.1	94.5	93.3	94.7	92.2	94.3
16.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0

19.	ANOHR Equation	10^6 / AKW * [275.87 - 16.87 * MAY - 11.84 * JUL - 10.07 * SEP] + 7,294 + 0.00822 * LSRF / AKW

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	DANIEL 1	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	98.3	98.0	98.4	98.3	98.4	98.3	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.7	2.0	1.6	1.7	1.6	1.7	
4.	EUOR (%)	1.7	2.0	1.6	1.7	1.6	1.7	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	732.0	684.0	731.0	708.0	732.0	708.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	12.0	12.0	12.0	12.0	12.0	12.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	13.0	14.0	12.0	12.0	12.0	12.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3584896.0	3352906.0	3678450.0	3463692.0	3429481.0	3421588.0	
13.	Net Gen (MWH)	354133.8	331249.4	364998.0	342093.0	336256.6	337268.4	
14.	ANOHR (Btu/KWH)	10123.0	10122.0	10078.0	10125.0	10199.0	10145.0	
15.	NOF %	96.2	96.3	99.3	96.1	91.3	94.7	
16.	NPC (MW)	503.0	503.0	503.0	503.0	503.0	503.0	

19.	ANOHR Equation	10^6 / AKW * [695.23] + 8,686

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	DANIEL 1	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	98.4	98.4	98.3	73.0	68.9	98.4	93.8
2.	POF (%)	0.0	0.0	0.0	0.0	30.0	0.0	2.5
3.	EUOF (%)	1.6	1.6	1.7	27.0	1.1	1.6	3.7
4.	EUOR (%)	1.6	1.6	1.7	27.0	1.6	1.6	3.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	732.0	732.0	708.0	543.0	497.0	732.0	8239.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	12.0	12.0	12.0	201.0	224.0	12.0	545.0
9.	POH	0.0	0.0	0.0	0.0	216.0	0.0	216.0
10.	FOH & EFOH	12.0	12.0	12.0	9.0	8.0	12.0	140.0
11.	MOH & EMOH	0.0	0.0	0.0	192.0	0.0	0.0	192.0
12.	Oper MBtu	3603258.0	3632402.0	3464949.0	2543470.0	2435961.0	3521690.0	40132743.0
13.	Net Gen (MWH)	356264.4	359608.2	342251.0	249359.8	240660.0	346862.0	3961004.6
14.	ANOHR (Btu/KWH)	10114.0	10101.0	10124.0	10200.0	10122.0	10153.0	10132.0
15.	NOF %	96.8	97.7	96.1	91.3	96.3	94.2	95.6
16.	NPC (MW)	503.0	503.0	503.0	503.0	503.0	503.0	503.0

19.	ANOHR Equation	10^6 / AKW * [695.23] + 8,686

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	DANIEL 2	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	
1.	EAF (%)	97.0	96.8	53.2	96.9	97.0	96.9	
2.	POF (%)	0.0	0.0	45.2	0.0	0.0	0.0	
3.	EUOF (%)	3.0	3.2	1.6	3.1	3.0	3.1	
4.	EUOR (%)	3.0	3.2	2.9	3.1	3.0	3.1	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	722.0	675.0	395.0	698.0	722.0	698.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	22.0	21.0	348.0	22.0	22.0	22.0	
9.	POH	0.0	0.0	336.0	0.0	0.0	0.0	
10.	FOH & EFOH	22.0	22.0	12.0	22.0	22.0	22.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3587007.0	3363870.0	1929304.0	3482911.0	3350943.0	3452098.0	
13.	Net Gen (MWH)	356242.6	334181.4	196607.0	346041.8	339198.6	342708.0	
14.	ANOHR (Btu/KWH)	10069.0	10066.0	9813.0	10065.0	9879.0	10073.0	
15.	NOF %	96.7	97.1	97.6	97.2	92.1	96.3	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [398.00 - 123.89 * MAR - 108.06 * MAY - 96.34 * SEP] + 9,262

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2008 - December 2008

	DANIEL 2	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Total
1.	EAF (%)	97.0	97.0	96.9	0.0	16.2	87.6	77.6
2.	POF (%)	0.0	0.0	0.0	100.0	83.2	0.0	19.1
3.	EUOF (%)	3.0	3.0	3.1	0.0	0.6	12.4	3.3
4.	EUOR (%)	3.0	3.0	3.1	0.0	3.3	12.4	4.0
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	722.0	722.0	698.0	0.0	117.0	652.0	6821.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	22.0	22.0	22.0	744.0	604.0	92.0	1963.0
9.	POH	0.0	0.0	0.0	744.0	600.0	0.0	1680.0
10.	FOH & EFOH	22.0	22.0	22.0	0.0	4.0	20.0	212.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	72.0	72.0
12.	Oper MBtu	3587238.0	3633296.0	3399000.0	0.0	540320.0	3178111.0	33504098.0
13.	Net Gen (MWH)	356301.0	361270.4	344237.4	0.0	53307.0	315101.2	3345196.4
14.	ANOHR (Btu/KWH)	10068.0	10057.0	9874.0	-	10136.0	10086.0	10016.0
15.	NOF %	96.8	98.1	96.7	0.0	89.3	94.8	96.2
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [398.00 - 123.89 * MAR - 108.06 * MAY - 96.34 * SEP] + 9,262

Issued by: S. N. Story

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2008 - December 2008

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 4	01/05/08	-	03/16/08	General boiler maintenance and inspection and turbine overhaul.
Crist 5	02/15/08	-	03/15/08	Common stack and scrubber duct work.
Crist 6	11/08/07	-	12/07/08	General boiler maintenance and inspection and scrubber duct work.
Crist 7	11/22/08	-	12/21/08	General boiler maintenance and inspection and scrubber duct work.
Smith 2	04/19/08	-	05/18/08	General boiler maintenance and inspection and turbine valve work.
Daniel 1	11/08/08	-	11/16/08	Common stack, tunnel, and travelling water screen work.
Daniel 2	03/03/08	-	03/16/08	General boiler maintenance.
Daniel 2	10/01/08	-	11/25/08	Boiler overhaul, maintenance, and inspection.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2008 - December 2008

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2008 - December 2008, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage

None

Filed: September 4, 2007
Suspended:
Effective: January 1, 2008
Docket No.: 070001-EI
Order No.:

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

Before me, the undersigned authority, personally appeared Lonzelle S. Noack, who being first duly sworn, deposes, and says that she is the Power Generation Specialist, Senior for Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Lonzelle S. Noack
Power Generation Specialist, Senior

Sworn to and subscribed before me this 29th day of August, 2007.

Notary Public, State of Florida at Large

LINDA C. WEBB
Notary Public-State of Florida
Comm. Exp. May 31, 2010
Comm. No. DD 541216

Commission Number: DD 541216

Commission Expires: May 31, 2010

DOCKET NO. 070001-EI
FAC 2006 FINAL TRUE-UP
EXHIBIT CA-1
DOCUMENT NO. 4

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2006 - DECEMBER 2006

SCHEDULES A1 THROUGH A9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 34
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-1)
DATE 11-06-07

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JANUARY 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	57,071,562	60,871,485	(3,799,923)	-6.2%	1,450,424	1,381,086	69,338	5.0%	3.93482	4.40751	(0.47269)	-10.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,028)	(6,734)	(294)	4.4%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	(0.00048)	(0.00049)	0.00000	-0.6%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	0	0	0	0.0%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	57,064,534	60,864,751	(3,800,217)	-6.2%	1,450,424	1,381,086	69,338	5.0%	3.93433	4.40702	(0.47269)	-10.7%
6. Fuel Cost of Purchased Power - Firm (A7)	1,544,930	11,825,800	(10,280,870)	-86.9%	31,505	198,168	(166,663)	-84.1%	4.90376	5.96756	(1.06380)	-17.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	2,974,114	0	2,974,114	0.0%	44,448	0	44,448	0.0%	6.69122	0.00000	6.69122	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,182,219	1,033,800	148,419	14.4%	41,790	35,798	5,992	16.7%	2.82895	2.88787	(0.05892)	-2.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	5,701,263	12,859,600	(7,158,337)	-55.7%	117,743	233,966	(116,223)	-49.7%	4.84212	5.49635	(0.65423)	-11.9%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,568,167	1,615,052	(46,885)	-2.9%				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	51,126	18,100	33,026	182.5%	1,230	971	259	26.7%	4.15659	1.86406	2.29253	123.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sep. Sales (A6)	402,653	0	402,653	0.0%	7,440	0	7,440	0.0%	5.41200	0.00000	5.41200	0.0%
17. Fuel Cost of Market Base Sales (A6)	781,493	1,241,300	(459,807)	-37.0%	12,868	27,706	(14,838)	-53.6%	6.07315	4.48026	1.59289	35.6%
18. Gains on Market Based Sales	146,276	912,100	(765,824)	-84.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	1,381,548	2,171,500	(789,952)	-36.4%	21,538	28,677	(7,139)	-24.9%	6.41447	7.57227	(1.15780)	-15.3%
20. Net Inadvertant Interchange					(1,051)	0	(1,051)	0.0%				
21. Wheeling Rec'd. less Wheeling Del'v'd.					614	0	614	0.0%				
22. Interchange and Wheeling Losses					1,147	500	647	129.4%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	61,384,248	71,552,851	(10,168,602)	-14.2%	1,545,045	1,585,875	(40,830)	-2.6%	3.97297	4.51188	(0.53891)	-11.9%
24. Net Unbilled	(4,937,414) (a)	(2,821,011) (a)	(2,116,403)	75.0%	(124,275)	(62,524)	(61,751)	98.8%	3.97297	4.51189	(0.53891)	-11.9%
25. Company Use	119,865 (a)	139,868 (a)	(20,003)	-14.3%	3,017	3,100	(83)	-2.7%	3.97299	4.51187	(0.53888)	-11.9%
26. T & D Losses	4,438,607 (a)	3,224,509 (a)	1,214,098	37.7%	111,720	71,467	40,253	56.3%	3.97297	4.51189	(0.53891)	-11.9%
27. System KWH Sales	61,384,248	71,552,851	(10,168,602)	-14.2%	1,554,583	1,573,832	(19,249)	-1.2%	3.94860	4.54641	(0.59781)	-13.1%
28. Wholesale KWH Sales	(3,353,624)	(1,241,628)	(2,111,997)	170.1%	(84,932)	(27,310)	(57,622)	211.0%	3.94860	4.54642	(0.59782)	-13.1%
29. Jurisdictional KWH Sales	58,030,624	70,311,223	(12,280,599)	-17.5%	1,469,651	1,546,522	(76,871)	-5.0%	3.94860	4.54641	(0.59781)	-13.1%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	58,080,530	70,371,691	(12,291,161)	-17.5%	1,469,651	1,546,522	(76,871)	-5.0%	3.95199	4.55032	(0.59832)	-13.1%
32. Other	0	0	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,071,311)	(1,276,250)	204,939	-16.1%	1,469,651	1,546,522	(76,871)	-5.0%	(0.07290)	(0.08252)	0.00963	-11.7%
34. Other	0	0	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.83725	0.79564	0.04162	5.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	69,313,904	81,400,126	(12,086,222)	-14.8%	1,469,651	1,546,522	(76,871)	-5.0%	4.71635	5.26343	(0.54708)	-10.4%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	69,363,810	81,458,734	(12,094,924)	-14.8%	1,469,651	1,546,522	(76,871)	-5.0%	4.71975	5.26722	(0.54747)	-10.4%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00414	0.00393	0.00021	5.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	69,424,605	81,519,529	(12,094,924)	-14.8%	1,469,651	1,546,522	(76,871)	-5.0%	4.72389	5.27115	(0.54726)	-10.4%
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									4.724	5.271	(0.547)	-10.4%

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JANUARY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	57,071,562	60,871,485	(3,799,923)	-6.2%	1,450,424	1,381,086	69,338	5.0%	3.93482	4.40751	(0.47269)	-10.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,028)	(6,734)	(294)	4.4%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	(0.00048)	(0.00049)	0.00000	-0.6%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	0	0	0	0.0%	1,450,424 (a)	1,381,086 (a)	69,338	5.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**57,064,534**	**60,864,751**	**(3,800,217)**	**-6.2%**	**1,450,424**	**1,381,086**	**69,338**	**5.0%**	**3.93433**	**4.40702**	**(0.47269)**	**-10.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	1,544,930	11,825,800	(10,280,870)	-86.9%	31,505	198,168	(166,663)	-84.1%	4.90376	5.96756	(1.06380)	-17.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	2,974,114	0	2,974,114	0.0%	44,448	0	44,448	0.0%	6.69122	0.00000	6.69122	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,182,219	1,033,800	148,419	14.4%	41,790	35,798	5,992	16.7%	2.82895	2.88787	(0.05892)	-2.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**5,701,263**	**12,859,600**	**(7,158,337)**	**-55.7%**	**117,743**	**233,966**	**(116,223)**	**-49.7%**	**4.84212**	**5.49635**	**(0.65423)**	**-11.9%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,568,167**	**1,615,052**	**(46,885)**	**-2.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	51,126	18,100	33,026	182.5%	1,230	971	259	26.7%	4.15659	1.86406	2.29253	123.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sep. Sales (A6)	402,653	0	402,653	0.0%	7,440	0	7,440	0.0%	5.41200	0.00000	5.41200	0.0%
17. Fuel Cost of Market Base Sales (A6)	781,493	1,241,300	(459,807)	-37.0%	12,868	27,706	(14,838)	-53.6%	6.07315	4.48026	1.59289	35.6%
18. Gains on Market Based Sales	146,276	912,100	(765,824)	-84.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**1,381,548**	**2,171,500**	**(789,952)**	**-36.4%**	**21,538**	**28,677**	**(7,139)**	**-24.9%**	**6.41447**	**7.57227**	**(1.15780)**	**-15.3%**
20. Net Inadvertant Interchange					(1,051)	0	(1,051)	0.0%				
21. Wheeling Rec'd. less Wheeling Del'd.					614	0	614	0.0%				
22. Interchange and Wheeling Losses					1,147	500	647	129.4%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**61,384,248**	**71,552,851**	**(10,168,602)**	**-14.2%**	**1,545,045**	**1,585,875**	**(40,830)**	**-2.6%**	**3.97297**	**4.51188**	**(0.53891)**	**-11.9%**
24. Net Unbilled	(4,937,414) (a)	(2,821,011) (a)	(2,116,403)	75.0%	(124,275)	(62,524)	(61,751)	98.8%	3.97297	4.51189	(0.53891)	-11.9%
25. Company Use	119,865 (a)	139,868 (a)	(20,003)	-14.3%	3,017	3,100	(83)	-2.7%	3.97299	4.51187	(0.53888)	-11.9%
26. T & D Losses	4,438,607 (a)	3,224,509 (a)	1,214,098	37.7%	111,720	71,467	40,253	56.3%	3.97297	4.51189	(0.53891)	-11.9%
27. System KWH Sales	61,384,248	71,552,851	(10,168,602)	-14.2%	1,554,583	1,573,832	(19,249)	-1.2%	3.94860	4.54641	(0.59781)	-13.1%
28. Wholesale KWH Sales	(3,353,624)	(1,241,628)	(2,111,997)	170.1%	(84,932)	(27,310)	(57,622)	211.0%	3.94860	4.54642	(0.59782)	-13.1%
29. Jurisdictional KWH Sales	58,030,624	70,311,223	(12,280,599)	-17.5%	1,469,651	1,546,522	(76,871)	-5.0%	3.94860	4.54641	(0.59781)	-13.1%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	58,080,530	70,371,691	(12,291,161)	-17.5%	1,469,651	1,546,522	(76,871)	-5.0%	3.95199	4.55032	(0.59832)	-13.1%
32. Peabody Coal Contract Buy-Out Amort. Jurisd.	0	0	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,071,311)	(1,276,250)	204,939	-16.1%	1,469,651	1,546,522	(76,871)	-5.0%	(0.07290)	(0.08252)	0.00963	-11.7%
34. Other	0	0	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.83725	0.79564	0.04162	5.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	69,313,904	81,400,126	(12,086,222)	-14.8%	1,469,651	1,546,522	(76,871)	-5.0%	4.71635	5.26343	(0.54708)	-10.4%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	69,363,810	81,458,734	(12,094,924)	-14.8%	1,469,651	1,546,522	(76,871)	-5.0%	4.71975	5.26722	(0.54747)	-10.4%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,469,651	1,546,522	(76,871)	-5.0%	0.00414	0.00393	0.00021	5.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**69,424,605**	**81,519,529**	**(12,094,924)**	**-14.8%**	**1,469,651**	**1,546,522**	**(76,871)**	**-5.0%**	**4.72389**	**5.27115**	**(0.54726)**	**-10.4%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									4.724	5.271	(0.547)	-10.4%

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	57,071,562	60,871,485	(3,799,923)	-6.2%	57,071,562	60,871,485	(3,799,923)	-6.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,235,272	1,259,400	(24,128)	-1.9%	1,235,272	1,259,400	(24,128)	-1.9%
2a. GAINS FROM MARKET BASED SALES	146,276	912,100	(765,824)	-84.0%	146,276	912,100	(765,824)	-84.0%
3. FUEL COST OF PURCHASED POWER	1,544,930	11,825,800	(10,280,870)	-86.9%	1,544,930	11,825,800	(10,280,870)	-86.9%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,182,219	1,033,800	148,419	14.4%	1,182,219	1,033,800	148,419	14.4%
4. ENERGY COST OF ECONOMY PURCHASES	2,974,114	0	2,974,114	0.0%	2,974,114	0	2,974,114	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	61,391,277	71,559,585	(10,168,308)	-14.2%	61,391,277	71,559,585	(10,168,308)	-14.2%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,028)	(6,734)	(294)	4.4%	(7,028)	(6,734)	(294)	4.4%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	61,384,248	71,552,851	(10,168,602)	-14.2%	61,384,248	71,552,851	(10,168,602)	-14.2%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,469,651	1,546,522	(76,871)	-5.0%	1,469,651	1,546,522	(76,871)	-5.0%
2. NONJURISDICTIONAL SALES	84,932	27,310	57,622	211.0%	84,932	27,310	57,622	211.0%
3. TOTAL SALES	1,554,583	1,573,832	(19,249)	-1.2%	1,554,583	1,573,832	(19,249)	-1.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9453667	0.9826474	(0.0372807)	-3.8%	0.9453667	0.9826474	(0.0372807)	-3.8%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	78,892,520	83,626,789	(4,734,269)	-5.7%	78,892,520	83,626,789	(4,734,269)	-5.7%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(12,304,685)	(12,304,685)	0	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(60,795)	(60,795)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	66,527,040	71,261,309	(4,734,269)	-6.6%	66,527,040	71,261,309	(4,734,269)	-6.6%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	61,384,248	71,552,851	(10,168,602)	-14.2%	61,384,248	71,552,851	(10,168,602)	-14.2%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9453667	0.9826474	(0.0372807)	-3.8%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	58,030,624	70,311,223	(12,280,599)	-17.5%	58,030,624	70,311,223	(12,280,599)	-17.5%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	58,080,530	70,371,691	(12,291,161)	-17.5%	58,080,530	70,371,691	(12,291,161)	-17.5%
6c. Other	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,071,311)	(1,276,250)	204,939	-16.1%	(1,071,311)	(1,276,250)	204,939	-16.1%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	57,009,219	69,095,441	(12,086,222)	-17.5%	57,009,219	69,095,441	(12,086,222)	-17.5%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	9,517,821	2,165,868	7,351,953	339.4%	9,517,821	2,165,868	7,351,953	339.4%
8. INTEREST PROVISION FOR THE MONTH	(892,771)	(512,536)	(380,235)	74.2%	(892,771)	(512,536)	(380,235)	74.2%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(254,173,059)	(147,656,222)	(106,516,837)	72.1%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(233,243,324)	(133,698,205)	(99,545,119)	74.5%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(254,173,059)	(147,656,222)	(106,516,837)	72.1%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(232,350,553)	(133,185,669)	(99,164,884)	74.5%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(486,523,612)	(280,841,891)	(205,681,721)	73.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(243,261,806)	(140,420,946)	(102,840,860)	73.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	4.300	4.250	0	1.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	4.510	4.500	0	0.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	8.810	8.750	0	0.7%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	4.405	4.375	0	0.7%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.367	0.365	0	0.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(892,771)	(512,536)	(380,235)	74.2%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	389,094	36,192	352,902	975.1%	389,094	36,192	352,902	975.1%
2	LIGHT OIL	251,824	779,629	(527,805)	-67.7%	251,824	779,629	(527,805)	-67.7%
3	COAL	27,279,569	23,581,537	3,698,032	15.7%	27,279,569	23,581,537	3,698,032	15.7%
4	NATURAL GAS	29,151,075	36,474,127	(7,323,052)	-20.1%	29,151,075	36,474,127	(7,323,052)	-20.1%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	57,071,562	60,871,485	(3,799,923)	-6.2%	57,071,562	60,871,485	(3,799,923)	-6.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,294	460	3,834	833.5%	4,294	460	3,834	833.5%
9	LIGHT OIL	1,274	5,596	(4,322)	-77.2%	1,274	5,596	(4,322)	-77.2%
10	COAL	1,094,440	923,456	170,984	18.5%	1,094,440	923,456	170,984	18.5%
11	NATURAL GAS	351,690	451,574	(99,884)	-22.1%	351,690	451,574	(99,884)	-22.1%
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)	1,451,698	1,381,086	70,612	5.1%	1,451,698	1,381,086	70,612	5.1%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	6,912	714	6,198	868.1%	6,912	714	6,198	868.1%
16	LIGHT OIL (BBL)	3,048	15,203	(12,155)	-80.0%	3,048	15,203	(12,155)	-80.0%
17	COAL (TON)	486,287	413,414	72,873	17.6%	486,287	413,414	72,873	17.6%
18	NATURAL GAS (MCF)	2,589,107	3,289,433	(700,326)	-21.3%	2,589,107	3,289,433	(700,326)	-21.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	43,365	4,483	38,882	867.3%	43,365	4,483	38,882	867.3%
22	LIGHT OIL	16,183	67,181	(50,998)	-75.9%	16,183	67,181	(50,998)	-75.9%
23	COAL	11,529,189	9,951,190	1,577,999	15.9%	11,529,189	9,951,190	1,577,999	15.9%
24	NATURAL GAS	2,673,936	3,381,415	(707,479)	-20.9%	2,673,936	3,381,415	(707,479)	-20.9%
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)	14,262,673	13,404,269	858,404	6.4%	14,262,673	13,404,269	858,404	6.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.30%	0.03%	0.00	-	0.30%	0.03%	0.00	-
29	LIGHT OIL	0.09%	0.41%	(0.00)	-	0.09%	0.41%	(0.00)	-
30	COAL	75.39%	66.86%	0.09	-	75.39%	66.86%	0.09	-
31	NATURAL GAS	24.23%	32.70%	(0.08)	-	24.23%	32.70%	(0.08)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	56.29	50.69	5.60	11.1%	56.29	50.69	5.60	11.1%
36	LIGHT OIL ($/BBL)	82.62	51.28	31.34	61.1%	82.62	51.28	31.34	61.1%
37	COAL ($/TON)	56.10	57.04	(0.94)	-1.7%	56.10	57.04	(0.94)	-1.7%
38	NATURAL GAS ($/MCF)	11.26	11.09	0.17	1.5%	11.26	11.09	0.17	1.5%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	8.97	8.07	0.90	11.1%	8.97	8.07	0.90	11.1%
42	LIGHT OIL	15.56	11.60	3.96	34.1%	15.56	11.60	3.96	34.1%
43	COAL	2.37	2.37	(0.00)	-0.2%	2.37	2.37	(0.00)	-0.2%
44	NATURAL GAS	10.90	10.79	0.12	1.1%	10.90	10.79	0.12	1.1%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.00	4.54	(0.54)	-11.9%	4.00	4.54	(0.54)	-11.9%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,099	9,746	353	3.6%	10,099	9,746	353	3.6%
49	LIGHT OIL	12,703	12,005	698	5.8%	12,703	12,005	698	5.8%
50	COAL	10,534	10,776	(242)	-2.2%	10,534	10,776	(242)	-2.2%
51	NATURAL GAS	7,603	7,488	115	1.5%	7,603	7,488	115	1.5%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,825	9,706	119	1.2%	9,825	9,706	119	1.2%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	9.06	7.87	1.19	15.1%	9.06	7.87	1.19	15.1%
56	LIGHT OIL	19.77	13.93	5.84	41.9%	19.77	13.93	5.84	41.9%
57	COAL	2.49	2.55	(0.06)	-2.4%	2.49	2.55	(0.06)	-2.4%
58	NATURAL GAS	8.29	8.08	0.21	2.6%	8.29	8.08	0.21	2.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.93	4.41	(0.48)	-10.9%	3.93	4.41	(0.48)	-10.9%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)
B.B.#1	411	203,426	66.5	73.4	70.8	10,715	COAL	94,471	23,073,420	2,179,774.4	5,250,960	2.58	55.58
B.B.#2	391	252,579	86.8	93.1	86.8	10,191	COAL	108,291	23,769,860	2,574,062.9	6,019,114	2.38	55.58
B.B.#3	433	225,773	70.1	78.7	72.8	10,686	COAL	104,162	23,161,220	2,412,519.0	5,789,612	2.56	55.58
B.B.#4	462	251,103	73.1	83.4	81.0	10,999	COAL	120,235	22,969,800	2,761,773.9	6,682,994	2.66	55.58
B.B. STATION	1,697	932,881	73.9	82.0	77.8	10,642	COAL	427,159	23,242,221	9,928,130.2	23,742,680	2.55	55.58
SEB-PHIL #1(HVY OIL)	18	2,158	16.1	100.0	80.2	10,099	HVY.OIL	3,473	6,273,540	21,788.8	195,504	9.06	56.29
SEB-PHIL #2(HVY OIL)	18	2,136	16.0	100.0	79.5	10,099	HVY.OIL	3,439	6,273,540	21,576.3	193,590	9.06	56.29
SEB-PHILLIPS TOTAL	36	4,294	16.0	100.0	79.8	10,099	HVY.OIL	6,912	6,273,540	43,365.1	389,094	9.06	56.29
POLK #1 GASIFIER	260	160,285	-	-	-	9,989	COAL	59,128	27,078,000	1,601,058.8	3,536,889	2.21	59.82
POLK #1 CT (OIL)	245	1,274	-	-	-	12,678	LGT.OIL	3,042	5,783,923	16,150.1	251,370	19.73	82.64
POLK #1 TOTAL	260	161,559	83.5	91.2	93.1	10,010	-	-	-	1,617,208.9	3,788,259	2.34	-
POLK #2 CT (GAS)	175	1,490	-	-	-	10,305	GAS	23,651	1,037,000	17,057.0	248,202	16.66	10.49
POLK #2 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	180	1,490	1.1	100.0	54.6	10,305	-	-	-	17,057.0	248,202	16.66	-
POLK #3 CT (GAS)	175	1,828	-	-	-	7,992	GAS	18,321	1,037,000	15,500.0	196,884	10.77	10.75
POLK #3 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	180	1,828	1.4	100.0	56.0	7,992	-	-	-	15,500.0	196,884	10.77	-
POLK STATION TOTAL	620	164,877	35.7	96.3	71.1	9,990	-	-	-	1,649,765.9	4,233,345	2.57	-
B.B.C.T.#1 *	15	0	0.0	100.0	0.0	0	LGT.OIL	6	5,810,858	33.2	454	0.00	75.67
B.B.C.T.#2	80	0	0.0	98.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	80	0	0.0	98.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	175	0	0.0	98.5	0.0	0	LGT.OIL	6	5,810,858	33.2	454	0.00	75.67
COT 1 *	3	(7)	0.0	100.0	0.0	0	GAS	32	1,037,000	33.5	568	(8.11)	17.57
COT 2 *	3	(7)	0.0	100.0	0.0	0	GAS	31	1,037,000	32.5	550	(7.86)	17.56
CITY OF TAMPA TOTAL	6	(14)	0.0	100.0	0.0	0	GAS	64	2,074,000	66.0	1,118	(7.99)	17.57
BAYSIDE ST 1	244	5,901	3.3	99.8	37.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	183	2,882	2.1	100.0	50.2	11,196	GAS	31,122	1,037,000	32,273.0	350,736	12.17	11.27
BAYSIDE CT1B	183	6,833	5.0	85.6	71.1	11,563	GAS	76,189	1,037,000	79,008.0	858,628	12.57	11.27
BAYSIDE CT1C	183	2,455	1.8	82.8	63.9	9,868	GAS	23,363	1,037,000	24,227.0	263,290	10.72	11.27
BAYSIDE UNIT 1 TOTAL	793	18,071	3.1	92.7	54.3	7,499	GAS	130,674	1,037,000	135,508.0	1,472,654	8.15	11.27
BAYSIDE ST 2	316	113,294	48.2	99.6	48.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	183	53,953	39.6	95.8	68.1	11,558	GAS	601,330	1,037,000	623,579.0	6,776,842	12.56	11.27
BAYSIDE CT2B	183	55,841	41.0	95.0	68.8	11,308	GAS	608,911	1,037,000	631,441.0	6,862,279	12.29	11.27
BAYSIDE CT2C	183	57,461	42.2	100.0	68.5	11,653	GAS	645,704	1,037,000	669,595.0	7,276,927	12.66	11.27
BAYSIDE CT2D	183	49,765	36.6	100.0	70.3	11,679	GAS	560,453	1,037,000	581,190.0	6,316,169	12.69	11.27
BAYSIDE UNIT 2 TOTAL	1,048	330,315	42.4	98.3	62.7	7,586	GAS	2,416,398	1,037,000	2,505,805.0	27,232,217	8.24	11.27
BAYSIDE STATION TOTAL	1,841	348,386	25.4	95.9	59.1	7,582	GAS	2,547,072	1,037,000	2,641,313.0	28,704,871	8.24	11.27
TOT. COAL (BB,POLK)	1,957	1,094,440	75.2	83.2	79.8	10,547	COAL	486,287	23,708,614	11,529,189.0	27,279,569	2.49	56.10
SYSTEM	4,375	1,450,424	44.6	90.7	65.8	9,832	-	-	-	14,262,673.4	57,071,562	3.93	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
* Ran for testing only.
SEB-PHIL = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES								
2 UNITS (BBL)	7,804	714	7,090	993.0%	7,804	714	7,090	993.0%
3 UNIT COST ($/BBL)	52.27	48.78	3.50	7.2%	52.27	48.78	3.50	7.2%
4 AMOUNT ($)	407,942	34,826	373,116	1071.4%	407,942	34,826	373,116	1071.4%
5 BURNED								
6 UNITS (BBL)	6,912	714	6,198	868.1%	6,912	714	6,198	868.1%
7 UNIT COST ($/BBL)	56.29	50.69	5.60	11.1%	56.29	50.69	5.60	11.1%
8 AMOUNT ($)	389,094	36,192	352,902	975.1%	389,094	36,192	352,902	975.1%
9 ENDING INVENTORY								
10 UNITS (BBL)	16,223	12,118	4,105	33.9%	16,223	12,118	4,105	33.9%
11 UNIT COST ($/BBL)	54.15	47.09	7.06	15.0%	54.15	47.09	7.06	15.0%
12 AMOUNT ($)	878,436	570,602	307,834	53.9%	878,436	570,602	307,834	53.9%
13								
14 DAYS SUPPLY	366	274	92	30.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES								
16 UNITS (BBL)	9,115	15,203	(6,088)	-40.0%	9,115	15,203	(6,088)	-40.0%
17 UNIT COST ($/BBL)	80.38	72.01	8.37	11.6%	80.38	72.01	8.37	11.6%
18 AMOUNT ($)	732,651	1,094,805	(362,154)	-33.1%	732,651	1,094,805	(362,154)	-33.1%
19 BURNED								
20 UNITS (BBL)	3,048	15,203	(12,155)	-80.0%	3,048	15,203	(12,155)	-80.0%
21 UNIT COST ($/BBL)	82.62	51.28	31.34	61.1%	82.62	51.28	31.34	61.1%
22 AMOUNT ($)	251,824	779,629	(527,805)	-67.7%	251,824	779,629	(527,805)	-67.7%
23 ENDING INVENTORY								
24 UNITS (BBL)	74,454	85,007	(10,553)	-12.4%	74,454	85,007	(10,553)	-12.4%
25 UNIT COST ($/BBL)	81.34	65.73	15.60	23.7%	81.34	65.73	15.60	23.7%
26 AMOUNT ($)	6,055,865	5,587,786	468,079	8.4%	6,055,865	5,587,786	468,079	8.4%
27								
28 DAYS SUPPLY: NORMAL	180	205	(25)	-10.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(2)	-12.4%	-	-	-	-
COAL[3]								
30 PURCHASES								
31 UNITS (TONS)	327,717	409,600	(81,883)	-20.0%	327,717	409,600	(81,883)	-20.0%
32 UNIT COST ($/TON)	55.39	57.56	(2.17)	-3.8%	55.39	57.56	(2.17)	-3.8%
33 AMOUNT ($)	18,152,735	23,577,650	(5,424,915)	-23.0%	18,152,735	23,577,650	(5,424,915)	-23.0%
34 BURNED								
35 UNITS (TONS)	486,287	413,414	72,873	17.6%	486,287	413,414	72,873	17.6%
36 UNIT COST ($/TON)	56.10	57.04	(0.94)	-1.7%	56.10	57.04	(0.94)	-1.7%
37 AMOUNT ($)	27,279,569	23,581,537	3,698,032	15.7%	27,279,569	23,581,537	3,698,032	15.7%
38 ENDING INVENTORY								
39 UNITS (TONS)	312,819	542,934	(230,115)	-42.4%	312,819	542,934	(230,115)	-42.4%
40 UNIT COST ($/TON)	55.26	56.28	(1.02)	-1.8%	55.26	56.28	(1.02)	-1.8%
41 AMOUNT ($)	17,286,977	30,558,992	(13,272,015)	-43.4%	17,286,977	30,558,992	(13,272,015)	-43.4%
42								
43 DAYS SUPPLY	24	45	(21)	-50.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES								
45 UNITS (MCF)	2,557,618	3,289,433	(731,815)	-22.2%	2,557,618	3,289,433	(731,815)	-22.2%
46 UNIT COST ($/MCF)	10.93	11.09	(0.16)	-1.5%	10.93	11.09	(0.16)	-1.5%
47 AMOUNT ($)	27,946,228	36,474,126	(8,527,898)	-23.4%	27,946,228	36,474,126	(8,527,898)	-23.4%
48 BURNED								
49 UNITS (MCF) [1]	2,589,107	3,289,433	(700,326)	-21.3%	2,589,107	3,289,433	(700,326)	-21.3%
50 UNIT COST ($/MCF)	11.26	11.09	0.17	1.5%	11.26	11.09	0.17	1.5%
51 AMOUNT ($)	29,151,075	36,474,127	(7,323,052)	-20.1%	29,151,075	36,474,127	(7,323,052)	-20.1%
52 ENDING INVENTORY								
53 UNITS (MCF)	154,777	0	154,777	0.0%	154,777	0	154,777	0.0%
54 UNIT COST ($/MCF)	8.65	0.00	8.65	0.0%	8.65	0.00	8.65	0.0%
55 AMOUNT ($)	1,339,351	0	1,339,351	0.0%	1,339,351	0	1,339,351	0.0%
56								
57 DAYS SUPPLY	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY	0	0	0	0.0%	-	-	-	-

Note 1: Includes consumption adjustment for December 2005 for Polk Unit 2 (1,628) and Polk Unit 3 (851).

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	26,528
FUEL ANALYSIS	0
TOTAL	26,528

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(2,622)	(208,807)
OTHER USAGE	(570)	(45,321)
TOTAL	(3,191)	(254,128)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	0
IGNITION #2 OIL	182,279
IGNITION PROPANE	13,745
AERIAL SURVEY ADJ.	0
ADDITIVES	17,687
GREEN FUEL	0
TOTAL	213,712

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:									
VARIOUS	JURISDIC. SCH. - D	971.0	0.0	971.0	1.864	1.864	18,100.00	18,100.00	
VARIOUS	JURISDIC. SCH. - MB	27,706.0	0.0	27,706.0	4.480	8.105	1,241,300.00	2,245,600.00	912,100.00
TOTAL		28,677.0	0.0	28,677.0	4.392	7.894	1,259,400.00	2,263,700.00	912,100.00
ACTUAL:									
SEMINOLE ELEC. PRECO-1	JURISDIC. SCH. - D	711.7	0.0	711.7	4.236	4.236	30,149.44	30,149.44	
SEMINOLE ELEC. HARDEE	JURISDIC. SCH. - D	518.0	0.0	518.0	4.049	4.049	20,976.18	20,976.18	
PROGRESS ENERGY FLORIDA	SCH. - MA	7,000.0	0.0	7,000.0	6.076	7.615	425,341.82	533,025.38	85,477.56
FLA. PWR. & LIGHT	SCH. - MA	1,600.0	0.0	1,600.0	6.184	8.814	98,939.50	141,024.79	36,649.29
CITY OF LAKELAND	SCH. - MA	420.0	0.0	420.0	5.251	7.720	22,053.90	32,421.94	8,919.04
CONOCO	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - MA	100.0	0.0	100.0	5.331	7.158	5,331.00	7,158.10	1,481.10
THE ENERGY AUTHORITY	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - MA	328.0	0.0	328.0	2.698	2.926	8,850.26	9,598.60	466.26
CALPEA	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(343.98)	(343.98)
TENASKA POWER CORP	SCH. - MA	420.0	0.0	420.0	6.999	10.560	29,396.75	44,353.53	13,826.78
NEW SMYRNA BEACH	SCH. - MA	3,000.0	0.0	3,000.0	6.386	7.386	191,580.60	221,580.60	0.00
HARDEE OTHERS*	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS	OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH	SEP SCH. - D	7,440.0	0.0	7,440.0	5.412	6.012	402,652.80	447,292.80	
NO PRIOR PERIOD ADJUSTMENTS									
SUB-TOTAL SEP SCHEDULE D POWER SALES		7,440.0	0.0	7,440.0	5.412	6.012	402,652.80	447,292.80	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		1,229.7	0.0	1,229.7	4.158	4.158	51,125.62	51,125.62	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.		12,868.0	0.0	12,868.0	6.073	7.684	781,493.83	988,818.96	146,276.05
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL		21,537.7	0.0	21,537.7	5.735	6.905	1,235,272.25	1,487,237.38	146,276.05
CURRENT MONTH:									
DIFFERENCE		(7,139.3)	0.0	(7,139.3)	1.343	(0.989)	(24,127.75)	(776,462.62)	(765,823.95)
DIFFERENCE %		-24.9%	0.0%	-24.9%	30.6%	-12.5%	-1.9%	-34.3%	-84.0%
PERIOD TO DATE:									
ACTUAL		21,537.7	0.0	21,537.7	5.735	6.905	1,235,272.25	1,487,237.38	146,276.05
ESTIMATED		28,677.0	0.0	28,677.0	4.392	7.894	1,259,400.00	2,263,700.00	912,100.00
DIFFERENCE		(7,139.3)	0.0	(7,139.3)	1.343	(0.989)	(24,127.75)	(776,462.62)	(765,823.95)
DIFFERENCE %		-24.9%	0.0%	-24.9%	30.6%	-12.5%	-1.9%	-34.3%	-84.0%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JANUARY 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH - J	252.0	0.0	125.0	127.0	12.598	12.598	16,000.00
HARDEE POWER PARTNERS		IPP	3,653.0	0.0	0.0	3,653.0	14.051	14.051	513,300.00
CALPINE		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASED	149,525.0	0.0	0.0	149,525.0	6.448	6.448	9,640,700.00
OTHER		SCH. - D	44,863.0	0.0	0.0	44,863.0	3.691	3.691	1,655,800.00
TOTAL			198,293.0	0.0	125.0	198,168.0	5.968	5.968	11,825,800.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	1,095.0	0.0	0.0	1,095.0	75.487	75.487	826,578.25
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	30,030.0	0.0	0.0	30,030.0	3.568	3.568	1,071,360.70
AUBURNDALE POWER PARTNERS		OATT	378.0	0.0	0.0	378.0	3.386	3.386	12,800.59
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	DEC 2005	IPP	(780.0)	0.0	0.0	(780.0)	42.621	42.621	(332,442.46)
HARDEE PWR. PART.-NATIVE	DEC 2005	IPP	780.0	0.0	0.0	780.0	55.534	55.534	433,166.62
PROGRESS ENERGY FLORIDA	DEC 2005	SCH. - D	(100,800.0)	0.0	0.0	(100,800.0)	5.084	5.084	(5,124,198.00)
PROGRESS ENERGY FLORIDA	DEC 2005	SCH. - D	100,800.0	0.0	0.0	100,800.0	4.621	4.621	4,657,494.00
AUBURNDALE POWER PARTNERS	DEC 2005	OATT	(257.0)	0.0	0.0	(257.0)	5.019	5.019	(12,897.87)
AUBURNDALE POWER PARTNERS	DEC 2005	OATT	259.0	0.0	0.0	259.0	5.046	5.046	13,067.87
SUB-TOTAL OF ADJUSTMENTS:			2.0	0.0	0.0	2.0	(18,290.492)	(18,290.492)	(365,809.84)
TOTAL			31,505.0	0.0	0.0	31,505.0	4.904	4.904	1,544,929.70
CURRENT MONTH:									
DIFFERENCE			(166,788.0)	0.0	(125.0)	(166,663.0)	(1.064)	(1.064)	(10,280,870.30)
DIFFERENCE %			-84.1%	0.0%	0.0%	-84.1%	-17.8%	-17.8%	-86.9%
PERIOD TO DATE:									
ACTUAL			31,505.0	0.0	0.0	31,505.0	4.904	4.904	1,544,929.70
ESTIMATED			198,293.0	0.0	125.0	198,168.0	5.968	5.968	11,825,800.00
DIFFERENCE			(166,788.0)	0.0	(125.0)	(166,663.0)	(1.064)	(1.064)	(10,280,870.30)
DIFFERENCE %			-84.1%	0.0%	-100.0%	-84.1%	-17.8%	-17.8%	-86.9%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN	35,798.0	0.0	0.0	35,798.0	2.888	2.888	1,033,800.00
TOTAL		**35,798.0**	**0.0**	**0.0**	**35,798.0**	**2.888**	**2.888**	**1,033,800.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	14,718.0	0.0	0.0	14,718.0	2.414	2.414	355,320.15
McKAY BAY REFUSE	COGEN.	14,309.0	0.0	0.0	14,309.0	2.427	2.427	347,226.59
ORANGE COGENERATION L.P.	COGEN.	5,704.0	0.0	0.0	5,704.0	2.235	2.235	127,478.69
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	43.0	0.0	0.0	43.0	6.134	6.134	2,637.73
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	882.0	0.0	0.0	882.0	5.256	5.256	46,354.03
CF INDUSTRIES INC.	COGEN.	1,395.0	0.0	0.0	1,395.0	5.138	5.138	71,673.10
IMC-AGRICO-NEW WALES	COGEN.	1,815.0	0.0	0.0	1,815.0	5.254	5.254	95,365.53
IMC-AGRICO-S. PIERCE	COGEN.	1,617.0	0.0	0.0	1,617.0	4.471	4.471	72,302.09
AUBURNDALE POWER PARTNERS	COGEN.	1,307.0	0.0	0.0	1,307.0	4.395	4.395	57,448.49
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR JANUARY 2006		41,790.0	0.0	0.0	41,790.0	2.814	2.814	1,175,806.40
ADJUSTMENTS FOR THE MONTH OF:	**DECEMBER 2005**							
HILLSBOROUGH COUNTY	COGEN.	(18,416.0)	0.0	0.0	(18,416.0)	2.511	2.511	(462,416.17)
		18,416.0	0.0	0.0	18,416.0	2.527	2.527	465,451.22
McKAY BAY REFUSE	COGEN.	(14,459.0)	0.0	0.0	(14,459.0)	2.511	2.511	(363,132.93)
		14,459.0	0.0	0.0	14,459.0	2.528	2.528	365,526.17
ORANGE COGENERATION L.P.	COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	2.264	2.264	(129,113.38)
		5,704.0	0.0	0.0	5,704.0	2.281	2.281	130,097.51
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**DECEMBER 2005**	0.0	0.0	0.0	0.0	0.000	0.000	6,412.42
GRAND TOTAL		**41,790.0**	**0.0**	**0.0**	**41,790.0**	**2.829**	**2.829**	**1,182,218.82**
CURRENT MONTH:								
DIFFERENCE		5,992.0	0.0	0.0	5,992.0	(0.059)	(0.059)	148,418.82
DIFFERENCE %		16.7%	0.0%	0.0%	16.7%	-2.0%	-2.0%	14.4%
PERIOD TO DATE:								
ACTUAL		41,790.0	0.0	0.0	41,790.0	2.829	2.829	1,182,218.82
ESTIMATED		35,798.0	0.0	0.0	35,798.0	2.888	2.888	1,033,800.00
DIFFERENCE		5,992.0	0.0	0.0	5,992.0	(0.059)	(0.059)	148,418.82
DIFFERENCE %		16.7%	0.0%	0.0%	16.7%	-2.0%	-2.0%	14.4%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	1,325.0	6.981	92,500.00	10.600	140,455.25	47,955.25
FLA. POWER & LIGHT	SCH. - JC	24,360.0	6.497	1,582,716.00	9.592	2,336,542.42	753,826.42
CITY OF LAKELAND	SCH. - JC	2,780.0	6.771	188,220.00	10.770	299,417.90	111,197.90
ORLANDO UTIL. COMM.	SCH. - JC	200.0	5.638	11,275.00	10.023	20,045.75	8,770.75
CAROLINA POWER & LIGHT	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	SCH. - JC	9,312.0	6.804	633,604.50	9.945	926,068.42	292,463.92
REEDY CREEK	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
OKEELANTA	SCH. - JC	914.0	7.796	71,257.02	11.159	101,995.45	30,738.43
CITY OF TALLAHASSEE	SCH. - JC	125.0	8.113	10,141.80	13.655	17,069.05	6,927.25
CALPINE	SCH. - JC	889.0	8.367	74,383.00	9.294	82,623.77	8,240.77
CARGILL ALLIANT	SCH. - JC	2,428.0	7.608	184,712.00	11.048	268,255.76	83,543.76
CONOCO	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CORAL POWER	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
RELIANT	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	2,115.0	5.925	125,305.00	8.805	186,215.90	60,910.90
DUKE ENERGY	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
DYNEGY POWER MARKETING	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMPRA ENERGY	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
WHEELABRATOR RIDGE ENERGY	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**44,448.0**	**6.691**	**2,974,114.32**	**9.851**	**4,378,689.67**	**1,404,575.35**
CURRENT MONTH:							
DIFFERENCE		44,448.0	6.691	2,974,114.32	9.851	4,378,689.67	1,404,575.35
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		44,448.0	6.691	2,974,114.32	9.851	4,378,689.67	1,404,575.35
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		44,448.0	6.691	2,974,114.32	9.851	4,378,689.67	1,404,575.35
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

FEBRUARY 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	57,669,411	52,144,398	5,525,013	10.6%	1,286,414	1,199,291	87,123	7.3%	4.48296	4.34794	0.13502	3.1%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,562)	(6,734)	(828)	12.3%	1,286,414 (a)	1,199,291 (a)	87,123	7.3%	(0.00059)	(0.00056)	(0.00003)	4.7%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,286,414 (a)	1,199,291 (a)	87,123	7.3%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	0	0	0	0.0%	1,286,414 (a)	1,199,291 (a)	87,123	7.3%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**57,661,849**	**52,137,664**	**5,524,185**	**10.6%**	**1,286,414**	**1,199,291**	**87,123**	**7.3%**	**4.48237**	**4.34737**	**0.13500**	**3.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	2,299,482	10,885,000	(8,585,518)	-78.9%	37,844	191,173	(153,329)	-80.2%	6.07621	5.69380	0.38242	6.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	3,971,594	0	3,971,594	0.0%	57,269	0	57,269	0.0%	6.93498	0.00000	6.93498	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,476,956	905,000	571,956	63.2%	41,306	32,329	8,977	27.8%	3.57565	2.79934	0.77630	27.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**7,748,032**	**11,790,000**	**(4,041,968)**	**-34.3%**	**136,419**	**223,502**	**(87,083)**	**-39.0%**	**5.67958**	**5.27512**	**0.40446**	**7.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,422,833**	**1,422,793**	**40**	**0.0%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	42,437	13,000	29,437	226.4%	1,006	824	182	22.1%	4.21839	1.57767	2.64072	167.4%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	171,110	0	171,110	0.0%	6,720	0	6,720	0.0%	2.54628	0.00000	2.54628	0.0%
17. Fuel Cost of Market Base Sales (A6)	258,180	644,600	(386,420)	-59.9%	5,286	14,626	(9,340)	-63.9%	4.88422	4.40722	0.47700	10.8%
18. Gains on Market Based Sales	83,586	337,460	(253,874)	-75.2%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**555,313**	**995,060**	**(439,747)**	**-44.2%**	**13,012**	**15,450**	**(2,438)**	**-15.8%**	**4.26770**	**6.44052**	**(2.17282)**	**-33.7%**
20. Net Inadvertant Interchange					467	0	467	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					1,438	0	1,438	0.0%				
22. Interchange and Wheeling Losses					1,252	300	952	317.3%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**64,854,569**	**62,932,604**	**1,921,965**	**3.1%**	**1,410,474**	**1,407,043**	**3,431**	**0.2%**	**4.59807**	**4.47269**	**0.12538**	**2.8%**
24. Net Unbilled	(1,059,257) (a)	(2,906,217) (a)	1,846,960	-63.6%	(23,037)	(64,977)	41,940	-64.5%	4.59807	4.47269	0.12538	2.8%
25. Company Use	127,412 (a)	138,653 (a)	(11,241)	-8.1%	2,771	3,100	(329)	-10.6%	4.59805	4.47268	0.12537	2.8%
26. T & D Losses	1,872,748 (a)	1,476,612 (a)	396,136	26.8%	40,729	33,014	7,715	23.4%	4.59807	4.47268	0.12539	2.8%
27. System KWH Sales	64,854,569	62,932,604	1,921,965	3.1%	1,390,011	1,435,906	(45,895)	-3.2%	4.66576	4.38278	0.28298	6.5%
28. Wholesale KWH Sales	(2,792,781)	(1,157,186)	(1,635,595)	141.3%	(59,857)	(26,403)	(33,454)	126.7%	4.66575	4.38278	0.28297	6.5%
29. Jurisdictional KWH Sales	62,061,788	61,775,418	286,370	0.5%	1,330,154	1,409,503	(79,349)	-5.6%	4.66576	4.38278	0.28298	6.5%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	62,115,161	61,828,545	286,616	0.5%	1,330,154	1,409,503	(79,349)	-5.6%	4.66977	4.38655	0.28322	6.5%
32. Other	0	0	0	0.0%	1,330,154	1,409,503	(79,349)	-5.6%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(859,769)	(1,276,250)	416,481	-32.6%	1,330,154	1,409,503	(79,349)	-5.6%	(0.06464)	(0.09055)	0.02591	-28.6%
34. Waterborne Transp. Adj to Sept 2004 Incl Interest	0	0	0	0.0%	1,330,154	1,409,503	(79,349)	-5.6%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,330,154	1,409,503	(79,349)	-5.6%	0.92506	0.87298	0.05208	6.0%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	73,560,077	72,856,980	703,097	1.0%	1,330,154	1,409,503	(79,349)	-5.6%	5.53019	5.16898	0.36121	7.0%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	73,613,040	72,909,437	703,603	1.0%	1,330,154	1,409,503	(79,349)	-5.6%	5.53417	5.17271	0.36146	7.0%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,330,154	1,409,503	(79,349)	-5.6%	0.00457	0.00431	0.00026	6.0%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**73,673,835**	**72,970,232**	**703,603**	**1.0%**	**1,330,154**	**1,409,503**	**(79,349)**	**-5.6%**	**5.53874**	**5.17702**	**0.36172**	**7.0%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.539**	**5.177**	**0.362**	**7.0%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: FEBRUARY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	114,740,973	113,015,883	1,725,090	1.5%	2,736,838	2,580,377	156,461	6.1%	4.19246	4.37982	(0.18736)	-4.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(14,590)	(13,468)	(1,122)	8.3%	2,736,838 (a)	2,580,377 (a)	156,461	6.1%	(0.00053)	(0.00052)	(0.00001)	2.1%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	2,736,838 (a)	2,580,377 (a)	156,461	6.1%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	0	0	0	0.0%	2,736,838 (a)	2,580,377 (a)	156,461	6.1%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**114,726,383**	**113,002,415**	**1,723,968**	**1.5%**	**2,736,838**	**2,580,377**	**156,461**	**6.1%**	**4.19193**	**4.37930**	**(0.18737)**	**-4.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	3,844,412	22,710,800	(18,866,388)	-83.1%	69,349	389,341	(319,992)	-82.2%	5.54357	5.83314	(0.28957)	-5.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	6,945,708	0	6,945,708	0.0%	101,717	0	101,717	0.0%	6.82846	0.00000	6.82846	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	2,659,175	1,938,800	720,375	37.2%	83,096	68,127	14,969	22.0%	3.20012	2.84586	0.35426	12.4%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**13,449,295**	**24,649,600**	**(11,200,305)**	**-45.4%**	**254,162**	**457,468**	**(203,306)**	**-44.4%**	**5.29162**	**5.38827**	**(0.09664)**	**-1.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**2,991,000**	**3,037,845**	**(46,845)**	**-1.5%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	93,563	31,100	62,463	200.8%	2,236	1,795	441	24.6%	4.18439	1.73259	2.45180	141.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	573,763	0	573,763	0.0%	14,160	0	14,160	0.0%	4.05200	0.00000	4.05200	0.0%
17. Fuel Cost of Market Base Sales (A6)	1,039,673	1,885,900	(846,227)	-44.9%	18,154	42,332	(24,178)	-57.1%	5.72696	4.45502	1.27194	28.6%
18. Gains on Market Based Sales	229,862	1,249,560	(1,019,698)	-81.6%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**1,936,861**	**3,166,560**	**(1,229,699)**	**-38.8%**	**34,550**	**44,127**	**(9,577)**	**-21.7%**	**5.60597**	**7.17601**	**(1.57005)**	**-21.9%**
20. Net Inadvertant Interchange					(584)	0	(584)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					2,052	0	2,052	0.0%				
22. Interchange and Wheeling Losses					2,399	800	1,599	199.9%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**126,238,817**	**134,485,455**	**(8,246,638)**	**-6.1%**	**2,955,519**	**2,992,918**	**(37,399)**	**-1.2%**	**4.27129**	**4.49346**	**(0.22217)**	**-4.9%**
24. Net Unbilled	(5,996,671) (a)	(5,727,228) (a)	(269,443)	4.7%	(147,312)	(127,501)	(19,811)	15.5%	4.07073	4.49191	(0.42118)	-9.4%
25. Company Use	247,277 (a)	278,521 (a)	(31,244)	-11.2%	5,788	6,200	(412)	-6.6%	4.27224	4.49227	(0.22004)	-4.9%
26. T & D Losses	6,311,355 (a)	4,701,121 (a)	1,610,234	34.3%	152,449	104,481	47,968	45.9%	4.13998	4.49950	(0.35952)	-8.0%
27. System KWH Sales	126,238,817	134,485,455	(8,246,638)	-6.1%	2,944,594	3,009,738	(65,144)	-2.2%	4.28714	4.46834	(0.18121)	-4.1%
28. Wholesale KWH Sales	(6,146,405)	(2,398,814)	(3,747,591)	156.2%	(144,789)	(53,713)	(91,076)	169.6%	4.24508	4.46598	(0.22091)	-4.9%
29. Jurisdictional KWH Sales	120,092,412	132,086,641	(11,994,229)	-9.1%	2,799,805	2,956,025	(156,220)	-5.3%	4.28931	4.46839	(0.17907)	-4.0%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	120,195,691	132,200,236	(12,004,545)	-9.1%	2,799,805	2,956,025	(156,220)	-5.3%	4.29300	4.47223	(0.17923)	-4.0%
32. Peabody Coal Contract Buy-Out Amort. Jurisd.	0	0	0	0.0%	2,799,805	2,956,025	(156,220)	-5.3%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,931,080)	(2,552,500)	621,420	-24.3%	2,799,805	2,956,025	(156,220)	-5.3%	(0.06897)	(0.08635)	0.01738	-20.1%
34. Waterborne Transp. Adj to Sept 2004 Incl Interest	0	0	0	0.0%	2,799,805	2,956,025	(156,220)	-5.3%	0.00000	0.00000	0.00000	0.0%
35. True-up *	24,609,370	24,609,370	(0)	0.0%	2,799,805	2,956,025	(156,220)	-5.3%	0.87897	0.83252	0.04645	5.6%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	142,873,981	154,257,106	(11,383,125)	-7.4%	2,799,805	2,956,025	(156,220)	-5.3%	5.10300	5.21840	(0.11540)	-2.2%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	142,976,850	154,368,171	(11,391,321)	-7.4%	2,799,805	2,956,025	(156,220)	-5.3%	5.10667	5.22215	(0.11548)	-2.2%
39. GPIF * (Already Adjusted for Taxes)	121,590	121,590	0	0.0%	2,799,805	2,956,025	(156,220)	-5.3%	0.00434	0.00411	0.00023	5.6%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**143,098,440**	**154,489,761**	**(11,391,321)**	**-7.4%**	**2,799,805**	**2,956,025**	**(156,220)**	**-5.3%**	**5.11101**	**5.22626**	**(0.11525)**	**-2.2%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.111**	**5.226**	**(0.115)**	**-2.2%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	57,669,411	52,144,398	5,525,013	10.6%	114,740,973	113,015,883	1,725,090	1.5%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	471,727	657,600	(185,873)	-28.3%	1,706,999	1,917,000	(210,001)	-11.0%
2a. GAINS FROM MARKET BASED SALES	83,586	337,460	(253,874)	-75.2%	229,862	1,249,560	(1,019,698)	-81.6%
3. FUEL COST OF PURCHASED POWER	2,299,482	10,885,000	(8,585,518)	-78.9%	3,844,412	22,710,800	(18,866,388)	-83.1%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,476,956	905,000	571,956	63.2%	2,659,175	1,938,800	720,375	37.2%
4. ENERGY COST OF ECONOMY PURCHASES	3,971,594	0	3,971,594	0.0%	6,945,708	0	6,945,708	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	64,862,130	62,939,338	1,922,792	3.1%	126,253,407	134,498,923	(8,245,516)	-6.1%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,562)	(6,734)	(828)	12.3%	(14,590)	(13,468)	(1,122)	8.3%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	64,854,568	62,932,604	1,921,964	3.1%	126,238,817	134,485,455	(8,246,638)	-6.1%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,330,154	1,409,503	(79,349)	-5.6%	2,799,805	2,956,025	(156,220)	-5.3%
2. NONJURISDICTIONAL SALES	59,857	26,403	33,454	126.7%	144,789	53,713	91,076	169.6%
3. TOTAL SALES	1,390,011	1,435,906	(45,895)	-3.2%	2,944,594	3,009,738	(65,144)	-2.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9569378	0.9816123	(0.0246745)	-2.5%	0.9508289	0.9821536	(0.0313247)	-3.2%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	71,463,740	76,210,129	(4,746,389)	-6.2%	150,356,260	159,836,918	(9,480,658)	-5.9%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(24,609,370)	(24,609,370)	0	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(121,590)	(121,590)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	59,098,260	63,844,649	(4,746,389)	-7.4%	125,625,300	135,105,958	(9,480,658)	-7.0%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	64,854,569	62,932,604	1,921,965	3.1%	126,238,817	134,485,455	(8,246,638)	-6.1%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9569378	0.9816123	(0.0246745)	-2.5%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	62,061,788	61,775,418	286,370	0.5%	120,092,412	132,086,641	(11,994,229)	-9.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	62,115,161	61,828,545	286,616	0.5%	120,195,691	132,200,236	(12,004,545)	-9.1%
6c. Other	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(859,769)	(1,276,250)	416,481	-32.6%	(1,931,080)	(2,552,500)	621,420	-24.3%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	61,255,392	60,552,295	703,097	1.2%	118,264,611	129,647,736	(11,383,125)	-8.8%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(2,157,132)	3,292,354	(5,449,486)	-165.5%	7,360,689	5,458,222	1,902,467	34.9%
8. INTEREST PROVISION FOR THE MONTH	(860,199)	(472,124)	(388,075)	82.2%	(1,752,970)	(984,660)	(768,310)	78.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(233,243,324)	(133,698,205)	(99,545,119)	74.5%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(223,955,970)	(118,573,290)	(105,382,680)	88.9%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(233,243,324)	(133,698,205)	(99,545,119)	74.5%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(223,095,771)	(118,101,166)	(104,994,605)	88.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(456,339,095)	(251,799,371)	(204,539,724)	81.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(228,169,548)	(125,899,686)	(102,269,862)	81.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	4.510	4.500	0.010	0.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	4.530	4.500	0.030	0.7%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	9.040	9.000	0.040	0.4%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	4.520	4.500	0.020	0.4%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.377	0.375	0.002	0.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(860,199)	(472,124)	(388,075)	82.2%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	111,103	3,561	107,542	3020.0%	500,197	39,753	460,444	1158.3%
2	LIGHT OIL	1,107,844	545,333	562,511	103.2%	1,359,668	1,324,962	34,706	2.6%
3	COAL	18,901,335	20,639,410	(1,738,075)	-8.4%	46,180,904	44,220,947	1,959,957	4.4%
4	NATURAL GAS	37,549,129	30,956,094	6,593,035	21.3%	66,700,204	67,430,221	(730,017)	-1.1%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	57,669,411	52,144,398	5,525,013	10.6%	114,740,973	113,015,883	1,725,090	1.5%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,073	39	1,034	2651.3%	5,367	499	4,868	975.6%
9	LIGHT OIL	8,738	4,418	4,320	97.8%	10,012	10,014	(2)	0.0%
10	COAL	775,213	806,759	(31,546)	-3.9%	1,869,653	1,730,215	139,438	8.1%
11	NATURAL GAS	501,390	388,075	113,315	29.2%	853,080	839,649	13,431	1.6%
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)	1,286,414	1,199,291	87,123	7.3%	2,738,112	2,580,377	157,735	6.1%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	1,874	60	1,814	3023.3%	8,786	774	8,012	1035.1%
16	LIGHT OIL (BBL)	13,837	10,793	3,044	28.2%	16,885	25,996	(9,111)	-35.0%
17	COAL (TON)	349,633	358,210	(8,577)	-2.4%	835,920	771,624	64,296	8.3%
18	NATURAL GAS (MCF)	3,551,109	2,811,124	739,985	26.3%	6,140,216	6,100,557	39,659	0.7%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	11,757	373	11,384	3052.0%	55,122	4,856	50,266	1035.1%
22	LIGHT OIL	79,826	46,728	33,098	70.8%	96,009	113,909	(17,900)	-15.7%
23	COAL	8,329,222	8,640,189	(310,967)	-3.6%	19,858,411	18,591,379	1,267,032	6.8%
24	NATURAL GAS	3,689,939	2,889,792	800,147	27.7%	6,363,875	6,271,207	92,668	1.5%
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)	12,110,744	11,577,082	533,662	4.6%	26,373,417	24,981,351	1,392,066	5.6%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.08%	0.00%	0.00	-	0.20%	0.02%	0.00	-
29	LIGHT OIL	0.68%	0.37%	0.00	-	0.37%	0.39%	(0.00)	-
30	COAL	60.26%	67.27%	(0.07)	-	68.28%	67.05%	0.01	-
31	NATURAL GAS	38.98%	32.36%	0.07	-	31.16%	32.54%	(0.01)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	59.29	59.35	(0.06)	-0.1%	56.93	51.36	5.57	10.8%
36	LIGHT OIL ($/BBL)	80.06	50.53	29.54	58.5%	80.53	50.97	29.56	58.0%
37	COAL ($/TON)	54.06	57.62	(3.56)	-6.2%	55.25	57.31	(2.06)	-3.6%
38	NATURAL GAS ($/MCF)	10.57	11.01	(0.44)	-4.0%	10.86	11.05	(0.19)	-1.7%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	9.45	9.55	(0.10)	-1.0%	9.07	8.19	0.89	10.8%
42	LIGHT OIL	13.88	11.67	2.21	18.9%	14.16	11.63	2.53	21.8%
43	COAL	2.27	2.39	(0.12)	-5.0%	2.33	2.38	(0.05)	-2.2%
44	NATURAL GAS	10.18	10.71	(0.54)	-5.0%	10.48	10.75	(0.27)	-2.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.76	4.50	0.26	5.7%	4.35	4.52	(0.17)	-3.8%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,957	9,564	1,393	14.6%	10,271	9,731	540	5.5%
49	LIGHT OIL	9,136	10,577	(1,441)	-13.6%	9,589	11,375	(1,786)	-15.7%
50	COAL	10,744	10,710	34	0.3%	10,621	10,745	(124)	-1.2%
51	NATURAL GAS	7,359	7,446	(87)	-1.2%	7,460	7,469	(9)	-0.1%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,414	9,653	(239)	-2.5%	9,632	9,681	(49)	-0.5%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	10.35	9.13	1.22	13.4%	9.32	7.97	1.35	16.9%
56	LIGHT OIL	12.68	12.34	0.34	2.8%	13.58	13.23	0.35	2.6%
57	COAL	2.44	2.56	(0.12)	-4.7%	2.47	2.56	(0.09)	-3.5%
58	NATURAL GAS	7.49	7.98	(0.49)	-6.1%	7.82	8.03	(0.21)	-2.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.48	4.35	0.13	3.0%	4.19	4.38	(0.19)	-4.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)
B.B.#1	411	128,337	46.5	51.1	69.0	10,974	COAL	61,191	23,015,140	1,408,319.4	3,301,686	2.57	53.96
B.B.#2	391	216,742	82.5	84.8	94.8	10,245	COAL	94,573	23,478,280	2,220,411.4	5,102,880	2.35	53.96
B.B.#3	433	214,486	73.7	77.2	73.7	10,844	COAL	99,209	23,445,280	2,325,974.1	5,353,025	2.50	53.96
B.B.#4	462	72,670	23.4	31.9	65.4	12,243	COAL	38,761	22,954,040	889,721.5	2,091,429	2.88	53.96
B.B. STATION	1,697	632,235	55.4	60.3	75.2	10,826	COAL	293,734	23,301,474	6,844,426.4	15,849,020	2.51	53.96
SEB-PHIL. #1(HVY OIL)	18	526	4.3	97.5	66.8	10,957	HVY.OIL	918	6,273,540	5,761.6	54,425	10.35	59.29
SEB-PHIL. #2(HVY OIL)	18	547	4.5	100.0	70.4	10,957	HVY.OIL	956	6,273,540	5,995.3	56,678	10.36	59.29
SEB-PHILLIPS TOTAL	36	1,073	4.4	98.7	68.6	10,957	HVY.OIL	1,874	6,273,540	11,756.9	111,103	10.35	59.29
POLK #1 GASIFIER	260	142,978	0.0	0.0	0.0	10,385	COAL	55,899	26,562,000	1,484,795.9	3,052,315	2.13	54.60
POLK #1 CT (OIL)	245	8,580	0.0	0.0	0.0	8,860	LGT.OIL	13,179	5,804,403	76,017.9	1,080,051	12.59	81.95
POLK #1 TOTAL	260	151,558	86.7	93.8	91.4	10,298	-	-	-	1,560,813.8	4,132,366	2.73	-
POLK #2 CT (GAS)	175	2,470	0.0	0.0	0.0	12,801	GAS	23,296	1,036,000	31,619.0	344,045	13.93	14.77
POLK #2 CT (OIL)	184	45	0.0	0.0	0.0	17,840	LGT.OIL	138	5,804,403	801.5	11,318	25.15	81.96
POLK #2 TOTAL	180	2,515	2.1	100.0	89.3	12,891	-	-	-	32,420.5	355,363	14.13	-
POLK #3 CT (GAS)	175	610	0.0	0.0	0.0	12,429	GAS	3,934	1,036,000	7,581.4	135,614	22.23	34.47
POLK #3 CT (OIL)	184	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	180	610	0.5	100.0	55.8	12,429	-	-	-	7,581.4	135,614	22.23	-
POLK STATION TOTAL	620	154,683	37.1	97.4	80.4	10,349	-	-	-	1,600,815.7	4,623,343	2.99	-
B.B.C.T.#1	15	32	0.3	100.0	42.7	17,994	LGT.OIL	99	5,812,721	575.8	3,137	9.80	31.69
B.B.C.T.#2 *	80	38	0.1	100.0	23.8	36,789	LGT.OIL	242	5,765,383	1,398.0	7,667	20.18	31.68
B.B.C.T.#3 *	80	43	0.1	100.0	53.8	24,023	LGT.OIL	179	5,765,418	1,033.0	5,671	13.19	31.68
C.T. TOTAL	175	113	0.1	100.0	39.1	26,609	LGT.OIL	520	5,774,534	3,006.8	16,475	14.58	31.68
COT 1 *	3	(5)	0.0	100.0	0.0	0	GAS	86	1,036,000	89.4	1,045	(20.90)	12.10
COT 2 *	3	(2)	0.0	100.0	0.0	0	GAS	33	1,036,000	34.6	404	(20.20)	12.11
CITY OF TAMPA TOTAL	6	(7)	0.0	100.0	0.0	0	GAS	120	1,036,000	124.0	1,449	(20.70)	12.11
BAYSIDE ST 1	244	60,745	37.0	78.3	48.6	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	183	39,175	31.9	73.8	73.2	11,375	GAS	430,119	1,036,000	445,604.0	4,123,896	10.53	9.59
BAYSIDE CT1B	183	46,696	38.0	78.3	73.7	11,326	GAS	510,502	1,036,000	528,880.0	4,894,592	10.48	9.59
BAYSIDE CT1C	183	34,626	28.2	74.5	71.7	11,036	GAS	368,841	1,036,000	382,119.0	3,536,372	10.21	9.59
BAYSIDE UNIT 1 TOTAL	793	181,242	34.0	76.4	65.4	7,485	GAS	1,309,462	1,036,000	1,356,603.0	12,554,860	6.93	9.59
BAYSIDE ST 2	316	106,321	50.1	100.0	50.1	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	183	55,714	45.3	95.5	82.8	10,441	GAS	561,482	1,036,000	581,695.1	6,215,832	11.16	11.07
BAYSIDE CT2B	183	60,160	48.9	100.0	72.9	11,115	GAS	645,450	1,036,000	668,686.1	7,145,392	11.88	11.07
BAYSIDE CT2C	183	68,782	55.9	100.0	73.2	11,100	GAS	736,940	1,036,000	763,470.1	8,158,223	11.86	11.07
BAYSIDE CT2D	183	26,100	21.2	100.0	81.3	10,734	GAS	270,425	1,036,000	280,160.1	2,993,714	11.47	11.07
BAYSIDE UNIT 2 TOTAL	1,048	317,075	45.0	99.2	69.3	7,235	GAS	2,214,297	1,036,000	2,294,011.4	24,513,161	7.73	11.07
BAYSIDE STATION TOTAL	1,841	498,317	40.3	89.4	67.6	7,326	GAS	3,523,759	1,036,000	3,650,614.4	37,068,021	7.44	10.52
TOT. COAL (BB,POLK)	1,957	775,213	58.9	64.7	77.3	10,744	COAL	349,633	23,822,766	8,329,222.3	18,901,335	2.44	54.06
SYSTEM	4,375	1,286,414	43.8	79.8	71.1	9,414	-	-	-	12,110,744.2	57,669,411	4.48	-

* Ran for testing only.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	2,542	60	2,482	4136.7%	10,346	774	9,572	1236.7%
3 UNIT COST ($/BBL)	55.04	48.50	6.54	13.5%	52.95	48.75	4.20	8.6%
4 AMOUNT ($)	139,903	2,910	136,993	4707.7%	547,845	37,736	510,109	1351.8%
5 BURNED:								
6 UNITS (BBL)	1,874	60	1,814	3023.3%	8,786	774	8,012	1035.1%
7 UNIT COST ($/BBL)	59.29	59.35	(0.06)	-0.1%	56.93	51.36	5.57	10.8%
8 AMOUNT ($)	111,103	3,561	107,542	3020.0%	500,197	39,753	460,444	1158.3%
9 ENDING INVENTORY:								
10 UNITS (BBL)	16,891	12,118	4,773	39.4%	16,891	12,118	4,773	39.4%
11 UNIT COST ($/BBL)	54.38	47.09	7.29	15.5%	54.38	47.09	7.29	15.5%
12 AMOUNT ($)	918,615	570,687	347,928	61.0%	918,615	570,687	347,928	61.0%
13								
14 DAYS SUPPLY:	335	240	95	40.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	14,770	10,793	3,977	36.8%	23,885	25,996	(2,111)	-8.1%
17 UNIT COST ($/BBL)	78.90	71.69	7.21	10.1%	79.46	71.88	7.58	10.6%
18 AMOUNT ($)	1,165,311	773,746	391,565	50.6%	1,897,962	1,868,551	29,411	1.6%
19 BURNED:								
20 UNITS (BBL)	13,837	10,793	3,044	28.2%	16,885	25,996	(9,111)	-35.0%
21 UNIT COST ($/BBL)	80.06	50.53	29.54	58.5%	80.53	50.97	29.56	58.0%
22 AMOUNT ($)	1,107,844	545,333	562,511	103.2%	1,359,668	1,324,962	34,706	2.6%
23 ENDING INVENTORY:								
24 UNITS (BBL)	72,374	85,007	(12,633)	-14.9%	72,374	85,007	(12,633)	-14.9%
25 UNIT COST ($/BBL)	80.81	66.33	14.47	21.8%	80.81	66.33	14.47	21.8%
26 AMOUNT ($)	5,848,516	5,638,910	209,606	3.7%	5,848,516	5,638,910	209,606	3.7%
27								
28 DAYS SUPPLY: NORMAL	176	206	(30)	-10.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	10	12	(2)	-14.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	272,488	354,000	(81,512)	-23.0%	600,205	763,600	(163,395)	-21.4%
32 UNIT COST ($/TON)	57.22	57.25	(0.03)	-0.1%	56.22	57.42	(1.20)	-2.1%
33 AMOUNT ($)	15,591,196	20,266,550	(4,675,354)	-23.1%	33,743,931	43,844,200	(10,100,269)	-23.0%
34 BURNED:								
35 UNITS (TONS)	349,633	358,210	(8,577)	-2.4%	835,920	771,624	64,296	8.3%
36 UNIT COST ($/TON)	54.06	57.62	(3.56)	-6.2%	55.25	57.31	(2.06)	-3.6%
37 AMOUNT ($)	18,901,335	20,639,410	(1,738,075)	-8.4%	46,180,904	44,220,947	1,959,957	4.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	235,674	538,724	(303,050)	-56.3%	235,674	538,724	(303,050)	-56.3%
40 UNIT COST ($/TON)	55.88	56.67	(0.79)	-1.4%	55.88	56.67	(0.79)	-1.4%
41 AMOUNT ($)	13,169,526	30,527,312	(17,357,786)	-56.9%	13,169,526	30,527,312	(17,357,786)	-56.9%
42								
43 DAYS SUPPLY:	19	43	(24)	-60.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	3,567,579	2,811,124	756,455	26.9%	6,125,197	6,100,557	24,640	0.4%
46 UNIT COST ($/MCF)	10.47	11.01	(0.54)	-4.9%	10.66	11.05	(0.39)	-3.5%
47 AMOUNT ($)	37,363,416	30,956,094	6,407,322	20.7%	65,309,644	67,430,220	(2,120,576)	-3.1%
48 BURNED:								
49 UNITS (MCF)	3,551,109	2,811,124	739,985	26.3%	6,140,216	6,100,557	39,659	0.7%
50 UNIT COST ($/MCF)	10.57	11.01	(0.44)	-4.0%	10.86	11.05	(0.19)	-1.7%
51 AMOUNT ($)	37,549,129	30,956,094	6,593,035	21.3%	66,700,204	67,430,221	(730,017)	-1.1%
52 ENDING INVENTORY:								
53 UNITS (MCF)	171,247	0	171,247	0.0%	171,247	0	171,247	0.0%
54 UNIT COST ($/MCF)	6.74	0.00	6.74	0.0%	6.74	0.00	6.74	0.0%
55 AMOUNT ($)	1,153,638	0	1,153,638	0.0%	1,153,638	0	1,153,638	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) *RECONCILIATION - HEAVY OIL*

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	11,379
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	11,379

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(2,435)	(218,771)
OTHER USAGE	(578)	(46,045)
TOTAL	(3,013)	(264,816)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	63,806
IGNITION #2 OIL	207,392
IGNITION PROPANE	12,651
AERIAL SURVEY ADJ.	(1,145,459)
ADDITIVES	54,298
GREEN FUEL	0
TOTAL	(807,312)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	824.0	0.0	824.0	1.578	1.578	13,000.00	13,000.00	
VARIOUS	JURISDIC.	SCH. - MB	14,626.0	0.0	14,626.0	4.407	7.572	644,600.00	1,107,500.00	337,460.00
TOTAL			15,450.0	0.0	15,450.0	4.256	7.252	657,600.00	1,120,500.00	337,460.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	333.4	0.0	333.4	4.309	4.309	14,365.23	14,365.23	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	672.4	0.0	672.4	4.175	4.175	28,071.89	28,071.89	
PROGRESS ENERGY FLORIDA		SCH. - MA	225.0	0.0	225.0	5.006	5.741	11,264.62	12,916.66	875.79
FLA. PWR. & LIGHT		SCH. - MA	1,450.0	0.0	1,450.0	4.951	6.239	71,785.29	90,471.26	13,754.47
CITY OF LAKELAND		SCH. - MA	30.0	0.0	30.0	5.562	6.654	1,668.60	1,996.09	223.99
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	635.0	0.0	635.0	3.640	5.003	23,110.99	31,768.51	7,389.82
THE ENERGY AUTHORITY		SCH. - MA	321.0	0.0	321.0	3.351	4.049	10,756.16	12,997.06	1,709.16
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	1,375.0	0.0	1,375.0	5.744	7.908	78,976.75	108,738.64	25,556.64
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(18,245.71)	(18,245.71)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	1,250.0	0.0	1,250.0	5.503	7.590	68,790.55	94,879.28	22,320.93
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SEP SCH. - D	6,720.0	0.0	6,720.0	4.052	4.052	272,294.40	272,294.40	
ADJUSTMENTS TO PRIOR MONTHS:										
NEW SMYRNA BEACH	JAN 2006	SCH. - MA	(3,000.0)	0.0	(3,000.0)	6.386	7.386	(191,580.60)	(221,580.60)	
NEW SMYRNA BEACH	JAN 2006	SCH. - MA	3,000.0	0.0	3,000.0	6.114	7.386	183,407.55	221,580.60	30,000.00
NEW SMYRNA BEACH	JAN 2006	SEP SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH	JAN 2006	SEP SCH. - D	0.0	0.0	0.0	0.000	0.000	(101,184.00)	(101,184.00)	0.00
SUB-TOTAL SEP SCHEDULE D POWER SALES			6,720.0	0.0	6,720.0	2.546	2.546	171,110.40	171,110.40	
SUB-TOTAL SCHEDULE D POWER SALES			1,005.8	0.0	1,005.8	4.219	4.219	42,437.12	42,437.12	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			5,286.0	0.0	5,286.0	4.884	6.347	258,179.91	335,521.79	83,585.09
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			13,011.8	0.0	13,011.8	3.625	4.220	471,727.43	549,069.31	83,585.09
CURRENT MONTH:										
DIFFERENCE			(2,438.2)	0.0	(2,438.2)	(0.631)	(3.032)	(185,872.57)	(571,430.69)	(253,874.91)
DIFFERENCE %			-15.8%	0.0%	-15.8%	-14.8%	-41.8%	-28.3%	-51.0%	-75.2%
PERIOD TO DATE:										
ACTUAL			34,549.5	0.0	34,549.5	4.941	5.894	1,706,999.68	2,036,306.69	229,861.14
ESTIMATED			44,127.0	0.0	44,127.0	4.344	7.669	1,917,000.00	3,384,200.00	1,249,560.00
DIFFERENCE			(9,577.5)	0.0	(9,577.5)	0.597	(1.775)	(210,000.32)	(1,347,893.31)	(1,019,698.86)
DIFFERENCE %			-21.7%	0.0%	-21.7%	13.7%	-23.1%	-11.0%	-39.8%	-81.6%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF FEBRUARY 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	12.0	0.0	8.0	4.0	7.500	7.500	300.00
HARDEE POWER PARTNERS		IPP	443.0	0.0	0.0	443.0	38.623	38.623	171,100.00
CALPINE		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASED	134,881.0	0.0	0.0	134,881.0	6.369	6.369	8,591,200.00
OTHER		SCH. - D	55,845.0	0.0	0.0	55,845.0	3.801	3.801	2,122,400.00
TOTAL			191,181.0	0.0	8.0	191,173.0	5.694	5.694	10,885,000.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	6,911.0	0.0	0.0	6,911.0	16.577	16.577	1,145,647.67
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	30,675.0	0.0	0.0	30,675.0	3.750	3.750	1,150,453.00
AUBURNDALE POWER PARTNERS		OATT	258.0	0.0	0.0	258.0	4.399	4.399	11,349.21
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	JAN 2006	IPP	(1,095.0)	0.0	0.0	(1,095.0)	75.487	75.487	(826,578.25)
HARDEE PWR. PART.-NATIVE	JAN 2006	IPP	1,095.0	0.0	0.0	1,095.0	69.631	69.631	762,454.68
PROGRESS ENERGY FLORIDA	JAN 2006	SCH. - D	(30,030.0)	0.0	0.0	(30,030.0)	3.568	3.568	(1,071,360.70)
PROGRESS ENERGY FLORIDA	JAN 2006	SCH. - D	30,030.0	0.0	0.0	30,030.0	3.755	3.755	1,127,516.80
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	(7,967.47)
TOTAL			37,844.0	0.0	0.0	37,844.0	6.076	6.076	2,299,482.41
CURRENT MONTH:									
DIFFERENCE			(153,337.0)	0.0	(8.0)	(153,329.0)	0.382	0.382	(8,585,517.59)
DIFFERENCE %			-80.2%	0.0%	0.0%	-80.2%	6.7%	6.7%	-78.9%
PERIOD TO DATE:									
ACTUAL			69,349.0	0.0	0.0	69,349.0	5.544	5.544	3,844,412.11
ESTIMATED			389,474.0	0.0	133.0	389,341.0	5.833	5.833	22,710,800.00
DIFFERENCE			(320,125.0)	0.0	(133.0)	(319,992.0)	(0.289)	(0.289)	(18,866,387.89)
DIFFERENCE %			-82.2%	0.0%	-100.0%	-82.2%	-5.0%	-5.0%	-83.1%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	32,329.0	0.0	0.0	32,329.0	2.799	2.799	905,000.00
TOTAL			**32,329.0**	**0.0**	**0.0**	**32,329.0**	**2.799**	**2.799**	**905,000.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	10,402.0	0.0	0.0	10,402.0	2.609	2.609	271,424.72
McKAY BAY REFUSE		COGEN.	12,726.0	0.0	0.0	12,726.0	2.604	2.604	331,328.33
ORANGE COGENERATION L.P.		COGEN.	5,060.0	0.0	0.0	5,060.0	2.411	2.411	122,018.54
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	51.0	0.0	0.0	51.0	5.597	5.597	2,854.34
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	1,115.0	0.0	0.0	1,115.0	4.117	4.117	45,905.94
CF INDUSTRIES INC.		COGEN.	1,318.0	0.0	0.0	1,318.0	5.258	5.258	69,304.90
IMC-AGRICO-NEW WALES		COGEN.	2,294.0	0.0	0.0	2,294.0	5.272	5.272	120,949.61
IMC-AGRICO-S. PIERCE		COGEN.	7,339.0	0.0	0.0	7,339.0	5.305	5.305	389,327.55
AUBURNDALE POWER PARTNERS		COGEN.	1,001.0	0.0	0.0	1,001.0	4.088	4.088	40,920.20
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR FEBRUARY 2006			41,306.0	0.0	0.0	41,306.0	3.375	3.375	1,394,034.13
ADJUSTMENTS FOR THE MONTH OF:	**JANUARY 2006**								
HILLSBOROUGH COUNTY		COGEN.	(14,718.0)	0.0	0.0	(14,718.0)	2.414	2.414	(355,320.15)
			14,718.0	0.0	0.0	14,718.0	2.580	2.580	379,651.92
McKAY BAY REFUSE		COGEN.	(14,309.0)	0.0	0.0	(14,309.0)	2.427	2.427	(347,226.59)
			14,309.0	0.0	0.0	14,309.0	2.590	2.590	370,657.29
ORANGE COGENERATION L.P.		COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	2.235	2.235	(127,478.69)
			5,704.0	0.0	0.0	5,704.0	2.416	2.416	137,814.84
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	May 2001 - Jan. 2006	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	24,822.97
SUBTOTAL			0.0	0.0	0.0	0.0	0.000	0.000	82,921.59
TOTAL			**41,306.0**	**0.0**	**0.0**	**41,306.0**	**3.576**	**3.576**	**1,476,955.72**
CURRENT MONTH:									
DIFFERENCE			8,977.0	0.0	0.0	8,977.0	0.776	0.776	571,955.72
DIFFERENCE %			27.8%	0.0%	0.0%	27.8%	27.7%	27.7%	63.2%
PERIOD TO DATE:									
ACTUAL			83,096.0	0.0	0.0	83,096.0	3.200	3.200	2,659,174.54
ESTIMATED			68,127.0	0.0	0.0	68,127.0	2.846	2.846	1,938,800.00
DIFFERENCE			14,969.0	0.0	0.0	14,969.0	0.354	0.354	720,374.54
DIFFERENCE %			22.0%	0.0%	0.0%	22.0%	12.4%	12.4%	37.2%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	3,160.0	6.138	193,975.00	7.848	248,008.35	54,033.35
FLA. POWER & LIGHT	SCH. - JC	37,075.0	5.899	2,186,910.00	7.751	2,873,544.25	686,634.25
CITY OF LAKELAND	SCH. - JC	2,225.0	7.191	160,000.00	10.119	225,137.20	65,137.20
ORLANDO UTIL. COMM.	SCH. - JC	650.0	50.000	325,000.00	50.000	325,000.00	0.00
THE ENERGY AUTHORITY	SCH. - JC	8,247.0	7.755	639,524.00	10.103	833,179.65	193,655.65
OKEELANTA	SCH. - JC	903.0	6.817	61,555.48	10.165	91,788.70	30,233.22
CITY OF TALLAHASSEE	SCH. - JC	445.0	8.668	38,573.80	12.480	55,537.60	16,963.80
CALPINE	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CARGILL ALLIANT	SCH. - JC	2,545.0	7.437	189,264.00	7.702	196,008.91	6,744.91
RELIANT	SCH. - JC	616.0	16.000	98,560.00	16.000	98,560.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	860.0	4.740	40,765.00	6.304	54,218.40	13,453.40
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	543.0	6.900	37,467.00	7.105	38,580.15	1,113.15
SUBTOTAL		57,269.0	6.935	3,971,594.28	8.800	5,039,563.21	1,067,968.93
NO PRIOR MONTH ADJUSTMENTS:							
TOTAL		**57,269.0**	**6.935**	**3,971,594.28**	**8.800**	**5,039,563.21**	**1,067,968.93**
CURRENT MONTH:							
DIFFERENCE		57,269.0	6.935	3,971,594.28	8.800	5,039,563.21	1,067,968.93
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		101,717.0	6.828	6,945,708.60	9.259	9,418,252.88	2,472,544.28
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		101,717.0	6.828	6,945,708.60	9.259	9,418,252.88	2,472,544.28
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MARCH 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	54,813,228	43,954,637	10,858,591	24.7%	1,396,779	1,082,421	314,358	29.0%	3.92426	4.06077	(0.13651)	-3.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,877)	(6,734)	(1,143)	17.0%	1,396,779 (a)	1,082,421 (a)	314,358	29.0%	(0.00056)	(0.00062)	0.00006	-9.4%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,396,779 (a)	1,082,421 (a)	314,358	29.0%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	0	0	0	0.0%	1,396,779 (a)	1,082,421 (a)	314,358	29.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**54,805,351**	**43,947,903**	**10,857,448**	**24.7%**	**1,396,779**	**1,082,421**	**314,358**	**29.0%**	**3.92370**	**4.06015**	**(0.13645)**	**-3.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	1,282,184	25,365,300	(24,083,116)	-94.9%	36,159	440,827	(404,668)	-91.8%	3.54596	5.75403	(2.20806)	-38.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	5,021,431	0	5,021,431	0.0%	65,148	0	65,148	0.0%	7.70773	0.00000	7.70773	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,107,457	1,043,400	64,057	6.1%	41,690	35,798	5,892	16.5%	2.65641	2.91469	(0.25828)	-8.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**7,411,072**	**26,408,700**	**(18,997,628)**	**-71.9%**	**142,997**	**476,625**	**(333,628)**	**-70.0%**	**5.18268**	**5.54077**	**(0.35809)**	**-6.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,539,776**	**1,559,046**	**(19,270)**	**-1.2%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	41,759	59,200	(17,441)	-29.5%	1,321	1,864	(543)	-29.1%	3.16117	3.17597	(0.01480)	-0.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	391,102	0	391,102	0.0%	7,440	0	7,440	0.0%	5.25675	0.00000	5.25675	0.0%
17. Fuel Cost of Market Base Sales (A6)	441,638	26,300	415,338	1579.2%	12,344	684	11,660	1704.7%	3.57775	3.84503	(0.26727)	-7.0%
18. Gains on Market Based Sales	88,472	21,520	66,952	311.1%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**962,971**	**107,020**	**855,951**	**799.8%**	**21,105**	**2,548**	**18,557**	**728.3%**	**4.56276**	**4.20016**	**0.36261**	**8.6%**
20. Net Inadvertant Interchange					(160)	0	(160)	0.0%				
21. Wheeling Rec'd. less Wheeling Del'd.					2,551	0	2,551	0.0%				
22. Interchange and Wheeling Losses					2,520	0	2,520	0.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**61,253,452**	**70,249,583**	**(8,996,131)**	**-12.8%**	**1,518,542**	**1,556,498**	**(37,956)**	**-2.4%**	**4.03370**	**4.51331**	**(0.47961)**	**-10.6%**
24. Net Unbilled	(2,373,228) (a)	2,924,851 (a)	(5,298,079)	-181.1%	(58,835)	64,805	(123,640)	-190.8%	4.03370	4.51331	(0.47961)	-10.6%
25. Company Use	113,226 (a)	139,913 (a)	(26,687)	-19.1%	2,807	3,100	(293)	-9.5%	4.03370	4.51332	(0.47962)	-10.6%
26. T & D Losses	7,762,778 (a)	3,105,834 (a)	4,656,944	149.9%	192,448	68,815	123,633	179.7%	4.03370	4.51331	(0.47961)	-10.6%
27. System KWH Sales	61,253,452	70,249,583	(8,996,131)	-12.8%	1,382,122	1,419,778	(37,656)	-2.7%	4.43184	4.94793	(0.51609)	-10.4%
28. Wholesale KWH Sales	(2,691,722)	(2,074,470)	(617,252)	29.8%	(60,736)	(41,926)	(18,810)	44.9%	4.43184	4.94793	(0.51609)	-10.4%
29. Jurisdictional KWH Sales	58,561,730	68,175,113	(9,613,383)	-14.1%	1,321,386	1,377,852	(56,466)	-4.1%	4.43184	4.94793	(0.51609)	-10.4%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	58,612,093	68,233,744	(9,621,651)	-14.1%	1,321,386	1,377,852	(56,466)	-4.1%	4.43565	4.95218	(0.51653)	-10.4%
32. Other	0	0	0	0.0%	1,321,386	1,377,852	(56,466)	-4.1%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,325,503)	(1,276,250)	(49,253)	3.9%	1,321,386	1,377,852	(56,466)	-4.1%	(0.10031)	(0.09263)	(0.00769)	8.3%
34. Other	0	0	0	0.0%	1,321,386	1,377,852	(56,466)	-4.1%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,321,386	1,377,852	(56,466)	-4.1%	0.93120	0.89303	0.03816	4.3%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	69,591,275	79,262,179	(9,670,904)	-12.2%	1,321,386	1,377,852	(56,466)	-4.1%	5.26654	5.75259	(0.48605)	-8.4%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	69,641,381	79,319,248	(9,677,867)	-12.2%	1,321,386	1,377,852	(56,466)	-4.1%	5.27033	5.75673	(0.48640)	-8.4%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,321,386	1,377,852	(56,466)	-4.1%	0.00460	0.00441	0.00019	4.3%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**69,702,176**	**79,380,043**	**(9,677,867)**	**-12.2%**	**1,321,386**	**1,377,852**	**(56,466)**	**-4.1%**	**5.27493**	**5.76114**	**(0.48621)**	**-8.4%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									5.275	5.761	(0.486)	-8.4%

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MARCH 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	169,554,201	156,970,520	12,583,681	8.0%	4,133,617	3,662,798	470,819	12.9%	4.10184	4.28554	(0.18370)	-4.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(22,467)	(20,202)	(2,265)	11.2%	4,133,617 (a)	3,662,798 (a)	470,819	12.9%	(0.00054)	(0.00055)	0.00001	-1.5%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	4,133,617 (a)	3,662,798 (a)	470,819	12.9%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	0	0	0	0.0%	4,133,617 (a)	3,662,798 (a)	470,819	12.9%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**169,531,734**	**156,950,318**	**12,581,416**	**8.0%**	**4,133,617**	**3,662,798**	**470,819**	**12.9%**	**4.10129**	**4.28498**	**(0.18369)**	**-4.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	5,126,596	48,076,100	(42,949,504)	-89.3%	105,508	830,168	(724,660)	-87.3%	4.85896	5.79113	(0.93216)	-16.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	11,967,139	0	11,967,139	0.0%	166,865	0	166,865	0.0%	7.17175	0.00000	7.17175	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	3,766,632	2,982,200	784,432	26.3%	124,786	103,925	20,861	20.1%	3.01847	2.86957	0.14890	5.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**20,860,367**	**51,058,300**	**(30,197,933)**	**-59.1%**	**397,159**	**934,093**	**(536,934)**	**-57.5%**	**5.25240**	**5.46608**	**(0.21369)**	**-3.9%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**4,530,776**	**4,596,891**	**(66,115)**	**-1.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	135,322	90,300	45,022	49.9%	3,557	3,659	(102)	-2.8%	3.80439	2.46789	1.33650	54.2%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	964,865	0	964,865	0.0%	21,600	0	21,600	0.0%	4.46697	0.00000	4.46697	0.0%
17. Fuel Cost of Market Base Sales (A6)	1,481,311	1,912,200	(430,889)	-22.5%	30,498	43,016	(12,518)	-29.1%	4.85708	4.44532	0.41175	9.3%
18. Gains on Market Based Sales	318,334	1,271,080	(952,746)	-75.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**2,899,832**	**3,273,580**	**(373,748)**	**-11.4%**	**55,655**	**46,675**	**8,980**	**19.2%**	**5.21037**	**7.01356**	**(1.80319)**	**-25.7%**
20. Net Inadvertant Interchange					(744)	0	(744)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					4,603	0	4,603	0.0%				
22. Interchange and Wheeling Losses					4,919	800	4,119	514.9%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**187,492,269**	**204,735,038**	**(17,242,769)**	**-8.4%**	**4,474,061**	**4,549,416**	**(75,355)**	**-1.7%**	**4.19065**	**4.50025**	**(0.30960)**	**-6.9%**
24. Net Unbilled	(8,369,899) (a)	(2,802,377) (a)	(5,567,522)	198.7%	(206,147)	(62,696)	(143,451)	228.8%	4.06016	4.46979	(0.40963)	-9.2%
25. Company Use	360,503 (a)	418,434 (a)	(57,931)	-13.8%	8,595	9,300	(705)	-7.6%	4.19433	4.49929	(0.30496)	-6.8%
26. T & D Losses	14,074,133 (a)	7,806,955 (a)	6,267,178	80.3%	344,897	173,296	171,601	99.0%	4.08068	4.50498	(0.42431)	-9.4%
27. System KWH Sales	187,492,269	204,735,038	(17,242,769)	-8.4%	4,326,716	4,429,516	(102,800)	-2.3%	4.33336	4.62206	(0.28870)	-6.2%
28. Wholesale KWH Sales	(8,838,127)	(4,473,284)	(4,364,843)	97.6%	(205,525)	(95,639)	(109,886)	114.9%	4.30027	4.67726	(0.37699)	-8.1%
29. Jurisdictional KWH Sales	178,654,142	200,261,754	(21,607,612)	-10.8%	4,121,191	4,333,877	(212,686)	-4.9%	4.33501	4.62085	(0.28583)	-6.2%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	178,807,784	200,433,980	(21,626,196)	-10.8%	4,121,191	4,333,877	(212,686)	-4.9%	4.33874	4.62482	(0.28608)	-6.2%
32. Other	0	0	0	0.0%	4,121,191	4,333,877	(212,686)	-4.9%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(3,256,583)	(3,828,750)	572,167	-14.9%	4,121,191	4,333,877	(212,686)	-4.9%	(0.07902)	(0.08834)	0.00932	-10.6%
34. Other	0	0	0	0.0%	4,121,191	4,333,877	(212,686)	-4.9%	0.00000	0.00000	0.00000	0.0%
35. True-up *	36,914,055	36,914,056	(1)	0.0%	4,121,191	4,333,877	(212,686)	-4.9%	0.89571	0.85176	0.04396	5.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	212,465,256	233,519,286	(21,054,030)	-9.0%	4,121,191	4,333,877	(212,686)	-4.9%	5.15543	5.38823	(0.23280)	-4.3%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	212,618,231	233,687,419	(21,069,188)	-9.0%	4,121,191	4,333,877	(212,686)	-4.9%	5.15915	5.39211	(0.23296)	-4.3%
39. GPIF * (Already Adjusted for Taxes)	182,385	182,385	0	0.0%	4,121,191	4,333,877	(212,686)	-4.9%	0.00443	0.00421	0.00022	5.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**212,800,616**	**233,869,804**	**(21,069,188)**	**-9.0%**	**4,121,191**	**4,333,877**	**(212,686)**	**-4.9%**	**5.16358**	**5.39632**	**(0.23274)**	**-4.3%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.164**	**5.396**	**(0.232)**	**-4.3%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	54,813,228	43,954,637	10,858,591	24.7%	169,554,201	156,970,520	12,583,681	8.0%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	874,499	85,500	788,999	922.8%	2,581,498	2,002,500	578,998	28.9%
2a. GAINS FROM MARKET BASED SALES	88,472	21,520	66,952	311.1%	318,334	1,271,080	(952,746)	-75.0%
3. FUEL COST OF PURCHASED POWER	1,282,184	25,365,300	(24,083,116)	-94.9%	5,126,596	48,076,100	(42,949,504)	-89.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,107,457	1,043,400	64,057	6.1%	3,766,632	2,982,200	784,432	26.3%
4. ENERGY COST OF ECONOMY PURCHASES	5,021,431	0	5,021,431	0.0%	11,967,139	0	11,967,139	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	61,261,329	70,256,317	(8,994,988)	-12.8%	187,514,736	204,755,240	(17,240,504)	-8.4%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,877)	(6,734)	(1,143)	17.0%	(22,467)	(20,202)	(2,265)	11.2%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	61,253,452	70,249,583	(8,996,131)	-12.8%	187,492,269	204,735,038	(17,242,769)	-8.4%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,321,386	1,377,852	(56,466)	-4.1%	4,121,191	4,333,877	(212,686)	-4.9%
2. NONJURISDICTIONAL SALES	60,736	41,926	18,810	44.9%	205,525	95,639	109,886	114.9%
3. TOTAL SALES	1,382,122	1,419,778	(37,656)	-2.7%	4,326,716	4,429,516	(102,800)	-2.3%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9560560	0.9704700	(0.0144140)	-1.5%	0.9524986	0 9784087	(0.0259101)	-2.6%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	70,849,707	74,473,379	(3,623,672)	-4.9%	221,205,967	234,310,297	(13,104,330)	-5.6%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(36,914,055)	(36,914,056)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(182,385)	(182,385)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	58,484,227	62,107,899	(3,623,672)	-5.8%	184,109,527	197,213,857	(13,104,330)	-6.6%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	61,253,452	70,249,583	(8,996,131)	-12.8%	187,492,269	204,735,038	(17,242,769)	-8.4%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9560560	0.9704700	(0.0144140)	-1.5%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	58,561,730	68,175,113	(9,613,383)	-14.1%	178,654,142	200,261,754	(21,607,612)	-10.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	58,612,093	68,233,744	(9,621,651)	-14.1%	178,807,784	200,433,980	(21,626,196)	-10.8%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,325,503)	(1,276,250)	(49,253)	3.9%	(3,256,583)	(3,828,750)	572,167	-14.9%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	57,286,590	66,957,494	(9,670,904)	-14.4%	175,551,201	196,605,230	(21,054,029)	-10.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	1,197,637	(4,849,595)	6,047,232	-124.7%	8,558,326	608,627	7,949,700	1306.2%
8. INTEREST PROVISION FOR THE MONTH	(842,755)	(430,672)	(412,083)	95.7%	(2,595,725)	(1,415,332)	(1,180,393)	83.4%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(223,955,970)	(118,573,290)	(105,382,680)	88.9%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(211,296,403)	(111,548,872)	(99,747,531)	89.4%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(223,955,970)	(118,573,290)	(105,382,680)	88.9%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(210,453,648)	(111,118,200)	(99,335,448)	89.4%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(434,409,618)	(229,691,490)	(204,718,128)	89.1%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(217,204,809)	(114,845,745)	(102,359,064)	89.1%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	4.530	4.500	0.030	0.7%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	4.780	4.500	0.280	6.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	9.310	9.000	0.310	3.4%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	4.655	4.500	0.155	3.4%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.388	0.375	0.013	3.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(842,755)	(430,672)	(412,083)	95.7%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	22,769	137,509	(114,740)	-83.4%	522,966	177,262	345,704	195.0%
2	LIGHT OIL	3,334,708	774,628	2,560,080	330.5%	4,694,376	2,099,590	2,594,786	123.6%
3	COAL	25,294,976	19,942,140	5,352,836	26.8%	71,475,880	64,163,087	7,312,793	11.4%
4	NATURAL GAS	26,160,775	23,100,360	3,060,415	13.2%	92,860,979	90,530,581	2,330,398	2.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	54,813,228	43,954,637	10,858,591	24.7%	169,554,201	156,970,520	12,583,681	8.0%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4	1,797	(1,793)	-99.8%	5,371	2,296	3,075	133.9%
9	LIGHT OIL	5,695	5,868	(173)	-2.9%	15,707	15,882	(175)	-1.1%
10	COAL	1,009,167	778,352	230,815	29.7%	2,878,820	2,508,567	370,253	14.8%
11	NATURAL GAS	381,913	296,404	85,509	28.8%	1,234,993	1,136,053	98,940	8.7%
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)	1,396,779	1,082,421	314,358	29.0%	4,134,891	3,662,798	472,093	12.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	276	2,797	(2,521)	-90.1%	9,062	3,571	5,491	153.8%
16	LIGHT OIL (BBL)	40,354	16,208	24,146	149.0%	57,239	42,204	15,035	35.6%
17	COAL (TON)	447,150	343,039	104,111	30.3%	1,283,070	1,114,663	168,407	15.1%
18	NATURAL GAS (MCF)	2,790,112	2,200,158	589,954	26.8%	8,930,328	8,300,715	629,613	7.6%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	1,735	17,557	(15,822)	-90.1%	56,857	22,413	34,444	153.7%
22	LIGHT OIL	52,201	65,433	(13,232)	-20.2%	148,210	179,342	(31,132)	-17.4%
23	COAL	10,610,574	8,334,600	2,275,974	27.3%	30,468,985	26,925,979	3,543,006	13.2%
24	NATURAL GAS	2,887,766	2,261,711	626,055	27.7%	9,251,641	8,532,918	718,723	8.4%
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)	13,552,276	10,679,301	2,872,975	26.9%	39,925,693	35,660,652	4,265,041	12.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.00%	0.17%	(0.00)	-	0.13%	0.06%	0.00	-
29	LIGHT OIL	0.41%	0.54%	(0.00)	-	0.38%	0.43%	(0.00)	-
30	COAL	72.25%	71.91%	0.00	-	69.62%	68.49%	0.01	-
31	NATURAL GAS	27.34%	27.38%	(0.00)	-	29.87%	31.02%	(0.01)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	82.50	49.16	33.33	67.8%	57.71	49.64	8.07	16.3%
36	LIGHT OIL ($/BBL)	82.64	47.79	34.84	72.9%	82.01	49.75	32.26	64.9%
37	COAL ($/TON)	56.57	58.13	(1.56)	-2.7%	55.71	57.56	(1.86)	-3.2%
38	NATURAL GAS ($/MCF)	9.38	10.50	(1.12)	-10.7%	10.40	10.91	(0.51)	-4.7%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	13.12	7.83	5.29	67.6%	9.20	7.91	1.29	16.3%
42	LIGHT OIL	63.88	11.84	52.04	439.6%	31.67	11.71	19.97	170.6%
43	COAL	2.38	2.39	(0.01)	-0.4%	2.35	2.38	(0.04)	-1.6%
44	NATURAL GAS	9.06	10.21	(1.15)	-11.3%	10.04	10.61	(0.57)	-5.4%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.04	4.12	(0.07)	-1.7%	4.25	4.40	(0.16)	-3.5%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	433,750	9,770	423,980	4339.6%	10,586	9,762	824	8.4%
49	LIGHT OIL	9,166	11,151	(1,985)	-17.8%	9,436	11,292	(1,856)	-16.4%
50	COAL	10,514	10,708	(194)	-1.8%	10,584	10,734	(150)	-1.4%
51	NATURAL GAS	7,561	7,631	(70)	-0.9%	7,491	7,511	(20)	-0.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,703	9,866	(163)	-1.7%	9,656	9,736	(80)	-0.8%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	569.23	7.65	561.58	7340.9%	9.74	7.72	2.02	26.2%
56	LIGHT OIL	58.56	13.20	45.36	343.6%	29.89	13.22	16.67	126.1%
57	COAL	2.51	2.56	(0.05)	-2.0%	2.48	2.56	(0.08)	-3.1%
58	NATURAL GAS	6.85	7.79	(0.94)	-12.1%	7.52	7.97	(0.45)	-5.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.92	4.06	(0.14)	-3.4%	4.10	4.29	(0.19)	-4.4%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	213,552	69.8	75.6	81.5	10,798	COAL	97,682	23,606,460	2,305,926.2	5,366,594	2.51	54.94
B.B.#2	391	254,463	87.5	91.7	87.5	10,209	COAL	109,860	23,647,020	2,597,855.2	6,035,647	2.37	54.94
B.B.#3	433	233,956	72.6	79.6	72.9	10,769	COAL	107,830	23,365,440	2,519,492.8	5,924,120	2.53	54.94
B.B.#4	462	151,694	44.1	52.4	79.3	11,020	COAL	73,300	22,805,800	1,671,665.1	4,027,061	2.65	54.94
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	3,847	5,782,623	22,245.3	312,702	-	81.28
B.B. STATION	1,697	853,665	67.6	74.0	80.1	10,654	COAL	-	-	-	21,666,124	2.54	-
SEB-PHIL #1(HVY OIL)	18	4	0.0	62.5	1.4	0	HVY.OIL	276	6,273,540	1,735.1	14,167	354.18	51.33
SEB-PHIL #2(HVY OIL)	18	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
SEB-PHIL IGNITION	-	-	-	-	-	-	LGT.OIL	97	5,782,623	561.7	8,602	-	88.68
SEB-PHILLIPS TOTAL	36	4	0.0	29.6	0.7	0	HVY.OIL	-	-	-	22,769	569.23	-
POLK #1 GASIFIER	260	155,502	-	-	-	9,747	COAL	58,478	25,918,000	1,515,634.6	3,628,852	2.33	62.05
POLK #1 CT (OIL)	245	5,650	-	-	-	9,019	LGT.OIL	40,139	5,814,209	50,958.8	3,292,273	58.27	82.02
POLK #1 TOTAL	260	161,152	83.3	94.9	83.3	9,721	-	-	-	1,566,593.4	6,921,125	4.29	-
POLK #2 CT (GAS)	175	8,157	-	-	-	11,760	GAS	92,684	1,035,000	95,928.0	817,171	10.02	8.82
POLK #2 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	180	8,157	6.1	98.4	0.0	11,760	-	-	-	95,928.0	817,171	10.02	-
POLK #3 CT (GAS)	175	7,208	-	-	-	12,049	GAS	83,910	1,035,000	86,846.8	729,480	10.12	8.69
POLK #3 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	180	7,208	5.4	100.0	0.0	12,049	-	-	-	86,846.8	729,480	10.12	-
POLK STATION TOTAL	620	176,517	38.3	97.4	34.9	9,910	-	-	-	1,749,368.2	8,467,776	4.80	-
B.B.C.T.#1	15	4	0.0	99.1	0.0	22,150	LGT.OIL	15	5,812,992	88.6	2,960	74.00	197.33
B.B.C.T.#2	80	11	0.0	100.0	13.8	33,782	LGT.OIL	64	5,765,400	371.6	12,632	114.84	197.38
B.B.C.T.#3	80	30	0.1	93.4	12.5	26,083	LGT.OIL	136	5,765,399	782.5	26,843	89.48	197.38
C.T. TOTAL	175	45	0.0	96.9	12.0	27,616	LGT.OIL	215	5,768,999	1,242.7	42,435	94.30	197.37
COT 1	3	(9)	0.0	0.0	0.0	0	GAS	0	0	0.0	121	(1.34)	0.00
COT 2	3	(10)	0.0	0.0	0.0	0	GAS	0	0	0.0	121	(1.21)	0.00
CITY OF TAMPA TOTAL *	6	(19)	0.0	0.0	0.0	0	GAS	0	0	0.0	242	(1.27)	0.00
BAYSIDE ST 1	244	86,665	47.7	80.4	59.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	183	50,319	37.0	79.7	67.4	11,757	GAS	571,587	1,035,000	591,593.0	5,189,834	10.31	9.08
BAYSIDE CT1B	183	56,137	41.2	81.9	66.8	11,753	GAS	637,487	1,035,000	659,799.0	5,788,186	10.31	9.08
BAYSIDE CT1C	183	51,415	37.8	83.6	64.4	11,171	GAS	554,916	1,035,000	574,338.0	5,038,466	9.80	9.08
BAYSIDE UNIT 1 TOTAL	793	244,536	41.4	81.3	64.1	7,466	GAS	1,763,990	1,035,000	1,825,730.0	16,016,486	6.55	9.08
BAYSIDE ST 2	316	41,302	17.6	32.2	54.5	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	183	23,646	17.4	32.2	66.6	10,634	GAS	242,936	1,035,000	251,439.0	2,458,562	10.40	10.12
BAYSIDE CT2B	183	21,541	15.8	29.1	72.1	11,060	GAS	230,184	1,035,000	238,240.0	2,329,509	10.81	10.12
BAYSIDE CT2C	183	19,638	14.4	32.0	71.5	10,952	GAS	207,802	1,035,000	215,075.0	2,102,998	10.71	10.12
BAYSIDE CT2D	183	15,904	11.7	31.8	80.0	10,972	GAS	168,606	1,035,000	174,507.0	1,706,327	10.73	10.12
BAYSIDE UNIT 2 TOTAL	1,048	122,031	15.7	31.6	67.1	7,205	GAS	849,528	1,035,000	879,261.0	8,597,396	7.05	10.12
BAYSIDE STATION TOTAL	1,841	366,567	26.8	53.0	65.8	7,379	GAS	2,613,518	1,035,000	2,704,991.0	24,613,882	6.71	9.42
SYSTEM	4,375	1,396,779	42.9	63.6	64.2	9,703	-	-	-	13,552,276.3	54,813,228	3.92	-

Footnotes: * Station service only. [1] As burned fuel cost system total inludes ignition oil. [2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	0	2,797	(2,797)	-100.0%	10,346	3,571	6,775	189.7%
3 UNIT COST ($/BBL)	0.00	47.66	(47.66)	-100.0%	52.95	47.90	5.05	10.5%
4 AMOUNT ($)	0	133,315	(133,315)	-100.0%	547,845	171,051	376,794	220.3%
5 BURNED:								
6 UNITS (BBL)	276	2,797	(2,521)	-90.1%	9,062	3,571	5,491	153.8%
7 UNIT COST ($/BBL)	82.50	49.16	33.33	67.8%	57.71	49.64	8.07	16.3%
8 AMOUNT ($)	22,769	137,509	(114,740)	-83.4%	522,966	177,262	345,704	195.0%
9 ENDING INVENTORY:								
10 UNITS (BBL)	16,615	12,118	4,497	37.1%	16,615	12,118	4,497	37.1%
11 UNIT COST ($/BBL)	54.39	47.20	7.19	15.2%	54.39	47.20	7.19	15.2%
12 AMOUNT ($)	903,675	571,983	331,692	58.0%	903,675	571,983	331,692	58.0%
13								
14 DAYS SUPPLY:	319	233	86	40.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	31,608	16,208	15,400	95.0%	55,493	42,204	13,289	31.5%
17 UNIT COST ($/BBL)	83.30	70.31	13.00	18.5%	81.65	71.28	10.38	14.6%
18 AMOUNT ($)	2,633,088	1,139,551	1,493,537	131.1%	4,531,050	3,008,102	1,522,948	50.6%
19 BURNED:								
20 UNITS (BBL)	40,354	16,208	24,146	149.0%	57,239	42,204	15,035	35.6%
21 UNIT COST ($/BBL)	82.64	47.79	34.84	72.9%	82.01	49.75	32.26	64.9%
22 AMOUNT ($)	3,334,708	774,628	2,560,080	330.5%	4,694,376	2,099,590	2,594,786	123.6%
23 ENDING INVENTORY:								
24 UNITS (BBL)	58,701	85,007	(26,306)	-30.9%	58,701	85,007	(26,306)	-30.9%
25 UNIT COST ($/BBL)	81.29	66.86	14.43	21.6%	81.29	66.86	14.43	21.6%
26 AMOUNT ($)	4,771,780	5,683,829	(912,049)	-16.0%	4,771,780	5,683,829	(912,049)	-16.0%
27								
28 DAYS SUPPLY: NORMAL	144	208	(64)	-30.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	8	12	(4)	-30.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	399,847	354,000	45,847	13.0%	1,000,052	1,117,600	(117,548)	-10.5%
32 UNIT COST ($/TON)	58.11	57.17	0.94	1.6%	56.98	57.34	(0.36)	-0.6%
33 AMOUNT ($)	23,234,597	20,238,428	2,996,169	14.8%	56,978,528	64,082,628	(7,104,100)	-11.1%
34 BURNED:								
35 UNITS (TONS)	447,150	343,039	104,111	30.3%	1,283,070	1,114,663	168,407	15.1%
36 UNIT COST ($/TON)	56.57	58.13	(1.56)	-2.7%	55.71	57.56	(1.86)	-3.2%
37 AMOUNT ($)	25,294,976	19,942,140	5,352,836	26.8%	71,475,880	64,163,087	7,312,793	11.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	188,371	549,685	(361,314)	-65.7%	188,371	549,685	(361,314)	-65.7%
40 UNIT COST ($/TON)	57.07	56.83	0.24	0.4%	57.07	56.83	0.24	0.4%
41 AMOUNT ($)	10,749,756	31,237,559	(20,487,803)	-65.6%	10,749,756	31,237,559	(20,487,803)	-65.6%
42								
43 DAYS SUPPLY:	14	40	(26)	-70.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	2,806,739	2,200,158	606,581	27.6%	8,931,936	8,300,715	631,221	7.6%
46 UNIT COST ($/MCF)	9.38	10.50	(1.12)	-10.6%	10.26	10.91	(0.65)	-5.9%
47 AMOUNT ($)	26,336,669	23,100,359	3,236,310	14.0%	91,646,313	90,530,579	1,115,734	1.2%
48 BURNED:								
49 UNITS (MCF)	2,790,112	2,200,158	589,954	26.8%	8,930,328	8,300,715	629,613	7.6%
50 UNIT COST ($/MCF)	9.38	10.50	(1.12)	-10.7%	10.40	10.91	(0.51)	-4.7%
51 AMOUNT ($)	26,160,775	23,100,360	3,060,415	13.2%	92,860,979	90,530,581	2,330,398	2.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	187,874	0	187,874	0.0%	187,874	0	187,874	0.0%
54 UNIT COST ($/MCF)	7.08	0.00	7.08	0.0%	7.08	0.00	7.08	0.0%
55 AMOUNT ($)	1,329,532	0	1,329,532	0.0%	1,329,532	0	1,329,532	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	7,829
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	7,829

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(4,257)	(320,531)
OTHER USAGE	(670)	(54,585)
TOTAL	(4,927)	(375,116)

(3) *RECONCILIATION - COAL*

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	17,819
IGNITION #2 OIL	312,702
IGNITION PROPANE	12,911
AERIAL SURVEY ADJ.	(745,031)
ADDITIVES	42,208
GREEN FUEL	0
TOTAL	(359,391)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,864.0	0.0	1,864.0	3.176	3.176	59,200.00	59,200.00	
VARIOUS	JURISDIC.	SCH. - MB	684.0	0.0	684.0	3.845	6.681	26,300.00	45,700.00	21,520.00
TOTAL			2,548.0	0.0	2,548.0	3.356	4.117	85,500.00	104,900.00	21,520.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	530.5	0.0	530.5	3.972	4.174	21,072.69	22,143.32	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	790.2	0.0	790.2	3.148	3.317	24,874.56	26,210.83	
PROGRESS ENERGY FLORIDA		SCH. - MA	200.0	0.0	200.0	4.461	5.697	8,921.50	11,393.06	1,781.56
FLA. PWR. & LIGHT		SCH. - MA	6,085.0	0.0	6,085.0	4.271	5.554	259,887.12	337,957.92	50,062.60
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	130.0	0.0	130.0	4.457	6.197	5,794.30	8,056.39	1,813.59
THE ENERGY AUTHORITY		SCH. - MA	151.0	0.0	151.0	3.167	4.162	4,782.13	6,284.50	1,265.42
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	2,609.0	0.0	2,609.0	2.630	3.198	68,613.98	83,439.71	12,851.33
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	800.0	0.0	800.0	2.635	3.104	21,078.33	24,835.43	3,177.10
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(1.62)	(1.62)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	740.0	0.0	740.0	4.424	5.942	32,740.48	43,968.33	9,066.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	1,629.0	0.0	1,629.0	2.444	3.028	39,820.41	49,329.10	8,456.35
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SEP SCH. - D	7,440.0	0.0	7,440.0	4.685	5.285	348,564.00	393,204.00	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. PRECO-1	JAN 2006	SCH. - D	(711.7)	0.0	(711.7)	4.236	4.236	(30,149.44)	(30,149.44)	
SEMINOLE ELEC. PRECO-1	JAN 2006	SCH. - D	711.7	0.0	711.7	4.036	4.236	28,723.67	30,149.44	
SEMINOLE ELEC. HARDEE	JAN 2006	SCH. - D	(518.0)	0.0	(518.0)	4.049	4.049	(20,976.18)	(20,976.18)	
SEMINOLE ELEC. HARDEE	JAN 2006	SCH. - D	518.0	0.0	518.0	3.976	4.049	20,605.86	20,976.18	
SEMINOLE ELEC. PRECO-1	FEB 2006	SCH. - D	(333.4)	0.0	(333.4)	4.309	4.309	(14,365.23)	(14,365.23)	
SEMINOLE ELEC. PRECO-1	FEB 2006	SCH. - D	333.4	0.0	333.4	4.073	4.309	13,579.85	14,365.23	
SEMINOLE ELEC. HARDEE	FEB 2006	SCH. - D	(672.4)	0.0	(672.4)	4.175	4.175	(28,071.89)	(28,071.89)	
SEMINOLE ELEC. HARDEE	FEB 2006	SCH. - D	672.4	0.0	672.4	3.936	4.175	26,464.87	28,071.89	
NEW SMYRNA BEACH	FEB 2006	SEP SCH. - D	(6,720.0)	0.0	(6,720.0)	4.052	4.052	(272,294.40)	(272,294.40)	
NEW SMYRNA BEACH	FEB 2006	SEP SCH. - D	6,720.0	0.0	6,720.0	4.685	5.285	314,832.00	355,152.00	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,440.0	0.0	7,440.0	5.257	6.399	391,101.60	476,061.60	
SUB-TOTAL SCHEDULE D POWER SALES			1,320.7	0.0	1,320.7	3.162	3.661	41,758.76	48,354.15	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			12,344.0	0.0	12,344.0	3.578	4.579	441,638.25	565,262.82	88,472.33
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			21,104.7	0.0	21,104.7	4.144	5.163	874,498.61	1,089,678.57	88,472.33
CURRENT MONTH:										
DIFFERENCE			18,556.7	0.0	18,556.7	0.788	1.046	788,998.61	984,778.57	66,952.33
DIFFERENCE %			728.3%	0.0%	728.3%	23.5%	25.4%	922.8%	938.8%	311.1%
PERIOD TO DATE:										
ACTUAL			55,654.2	0.0	55,654.2	4.638	5.617	2,581,498.29	3,125,985.26	318,333.47
ESTIMATED			46,675.0	0.0	46,675.0	4.290	7.475	2,002,500.00	3,489,100.00	1,271,080.00
DIFFERENCE			8,979.2	0.0	8,979.2	0.348	(1.858)	578,998.29	(363,114.74)	(952,746.53)
DIFFERENCE %			19.2%	0.0%	19.2%	8.1%	-24.9%	28.9%	-10.4%	-75.0%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF MARCH 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	3,964.0	0.0	2,352.0	1,612.0	8.337	8.337	134,400.00
HARDEE POWER PARTNERS		IPP	4,071.0	0.0	0.0	4,071.0	11.184	11.184	455,300.00
CALPINE		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASED	350,052.0	0.0	0.0	350,052.0	6.207	6.207	21,729,000.00
OTHER		SCH. - D	85,092.0	0.0	0.0	85,092.0	3.580	3.580	3,046,600.00
TOTAL			443,179.0	0.0	2,352.0	440,827.0	5.754	5.754	25,365,300.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	7,275.0	0.0	0.0	7,275.0	10.915	10.915	794,085.69
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	27,660.0	0.0	0.0	27,660.0	3.483	3.483	963,302.20
AUBURNDALE POWER PARTNERS		OATT	850.0	0.0	0.0	850.0	3.461	3.461	29,420.05
PRIOR MONTH ADJUSTMENTS:									
HARDEE PWR. PART.-NATIVE	FEB 2006	IPP	(6,911.0)	0.0	0.0	(6,911.0)	16.577	16.577	(1,145,647.67)
HARDEE PWR. PART.-NATIVE	FEB 2006	IPP	7,285.0	0.0	0.0	7,285.0	10.016	10.016	729,674.86
PROGRESS ENERGY FLORIDA	FEB 2006	SCH. - D	(30,675.0)	0.0	0.0	(30,675.0)	3.750	3.750	(1,150,453.00)
PROGRESS ENERGY FLORIDA	FEB 2006	SCH. - D	30,675.0	0.0	0.0	30,675.0	3.461	3.461	1,061,802.25
SUB-TOTAL OF ADJUSTMENTS:			374.0	0.0	0.0	374.0	(134.926)	(134.926)	(504,623.56)
TOTAL			36,159.0	0.0	0.0	36,159.0	3.546	3.546	1,282,184.38
CURRENT MONTH:									
DIFFERENCE			(407,020.0)	0.0	(2,352.0)	(404,668.0)	(2.208)	(2.208)	(24,083,115.62)
DIFFERENCE %			-91.8%	0.0%	0.0%	-91.8%	-38.4%	-38.4%	-94.9%
PERIOD TO DATE:									
ACTUAL			105,508.0	0.0	0.0	105,508.0	4.859	4.859	5,126,596.49
ESTIMATED			832,653.0	0.0	2,485.0	830,168.0	5.791	5.791	48,076,100.00
DIFFERENCE			(727,145.0)	0.0	(2,485.0)	(724,660.0)	(0.932)	(0.932)	(42,949,503.51)
DIFFERENCE %			-87.3%	0.0%	-100.0%	-87.3%	-16.1%	-16.1%	-89.3%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	35,798.0	0.0	0.0	35,798.0	2.915	2.915	1,043,400.00
TOTAL		**35,798.0**	**0.0**	**0.0**	**35,798.0**	**2.915**	**2.915**	**1,043,400.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	18,791.0	0.0	0.0	18,791.0	2.532	2.532	475,846.18
McKAY BAY REFUSE	COGEN.	12,684.0	0.0	0.0	12,684.0	2.534	2.534	321,387.48
ORANGE COGENERATION L.P.	COGEN.	5,704.0	0.0	0.0	5,704.0	2.343	2.343	133,630.53
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	62.0	0.0	0.0	62.0	8.310	8.310	5,152.16
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	856.0	0.0	0.0	856.0	4.151	4.151	35,529.07
CF INDUSTRIES INC.	COGEN.	1,054.0	0.0	0.0	1,054.0	4.576	4.576	48,232.19
IMC-AGRICO-NEW WALES	COGEN.	704.0	0.0	0.0	704.0	4.874	4.874	34,309.92
IMC-AGRICO-S. PIERCE	COGEN.	596.0	0.0	0.0	596.0	5.318	5.318	31,696.68
AUBURNDALE POWER PARTNERS	COGEN.	1,239.0	0.0	0.0	1,239.0	3.247	3.247	40,224.89
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR MARCH 2006		41,690.0	0.0	0.0	41,690.0	2.701	2.701	1,126,009.10
ADJUSTMENTS FOR THE MONTH OF:	**FEBRUARY 2006**							
HILLSBOROUGH COUNTY	COGEN.	(10,402.0)	0.0	0.0	(10,402.0)	2.609	2.609	(271,424.72)
		10,402.0	0.0	0.0	10,402.0	2.544	2.544	264,580.92
McKAY BAY REFUSE	COGEN.	(12,726.0)	0.0	0.0	(12,726.0)	2.604	2.604	(331,328.33)
		12,726.0	0.0	0.0	12,726.0	2.540	2.540	323,251.35
ORANGE COGENERATION L.P.	COGEN.	(5,060.0)	0.0	0.0	(5,060.0)	2.411	2.411	(122,018.54)
		5,060.0	0.0	0.0	5,060.0	2.340	2.340	118,387.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	(18,552.32)
TOTAL		**41,690.0**	**0.0**	**0.0**	**41,690.0**	**2.656**	**2.656**	**1,107,456.78**
CURRENT MONTH:								
DIFFERENCE		5,892.0	0.0	0.0	5,892.0	(0.258)	(0.258)	64,056.78
DIFFERENCE %		16.5%	0.0%	0.0%	16.5%	-8.9%	-8.9%	6.1%
PERIOD TO DATE:								
ACTUAL		124,786.0	0.0	0.0	124,786.0	3.018	3.018	3,766,631.32
ESTIMATED		103,925.0	0.0	0.0	103,925.0	2.870	2.870	2,982,200.00
DIFFERENCE		20,861.0	0.0	0.0	20,861.0	0.149	0.149	784,431.32
DIFFERENCE %		20.1%	0.0%	0.0%	20.1%	5.2%	5.2%	26.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	4,100.0	6.511	266,955.00	10.033	411,362.20	144,407.20
FLA. POWER & LIGHT	SCH. - JC	28,895.0	7.045	2,035,725.00	9.032	2,609,713.15	573,988.15
CITY OF LAKELAND	SCH. - JC	1,874.0	9.224	172,865.00	12.262	229,783.24	56,918.24
ORLANDO UTIL. COMM.	SCH. - JC	1,822.0	11.699	213,150.00	12.277	223,688.15	10,538.15
THE ENERGY AUTHORITY	SCH. - JC	13,188.0	7.786	1,026,864.00	10.587	1,396,157.50	369,293.50
OKEELANTA	SCH. - JC	1,345.0	7.982	107,356.50	10.823	145,571.80	38,215.30
CITY OF TALLAHASSEE	SCH. - JC	75.0	8.892	6,669.00	12.110	9,082.50	2,413.50
CALPINE	SCH. - JC	155.0	7.601	11,781.00	11.695	18,127.25	6,346.25
CARGILL ALLIANT	SCH. - JC	6,055.0	7.394	447,731.00	9.015	545,830.19	98,099.19
RELIANT	SCH. - JC	5,056.0	11.500	581,440.00	16.235	820,863.72	239,423.72
RAINBOW ENERGY MARKETERS	SCH. - JC	14.0	5.600	784.00	11.966	1,675.24	891.24
SEMINOLE ELEC. CO-OP	SCH. - JC	715.0	5.372	38,410.00	7.557	54,035.65	15,625.65
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	1,854.0	6.025	111,700.00	9.258	171,635.68	59,935.68
SUBTOTAL		65,148.0	7.708	5,021,430.50	10.188	6,637,526.27	1,616,095.77
NO PRIOR MONTH ADJUSTMENTS.							
TOTAL		**65,148.0**	**7.708**	**5,021,430.50**	**10.188**	**6,637,526.27**	**1,616,095.77**
CURRENT MONTH:							
DIFFERENCE		65,148.0	7.708	5,021,430.50	10.188	6,637,526.27	1,616,095.77
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		166,865.0	7.172	11,967,139.10	9.622	16,055,779.15	4,088,640.05
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		166,865.0	7.172	11,967,139.10	9.622	16,055,779.15	4,088,640.05
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

APRIL 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	64,370,752	56,698,856	7,671,896	13.5%	1,459,763	1,294,235	165,528	12.8%	4.40967	4.38088	0.02879	0.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,687)	(6,734)	(1,953)	29.0%	1,459,763 (a)	1,294,235 (a)	165,528	12.8%	(0.00060)	(0.00052)	(0.00007)	14.4%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,459,763 (a)	1,294,235 (a)	165,528	12.8%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	7,733	17,367	(9,634)	-55.5%	1,459,763 (a)	1,294,235 (a)	165,528	12.8%	0.00053	0.00134	(0.00081)	-60.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**64,369,798**	**56,709,489**	**7,660,309**	**13.5%**	**1,459,763**	**1,294,235**	**165,528**	**12.8%**	**4.40961**	**4.38170**	**0.02791**	**0.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	3,578,250	12,009,100	(8,430,850)	-70.2%	62,608	240,754	(178,146)	-74.0%	5.71532	4.98812	0.72720	14.6%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	7,058,067	0	7,058,067	0.0%	94,551	0	94,551	0.0%	7.46483	0.00000	7.46483	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,201,587	1,048,600	152,987	14.6%	42,172	36,546	5,626	15.4%	2.84925	2.86926	(0.02001)	-0.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**11,837,904**	**13,057,700**	**(1,219,796)**	**-9.3%**	**199,331**	**277,300**	**(77,969)**	**-28.1%**	**5.93882**	**4.70887**	**1.22995**	**26.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,659,094**	**1,571,535**	**87,559**	**5.6%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	63,064	47,000	16,064	34.2%	1,544	1,511	33	2.2%	4.08446	3.11052	0.97393	31.3%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	252,875	0	252,875	0.0%	7,190	0	7,190	0.0%	3.51704	0.00000	3.51704	0.0%
17. Fuel Cost of Market Base Sales (A6)	481,453	907,300	(425,847)	-46.9%	11,027	16,448	(5,421)	-33.0%	4.36613	5.51617	(1.15004)	-20.8%
18. Gains on Market Based Sales	117,404	154,720	(37,316)	-24.1%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**914,796**	**1,109,020**	**(194,224)**	**-17.5%**	**19,761**	**17,959**	**1,802**	**10.0%**	**4.62930**	**6.17529**	**(1.54599)**	**-25.0%**
20. Net Inadvertant Interchange					122	0	122	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					3,373	0	3,373	0.0%				
22. Interchange and Wheeling Losses					4,041	300	3,741	1247.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**75,292,906**	**68,658,169**	**6,634,737**	**9.7%**	**1,638,787**	**1,553,276**	**85,511**	**5.5%**	**4.59443**	**4.42022**	**0.17421**	**3.9%**
24. Net Unbilled	3,842,045 (a)	708,959 (a)	3,133,086	441.9%	83,624	16,039	67,585	421.4%	4.59443	4.42022	0.17421	3.9%
25. Company Use	132,871 (a)	137,027 (a)	(4,156)	-3.0%	2,892	3,100	(208)	-6.7%	4.59443	4.42023	0.17421	3.9%
26. T & D Losses	4,490,687 (a)	3,049,640 (a)	1,441,047	47.3%	97,742	68,993	28,749	41.7%	4.59443	4.42022	0.17421	3.9%
27. System KWH Sales	75,292,906	68,658,169	6,634,737	9.7%	1,454,529	1,465,144	(10,615)	-0.7%	5.17645	4.68610	0.49034	10.5%
28. Wholesale KWH Sales	(2,929,917)	(1,847,592)	(1,082,325)	58.6%	(56,601)	(39,427)	(17,174)	43.6%	5.17644	4.68611	0.49033	10.5%
29. Jurisdictional KWH Sales	72,362,989	66,810,577	5,552,412	8.3%	1,397,928	1,425,717	(27,789)	-1.9%	5.17645	4.68610	0.49034	10.5%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	72,425,221	66,868,034	5,557,187	8.3%	1,397,928	1,425,717	(27,789)	-1.9%	5.18090	4.69013	0.49076	10.5%
32. Other	0	0	0	0.0%	1,397,928	1,425,717	(27,789)	-1.9%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(2,071,141)	(1,276,250)	(794,891)	62.3%	1,397,928	1,425,717	(27,789)	-1.9%	(0.14816)	(0.08952)	(0.05864)	65.5%
34. Other	0	0	0	0.0%	1,397,928	1,425,717	(27,789)	-1.9%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,397,928	1,425,717	(27,789)	-1.9%	0.88021	0.86305	0.01716	2.0%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	82,658,765	77,896,469	4,762,296	6.1%	1,397,928	1,425,717	(27,789)	-1.9%	5.91295	5.46367	0.44928	8.2%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	82,718,279	77,952,555	4,765,724	6.1%	1,397,928	1,425,717	(27,789)	-1.9%	5.91721	5.46760	0.44961	8.2%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,397,928	1,425,717	(27,789)	-1.9%	0.00435	0.00426	0.00008	2.0%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**82,779,074**	**78,013,350**	**4,765,724**	**6.1%**	**1,397,928**	**1,425,717**	**(27,789)**	**-1.9%**	**5.92156**	**5.47186**	**0.44969**	**8.2%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.922**	**5.472**	**0.450**	**8.2%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: APRIL 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	233,924,953	213,669,376	20,255,577	9.5%	5,593,380	4,957,033	636,347	12.8%	4.18218	4.31043	(0.12825)	-3.0%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft Meade/Wauch. Wheeling Losses)	(31,154)	(26,936)	(4,218)	15.7%	5,593,380 (a)	4,957,033 (a)	636,347	12.8%	(0.00056)	(0.00054)	(0.00001)	2.5%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	5,593,380 (a)	4,957,033 (a)	636,347	12.8%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	7,733	17,367	(9,634)	-55.5%	5,593,380 (a)	4,957,033 (a)	636,347	12.8%	0.00014	0.00035	(0.00021)	-60.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**233,901,532**	**213,659,807**	**20,241,725**	**9.5%**	**5,593,380**	**4,957,033**	**636,347**	**12.8%**	**4.18176**	**4.31024**	**(0.12848)**	**-3.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	8,704,846	60,085,200	(51,380,354)	-85.5%	168,116	1,070,922	(902,806)	-84.3%	5.17788	5.61060	(0.43272)	-7.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	19,025,206	0	19,025,206	0.0%	261,416	0	261,416	0.0%	7.27775	0.00000	7.27775	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	4,968,219	4,030,800	937,419	23.3%	166,958	140,471	26,487	18.9%	2.97573	2.86949	0.10624	3.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**32,698,271**	**64,116,000**	**(31,417,729)**	**-49.0%**	**596,490**	**1,211,393**	**(614,903)**	**-50.8%**	**5.48178**	**5.29275**	**0.18903**	**3.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**6,189,870**	**6,168,426**	**21,444**	**0.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	198,386	137,300	61,086	44.5%	5,101	5,170	(69)	-1.3%	3.88916	2.65571	1.23345	46.4%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	1,217,740	0	1,217,740	0.0%	28,790	0	28,790	0.0%	4.22973	0.00000	4.22973	0.0%
17. Fuel Cost of Market Base Sales (A6)	1,962,764	2,819,500	(856,736)	-30.4%	41,525	59,464	(17,939)	-30.2%	4.72670	4.74152	(0.01482)	-0.3%
18. Gains on Market Based Sales	435,738	1,425,800	(990,062)	-69.4%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**3,814,628**	**4,382,600**	**(567,972)**	**-13.0%**	**75,416**	**64,634**	**10,782**	**16.7%**	**5.05811**	**6.78064**	**(1.72253)**	**-25.4%**
20. Net Inadvertant Interchange					(622)	0	(622)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					7,976	0	7,976	0.0%				
22. Interchange and Wheeling Losses					8,960	1,100	7,860	714.5%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**262,785,175**	**273,393,207**	**(10,608,032)**	**-3.9%**	**6,112,848**	**6,102,692**	**10,156**	**0.2%**	**4.29890**	**4.47988**	**(0.18098)**	**-4.0%**
24. Net Unbilled	(4,527,854) (a)	(2,093,418) (a)	(2,434,436)	116.3%	(122,523)	(46,657)	(75,866)	162.6%	3.69551	4.48683	(0.79131)	-17.6%
25. Company Use	493,374 (a)	555,461 (a)	(62,087)	-11.2%	11,487	12,400	(913)	-7.4%	4.29506	4.47952	(0.18446)	-4.1%
26. T & D Losses	18,564,820 (a)	10,856,595 (a)	7,708,225	71.0%	442,639	242,289	200,350	82.7%	4.19412	4.48085	(0.28672)	-6.4%
27. System KWH Sales	262,785,175	273,393,207	(10,608,032)	-3.9%	5,781,245	5,894,660	(113,415)	-1.9%	4.54548	4.63798	(0.09250)	-2.0%
28. Wholesale KWH Sales	(11,768,044)	(6,320,876)	(5,447,168)	86.2%	(262,126)	(135,066)	(127,060)	94.1%	4.48946	4.67984	(0.19038)	-4.1%
29. Jurisdictional KWH Sales	251,017,131	267,072,331	(16,055,200)	-6.0%	5,519,119	5,759,594	(240,475)	-4.2%	4.54814	4.63700	(0.08886)	-1.9%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	251,233,005	267,302,014	(16,069,009)	-6.0%	5,519,119	5,759,594	(240,475)	-4.2%	4.55205	4.64099	(0.08894)	-1.9%
32. Other	0	0	0	0.0%	5,519,119	5,759,594	(240,475)	-4.2%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(5,327,724)	(5,105,000)	(222,724)	4.4%	5,519,119	5,759,594	(240,475)	-4.2%	(0.09653)	(0.08863)	(0.00790)	8.9%
34. Other	0	0	0	0.0%	5,519,119	5,759,594	(240,475)	-4.2%	0.00000	0.00000	0.00000	0.0%
35. True-up *	49,218,740	49,218,741	(1)	0.0%	5,519,119	5,759,594	(240,475)	-4.2%	0.89179	0.85455	0.03723	4.4%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	295,124,021	311,415,755	(16,291,734)	-5.2%	5,519,119	5,759,594	(240,475)	-4.2%	5.34730	5.40690	(0.05960)	-1.1%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	295,336,510	311,639,974	(16,303,464)	-5.2%	5,519,119	5,759,594	(240,475)	-4.2%	5.35115	5.41080	(0.05965)	-1.1%
39. GPIF * (Already Adjusted for Taxes)	243,180	243,180	0	0.0%	5,519,119	5,759,594	(240,475)	-4.2%	0.00441	0.00422	0.00018	4.4%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**295,579,690**	**311,883,154**	**(16,303,464)**	**-5.2%**	**5,519,119**	**5,759,594**	**(240,475)**	**-4.2%**	**5.35556**	**5.41502**	**(0.05947)**	**-1.1%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									5.356	5.415	(0.059)	-1.1%

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	64,370,752	56,698,856	7,671,896	13.5%	233,924,953	213,669,376	20,255,577	9.5%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	797,392	954,300	(156,908)	-16.4%	3,378,890	2,956,800	422,090	14.3%
2a. GAINS FROM MARKET BASED SALES	117,404	154,720	(37,316)	-24.1%	435,738	1,425,800	(990,062)	-69.4%
3. FUEL COST OF PURCHASED POWER	3,578,250	12,009,100	(8,430,850)	-70.2%	8,704,846	60,085,200	(51,380,354)	-85.5%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,201,587	1,048,600	152,987	14.6%	4,968,219	4,030,800	937,419	23.3%
4. ENERGY COST OF ECONOMY PURCHASES	7,058,067	0	7,058,067	0.0%	19,025,206	0	19,025,206	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	75,293,860	68,647,536	6,646,324	9.7%	262,808,596	273,402,776	(10,594,180)	-3.9%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,687)	(6,734)	(1,953)	29.0%	(31,154)	(26,936)	(4,218)	15.7%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	7,733	17,367	(9,634)	-55.5%	7,733	17,367	(9,634)	-55.5%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	75,292,906	68,658,169	6,634,737	9.7%	262,785,175	273,393,207	(10,608,032)	-3.9%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,397,928	1,425,717	(27,789)	-1.9%	5,519,119	5,759,594	(240,475)	-4.2%
2. NONJURISDICTIONAL SALES	56,601	39,427	17,174	43.6%	262,126	135,066	127,060	94.1%
3. TOTAL SALES	1,454,529	1,465,144	(10,615)	-0.7%	5,781,245	5,894,660	(113,415)	-1.9%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9610864	0.9730900	(0.0120036)	-1.2%	0.9546592	0.9770867	(0.0224275)	-2.3%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	75,032,639	77,069,510	(2,036,871)	-2.6%	296,238,606	311,379,807	(15,141,201)	-4.9%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(49,218,740)	(49,218,741)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(243,180)	(243,180)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	62,667,159	64,704,030	(2,036,871)	-3.1%	246,776,686	261,917,886	(15,141,200)	-5.8%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	75,292,906	68,658,169	6,634,737	9.7%	262,785,175	273,393,207	(10,608,032)	-3.9%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9610864	0.9730900	(0.0120036)	-1.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	72,362,989	66,810,577	5,552,412	8.3%	251,017,131	267,072,331	(16,055,200)	-6.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	72,425,221	66,868,034	5,557,187	8.3%	251,233,005	267,302,014	(16,069,009)	-6.0%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(2,071,141)	(1,276,250)	(794,891)	62.3%	(5,327,724)	(5,105,000)	(222,724)	4.4%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	70,354,080	65,591,784	4,762,296	7.3%	245,905,281	262,197,014	(16,291,733)	-6.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(7,686,921)	(887,754)	(6,799,167)	765.9%	871,405	(279,128)	1,150,533	-412.2%
8. INTEREST PROVISION FOR THE MONTH	(848,489)	(396,902)	(451,587)	113.8%	(3,444,214)	(1,812,234)	(1,631,980)	90.1%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(211,296,403)	(111,548,872)	(99,747,531)	89.4%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(207,527,128)	(100,528,843)	(106,998,285)	106.4%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(211,296,403)	(111,548,872)	(99,747,531)	89.4%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(206,678,639)	(100,131,941)	(106,546,698)	106.4%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(417,975,042)	(211,680,813)	(206,294,229)	97.5%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(208,987,521)	(105,840,407)	(103,147,114)	97.5%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	4.780	4.500	0.280	6.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	4.960	4.500	0.460	10.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	9.740	9.000	0.740	8.2%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	4.870	4.500	0.370	8.2%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.406	0.375	0.031	8.3%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(848,489)	(396,902)	(451,587)	113.8%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	309,261	4,603	304,658	6618.7%	832,227	181,865	650,362	357.6%
2	LIGHT OIL	(2,412,455)	267,142	(2,679,597)	-1003.1%	2,281,921	2,366,732	(84,811)	-3.6%
3	COAL	20,681,632	21,804,108	(1,122,476)	-5.1%	92,157,512	85,967,195	6,190,317	7.2%
4	NATURAL GAS	45,792,314	34,623,003	11,169,311	32.3%	138,653,293	125,153,584	13,499,709	10.8%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	64,370,752	56,698,856	7,671,896	13.5%	233,924,953	213,669,376	20,255,577	9.5%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	3,309	52	3,257	6263.5%	8,680	2,348	6,332	269.7%
9	LIGHT OIL	406	2,184	(1,778)	-81.4%	16,113	18,066	(1,953)	-10.8%
10	COAL	778,683	829,550	(50,867)	-6.1%	3,657,503	3,338,117	319,386	9.6%
11	NATURAL GAS	677,365	462,449	214,916	46.5%	1,912,358	1,598,502	313,856	19.6%
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)	1,459,763	1,294,235	165,528	12.8%	5,594,654	4,957,033	637,621	12.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	5,208	82	5,126	6251.2%	14,270	3,653	10,617	290.6%
16	LIGHT OIL (BBL)	(29,432)	7,427	(36,859)	-496.3%	27,807	49,631	(21,824)	-44.0%
17	COAL (TON)	360,024	374,546	(14,522)	-3.9%	1,643,094	1,489,209	153,885	10.3%
18	NATURAL GAS (MCF)	4,866,880	3,363,976	1,502,904	44.7%	13,797,208	11,664,691	2,132,517	18.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	32,672	513	32,159	6268.8%	89,529	22,926	66,603	290.5%
22	LIGHT OIL	8,046	22,991	(14,945)	-65.0%	156,256	202,333	(46,077)	-22.8%
23	COAL	8,451,324	8,925,388	(474,064)	-5.3%	38,920,309	35,851,367	3,068,942	8.6%
24	NATURAL GAS	5,027,487	3,458,173	1,569,314	45.4%	14,279,128	11,991,091	2,288,037	19.1%
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)	13,519,529	12,407,065	1,112,464	9.0%	53,445,222	48,067,717	5,377,505	11.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.23%	0.00%	0.00	-	0.16%	0.05%	0.00	-
29	LIGHT OIL	0.03%	0.17%	(0.00)	-	0.29%	0.36%	(0.00)	-
30	COAL	53.34%	64.10%	(0.11)	-	65.37%	67.34%	(0.02)	-
31	NATURAL GAS	46.40%	35.73%	0.11	-	34.18%	32.25%	0.02	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	59.38	56.13	3.25	5.8%	58.32	49.79	8.53	17.1%
36	LIGHT OIL ($/BBL)	81.97	35.97	46.00	127.9%	82.06	47.69	34.38	72.1%
37	COAL ($/TON)	57.45	58.21	(0.77)	-1.3%	56.09	57.73	(1.64)	-2.8%
38	NATURAL GAS ($/MCF)	9.41	10.29	(0.88)	-8.6%	10.05	10.73	(0.68)	-6.3%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	9.47	8.97	0.49	5.5%	9.30	7.93	1.36	17.2%
42	LIGHT OIL	(299.84)	11.62	(311.46)	-2680.5%	14.60	11.70	2.91	24.8%
43	COAL	2.45	2.44	0.00	0.2%	2.37	2.40	(0.03)	-1.3%
44	NATURAL GAS	9.11	10.01	(0.90)	-9.0%	9.71	10.44	(0.73)	-7.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.76	4.57	0.19	4.2%	4.38	4.45	(0.07)	-1.5%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,874	9,865	9	0.1%	10,314	9,764	550	5.6%
49	LIGHT OIL	19,817	10,527	9,290	88.2%	9,698	11,200	(1,502)	-13.4%
50	COAL	10,853	10,759	94	0.9%	10,641	10,740	(99)	-0.9%
51	NATURAL GAS	7,422	7,478	(56)	-0.7%	7,467	7,501	(34)	-0.5%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,261	9,586	(325)	-3.4%	9,553	9,697	(144)	-1.5%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	9.35	8.85	0.50	5.6%	9.59	7.75	1.84	23.7%
56	LIGHT OIL	(594.20)	12.23	(606.43)	-4958.5%	14.16	13.10	1.06	8.1%
57	COAL	2.66	2.63	0.03	1.1%	2.52	2.58	(0.06)	-2.3%
58	NATURAL GAS	6.76	7.49	(0.73)	-9.7%	7.25	7.83	(0.58)	-7.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.41	4.38	0.03	0.7%	4.18	4.31	(0.13)	-3.0%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	241,557	81.7	85.6	81.7	11,135	COAL	115,285	23,330,380	2,689,642.9	6,541,403	2.71	56.74
B.B.#2	391	188,185	66.9	69.6	82.7	10,328	COAL	83,611	23,245,520	1,943,581.2	4,744,184	2.52	56.74
B.B.#3	414	3,461	1.2	1.2	35.9	10,550	COAL	1,623	22,498,000	36,514.3	92,091	2.66	56.74
B.B.#4	457	287,968	87.6	93.8	87.6	10,857	COAL	133,979	23,336,080	3,126,544.7	7,602,122	2.64	56.74
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	1,347	5,786,990	7,794.8	111,856	-	83.04
B.B. STATION	1,673	721,171	60.0	63.2	72.2	10,811	-	-	-	-	19,091,656	2.65	-
SEB-PHIL. #1(HVY OIL)	17	1,563	12.8	100.0	81.8	9,874	HVY.OIL	2,459	6,273,540	15,429.4	129,433	8.28	52.64
SEB-PHIL. #2(HVY OIL)	17	1,746	14.3	61.7	83.0	9,874	HVY.OIL	2,749	6,273,540	17,242.5	144,697	8.29	52.64
SEB-PHIL IGNITION	-	-	-	-	-	-	LGT.OIL	248	5,786,990	1,434.7	35,131	-	141.66
SEB-PHILLIPS TOTAL	34	3,309	13.5	80.8	82.4	9,874	-	-	-	-	309,261	9.35	-
POLK #1 GASIFIER	255	57,512	-	-	-	11,390	COAL	25,526	25,662,000	655,041.0	1,589,976	2.76	62.29
POLK #1 CT (OIL) *	225	37	-	-	-	20,787	LGT.OIL	-30,704	5,807,087	763.7	(2,518,112)	(6805.71)	82.01
POLK #1 TOTAL	255	57,549	31.4	38.6	77.7	11,396	-	-	-	655,804.7	(928,136)	(1.61)	-
POLK #2 CT (GAS)	150	8,905	-	-	-	11,676	GAS	100,656	1,033,000	103,977.7	927,202	10.41	9.21
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	155	8,905	8.0	100.0	77.2	11,676	-	-	-	103,977.7	927,202	10.41	-
POLK #3 CT (GAS)	150	4,186	-	-	-	12,295	GAS	49,821	1,033,000	51,465.1	464,061	11.09	9.31
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	155	4,186	3.8	100.0	75.8	12,295	-	-	-	51,465.1	464,061	11.09	-
POLK STATION TOTAL	565	70,640	17.4	72.3	77.1	11,899	-	-	-	811,247.5	463,127	0.66	-
B.B.C.T.#1 *	14	5	0.0	99.1	17.9	37,200	LGT.OIL	32	5,744,904	186.0	2,658	53.16	83.06
B.B.C.T.#2	66	150	0.3	99.7	37.9	20,823	LGT.OIL	546	5,723,306	3,123.4	45,353	30.24	83.06
B.B.C.T.#3	66	214	0.5	99.7	46.3	18,566	LGT.OIL	694	5,723,307	3,973.1	57,646	26.94	83.06
C.T. TOTAL	146	369	0.4	99.7	39.8	19,736	LGT.OIL	1,272	5,723,841	7,282.5	105,657	28.63	83.06
COT 1	3	4	0.2	100.0	25.7	35,897	GAS	142	1,033,000	145.9	1,395	34.88	9.82
COT 2	3	4	0.2	100.0	26.4	35,897	GAS	143	1,033,000	148.1	1,395	34.88	9.76
CITY OF TAMPA TOTAL	6	8	0.2	100.0	26.1	36,750	GAS	285	1,033,000	294.0	2,790	34.88	9.79
BAYSIDE ST 1	234	96,433	57.3	94.5	60.6	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	64,227	57.3	94.4	85.9	10,892	GAS	677,189	1,033,000	699,536.3	6,509,718	10.14	9.61
BAYSIDE CT1B	156	55,176	49.2	91.2	86.7	11,168	GAS	596,542	1,033,000	616,228.3	5,734,471	10.39	9.61
BAYSIDE CT1C	156	67,146	59.9	95.1	86.6	10,876	GAS	706,963	1,033,000	730,292.3	6,795,932	10.12	9.61
BAYSIDE UNIT 1 TOTAL	702	282,982	56.1	93.9	77.8	7,230	GAS	1,980,694	1,033,000	2,046,056.9	19,040,121	6.73	9.61
BAYSIDE ST 2	306	128,269	58.3	98.2	59.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	56,109	50.0	96.3	88.0	11,220	GAS	609,428	1,033,000	629,538.8	5,649,567	10.07	9.27
BAYSIDE CT2B	156	63,488	56.6	93.3	87.7	11,191	GAS	687,801	1,033,000	710,498.8	6,376,106	10.04	9.27
BAYSIDE CT2C	156	51,149	45.6	97.3	88.3	11,138	GAS	551,509	1,033,000	569,708.8	5,112,642	10.00	9.27
BAYSIDE CT2D	156	82,269	73.3	98.0	86.3	11,134	GAS	886,686	1,033,000	915,946.8	8,219,825	9.99	9.27
BAYSIDE UNIT 2 TOTAL	930	381,284	57.0	96.9	78.3	7,411	GAS	2,735,424	1,033,000	2,825,693.2	25,358,140	6.65	9.27
BAYSIDE STATION TOTAL	1,632	664,266	56.6	95.6	78.1	7,334	GAS	4,716,118	1,033,000	4,871,750.1	44,398,261	6.68	9.41
SYSTEM	4,056	1,459,763	50.1	79.0	74.1	9,261	-	-	-	13,519,529.1	64,370,752	4.41	-

Footnotes:

* Ran for testing only.

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	4,100	82	4,018	4900.0%	14,446	3,653	10,793	295.5%
3 UNIT COST ($/BBL)	68.42	46.30	22.12	47.8%	57.34	47.86	9.48	19.8%
4 AMOUNT ($)	280,524	3,797	276,727	7288.0%	828,369	174,848	653,521	373.8%
5 BURNED:								
6 UNITS (BBL)	5,208	82	5,126	6251.2%	14,270	3,653	10,617	290.6%
7 UNIT COST ($/BBL)	59.38	56.13	3.25	5.8%	58.32	49.79	8.53	17.1%
8 AMOUNT ($)	309,261	4,603	304,658	6618.7%	832,227	181,865	650,362	357.6%
9 ENDING INVENTORY:								
10 UNITS (BBL)	15,507	12,118	3,389	28.0%	15,507	12,118	3,389	28.0%
11 UNIT COST ($/BBL)	57.75	47.20	10.56	22.4%	57.75	47.20	10.56	22.4%
12 AMOUNT ($)	895,575	571,910	323,665	56.6%	895,575	571,910	323,665	56.6%
13								
14 DAYS SUPPLY:	243	190	53	30.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	21,130	7,427	13,703	184.5%	76,623	49,631	26,992	54.4%
17 UNIT COST ($/BBL)	88.57	68.03	20.54	30.2%	83.56	70.79	12.77	18.0%
18 AMOUNT ($)	1,871,505	505,281	1,366,224	270.4%	6,402,555	3,513,383	2,889,172	82.2%
19 BURNED:								
20 UNITS (BBL) [1]	(29,432)	7,427	(36,859)	-496.3%	27,807	49,631	(21,824)	-44.0%
21 UNIT COST ($/BBL)	81.97	35.97	46.00	127.9%	82.06	47.69	34.38	72.1%
22 AMOUNT ($)	(2,412,455)	267,142	(2,679,597)	-1003.1%	2,281,921	2,366,732	(84,811)	-3.6%
23 ENDING INVENTORY:								
24 UNITS (BBL)	107,054	85,007	22,047	25.9%	107,054	85,007	22,047	25.9%
25 UNIT COST ($/BBL)	82.88	66.96	15.91	23.8%	82.88	66.96	15.91	23.8%
26 AMOUNT ($)	8,872,291	5,692,272	3,180,019	55.9%	8,872,291	5,692,272	3,180,019	55.9%
27								
28 DAYS SUPPLY: NORMAL	260	206	54	30.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	12	3	25.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	704,189	352,400	351,789	99.8%	1,704,241	1,470,000	234,241	15.9%
32 UNIT COST ($/TON)	56.56	58.43	(1.86)	-3.2%	56.81	57.60	(0.80)	-1.4%
33 AMOUNT ($)	39,831,547	20,590,225	19,241,322	93.4%	96,810,075	84,672,853	12,137,222	14.3%
34 BURNED:								
35 UNITS (TONS)	360,024	374,546	(14,522)	-3.9%	1,643,094	1,489,209	153,885	10.3%
36 UNIT COST ($/TON)	57.45	58.21	(0.77)	-1.3%	56.09	57.73	(1.64)	-2.8%
37 AMOUNT ($)	20,681,632	21,804,108	(1,122,476)	-5.1%	92,157,512	85,967,195	6,190,317	7.2%
38 ENDING INVENTORY:								
39 UNITS (TONS)	532,536	527,539	4,997	0.9%	532,536	527,539	4,997	0.9%
40 UNIT COST ($/TON)	56.58	57.53	(0.95)	-1.7%	56.58	57.53	(0.95)	-1.7%
41 AMOUNT ($)	30,129,708	30,348,021	(218,313)	-0.7%	30,129,708	30,348,021	(218,313)	-0.7%
42								
43 DAYS SUPPLY:	40	38	2	10.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	4,852,896	3,363,976	1,488,920	44.3%	13,784,832	11,664,691	2,120,141	18.2%
46 UNIT COST ($/MCF)	9.43	10.29	(0.86)	-8.4%	9.97	10.73	(0.76)	-7.1%
47 AMOUNT ($)	45,769,302	34,623,003	11,146,299	32.2%	137,415,615	125,153,582	12,262,033	9.8%
48 BURNED:								
49 UNITS (MCF)	4,866,880	3,363,976	1,502,904	44.7%	13,797,208	11,664,691	2,132,517	18.3%
50 UNIT COST ($/MCF)	9.41	10.29	(0.88)	-8.6%	10.05	10.73	(0.68)	-6.3%
51 AMOUNT ($)	45,792,314	34,623,003	11,169,311	32.3%	138,653,293	125,153,584	13,499,709	10.8%
52 ENDING INVENTORY:								
53 UNITS (MCF)	173,890	0	173,890	0.0%	173,890	0	173,890	0.0%
54 UNIT COST ($/MCF)	7.51	0.00	7.51	0.0%	7.51	0.00	7.51	0.0%
55 AMOUNT ($)	1,306,520	0	1,306,520	0.0%	1,306,520	0	1,306,520	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

	CURRENT MONTH				PERIOD TO DATE			
			DIFFERENCE				DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

Note 1: Includes Polk #1 CT adjustment of (30,598.09) bbls for March 2006.

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	20,637
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	20,637

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(1,595)	(132,493)
OTHER USAGE	(614)	(50,956)
TOTAL	(2,209)	(183,449)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	29,625
IGNITION #2 OIL	111,856
IGNITION PROPANE	6,927
AERIAL SURVEY ADJ.	0
ADDITIVES	81,629
GREEN FUEL	0
TOTAL	230,037

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC	SCH. - D	1,511.0	0.0	1,511.0	3.111	3.111	47,000.00	47,000.00	
VARIOUS	JURISDIC	SCH. - MB	16,448.0	0.0	16,448.0	5.516	6.994	907,300.00	1,150,300.00	154,720.00
TOTAL			17,959.0	0.0	17,959.0	5.314	6.667	954,300.00	1,197,300.00	154,720.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	600.5	5.3	595.2	4.386	4.600	26,103.06	27,382.01	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	950.0	0.0	950.0	3.891	4.103	36,961.37	38,981.40	
PROGRESS ENERGY FLORIDA		SCH. - MA	760.0	0.0	760.0	4.282	5.713	32,545.00	43,421.27	8,584.27
FLA. PWR. & LIGHT		SCH. - MA	5,950.0	0.0	5,950.0	4.537	5.866	269,964.54	349,029.15	58,537.11
CITY OF LAKELAND		SCH. - MA	835.0	0.0	835.0	4.999	6.781	41,743.75	56,619.30	10,627.50
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	935.0	0.0	935.0	4.448	6.556	41,593.00	61,297.92	16,479.17
THE ENERGY AUTHORITY		SCH. - MA	777.0	0.0	777.0	4.421	6.069	34,348.42	47,155.95	10,126.88
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	889.0	0.0	889.0	3.710	4.877	32,977.64	43,353.98	8,032.45
CITY OF TALLAHASSEE		SCH. - MA	30.0	0.0	30.0	4.147	5.865	1,244.10	1,759.45	411.85
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	300.0	0.0	300.0	2.762	3.146	7,577.51	8,951.32	1,196.81
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(11.67)	(11.67)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	245.0	0.0	245.0	4.560	5.905	11,172.18	14,466.58	2,450.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	306.0	0.0	306.0	2.708	3.084	8,285.98	9,436.54	970.02
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SEP SCH. - D	7,190.0	0.0	7,190.0	4.111	4.711	295,580.90	338,720.90	
ADJUSTMENTS TO PRIOR MONTHS:										
TEC WHOLESALE MARKETING	FEB 2006	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	18,245.71	18,245.71
TEC WHOLESALE MARKETING	FEB 2006	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(21,795.31)	(21,795.31)
NEW SMYRNA BEACH	FEB 2006	SCH. - MA	(1,250.0)	0.0	(1,250.0)	5.503	7.590	(68,790.55)	(94,879.28)	(22,320.93)
NEW SMYRNA BEACH	FEB 2006	SCH. - MA	1,250.0	0.0	1,250.0	5.503	7.874	68,790.55	98,428.88	25,870.53
NEW SMYRNA BEACH	MAR 2006	SEP SCH. - D	(7,440.0)	0.0	(7,440.0)	4.685	5.285	(348,564.00)	(393,204.00)	
NEW SMYRNA BEACH	MAR 2006	SEP SCH. - D	7,440.0	0.0	7,440.0	4.111	4.711	305,858.40	350,498.40	
SEMINOLE ELEC. PRECO-1	MAR 2006	SCH. - D	(530.5)	0.0	(530.5)	3.972	4.174	(21,072.69)	(22,143.32)	
SEMINOLE ELEC. PRECO-1	MAR 2006	SCH. - D	530.5	1.4	529.1	3.983	4.185	21,072.69	22,143.32	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,190.0	0.0	7,190.0	3.517	4.117	252,875.30	296,015.30	
SUB-TOTAL SCHEDULE D POWER SALES			1,550.5	6.7	1,543.8	4.085	4.299	63,064.43	66,363.41	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			11,027.0	0.0	11,027.0	4.366	5.763	481,452.12	635,479.79	117,404.39
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			19,767.5	6.7	19,760.8	4.035	5.050	797,391.85	997,858.50	117,404.39
CURRENT MONTH:										
DIFFERENCE			1,808.5	6.7	1,801.8	(1.279)	(1.617)	(156,908.15)	(199,441.50)	(37,315.61)
DIFFERENCE %			10.1%	0.0%	10.0%	-24.1%	-24.3%	-16.4%	-16.7%	-24.1%
PERIOD TO DATE:										
ACTUAL			75,421.7	6.7	75,415.0	4.480	5.468	3,378,890.14	4,123,843.76	435,737.86
ESTIMATED			64,634.0	0.0	64,634.0	4.575	7.251	2,956,800.00	4,686,400.00	1,425,800.00
DIFFERENCE			10,787.7	6.7	10,781.0	(0.095)	(1.783)	422,090.14	(562,556.24)	(990,062.14)
DIFFERENCE %			16.7%	0.0%	16.7%	-2.1%	-24.6%	14.3%	-12.0%	-69.4%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF APRIL 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	122.0	0.0	93.0	29.0	7.931	7.931	2,300.00
HARDEE POWER PARTNERS		IPP	618.0	0.0	0.0	618.0	27.136	27.136	167,700.00
CALPINE		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASED	155,755.0	0.0	0.0	155,755.0	5.581	5.581	8,692,500.00
OTHER		SCH. - D	84,352.0	0.0	0.0	84,352.0	3.730	3.730	3,146,600.00
TOTAL			**240,847.0**	**0.0**	**93.0**	**240,754.0**	**4.988**	**4.988**	**12,009,100.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	28,559.0	0.0	0.0	28,559.0	8.472	8.472	2,419,403.37
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	32,550.0	0.0	0.0	32,550.0	3.647	3.647	1,187,098.50
AUBURNDALE POWER PARTNERS		OATT	1,499.0	0.0	0.0	1,499.0	4.184	4.184	62,721.30
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	MAR 2006	IPP	(7,275.0)	0.0	0.0	(7,275.0)	10.915	10.915	(794,085.69)
HARDEE PWR. PART.-NATIVE	MAR 2006	IPP	7,275.0	0.0	0.0	7,275.0	10.680	10.680	776,954.57
PROGRESS ENERGY FLORIDA	JAN 2006	SCH. - D	(30,030.0)	0.0	0.0	(30,030.0)	3.568	3.568	(1,071,360.70)
PROGRESS ENERGY FLORIDA	JAN 2006	SCH. - D	30,030.0	0.0	0.0	30,030.0	3.369	3.369	1,011,710.70
PROGRESS ENERGY FLORIDA	FEB 2006	SCH. - D	(30,675.0)	0.0	0.0	(30,675.0)	3.750	3.750	(1,150,453.00)
PROGRESS ENERGY FLORIDA	FEB 2006	SCH. - D	30,675.0	0.0	0.0	30,675.0	3.556	3.556	1,090,803.00
PROGRESS ENERGY FLORIDA	MAR 2006	SCH. - D	(27,660.0)	0.0	0.0	(27,660.0)	3.483	3.483	(963,302.20)
PROGRESS ENERGY FLORIDA	MAR 2006	SCH. - D	27,660.0	0.0	0.0	27,660.0	3.647	3.647	1,008,760.20
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	(90,973.12)
TOTAL			**62,608.0**	**0.0**	**0.0**	**62,608.0**	**5.715**	**5.715**	**3,578,250.05**
CURRENT MONTH:									
DIFFERENCE			(178,239.0)	0.0	(93.0)	(178,146.0)	0.727	0.727	(8,430,849.95)
DIFFERENCE %			-74.0%	0.0%	0.0%	-74.0%	14.6%	14.6%	-70.2%
PERIOD TO DATE:									
ACTUAL			168,116.0	0.0	0.0	168,116.0	5.178	5.178	8,704,846.54
ESTIMATED			1,073,500.0	0.0	2,578.0	1,070,922.0	5.611	5.611	60,085,200.00
DIFFERENCE			(905,384.0)	0.0	(2,578.0)	(902,806.0)	(0.433)	(0.433)	(51,380,353.46)
DIFFERENCE %			-84.3%	0.0%	-100.0%	-84.3%	-7.7%	-7.7%	-85.5%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	36,546.0	0.0	0.0	36,546.0	2.869	2.869	1,048,600.00
TOTAL			**36,546.0**	**0.0**	**0.0**	**36,546.0**	**2.869**	**2.869**	**1,048,600.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	18,151.0	0.0	0.0	18,151.0	2.593	2.593	470,599.04
McKAY BAY REFUSE		COGEN.	12,690.0	0.0	0.0	12,690.0	2.588	2.588	328,466.66
ORANGE COGENERATION L.P.		COGEN.	7,360.0	0.0	0.0	7,360.0	2.398	2.398	176,476.93
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	123.0	0.0	0.0	123.0	7.666	7.666	9,429.32
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	289.0	0.0	0.0	289.0	6.023	6.023	17,406.51
CF INDUSTRIES INC.		COGEN.	597.0	0.0	0.0	597.0	4.646	4.646	27,735.43
IMC-AGRICO-NEW WALES		COGEN.	1,303.0	0.0	0.0	1,303.0	5.623	5.623	73,268.36
IMC-AGRICO-S. PIERCE		COGEN.	605.0	0.0	0.0	605.0	5.274	5.274	31,905.06
AUBURNDALE POWER PARTNERS		COGEN.	1,054.0	0.0	0.0	1,054.0	4.508	4.508	47,517.27
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR APRIL 2006			42,172.0	0.0	0.0	42,172.0	2.805	2.805	1,182,804.58
ADJUSTMENTS FOR THE MONTH OF:	**MARCH 2006**								
HILLSBOROUGH COUNTY		COGEN.	(18,791.0)	0.0	0.0	(18,791.0)	2.532	2.532	(475,846.18)
			18,791.0	0.0	0.0	18,791.0	2.584	2.584	485,575.09
McKAY BAY REFUSE		COGEN.	(12,684.0)	0.0	0.0	(12,684.0)	2.534	2.534	(321,387.48)
			12,684.0	0.0	0.0	12,684.0	2.585	2.585	327,942.32
ORANGE COGENERATION L.P.		COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	2.343	2.343	(133,630.53)
			5,704.0	0.0	0.0	5,704.0	2.387	2.387	136,128.87
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL			0.0	0.0	0.0	0.0	0.000	0.000	18,782.09
TOTAL			**42,172.0**	**0.0**	**0.0**	**42,172.0**	**2.849**	**2.849**	**1,201,586.67**
CURRENT MONTH:									
DIFFERENCE			5,626.0	0.0	0.0	5,626.0	(0.020)	(0.020)	152,986.67
DIFFERENCE %			15.4%	0.0%	0.0%	15.4%	-0.7%	-0.7%	14.6%
PERIOD TO DATE:									
ACTUAL			166,958.0	0.0	0.0	166,958.0	2.976	2.976	4,968,217.99
ESTIMATED			140,471.0	0.0	0.0	140,471.0	2.869	2.869	4,030,800.00
DIFFERENCE			26,487.0	0.0	0.0	26,487.0	0.106	0.106	937,417.99
DIFFERENCE %			18.9%	0.0%	0.0%	18.9%	3.7%	3.7%	23.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:								
VARIOUS		ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:								
PROGRESS ENERGY FLORIDA		SCH. - JC	5,378.4	5.904	317,516.00	6.949	373,733.05	56,217.05
FLA. POWER & LIGHT		SCH. - JC	20,597.0	6.038	1,243,558.00	7.196	1,482,212.32	238,654.32
CITY OF LAKELAND		SCH. - JC	1,992.0	6.621	131,887.00	8.233	163,992.50	32,105.50
ORLANDO UTIL. COMM.		SCH. - JC	14,480.0	8.645	1,251,740.00	9.292	1,345,533.50	93,793.50
THE ENERGY AUTHORITY		SCH. - JC	20,948.4	7.587	1,589,256.40	8.845	1,852,883.74	263,627.34
OKEELANTA		SCH. - JC	352.0	6.193	21,800.00	8.416	29,623.40	7,823.40
CITY OF TALLAHASSEE		SCH. - JC	470.0	8.591	40,380.00	9.969	46,855.00	6,475.00
CALPINE		SCH. - JC	14,037.0	8.647	1,213,730.00	9.560	1,341,888.73	128,158.73
CARGILL ALLIANT		SCH. - JC	9,948.1	7.435	739,677.62	8.490	844,635.93	104,958.31
RELIANT		SCH. - JC	3,369.0	11.335	381,864.00	12.411	418,118.40	36,254.40
RAINBOW ENERGY MARKETERS		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - JC	825.0	5.348	44,125.00	8.045	66,370.50	22,245.50
ENTERGY-KOCH TRADING		SCH. - JC	0.0	0.000	(23,853.15)	0.000	(12,789.15)	11,064.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JC	800.0	4.500	36,000.00	5.883	47,064.00	11,064.00
CINCINATTI GAS & ELECTRIC		SCH. - JC	1,593.0	7.821	124,593.00	10.734	170,989.34	46,396.34
SUBTOTAL			94,789.9	7.503	7,112,273.87	8.620	8,171,111.26	1,058,837.39
ADJUSTMENTS TO PRIOR MONTHS:								
CITY OF TALLAHASSEE	JAN 2006	SCH. - JC	(125.0)	8.113	(10,141.80)	13.655	(17,069.05)	(6,927.25)
CITY OF TALLAHASSEE	JAN 2006	SCH. - JC	125.0	7.872	9,840.00	13.414	16,767.25	6,927.25
CITY OF TALLAHASSEE	FEB 2006	SCH. - JC	(445.0)	8.668	(38,573.80)	12.480	(55,537.60)	(16,963.80)
CITY OF TALLAHASSEE	FEB 2006	SCH. - JC	445.0	8.425	37,490.00	12.237	54,453.80	16,963.80
CITY OF TALLAHASSEE	MAR 2006	SCH. - JC	(75.0)	8.892	(6,669.00)	12.110	(9,082.50)	(2,413.50)
CITY OF TALLAHASSEE	MAR 2006	SCH. - JC	75.0	8.600	6,450.00	11.818	8,863.50	2,413.50
FLA. POWER & LIGHT	MAR 2006	SCH. - JC	(28,895.0)	7.045	(2,035,725.00)	9.032	(2,609,713.15)	(573,988.15)
FLA. POWER & LIGHT	MAR 2006	SCH. - JC	28,801.0	7.037	2,026,793.88	9.030	2,600,782.03	573,988.15
OKEELANTA	JAN 2006	SCH. - JC	(914.0)	7.796	(71,257.02)	11.159	(101,995.45)	(30,738.43)
OKEELANTA	JAN 2006	SCH. - JC	914.0	7.573	69,218.00	10.936	99,956.43	30,738.43
OKEELANTA	FEB 2006	SCH. - JC	(903.0)	6.817	(61,555.48)	10.165	(91,788.70)	(30,233.22)
OKEELANTA	FEB 2006	SCH. - JC	903.0	6.795	61,360.00	10.143	91,593.22	30,233.22
OKEELANTA	MAR 2006	SCH. - JC	(1,345.0)	7.982	(107,356.50)	10.823	(145,571.80)	(38,215.30)
OKEELANTA	MAR 2006	SCH. - JC	1,345.0	7.975	107,270.00	10.817	145,485.30	38,215.30
ORLANDO UTIL. COMM.	MAR 2006	SCH. - JC	(1,822.0)	11.699	(213,150.00)	12.277	(223,688.15)	(10,538.15)
ORLANDO UTIL. COMM.	MAR 2006	SCH. - JC	1,677.0	10.244	171,800.00	10.873	182,338.15	10,538.15
SUBTOTAL			(239.0)	22.681	(54,206.72)	22.681	(54,206.72)	0.00
TOTAL			**94,550.9**	**7.465**	**7,058,067.15**	**8.585**	**8,116,904.54**	**1,058,837.39**
CURRENT MONTH:								
DIFFERENCE			94,550.9	7.465	7,058,067.15	8.585	8,116,904.54	1,058,837.39
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:								
ACTUAL			261,415.9	7.278	19,025,206.25	9.247	24,172,683.69	5,147,477.44
ESTIMATED			0.0	0.000	0.0	0.000	0.0	0.00
DIFFERENCE			261,415.9	7.278	19,025,206.25	9.247	24,172,683.69	5,147,477.44
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MAY 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	78,904,369	77,026,750	1,877,619	2.4%	1,595,579	1,703,606	(108,027)	-6.3%	4.94519	4.52139	0.42379	9.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(9,632)	(6,734)	(2,898)	43.0%	1,595,579 (a)	1,703,606 (a)	(108,027)	-6.3%	(0.00060)	(0.00040)	(0.00021)	52.7%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,595,579 (a)	1,703,606 (a)	(108,027)	-6.3%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	27,262	25,713	1,549	6.0%	1,595,579 (a)	1,703,606 (a)	(108,027)	-6.3%	0.00171	0.00151	0.00020	13.2%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**78,921,999**	**77,045,729**	**1,876,270**	**2.4%**	**1,595,579**	**1,703,606**	**(108,027)**	**-6.3%**	**4.94629**	**4.52251**	**0.42378**	**9.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	6,089,264	9,522,800	(3,433,536)	-36.1%	94,058	170,652	(76,594)	-44.9%	6.47395	5.58025	0.89370	16.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	6,938,548	0	6,938,548	0.0%	104,659	0	104,659	0.0%	6.62967	0.00000	6.62967	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,582,926	1,206,200	376,726	31.2%	50,853	37,769	13,084	34.6%	3.11275	3.19362	(0.08088)	-2.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**14,610,738**	**10,729,000**	**3,881,738**	**36.2%**	**249,570**	**208,421**	**41,149**	**19.7%**	**5.85436**	**5.14775**	**0.70661**	**13.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,845,149**	**1,912,027**	**(66,878)**	**-3.5%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	67,119	64,600	2,519	3.9%	1,867	1,992	(126)	-6.3%	3.59598	3.24297	0.35301	10.9%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(24,862)	0	(24,862)	0.0%	(15)	0	(15)	0.0%	165.74667	0.00000	165.74667	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	389,249	0	389,249	0.0%	7,440	0	7,440	0.0%	5.23184	0.00000	5.23184	0.0%
17. Fuel Cost of Market Base Sales (A6)	228,547	2,248,500	(2,019,953)	-89.8%	5,127	37,219	(32,092)	-86.2%	4.45771	6.04127	(1.58356)	-26.2%
18. Gains on Market Based Sales	59,829	434,800	(374,971)	-86.2%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**719,882**	**2,747,900**	**(2,028,018)**	**-73.8%**	**14,419**	**39,211**	**(24,792)**	**-63.2%**	**4.99259**	**7.00798**	**(2.01539)**	**-28.8%**
20. Net Inadvertant Interchange					(37)	0	(37)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					5,873	0	5,873	0.0%				
22. Interchange and Wheeling Losses					5,104	700	4,404	629.1%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**92,812,855**	**85,026,829**	**7,786,026**	**9.2%**	**1,831,462**	**1,872,116**	**(40,654)**	**-2.2%**	**5.06769**	**4.54175**	**0.52594**	**11.6%**
24. Net Unbilled	6,386,863 (a)	7,981,081 (a)	(1,594,218)	-20.0%	126,031	175,727	(49,696)	-28.3%	5.06769	4.54175	0.52594	11.6%
25. Company Use	152,639 (a)	140,794 (a)	11,845	8.4%	3,012	3,100	(88)	-2.8%	5.06770	4.54174	0.52595	11.6%
26. T & D Losses	3,767,930 (a)	3,633,082 (a)	134,848	3.7%	74,352	79,993	(5,641)	-7.1%	5.06769	4.54175	0.52594	11.6%
27. System KWH Sales	92,812,855	85,026,829	7,786,026	9.2%	1,628,067	1,613,296	14,771	0.9%	5.70080	5.27038	0.43042	8.2%
28. Wholesale KWH Sales	(2,659,711)	(2,697,009)	37,298	-1.4%	(46,655)	(51,173)	4,518	-8.8%	5.70081	5.27038	0.43043	8.2%
29. Jurisdictional KWH Sales	90,153,144	82,329,820	7,823,324	9.5%	1,581,412	1,562,123	19,289	1.2%	5.70080	5.27038	0.43042	8.2%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	90,230,676	82,400,624	7,830,052	9.5%	1,581,412	1,562,123	19,289	1.2%	5.70570	5.27491	0.43079	8.2%
32. Other	0	0	0	0.0%	1,581,412	1,562,123	19,289	1.2%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,965,800)	(1,276,250)	(689,550)	54.0%	1,581,412	1,562,123	19,289	1.2%	(0.12431)	(0.08170)	(0.04261)	52.2%
34. Other	0	0	0	0.0%	1,581,412	1,562,123	19,289	1.2%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,581,412	1,562,123	19,289	1.2%	0.77808	0.78769	(0.00961)	-1.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	100,569,561	93,429,059	7,140,502	7.6%	1,581,412	1,562,123	19,289	1.2%	6.35948	5.98090	0.37858	6.3%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	100,641,971	93,496,328	7,145,643	7.6%	1,581,412	1,562,123	19,289	1.2%	6.36406	5.98521	0.37885	6.3%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,581,412	1,562,123	19,289	1.2%	0.00384	0.00389	(0.00005)	-1.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**100,702,766**	**93,557,123**	**7,145,643**	**7.6%**	**1,581,412**	**1,562,123**	**19,289**	**1.2%**	**6.36790**	**5.98910**	**0.37880**	**6.3%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**6.368**	**5.989**	**0.379**	**6.3%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MAY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	312,829,322	290,696,126	22,133,196	7.6%	7,188,959	6,660,639	528,320	7.9%	4.35152	4.36439	(0.01286)	-0.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(40,786)	(33,670)	(7,116)	21.1%	7,188,959 (a)	6,660,639 (a)	528,320	7.9%	(0.00057)	(0.00051)	(0.00006)	12.2%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	7,188,959 (a)	6,660,639 (a)	528,320	7.9%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	34,995	43,080	(8,085)	-18.8%	7,188,959 (a)	6,660,639 (a)	528,320	7.9%	0.00049	0.00065	(0.00016)	-24.7%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**312,823,531**	**290,705,536**	**22,117,995**	**7.6%**	**7,188,959**	**6,660,639**	**528,320**	**7.9%**	**4.35144**	**4.36453**	**(0.01309)**	**-0.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	14,794,110	69,608,000	(54,813,890)	-78.7%	262,174	1,241,574	(979,400)	-78.9%	5.64286	5.60643	0.03643	0.6%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	25,963,754	0	25,963,754	0.0%	366,075	0	366,075	0.0%	7.09247	0.00000	7.09247	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	6,551,145	5,237,000	1,314,145	25.1%	217,811	178,240	39,571	22.2%	3.00772	2.93817	0.06955	2.4%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**47,309,009**	**74,845,000**	**(27,535,991)**	**-36.8%**	**846,060**	**1,419,814**	**(573,754)**	**-40.4%**	**5.59168**	**5.27147**	**0.32022**	**6.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**8,035,019**	**8,080,453**	**(45,434)**	**-0.6%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	265,505	201,900	63,605	31.5%	6,968	7,162	(195)	-2.7%	3.81062	2.81904	0.99158	35.2%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(24,862)	0	(24,862)	0.0%	(15)	0	(15)	0.0%	165.74667	0.00000	165.74667	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	1,606,989	0	1,606,989	0.0%	36,230	0	36,230	0.0%	4.43552	0.00000	4.43552	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,191,311	5,068,000	(2,876,689)	-56.8%	46,652	96,683	(50,031)	-51.7%	4.69714	5.24187	(0.54473)	-10.4%
18. Gains on Market Based Sales	495,567	1,860,600	(1,365,033)	-73.4%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**4,534,510**	**7,130,500**	**(2,595,990)**	**-36.4%**	**89,835**	**103,845**	**(14,010)**	**-13.5%**	**5.04760**	**6.86648**	**(1.81889)**	**-26.5%**
20. Net Inadvertant Interchange					(659)	0	(659)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					13,849	0	13,849	0.0%				
22. Interchange and Wheeling Losses					14,064	1,800	12,264	681.3%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**355,598,030**	**358,420,036**	**(2,822,006)**	**-0.8%**	**7,944,310**	**7,974,808**	**(30,498)**	**-0.4%**	**4.47613**	**4.49440**	**(0.01827)**	**-0.4%**
24. Net Unbilled	1,859,009 (a)	5,887,663 (a)	(4,028,654)	-68.4%	3,508	129,070	(125,562)	-97.3%	52.99342	4.56160	48.43181	1061.7%
25. Company Use	646,013 (a)	696,255 (a)	(50,242)	-7.2%	14,499	15,500	(1,001)	-6.5%	4.45557	4.49197	(0.03640)	-0.8%
26. T & D Losses	22,332,750 (a)	14,489,677 (a)	7,843,073	54.1%	516,991	322,282	194,709	60.4%	4.31976	4.49596	(0.17621)	-3.9%
27. System KWH Sales	355,598,030	358,420,036	(2,822,006)	-0.8%	7,409,312	7,507,956	(98,644)	-1.3%	4.79934	4.77387	0.02547	0.5%
28. Wholesale KWH Sales	(14,427,755)	(9,017,885)	(5,409,870)	60.0%	(308,781)	(186,239)	(122,542)	65.8%	4.67249	4.84210	(0.16962)	-3.5%
29. Jurisdictional KWH Sales	341,170,275	349,402,151	(8,231,876)	-2.4%	7,100,531	7,321,717	(221,186)	-3.0%	4.80486	4.77213	0.03272	0.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	341,463,681	349,702,638	(8,238,957)	-2.4%	7,100,531	7,321,717	(221,186)	-3.0%	4.80899	4.77624	0.03275	0.7%
32. Other	0	0	0	0.0%	7,100,531	7,321,717	(221,186)	-3.0%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(7,293,524)	(6,381,250)	(912,274)	14.3%	7,100,531	7,321,717	(221,186)	-3.0%	(0.10272)	(0.08716)	(0.01556)	17.9%
34. Other	0	0	0	0.0%	7,100,531	7,321,717	(221,186)	-3.0%	0.00000	0.00000	0.00000	0.0%
35. True-up *	61,523,425	61,523,426	(1)	0.0%	7,100,531	7,321,717	(221,186)	-3.0%	0.86646	0.84029	0.02618	3.1%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	395,693,582	404,844,814	(9,151,232)	-2.3%	7,100,531	7,321,717	(221,186)	-3.0%	5.57273	5.52937	0.04336	0.8%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	395,978,481	405,136,302	(9,157,821)	-2.3%	7,100,531	7,321,717	(221,186)	-3.0%	5.57674	5.53335	0.04339	0.8%
39. GPIF * (Already Adjusted for Taxes)	303,975	303,975	0	0.0%	7,100,531	7,321,717	(221,186)	-3.0%	0.00428	0.00415	0.00013	3.1%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**396,282,456**	**405,440,277**	**(9,157,821)**	**-2.3%**	**7,100,531**	**7,321,717**	**(221,186)**	**-3.0%**	**5.58102**	**5.53750**	**0.04352**	**0.8%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.581**	**5.538**	**0.043**	**0.8%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	78,904,369	77,026,750	1,877,619	2.4%	312,829,322	290,696,126	22,133,196	7.6%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	660,053	2,313,100	(1,653,047)	-71.5%	4,038,943	5,269,900	(1,230,957)	-23.4%
2a. GAINS FROM MARKET BASED SALES	59,829	434,800	(374,971)	-86.2%	495,567	1,860,600	(1,365,033)	-73.4%
3. FUEL COST OF PURCHASED POWER	6,089,264	9,522,800	(3,433,536)	-36.1%	14,794,110	69,608,000	(54,813,890)	-78.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,582,926	1,206,200	376,726	31.2%	6,551,145	5,237,000	1,314,145	25.1%
4. ENERGY COST OF ECONOMY PURCHASES	6,938,548	0	6,938,548	0.0%	25,963,754	0	25,963,754	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	92,795,225	85,007,850	7,787,375	9.2%	355,603,821	358,410,626	(2,806,805)	-0.8%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(9,632)	(6,734)	(2,898)	43.0%	(40,786)	(33,670)	(7,116)	21.1%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	27,262	25,713	1,549	6.0%	34,995	43,080	(8,085)	-18.8%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	92,812,855	85,026,829	7,786,026	9.2%	355,598,030	358,420,036	(2,822,006)	-0.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,581,412	1,562,123	19,289	1.2%	7,100,531	7,321,717	(221,186)	-3.0%
2. NONJURISDICTIONAL SALES	46,655	51,173	(4,518)	-8.8%	308,781	186,239	122,542	65.8%
3. TOTAL SALES	1,628,067	1,613,296	14,771	0.9%	7,409,312	7,507,956	(98,644)	-1.3%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9713433	0.9682805	0.0030628	0.3%	0.9583253	0.9751944	(0.0168691)	-1.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	85,084,903	84,465,185	619,718	0.7%	381,323,509	395,844,992	(14,521,483)	-3.7%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(61,523,425)	(61,523,426)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(303,975)	(303,975)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	72,719,423	72,099,705	619,718	0.9%	319,496,109	334,017,591	(14,521,482)	-4.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	92,812,855	85,026,829	7,786,026	9.2%	355,598,030	358,420,036	(2,822,006)	-0.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9713433	0.9682805	0.0030628	0.3%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	90,153,144	82,329,820	7,823,324	9.5%	341,170,275	349,402,151	(8,231,876)	-2.4%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	90,230,676	82,400,624	7,830,052	9.5%	341,463,681	349,702,638	(8,238,957)	-2.4%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,965,800)	(1,276,250)	(689,550)	54.0%	(7,293,524)	(6,381,250)	(912,274)	14.3%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	88,264,876	81,124,374	7,140,502	8.8%	334,170,157	343,321,388	(9,151,231)	-2.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(15,545,453)	(9,024,669)	(6,520,784)	72.3%	(14,674,048)	(9,303,797)	(5,370,251)	57.7%
8. INTEREST PROVISION FOR THE MONTH	(867,962)	(370,833)	(497,129)	134.1%	(4,312,176)	(2,183,067)	(2,129,109)	97.5%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(207,527,128)	(100,528,843)	(106,998,285)	106.4%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(211,635,858)	(97,619,660)	(114,016,198)	116.8%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(207,527,128)	(100,528,843)	(106,998,285)	106.4%	---NOT APPLICABLE---			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(210,767,896)	(97,248,827)	(113,519,069)	116.7%	---NOT APPLICABLE---			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(418,295,024)	(197,777,670)	(220,517,354)	111.5%	---NOT APPLICABLE---			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(209,147,512)	(98,888,835)	(110,258,677)	111.5%	---NOT APPLICABLE---			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	4.960	4.500	0.460	10.2%	---NOT APPLICABLE---			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.010	4.500	0.510	11.3%	---NOT APPLICABLE---			
7. TOTAL (LINE D5 + LINE D6)	9.970	9.000	0.970	10.8%	---NOT APPLICABLE---			
8. AVERAGE INT. RATE (50% OF LINE D7)	4.985	4.500	0.485	10.8%	---NOT APPLICABLE---			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.415	0.375	0.040	10.7%	---NOT APPLICABLE---			
10. INT. PROVISION (LINE D4 x LINE D9)	(867,962)	(370,833)	(497,129)	134.1%	---NOT APPLICABLE---			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	402,113	195,415	206,698	105.8%	1,234,340	377,280	857,060	227.2%
2	LIGHT OIL	321,404	339,494	(18,090)	-5.3%	2,603,325	2,706,226	(102,901)	-3.8%
3	COAL	24,382,486	25,081,004	(698,518)	-2.8%	116,539,998	111,048,199	5,491,799	4.9%
4	NATURAL GAS	53,798,366	51,410,837	2,387,529	4.6%	192,451,659	176,564,421	15,887,238	9.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	78,904,369	77,026,750	1,877,619	2.4%	312,829,322	290,696,126	22,133,196	7.6%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,160	2,560	1,600	62.5%	12,840	4,908	7,932	161.6%
9	LIGHT OIL	921	2,682	(1,761)	-65.7%	17,034	20,748	(3,714)	-17.9%
10	COAL	867,381	940,242	(72,861)	-7.7%	4,524,884	4,278,359	246,525	5.8%
11	NATURAL GAS	723,117	758,122	(35,005)	-4.6%	2,635,475	2,356,624	278,851	11.8%
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)	1,595,579	1,703,606	(108,027)	-6.3%	7,190,233	6,660,639	529,594	8.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	6,453	3,965	2,488	62.7%	20,723	7,618	13,105	172.0%
16	LIGHT OIL (BBL)	3,882	8,613	(4,731)	-54.9%	31,689	58,244	(26,555)	-45.6%
17	COAL (TON)	412,725	427,187	(14,462)	-3.4%	2,055,819	1,916,396	139,423	7.3%
18	NATURAL GAS (MCF)	5,269,006	5,515,283	(246,277)	-4.5%	19,066,214	17,179,974	1,886,240	11.0%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	40,481	24,895	15,586	62.6%	130,010	47,821	82,189	171.9%
22	LIGHT OIL	21,266	29,057	(7,791)	-26.8%	177,522	231,390	(53,868)	-23.3%
23	COAL	9,457,260	10,159,321	(702,061)	-6.9%	48,377,569	46,010,688	2,366,881	5.1%
24	NATURAL GAS	5,448,152	5,669,721	(221,569)	-3.9%	19,727,280	17,660,812	2,066,468	11.7%
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)	14,967,159	15,882,994	(915,835)	-5.8%	68,412,381	63,950,711	4,461,670	7.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.26%	0.15%	0.00	-	0.18%	0.07%	0.00	-
29	LIGHT OIL	0.06%	0.16%	(0.00)	-	0.24%	0.31%	(0.00)	-
30	COAL	54.36%	55.19%	(0.01)	-	62.93%	64.23%	(0.01)	-
31	NATURAL GAS	45.32%	44.50%	0.01	-	36.65%	35.38%	0.01	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	62.31	49.28	13.03	26.4%	59.56	49.52	10.04	20.3%
36	LIGHT OIL ($/BBL)	82.79	39.42	43.38	110.0%	82.15	46.46	35.69	76.8%
37	COAL ($/TON)	59.08	58.71	0.36	0.6%	56.69	57.95	(1.26)	-2.2%
38	NATURAL GAS ($/MCF)	10.21	9.32	0.89	9.5%	10.09	10.28	(0.18)	-1.8%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	9.93	7.85	2.08	26.5%	9.49	7.89	1.60	20.3%
42	LIGHT OIL	15.11	11.68	3.43	29.4%	14.66	11.70	2.97	25.4%
43	COAL	2.58	2.47	0.11	4.4%	2.41	2.41	(0.00)	-0.2%
44	NATURAL GAS	9.87	9.07	0.81	8.9%	9.76	10.00	(0.24)	-2.4%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	5.27	4.85	0.42	8.7%	4.57	4.55	0.03	0.6%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,731	9,725	6	0.1%	10,125	9,743	382	3.9%
49	LIGHT OIL	23,090	10,834	12,256	113.1%	10,422	11,152	(730)	-6.5%
50	COAL	10,903	10,805	98	0.9%	10,691	10,754	(63)	-0.6%
51	NATURAL GAS	7,534	7,479	55	0.7%	7,485	7,494	(9)	-0.1%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,380	9,323	57	0.6%	9,515	9,601	(86)	-0.9%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	9.67	7.63	2.04	26.7%	9.61	7.69	1.92	25.0%
56	LIGHT OIL	34.90	12.66	22.24	175.7%	15.28	13.04	2.24	17.2%
57	COAL	2.81	2.67	0.14	5.2%	2.58	2.60	(0.02)	-0.8%
58	NATURAL GAS	7.44	6.78	0.66	9.7%	7.30	7.49	(0.19)	-2.5%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.95	4.52	0.43	9.5%	4.35	4.36	(0.01)	-0.2%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	185,664	60.7	64.2	78.2	11,212	COAL	89,496	23,258,980	2,081,585.7	5,195,394	2.80	58.05
B.B.#2	391	262,277	90.2	92.2	91.1	10,308	COAL	117,633	22,982,840	2,703,540.4	6,828,794	2.60	58.05
B.B.#3	414	184,588	59.9	63.7	73.8	10,685	COAL	86,607	22,772,400	1,972,249.2	5,027,682	2.72	58.05
B.B.#4	457	228,884	67.3	76.1	76.4	11,046	COAL	112,129	22,547,800	2,528,262.3	6,509,277	2.84	58.05
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	4,137	5,786,990	23,943.2	346,717	-	83.81
B.B. STATION	**1,673**	**861,413**	**69.2**	**73.9**	**79.6**	**10,780**	-	-	-	-	**23,907,864**	**2.78**	-
SEB-PHIL #1(HVY OIL)	17	2,064	16.3	100.0	81.9	9,731	HVY.OIL	3,202	6,273,540	20,085.5	176,205	8.54	55.03
SEB-PHIL #2(HVY OIL)	17	2,096	16.6	100.0	82.7	9,731	HVY.OIL	3,251	6,273,540	20,395.3	178,902	8.54	55.03
SEB-PHIL IGNITION	-	-	-	-	-	-	LGT.OIL	360	5,786,990	2,080.7	47,006	-	130.57
SEB-PHILLIPS TOTAL	**34**	**4,160**	**16.4**	**100.0**	**82.3**	**9,731**	-	-	-	-	402,113	9.67	-
POLK #1 GASIFIER	255	5,968	-	-	-	28,756	COAL	6,860	25,016,000	171,622.5	474,622	7.95	69.19
POLK #1 CT (OIL)	225	895	-	-	-	22,821	LGT.OIL	3,735	5,807,082	20,419.8	309,090	34.54	82.76
POLK #1 TOTAL	**255**	**6,863**	**3.6**	**10.8**	**31.7**	**27,982**	-	-	-	**192,042.3**	**783,712**	**11.42**	-
POLK #2 CT (GAS)	150	10,849	-	-	-	12,909	GAS	135,440	1,034,000	140,045.0	1,314,467	12.12	9.71
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**10,849**	**9.4**	**92.2**	**74.0**	**12,909**	-	-	-	**140,045.0**	**1,314,467**	**12.12**	-
POLK #3 CT (GAS)	150	7,844	-	-	-	12,916	GAS	97,983	1,034,000	101,315.0	944,692	12.04	9.64
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**7,844**	**6.8**	**92.2**	**86.6**	**12,916**	-	-	-	**101,315.0**	**944,692**	**12.04**	-
POLK STATION TOTAL	**565**	**25,556**	**6.1**	**55.5**	**58.4**	**16,959**	-	-	-	**433,402.3**	**3,042,871**	**11.91**	-
B.B.C.T.#1 *	14	3	0.0	100.0	0.0	25,667	LGT.OIL	13	5,777,194	77.0	1,089	36.30	83.77
B.B.C.T.#2 *	66	15	0.0	100.0	22.7	30,200	LGT.OIL	79	5,760,173	453.0	6,618	44.12	83.77
B.B.C.T.#3 *	66	8	0.0	99.5	12.1	39,588	LGT.OIL	55	5,760,276	316.7	4,607	57.59	83.76
C.T. TOTAL	**146**	**26**	**0.0**	**99.8**	**15.7**	**0**	**LGT.OIL**	**147**	**5,761,824**	**846.7**	**12,314**	**47.36**	**83.77**
COT 1 *	3	(4)	0.0	100.0	0.0	0	GAS	81	1,034,000	83.9	9,151	(228.78)	112.98
COT 2 *	3	(3)	0.0	100.0	0.0	0	GAS	77	1,034,000	79.1	8,699	(289.97)	112.97
CITY OF TAMPA TOTAL	**6**	**(7)**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**158**	**1,034,000**	**163.0**	**17,850**	**(255.00)**	**112.97**
BAYSIDE ST 1	234	109,767	63.0	100.0	63.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	71,382	61.5	100.0	85.5	10,913	GAS	753,345	1,034,000	778,959.0	7,673,606	10.75	10.19
BAYSIDE CT1B	156	73,888	63.7	95.4	89.6	11,465	GAS	819,302	1,034,000	847,158.0	8,345,446	11.29	10.19
BAYSIDE CT1C	156	67,474	58.1	98.0	87.2	10,477	GAS	683,713	1,034,000	706,959.0	6,964,331	10.32	10.19
BAYSIDE UNIT 1 TOTAL	**702**	**322,511**	**61.7**	**98.5**	**79.3**	**7,234**	**GAS**	**2,256,360**	**1,034,000**	**2,333,076.0**	**22,983,383**	**7.13**	**10.19**
BAYSIDE ST 2	306	127,649	56.1	91.4	61.3	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	65,820	56.7	91.0	87.8	11,048	GAS	703,249	1,034,000	727,159.0	7,221,602	10.97	10.27
BAYSIDE CT2B	156	65,536	56.5	91.0	92.0	11,360	GAS	720,010	1,034,000	744,490.0	7,393,719	11.28	10.27
BAYSIDE CT2C	156	62,954	54.2	90.6	85.9	11,370	GAS	692,230	1,034,000	715,766.0	7,108,449	11.29	10.27
BAYSIDE CT2D	156	59,961	51.7	92.0	86.3	11,443	GAS	663,576	1,034,000	686,138.0	6,814,204	11.36	10.27
BAYSIDE UNIT 2 TOTAL	**930**	**381,920**	**55.2**	**91.3**	**79.2**	**7,524**	**GAS**	**2,779,065**	**1,034,000**	**2,873,553.0**	**28,537,974**	**7.47**	**10.27**
BAYSIDE STATION TOTAL	**1,632**	**704,431**	**58.0**	**94.4**	**79.3**	**7,391**	**GAS**	**5,035,425**	**1,034,000**	**5,206,629.0**	**51,521,357**	**7.31**	**10.23**
SYSTEM	**4,056**	**1,595,579**	**52.9**	**80.8**	**74.1**	**9,380**	-	-	-	**14,967,159.4**	**78,904,369**	**4.95**	-

Footnotes: * Ran for testing only. [1] As burned fuel cost system total inludes ignition oil. [2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES								
2 UNITS (BBL)	11,722	3,965	7,757	195.6%	26,168	7,618	18,550	243.5%
3 UNIT COST ($/BBL)	58.15	46.10	12.05	26.1%	57.70	46.94	10.76	22.9%
4 AMOUNT ($)	681,615	182,769	498,846	272.9%	1,509,984	357,617	1,152,367	322.2%
5 BURNED								
6 UNITS (BBL)	6,453	3,965	2,488	62.7%	20,723	7,618	13,105	172.0%
7 UNIT COST ($/BBL)	62.31	49.28	13.03	26.4%	59.56	49.52	10.04	20.3%
8 AMOUNT ($)	402,113	195,415	206,698	105.8%	1,234,340	377,280	857,060	227.2%
9 ENDING INVENTORY								
10 UNITS (BBL)	20,776	12,118	8,658	71.4%	20,776	12,118	8,658	71.4%
11 UNIT COST ($/BBL)	58.10	46.92	11.18	23.8%	58.10	46.92	11.18	23.8%
12 AMOUNT ($)	1,207,114	568,630	638,484	112.3%	1,207,114	568,630	638,484	112.3%
13								
14 DAYS SUPPLY:	308	179	129	70.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	6,739	8,613	(1,874)	-21.8%	83,362	58,244	25,118	43.1%
17 UNIT COST ($/BBL)	91.69	67.76	23.93	35.3%	84.22	70.34	13.87	19.7%
18 AMOUNT ($)	617,902	583,590	34,312	5.9%	7,020,457	4,096,973	2,923,484	71.4%
19 BURNED:								
20 UNITS (BBL)	3,882	8,613	(4,731)	-54.9%	31,689	58,244	(26,555)	-45.6%
21 UNIT COST ($/BBL)	82.79	39.42	43.38	110.0%	82.15	46.46	35.69	76.8%
22 AMOUNT ($)	321,404	339,494	(18,090)	-5.3%	2,603,325	2,706,226	(102,901)	-3.8%
23 ENDING INVENTORY:								
24 UNITS (BBL)	104,610	85,007	19,603	23.1%	104,610	85,007	19,603	23.1%
25 UNIT COST ($/BBL)	83.39	67.03	16.36	24.4%	83.39	67.03	16.36	24.4%
26 AMOUNT ($)	8,723,131	5,697,596	3,025,535	53.1%	8,723,131	5,697,596	3,025,535	53.1%
27								
28 DAYS SUPPLY: NORMAL	247	201	46	20.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	12	3	23.1%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	643,324	431,600	211,724	49.1%	2,347,565	1,901,600	445,965	23.5%
32 UNIT COST ($/TON)	58.92	58.37	0.54	0.9%	57.38	57.78	(0.39)	-0.7%
33 AMOUNT ($)	37,903,341	25,194,201	12,709,140	50.4%	134,713,416	109,867,054	24,846,362	22.6%
34 BURNED:								
35 UNITS (TONS)	412,725	427,187	(14,462)	-3.4%	2,055,819	1,916,396	139,423	7.3%
36 UNIT COST ($/TON)	59.08	58.71	0.36	0.6%	56.69	57.95	(1.26)	-2.2%
37 AMOUNT ($)	24,382,486	25,081,004	(698,518)	-2.8%	116,539,998	111,048,199	5,491,799	4.9%
38 ENDING INVENTORY:								
39 UNITS (TONS)	763,135	531,952	231,183	43.5%	763,135	531,952	231,183	43.5%
40 UNIT COST ($/TON)	57.78	57.87	(0.10)	-0.2%	57.78	57.87	(0.10)	-0.2%
41 AMOUNT ($)	44,090,936	30,785,123	13,305,813	43.2%	44,090,936	30,785,123	13,305,813	43.2%
42								
43 DAYS SUPPLY:	58	40	18	50.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	5,146,489	5,515,283	(368,794)	-6.7%	18,931,321	17,179,974	1,751,347	10.2%
46 UNIT COST ($/MCF)	10.27	9.32	0.94	10.1%	10.05	10.28	(0.23)	-2.2%
47 AMOUNT ($)	52,830,892	51,410,837	1,420,055	2.8%	190,246,507	176,564,419	13,682,088	7.7%
48 BURNED								
49 UNITS (MCF)	5,269,006	5,515,283	(246,277)	-4.5%	19,066,214	17,179,974	1,886,240	11.0%
50 UNIT COST ($/MCF)	10.21	9.32	0.89	9.5%	10.09	10.28	(0.18)	-1.8%
51 AMOUNT ($)	53,798,366	51,410,837	2,387,529	4.6%	192,451,659	176,564,421	15,887,238	9.0%
52 ENDING INVENTORY:								
53 UNITS (MCF)	51,373	0	51,373	0.0%	51,373	0	51,373	0.0%
54 UNIT COST ($/MCF)	6.60	0.00	6.60	0.0%	6.60	0.00	6.60	0.0%
55 AMOUNT ($)	339,046	0	339,046	0.0%	339,046	0	339,046	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	31,887
LUBE OIL	0
FUEL ANALYSIS	150
TOTAL	32,037

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(4,497)	(378,604)
OTHER USAGE	(804)	(67,054)
TOTAL	(5,301)	(445,658)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	69,572
IGNITION #2 OIL	346,717
IGNITION PROPANE	18,459
AERIAL SURVEY ADJ.	0
ADDITIVES	5,625
GREEN FUEL	0
TOTAL	440,373

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC	SCH. - D	1,992.0	0.0	1,992.0	3.243	3.243	64,600.00	64,600.00	
VARIOUS	JURISDIC	SCH - MB	37,219.0	0.0	37,219.0	6.041	7.823	2,248,500.00	2,911,800.00	434,800.00
TOTAL			39,211.0	0.0	39,211.0	5.899	7.591	2,313,100.00	2,976,400.00	434,800.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	611.5	0.3	611.2	3.993	4.204	24,404.64	25,696.10	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,255.0	0.0	1,255.0	3.404	3.589	42,714.41	45,040.20	
PROGRESS ENERGY FLORIDA		SCH. - MA	280.0	0.0	280.0	3.744	6.452	10,483.20	18,064.49	6,713.29
FLA. PWR. & LIGHT		SCH. - MA	3,640.0	0.0	3,640.0	4.619	5.624	168,120.39	204,707.78	25,275.19
CITY OF LAKELAND		SCH. - MA	100.0	0.0	100.0	3.557	4.905	3,556.50	4,904.78	1,038.28
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	550.0	0.0	550.0	3.711	7.403	20,409.00	40,715.53	18,601.53
THE ENERGY AUTHORITY		SCH. - MA	182.0	0.0	182.0	3.686	7.322	6,709.08	13,326.38	6,053.10
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(25,044.47)	(25,044.47)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	255.0	0.0	255.0	5.273	16.042	13,446.94	40,907.86	26,716.32
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE FOR PROGRESS ENERGY FLORIDA*		SCH. - MA	120.0	0.0	120.0	4.851	5.261	5,820.65	6,313.56	476.11
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SEP SCH. - D	7,440.0	0.0	7,440.0	4.681	5.281	348,266.40	392,906.40	
ADJUSTMENTS TO PRIOR MONTHS:										
NEW SMYRNA BEACH	APR 2006	SEP SCH. - D	(7,190.0)	0.0	(7,190.0)	4.111	4.711	(295,580.90)	(338,720.90)	
NEW SMYRNA BEACH	APR 2006	SEP SCH. - D	7,190.0	0.0	7,190.0	4.681	5.281	336,563.90	379,703.90	
AUBURNDALE POWER PARTNERS	APR - OCT 2004	OATT	14,880.0	0.0	14,880.0	2.856	2.856	424,940.73	424,940.73	
AUBURNDALE POWER PARTNERS	APR - OCT 2004	OATT	(14,895.0)	0.0	(14,895.0)	3.020	3.020	(449,802.29)	(449,802.29)	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,440.0	0.0	7,440.0	5.232	5.832	389,249.40	433,889.40	
SUB-TOTAL SCHEDULE D POWER SALES			1,866.5	0.3	1,866.2	3.597	3.790	67,119.05	70,736.30	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			5,127.0	0.0	5,127.0	4.458	5.927	228,545.76	303,895.91	59,829.35
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			(15.0)	0.0	(15.0)	165.744	165.744	(24,861.56)	(24,861.56)	
TOTAL			14,418.5	0.3	14,418.2	4.578	5.435	660,052.65	783,660.05	59,829.35
CURRENT MONTH:										
DIFFERENCE			(24,792.5)	0.3	(24,792.8)	(1.321)	(2.156)	(1,653,047.35)	(2,192,739.95)	(374,970.65)
DIFFERENCE %			-63.2%	0.0%	-63.2%	-22.4%	-28.4%	-71.5%	-73.7%	-86.2%
PERIOD TO DATE:										
ACTUAL			89,840.2	7.0	89,833.2	4.496	5.463	4,038,942.79	4,907,503.81	495,567.21
ESTIMATED			103,845.0	0.0	103,845.0	5.075	7.379	5,269,900.00	7,662,800.00	1,860,600.00
DIFFERENCE			(14,004.8)	7.0	(14,011.8)	(0.579)	(1.916)	(1,230,957.21)	(2,755,296.19)	(1,365,032.79)
DIFFERENCE %			-13.5%	0.0%	-13.5%	-11.4%	-26.0%	-23.4%	-36.0%	-73.4%

* SEC 60% PROFIT OR $714.18 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	375.0	0.0	257.0	118.0	10.085	10.085	11,900.00
HARDEE POWER PARTNERS		IPP	31,177.0	0.0	0.0	31,177.0	8.048	8.048	2,509,100.00
CALPINE		SCH. - D	4,955.0	0.0	0.0	4,955.0	10.129	10.129	501,900.00
VARIOUS		MKT. BASED	41,390.0	0.0	0.0	41,390.0	8.198	8.198	3,393,000.00
OTHER		SCH. - D	93,012.0	0.0	0.0	93,012.0	3.340	3.340	3,106,900.00
TOTAL			170,909.0	0.0	257.0	170,652.0	5.580	5.580	9,522,800.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	40,607.0	0.0	0.0	40,607.0	7.850	7.850	3,187,592.04
HARDEE PWR. PART.-OTHERS		IPP	120.0	0.0	0.0	120.0	4.865	4.865	5,837.45
PROGRESS ENERGY FLORIDA		SCH. - D	34,800.0	0.0	0.0	34,800.0	3.629	3.629	1,262,892.00
CALPINE		SCH. - D	17,310.0	0.0	0.0	17,310.0	9.153	9.153	1,584,430.36
AUBURNDALE POWER PARTNERS		OATT	1,145.0	0.0	0.0	1,145.0	3.210	3.210	36,753.94
TEC MARKETING		OATT	76.0	0.0	0.0	76.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	APR 2006	IPP	(28,559.0)	0.0	0.0	(28,559.0)	8.472	8.472	(2,419,403.37)
HARDEE PWR. PART.-NATIVE	APR 2006	IPP	28,559.0	0.0	0.0	28,559.0	8.533	8.533	2,437,020.87
PROGRESS ENERGY FLORIDA	APR 2006	SCH. - D	(32,550.0)	0.0	0.0	(32,550.0)	3.647	3.647	(1,187,098.50)
PROGRESS ENERGY FLORIDA	APR 2006	SCH. - D	32,550.0	0.0	0.0	32,550.0	3.629	3.629	1,181,239.50
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	11,758.50
TOTAL			94,058.0	0.0	0.0	94,058.0	6.474	6.474	6,089,264.29
CURRENT MONTH:									
DIFFERENCE			(76,851.0)	0.0	(257.0)	(76,594.0)	0.894	0.894	(3,433,535.71)
DIFFERENCE %			-45.0%	0.0%	0.0%	-44.9%	16.0%	16.0%	-36.1%
PERIOD TO DATE:									
ACTUAL			262,174.0	0.0	0.0	262,174.0	5.643	5.643	14,794,110.83
ESTIMATED			1,244,409.0	0.0	2,835.0	1,241,574.0	5.606	5.606	69,608,000.00
DIFFERENCE			(982,235.0)	0.0	(2,835.0)	(979,400.0)	0.037	0.037	(54,813,889.17)
DIFFERENCE %			-78.9%	0.0%	-100.0%	-78.9%	0.7%	0.7%	-78.7%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	37,769.0	0.0	0.0	37,769.0	3.194	3.194	1,206,200.00
TOTAL			**37,769.0**	**0.0**	**0.0**	**37,769.0**	**3.194**	**3.194**	**1,206,200.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	17,113.0	0.0	0.0	17,113.0	2.630	2.630	450,085.58
McKAY BAY REFUSE		COGEN.	14,288.0	0.0	0.0	14,288.0	2.631	2.631	375,848.61
ORANGE COGENERATION L.P.		COGEN.	7,843.0	0.0	0.0	7,843.0	2.425	2.425	190,215.23
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	28.0	0.0	0.0	28.0	8.023	8.023	2,246.50
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	2,252.0	0.0	0.0	2,252.0	4.246	4.246	95,624.22
CF INDUSTRIES INC.		COGEN.	1,216.0	0.0	0.0	1,216.0	5.134	5.134	62,426.53
IMC-AGRICO-NEW WALES		COGEN.	702.0	0.0	0.0	702.0	4.667	4.667	32,759.99
IMC-AGRICO-S. PIERCE		COGEN.	6,257.0	0.0	0.0	6,257.0	5.173	5.173	323,673.41
AUBURNDALE POWER PARTNERS		COGEN.	1,154.0	0.0	0.0	1,154.0	4.770	4.770	55,046.02
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR MAY 2006			50,853.0	0.0	0.0	50,853.0	3.123	3.123	1,587,926.09
ADJUSTMENTS FOR THE MONTH OF:	**APRIL 2006**								
HILLSBOROUGH COUNTY		COGEN.	(18,151.0)	0.0	0.0	(18,151.0)	2.593	2.593	(470,599.04)
			18,151.0	0.0	0.0	18,151.0	2.580	2.580	468,211.01
McKAY BAY REFUSE		COGEN.	(12,690.0)	0.0	0.0	(12,690.0)	2.588	2.588	(328,466.66)
			12,690.0	0.0	0.0	12,690.0	2.575	2.575	326,829.20
ORANGE COGENERATION L.P.		COGEN.	(7,360.0)	0.0	0.0	(7,360.0)	2.398	2.398	(176,476.93)
			7,360.0	0.0	0.0	7,360.0	2.385	2.385	175,502.33
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL			0.0	0.0	0.0	0.0	0.000	0.000	(5,000.09)
TOTAL			**50,853.0**	**0.0**	**0.0**	**50,853.0**	**3.113**	**3.113**	**1,582,926.00**
CURRENT MONTH:									
DIFFERENCE			13,084.0	0.0	0.0	13,084.0	(0.081)	(0.081)	376,726.00
DIFFERENCE %			34.6%	0.0%	0.0%	34.6%	-2.5%	-2.5%	31.2%
PERIOD TO DATE:									
ACTUAL			217,811.0	0.0	0.0	217,811.0	3.008	3.008	6,551,143.99
ESTIMATED			178,240.0	0.0	0.0	178,240.0	2.938	2.938	5,237,000.00
DIFFERENCE			39,571.0	0.0	0.0	39,571.0	0.070	0.070	1,314,143.99
DIFFERENCE %			22.2%	0.0%	0.0%	22.2%	2.4%	2.4%	25.1%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	21,563.0	5.418	1,168,207.00	6.591	1,421,304.63	253,097.63
FLA. POWER & LIGHT	SCH. - JC	37,419.0	6.776	2,535,489.00	8.416	3,149,256.31	613,767.31
CITY OF LAKELAND	SCH. - JC	1,390.0	7.264	100,972.50	9.502	132,083.65	31,111.15
ORLANDO UTIL. COMM.	SCH. - JC	615.0	7.569	46,550.00	9.962	61,268.30	14,718.30
THE ENERGY AUTHORITY	SCH. - JC	17,109.0	7.194	1,230,743.00	9.436	1,614,478.91	383,735.91
OKEELANTA	SCH. - JC	1,484.0	7.984	118,489.00	8.495	126,072.98	7,583.98
CITY OF TALLAHASSEE	SCH. - JC	175.0	7.617	13,330.00	10.971	19,199.65	5,869.65
CALPINE	SCH. - JC	7,361.0	6.786	499,541.00	8.711	641,241.53	141,700.53
CARGILL ALLIANT	SCH. - JC	4,681.0	6.275	293,739.00	9.479	443,710.32	149,971.32
RELIANT	SCH. - JC	6,250.0	10.122	632,635.00	11.281	705,040.50	72,405.50
RAINBOW ENERGY MARKETERS	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	1,940.0	4.739	91,940.00	7.748	150,316.30	58,376.30
ENTERGY-KOCH TRADING	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	3,903.0	3.887	151,714.00	5.408	211,079.71	59,365.71
CINCINATTI GAS & ELECTRIC	SCH. - JC	769.0	7.178	55,198.00	8.861	68,138.66	12,940.66
SUBTOTAL		104,659.0	6.630	6,938,547.50	8.354	8,743,191.45	1,804,643.95
NO ADJUSTMENTS TO PRIOR MONTHS.							
TOTAL		**104,659.0**	**6.630**	**6,938,547.50**	**8.354**	**8,743,191.45**	**1,804,643.95**
CURRENT MONTH:							
DIFFERENCE		104,659.0	6.630	6,938,547.50	8.354	8,743,191.45	1,804,643.95
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		366,074.9	7.092	25,963,753.75	8.992	32,915,875.14	6,952,121.39
ESTIMATED		0.0	0.000	0.0	0.000	0.0	0.00
DIFFERENCE		366,074.9	7.092	25,963,753.75	8.992	32,915,875.14	6,952,121.39
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JUNE 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	79,107,064	74,485,771	4,621,293	6.2%	1,725,562	1,716,279	9,283	0.5%	4.58442	4.33996	0.24447	5.6%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(10,127)	(6,734)	(3,393)	50.4%	1,725,562 (a)	1,716,279 (a)	9,283	0.5%	(0.00059)	(0.00039)	(0.00019)	49.6%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,725,562 (a)	1,716,279 (a)	9,283	0.5%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	20,752	25,713	(4,961)	-19.3%	1,725,562 (a)	1,716,279 (a)	9,283	0.5%	0.00120	0.00150	(0.00030)	-19.7%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**79,117,689**	**74,504,750**	**4,612,939**	**6.2%**	**1,725,562**	**1,716,279**	**9,283**	**0.5%**	**4.58504**	**4.34106**	**0.24398**	**5.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	4,956,675	15,333,400	(10,376,725)	-67.7%	88,635	244,612	(155,977)	-63.8%	5.59223	6.26846	(0.67623)	-10.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	7,884,596	0	7,884,596	0.0%	128,964	0	128,964	0.0%	6.11380	0.00000	6.11380	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,337,418	1,108,600	228,818	20.6%	43,416	36,546	6,870	18.8%	3.08047	3.03344	0.04704	1.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**14,178,689**	**16,442,000**	**(2,263,311)**	**-13.8%**	**261,015**	**281,158**	**(20,143)**	**-7.2%**	**5.43214**	**5.84796**	**(0.41582)**	**-7.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,986,577**	**1,997,437**	**(10,860)**	**-0.5%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	74,460	67,400	7,060	10.5%	1,950	1,943	7	0.3%	3.81905	3.46886	0.35019	10.1%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	3,777	0	3,777	0.0%	43	0	43	0.0%	8.78372	0.00000	8.78372	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	410,671	0	410,671	0.0%	7,200	0	7,200	0.0%	5.70376	0.00000	5.70376	0.0%
17. Fuel Cost of Market Base Sales (A6)	560,031	1,633,900	(1,073,869)	-65.7%	8,690	25,442	(16,752)	-65.8%	6.44455	6.42206	0.02249	0.4%
18. Gains on Market Based Sales	89,900	271,440	(181,540)	-66.9%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**1,138,839**	**1,972,740**	**(833,901)**	**-42.3%**	**17,883**	**27,385**	**(9,502)**	**-34.7%**	**6.36828**	**7.20372**	**(0.83545)**	**-11.6%**
20. Net Inadvertant Interchange					(241)	0	(241)	0.0%				
21. Wheeling Rec'd. less Wheeling Del'v'd.					3,827	0	3,827	0.0%				
22. Interchange and Wheeling Losses					4,875	500	4,375	875.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**92,157,539**	**88,974,010**	**3,183,529**	**3.6%**	**1,967,405**	**1,969,552**	**(2,147)**	**-0.1%**	**4.68422**	**4.51747**	**0.16674**	**3.7%**
24. Net Unbilled	2,481,230 (a)	2,014,839 (a)	466,391	23.1%	52,970	44,601	8,369	18.8%	4.68422	4.51747	0.16674	3.7%
25. Company Use	145,258 (a)	140,042 (a)	5,216	3.7%	3,101	3,100	1	0.0%	4.68423	4.51748	0.16675	3.7%
26. T & D Losses	4,487,668 (a)	2,412,151 (a)	2,075,517	86.0%	95,804	53,396	42,408	79.4%	4.68422	4.51748	0.16674	3.7%
27. System KWH Sales	92,157,539	88,974,010	3,183,529	3.6%	1,815,530	1,868,455	(52,925)	-2.8%	5.07607	4.76190	0.31417	6.6%
28. Wholesale KWH Sales	(2,732,802)	(2,431,002)	(301,800)	12.4%	(53,837)	(51,051)	(2,786)	5.5%	5.07607	4.76191	0.31416	6.6%
29. Jurisdictional KWH Sales	89,424,737	86,543,008	2,881,729	3.3%	1,761,693	1,817,404	(55,711)	-3.1%	5.07607	4.76190	0.31417	6.6%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	89,501,642	86,617,435	2,884,207	3.3%	1,761,693	1,817,404	(55,711)	-3.1%	5.08043	4.76600	0.31444	6.6%
32. Other	0	0	0	0.0%	1,761,693	1,817,404	(55,711)	-3.1%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,090,636)	(1,276,250)	185,614	-14.5%	1,761,693	1,817,404	(55,711)	-3.1%	(0.06191)	(0.07022)	0.00832	-11.8%
34. Other	0	0	0	0.0%	1,761,693	1,817,404	(55,711)	-3.1%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,761,693	1,817,404	(55,711)	-3.1%	0.69846	0.67705	0.02141	3.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	100,715,691	97,645,870	3,069,821	3.1%	1,761,693	1,817,404	(55,711)	-3.1%	5.71698	5.37282	0.34416	6.4%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	100,788,206	97,716,175	3,072,031	3.1%	1,761,693	1,817,404	(55,711)	-3.1%	5.72110	5.37669	0.34441	6.4%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,761,693	1,817,404	(55,711)	-3.1%	0.00345	0.00335	0.00011	3.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**100,849,001**	**97,776,970**	**3,072,031**	**3.1%**	**1,761,693**	**1,817,404**	**(55,711)**	**-3.1%**	**5.72455**	**5.38004**	**0.34452**	**6.4%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.725**	**5.380**	**0.345**	**6.4%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JUNE 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	391,936,386	365,181,897	26,754,489	7.3%	8,914,521	8,376,918	537,603	6.4%	4.39661	4.35938	0.03722	0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft Meade/Wauch. Wheeling Losses)	(50,913)	(40,404)	(10,509)	26.0%	8,914,521 (a)	8,376,918 (a)	537,603	6.4%	(0.00057)	(0.00048)	(0.00009)	18.4%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	8,914,521 (a)	8,376,918 (a)	537,603	6.4%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	55,747	68,793	(13,046)	-19.0%	8,914,521 (a)	8,376,918 (a)	537,603	6.4%	0.00063	0.00082	(0.00020)	-23.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**391,941,220**	**365,210,286**	**26,730,934**	**7.3%**	**8,914,521**	**8,376,918**	**537,603**	**6.4%**	**4.39666**	**4.35972**	**0.03694**	**0.8%**
6. Fuel Cost of Purchased Power - Firm (A7)	19,750,785	84,941,400	(65,190,615)	-76.7%	350,809	1,486,186	(1,135,377)	-76.4%	5.63007	5.71539	(0.08533)	-1.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	33,848,350	0	33,848,350	0.0%	495,039	0	495,039	0.0%	6.83751	0.00000	6.83751	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	7,888,563	6,345,600	1,542,963	24.3%	261,227	214,786	46,441	21.6%	3.01981	2.95438	0.06543	2.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**61,487,698**	**91,287,000**	**(29,799,302)**	**-32.6%**	**1,107,075**	**1,700,972**	**(593,897)**	**-34.9%**	**5.55407**	**5.36676**	**0.18731**	**3.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**10,021,596**	**10,077,890**	**(56,294)**	**-0.6%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	339,965	269,300	70,665	26.2%	8,917	9,105	(188)	-2.1%	3.81246	2.95772	0.85475	28.9%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,085)	0	(21,085)	0.0%	28	0	28	0.0%	(75.30357)	0.00000	(75.30357)	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	2,017,660	0	2,017,660	0.0%	43,430	0	43,430	0.0%	4.64577	0.00000	4.64577	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,751,342	6,701,900	(3,950,558)	-58.9%	55,342	122,125	(66,783)	-54.7%	4.97153	5.48774	(0.51621)	-9.4%
18. Gains on Market Based Sales	585,467	2,132,040	(1,546,573)	-72.5%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**5,673,349**	**9,103,240**	**(3,429,891)**	**-37.7%**	**107,718**	**131,230**	**(23,512)**	**-17.9%**	**5.26685**	**6.93686**	**(1.67001)**	**-24.1%**
20. Net Inadvertant Interchange					(900)	0	(900)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					17,676	0	17,676	0.0%				
22. Interchange and Wheeling Losses					18,939	2,300	16,639	723.4%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**447,755,569**	**447,394,046**	**361,523**	**0.1%**	**9,911,715**	**9,944,360**	**(32,645)**	**-0.3%**	**4.51744**	**4.49897**	**0.01847**	**0.4%**
24. Net Unbilled	4,340,239 (a)	7,902,502 (a)	(3,562,263)	-45.1%	56,478	173,671	(117,193)	-67.5%	7.68483	4.55027	3.13456	68.9%
25. Company Use	791,271 (a)	836,297 (a)	(45,026)	-5.4%	17,600	18,600	(1,000)	-5.4%	4.49586	4.49622	(0.00036)	0.0%
26. T & D Losses	26,820,418 (a)	16,901,828 (a)	9,918,590	58.7%	612,795	375,678	237,117	63.1%	4.37674	4.49902	(0.12228)	-2.7%
27. System KWH Sales	447,755,569	447,394,046	361,523	0.1%	9,224,842	9,376,411	(151,569)	-1.6%	4.85380	4.77149	0.08232	1.7%
28. Wholesale KWH Sales	(17,160,557)	(11,448,887)	(5,711,670)	49.9%	(362,618)	(237,290)	(125,328)	52.8%	4.73241	4.82485	(0.09244)	-1.9%
29. Jurisdictional KWH Sales	430,595,012	435,945,159	(5,350,147)	-1.2%	8,862,224	9,139,121	(276,897)	-3.0%	4.85877	4.77010	0.08867	1.9%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	430,965,323	436,320,073	(5,354,750)	-1.2%	8,862,224	9,139,121	(276,897)	-3.0%	4.86295	4.77420	0.08875	1.9%
32. Other	0	0	0	0.0%	8,862,224	9,139,121	(276,897)	-3.0%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(8,384,160)	(7,657,500)	(726,660)	9.5%	8,862,224	9,139,121	(276,897)	-3.0%	(0.09461)	(0.08379)	(0.01082)	12.9%
34. Other	0	0	0	0.0%	8,862,224	9,139,121	(276,897)	-3.0%	0.00000	0.00000	0.00000	0.0%
35. True-up *	73,828,110	73,828,111	(1)	0.0%	8,862,224	9,139,121	(276,897)	-3.0%	0.83307	0.80783	0.02524	3.1%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	496,409,273	502,490,684	(6,081,411)	-1.2%	8,862,224	9,139,121	(276,897)	-3.0%	5.60141	5.49824	0.10317	1.9%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	496,766,687	502,852,477	(6,085,790)	-1.2%	8,862,224	9,139,121	(276,897)	-3.0%	5.60544	5.50220	0.10324	1.9%
39. GPIF * (Already Adjusted for Taxes)	364,770	364,770	0	0.0%	8,862,224	9,139,121	(276,897)	-3.0%	0.00412	0.00399	0.00012	3.1%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**497,131,457**	**503,217,247**	**(6,085,790)**	**-1.2%**	**8,862,224**	**9,139,121**	**(276,897)**	**-3.0%**	**5.60956**	**5.50619**	**0.10336**	**1.9%**
									5.610	5.506	0.104	1.9%

41. Fuel FAC Rounded to the Nearest .001 cents per KWH

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	79,107,064	74,485,771	4,621,293	6.2%	391,936,386	365,181,897	26,754,489	7.3%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,048,939	1,701,300	(652,361)	-38.3%	5,087,882	6,971,200	(1,883,318)	-27.0%
2a. GAINS FROM MARKET BASED SALES	89,900	271,440	(181,540)	-66.9%	585,467	2,132,040	(1,546,573)	-72.5%
3. FUEL COST OF PURCHASED POWER	4,956,675	15,333,400	(10,376,725)	-67.7%	19,750,785	84,941,400	(65,190,615)	-76.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,337,418	1,108,600	228,818	20.6%	7,888,563	6,345,600	1,542,963	24.3%
4. ENERGY COST OF ECONOMY PURCHASES	7,884,596	0	7,884,596	0.0%	33,848,350	0	33,848,350	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	92,146,914	88,955,031	3,191,883	3.6%	447,750,735	447,365,657	385,078	0.1%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(10,127)	(6,734)	(3,393)	50.4%	(50,913)	(40,404)	(10,509)	26.0%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	20,752	25,713	(4,961)	-19.3%	55,747	68,793	(13,046)	-19.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	92,157,539	88,974,010	3,183,529	3.6%	447,755,569	447,394,046	361,523	0.1%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,761,693	1,817,404	(55,711)	-3.1%	8,862,224	9,139,121	(276,897)	-3.0%
2. NONJURISDICTIONAL SALES	53,837	51,051	2,786	5.5%	362,618	237,290	125,328	52.8%
3. TOTAL SALES	1,815,530	1,868,455	(52,925)	-2.8%	9,224,842	9,376,411	(151,569)	-1.6%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9703464	0.9726774	(0.0023310)	-0.2%	0.9606911	0.9746929	(0.0140018)	-1.4%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	94,864,023	98,323,207	(3,459,184)	-3.5%	476,187,532	494,168,199	(17,980,667)	-3.6%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(73,828,110)	(73,828,111)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(364,770)	(364,770)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	82,498,543	85,957,727	(3,459,184)	-4.0%	401,994,652	419,975,318	(17,980,666)	-4.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	92,157,539	88,974,010	3,183,529	3.6%	447,755,569	447,394,046	361,523	0.1%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9703464	0.9726774	(0.0023310)	-0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	89,424,737	86,543,008	2,881,729	3.3%	430,595,012	435,945,159	(5,350,147)	-1.2%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	89,501,642	86,617,435	2,884,207	3.3%	430,965,323	436,320,073	(5,354,750)	-1.2%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,090,636)	(1,276,250)	185,614	-14.5%	(8,384,160)	(7,657,500)	(726,660)	9.5%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	88,411,006	85,341,185	3,069,821	3.6%	422,581,163	428,662,573	(6,081,410)	-1.4%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(5,912,463)	616,542	(6,529,005)	-1059.0%	(20,586,511)	(8,687,255)	(11,899,256)	137.0%
8. INTEREST PROVISION FOR THE MONTH	(894,207)	(341,846)	(552,361)	161.6%	(5,206,383)	(2,524,913)	(2,681,470)	106.2%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(211,635,858)	(97,619,660)	(114,016,198)	116.8%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(206,137,843)	(85,040,279)	(121,097,564)	142.4%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(211,635,858)	(97,619,660)	(114,016,198)	116.8%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(205,243,636)	(84,698,433)	(120,545,203)	142.3%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(416,879,494)	(182,318,093)	(234,561,401)	128.7%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(208,439,747)	(91,159,047)	(117,280,700)	128.7%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.010	4.500	0.510	11.3%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.290	4.500	0.790	17.6%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	10.300	9.000	1.300	14.4%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.150	4.500	0.650	14.4%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.429	0.375	0.054	14.4%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(894,207)	(341,846)	(552,361)	161.6%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	201,528	273,263	(71,735)	-26.3%	1,435,868	650,543	785,325	120.7%
2	LIGHT OIL	609,492	593,686	15,806	2.7%	3,212,817	3,299,912	(87,095)	-2.6%
3	COAL	27,316,897	25,954,221	1,362,676	5.3%	143,856,895	137,002,420	6,854,475	5.0%
4	NATURAL GAS	50,979,147	47,664,601	3,314,546	7.0%	243,430,806	224,229,022	19,201,784	8.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	79,107,064	74,485,771	4,621,293	6.2%	391,936,386	365,181,897	26,754,489	7.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,931	3,594	(1,663)	-46.3%	14,771	8,502	6,269	73.7%
9	LIGHT OIL	4,661	4,572	89	1.9%	21,695	25,320	(3,625)	-14.3%
10	COAL	1,000,369	968,355	32,014	3.3%	5,525,253	5,246,714	278,539	5.3%
11	NATURAL GAS	718,601	739,758	(21,157)	-2.9%	3,354,076	3,096,382	257,694	8.3%
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)	1,725,562	1,716,279	9,283	0.5%	8,915,795	8,376,918	538,877	6.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	3,206	5,585	(2,379)	-42.6%	23,929	13,203	10,726	81.2%
16	LIGHT OIL (BBL)	7,228	12,266	(5,038)	-41.1%	38,917	70,510	(31,593)	-44.8%
17	COAL (TON)	463,733	438,514	25,219	5.8%	2,519,552	2,354,910	164,642	7.0%
18	NATURAL GAS (MCF)	5,144,744	5,402,229	(257,485)	-4.8%	24,210,958	22,582,203	1,628,755	7.2%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	20,114	35,066	(14,952)	-42.6%	150,124	82,887	67,237	81.1%
22	LIGHT OIL	41,905	49,721	(7,816)	-15.7%	219,427	281,111	(61,684)	-21.9%
23	COAL	10,771,088	10,497,890	273,198	2.6%	59,148,657	56,508,578	2,640,079	4.7%
24	NATURAL GAS	5,329,954	5,553,471	(223,517)	-4.0%	25,057,234	23,214,283	1,842,951	7.9%
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)	16,163,061	16,136,148	26,913	0.2%	84,575,442	80,086,859	4,488,583	5.6%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.11%	0.21%	(0.00)	-	0.17%	0.10%	0.00	-
29	LIGHT OIL	0.27%	0.27%	0.00	-	0.24%	0.30%	(0.00)	-
30	COAL	57.97%	56.42%	0.02	-	61.97%	62.63%	(0.01)	-
31	NATURAL GAS	41.64%	43.10%	(0.01)	-	37.62%	36.96%	0.01	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	62.86	48.93	13.93	28.5%	60.01	49.27	10.73	21.8%
36	LIGHT OIL ($/BBL)	84.32	48.40	35.92	74.2%	82.56	46.80	35.75	76.4%
37	COAL ($/TON)	58.91	59.19	(0.28)	-0.5%	57.10	58.18	(1.08)	-1.9%
38	NATURAL GAS ($/MCF)	9.91	8.82	1.09	12.3%	10.05	9.93	0.13	1.3%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	10.02	7.79	2.23	28.6%	9.56	7.85	1.72	21.9%
42	LIGHT OIL	14.54	11.94	2.60	21.8%	14.64	11.74	2.90	24.7%
43	COAL	2.54	2.47	0.06	2.6%	2.43	2.42	0.01	0.3%
44	NATURAL GAS	9.56	8.58	0.98	11.4%	9.71	9.66	0.06	0.6%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.89	4.62	0.28	6.0%	4.63	4.56	0.07	1.6%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,416	9,757	659	6.8%	10,163	9,749	414	4.2%
49	LIGHT OIL	8,991	10,875	(1,884)	-17.3%	10,114	11,102	(988)	-8.9%
50	COAL	10,767	10,841	(74)	-0.7%	10,705	10,770	(65)	-0.6%
51	NATURAL GAS	7,417	7,507	(90)	-1.2%	7,471	7,497	(26)	-0.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,367	9,402	(35)	-0.4%	9,486	9,560	(74)	-0.8%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	10.44	7.60	2.84	37.4%	9.72	7.65	2.07	27.1%
56	LIGHT OIL	13.08	12.99	0.09	0.7%	14.81	13.03	1.78	13.7%
57	COAL	2.73	2.68	0.05	1.9%	2.60	2.61	(0.01)	-0.4%
58	NATURAL GAS	7.09	6.44	0.65	10.1%	7.26	7.24	0.02	0.3%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.58	4.34	0.24	5.5%	4.40	4.36	0.04	0.9%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	196,328	66.3	71.3	73.6	10,955	COAL	95,254	22,578,760	2,150,717.2	5,526,895	2.82	58.02
B.B.#2	391	207,185	73.6	75.2	90.7	10,470	COAL	93,128	23,292,040	2,169,141.1	5,403,539	2.61	58.02
B.B.#3	414	185,392	62.2	65.6	79.6	10,726	COAL	85,743	23,191,380	1,988,498.5	4,975,041	2.68	58.02
B.B.#4	457	247,663	75.3	85.7	75.3	11,040	COAL	121,534	22,497,460	2,734,206.3	7,051,732	2.85	58.02
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	3,291	5,774,389	19,004.1	278,434	-	84.60
B.B. STATION	**1,673**	**836,568**	**69.5**	**74.7**	**79.5**	**10,809**	-	-	-	-	23,235,641	2.78	-
SEB-PHIL. #1(HVY OIL)	17	876	7.2	100.0	78.1	10,416	HVY.OIL	1,455	6,273,540	9,128.9	79,626	9.09	54.73
SEB-PHIL. #2(HVY OIL)	17	1,055	8.6	100.0	76.9	10,416	HVY.OIL	1,751	6,273,540	10,985.2	95,824	9.08	54.73
SEB-PHIL. IGNITION	-	-	-	-	-	-	LGT.OIL	219	5,774,389	1,263.7	26,078	-	119.08
SEB-PHILLIPS TOTAL	**34**	**1,931**	**7.9**	**100.0**	**77.5**	**10,416**	-	-	-	-	201,528	10.44	-
POLK #1 GASIFIER	255	163,801	-	-	-	10,553	COAL	68,074	25,392,000	1,728,525.1	4,081,256	2.49	59.95
POLK #1 CT (OIL)	225	4,381	-	-	-	8,504	LGT.OIL	6,426	5,797,253	37,255.0	541,866	12.37	84.32
POLK #1 TOTAL	**255**	**168,182**	**91.6**	**95.9**	**92.9**	**10,499**	-	-	-	**1,765,780.1**	4,623,122	2.75	-
POLK #2 CT (GAS)	150	4,284	-	-	-	12,040	GAS	49,783	1,036,000	51,575.0	521,140	12.16	10.47
POLK #2 CT (OIL)	160	280	-	-	-	0	LGT.OIL	802	5,797,259	4,649.5	67,626	24.15	84.32
POLK #2 TOTAL	**155**	**4,564**	**4.1**	**85.3**	**68.3**	**12,319**	-	-	-	**56,224.5**	**588,766**	**12.90**	-
POLK #3 CT (GAS)	150	5,638	-	-	-	12,010	GAS	65,360	1,036,000	67,713.0	654,054	11.60	10.01
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**5,638**	**5.1**	**100.0**	**75.0**	**12,010**	-	-	-	**67,713.0**	654,054	11.60	-
POLK STATION TOTAL	**565**	**178,384**	**43.9**	**94.1**	**81.2**	**10,594**	-	-	-	1,889,717.6	5,865,942	3.29	-
B.B.C.T.#1	14	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**146**	**0**	**0.0**	**100.0**	**0.0**	**0**	LGT.OIL	**0**	**0**	**0.0**	0	0.00	**0.00**
COT 1	3	80	3.7	100.0	87.2	11,893	GAS	920	1,036,000	953.2	858	1.07	0.93
COT 2	3	72	3.3	100.0	74.0	11,893	GAS	824	1,036,000	853.2	769	1.07	0.93
CITY OF TAMPA TOTAL	**6**	**152**	**3.5**	**100.0**	**80.6**	**11,884**	**GAS**	**1,744**	**1,036,000**	1,806.4	**1,627**	1.07	**0.93**
BAYSIDE ST 1	234	105,366	62.5	100.0	62.5	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	67,629	60.2	99.9	92.0	11,194	GAS	730,743	1,036,000	757,049.8	7,250,370	10.72	9.92
BAYSIDE CT1B	156	62,288	55.5	99.2	84.6	11,386	GAS	684,572	1,036,000	709,217.0	6,792,265	10.90	9.92
BAYSIDE CT1C	156	73,437	65.4	97.5	85.1	10,719	GAS	759,807	1,036,000	787,160.0	7,538,741	10.27	9.92
BAYSIDE UNIT 1 TOTAL	**702**	**308,720**	**61.1**	**99.2**	**79.0**	**7,299**	**GAS**	**2,175,122**	**1,036,000**	**2,253,426.8**	21,581,376	6.99	**9.92**
BAYSIDE ST 2	306	136,613	62.0	100.0	62.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	64,355	57.3	100.0	84.8	11,073	GAS	687,813	1,036,000	712,574.0	6,804,255	10.57	9.89
BAYSIDE CT2B	156	68,358	60.9	99.3	84.0	11,345	GAS	748,593	1,036,000	775,542.0	7,405,527	10.83	9.89
BAYSIDE CT2C	156	65,844	58.6	100.0	84.0	11,285	GAS	717,224	1,036,000	743,044.0	7,095,206	10.78	9.89
BAYSIDE CT2D	156	64,637	57.5	100.0	84.0	11,205	GAS	699,105	1,036,000	724,273.0	6,915,962	10.70	9.89
BAYSIDE UNIT 2 TOTAL	**930**	**399,807**	**59.7**	**99.9**	**76.9**	**7,392**	**GAS**	**2,852,735**	**1,036,000**	**2,955,433.0**	28,220,950	7.06	**9.89**
BAYSIDE STATION TOTAL	**1,632**	**708,527**	**60.3**	**99.6**	**77.8**	**7,352**	**GAS**	**5,027,857**	**1,036,000**	**5,208,859.8**	49,802,326	7.03	**9.91**
SYSTEM	**4,056**	**1,725,562**	**59.1**	**88.6**	**76.2**	**9,367**	-	-	-	**16,163,061.0**	79,107,064	4.58	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:

B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	0	5,585	(5,585)	-100.0%	26,168	13,203	12,965	98.2%
3 UNIT COST ($/BBL)	0.00	47.79	(47.79)	-100.0%	57.48	47.30	10.18	21.5%
4 AMOUNT ($)	(5,968)	266,886	(272,854)	-102.2%	1,504,016	624,503	879,513	140.8%
5 BURNED								
6 UNITS (BBL)	3,206	5,585	(2,379)	-42.6%	23,929	13,203	10,726	81.2%
7 UNIT COST ($/BBL)	62.86	48.93	13.93	28.5%	60.01	49.27	10.73	21.8%
8 AMOUNT ($)	201,528	273,263	(71,735)	-26.3%	1,435,868	650,543	785,325	120.7%
9 ENDING INVENTORY								
10 UNITS (BBL)	17,570	12,118	5,452	45.0%	17,570	12,118	5,452	45.0%
11 UNIT COST ($/BBL)	58.00	47.20	10.80	22.9%	58.00	47.20	10.80	22.9%
12 AMOUNT ($)	1,019,026	571,930	447,096	78.2%	1,019,026	571,930	447,096	78.2%
13								
14 DAYS SUPPLY:	252	174	78	40.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	11,363	12,266	(903)	-7.4%	94,725	70,510	24,215	34.3%
17 UNIT COST ($/BBL)	94.74	70.54	24.20	34.3%	85.48	70.38	15.10	21.5%
18 AMOUNT ($)	1,076,531	865,256	211,275	24.4%	8,096,988	4,962,229	3,134,759	63.2%
19 BURNED:								
20 UNITS (BBL)	7,228	12,266	(5,038)	-41.1%	38,917	70,510	(31,593)	-44.8%
21 UNIT COST ($/BBL)	84.32	48.40	35.92	74.2%	82.56	46.80	35.75	76.4%
22 AMOUNT ($)	609,492	593,686	15,806	2.7%	3,212,817	3,299,912	(87,095)	-2.6%
23 ENDING INVENTORY:								
24 UNITS (BBL)	104,852	85,007	19,845	23.3%	104,852	85,007	19,845	23.3%
25 UNIT COST ($/BBL)	84.50	67.39	17.11	25.4%	84.50	67.39	17.11	25.4%
26 AMOUNT ($)	8,859,891	5,728,627	3,131,264	54.7%	8,859,891	5,728,627	3,131,264	54.7%
27								
28 DAYS SUPPLY: NORMAL	244	198	46	20.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	12	3	23.3%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	369,006	432,700	(63,694)	-14.7%	2,716,571	2,334,300	382,271	16.4%
32 UNIT COST ($/TON)	57.46	59.13	(1.67)	-2.8%	57.39	58.03	(0.63)	-1.1%
33 AMOUNT ($)	21,202,717	25,584,539	(4,381,822)	-17.1%	155,916,133	135,451,593	20,464,540	15.1%
34 BURNED:								
35 UNITS (TONS)	463,733	438,514	25,219	5.8%	2,519,552	2,354,910	164,642	7.0%
36 UNIT COST ($/TON)	58.91	59.19	(0.28)	-0.5%	57.10	58.18	(1.08)	-1.9%
37 AMOUNT ($)	27,316,897	25,954,221	1,362,676	5.3%	143,856,895	137,002,420	6,854,475	5.0%
38 ENDING INVENTORY:								
39 UNITS (TONS)	668,408	526,138	142,270	27.0%	668,408	526,138	142,270	27.0%
40 UNIT COST ($/TON)	57.53	58.43	(0.90)	-1.5%	57.53	58.43	(0.90)	-1.5%
41 AMOUNT ($)	38,452,818	30,742,180	7,710,638	25.1%	38,452,818	30,742,180	7,710,638	25.1%
42								
43 DAYS SUPPLY:	51	41	10	20.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	5,246,220	5,402,229	(156,009)	-2.9%	24,177,541	22,582,203	1,595,338	7.1%
46 UNIT COST ($/MCF)	9.86	8.82	1.04	11.7%	10.01	9.93	0.08	0.8%
47 AMOUNT ($)	51,719,273	47,664,601	4,054,672	8.5%	241,965,780	224,229,020	17,736,760	7.9%
48 BURNED:								
49 UNITS (MCF)	5,144,744	5,402,229	(257,485)	-4.8%	24,210,958	22,582,203	1,628,755	7.2%
50 UNIT COST ($/MCF)	9.91	8.82	1.09	12.3%	10.05	9.93	0.13	1.3%
51 AMOUNT ($)	50,979,147	47,664,601	3,314,546	7.0%	243,430,806	224,229,022	19,201,784	8.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	152,849	0	152,849	0.0%	152,849	0	152,849	0.0%
54 UNIT COST ($/MCF)	7.06	0.00	7.06	0.0%	7.06	0.00	7.06	0.0%
55 AMOUNT ($)	1,079,172	0	1,079,172	0.0%	1,079,172	0	1,079,172	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	19,408
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	19,408

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(3,510)	(297,842)
OTHER USAGE	(383)	(32,437)
TOTAL	(3,893)	(330,279)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	74,947
IGNITION #2 OIL	278,434
IGNITION PROPANE	10,259
AERIAL SURVEY ADJ.	0
ADDITIVES	112,422
GREEN FUEL	0
TOTAL	476,062

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC	SCH. - D	1,943.0	0.0	1,943.0	3.469	3.469	67,400.00	67,400.00	
VARIOUS	JURISDIC	SCH. - MB	25,442.0	0.0	25,442.0	6.422	8.064	1,633,900.00	2,051,700.00	271,440.00
TOTAL			**27,385.0**	**0.0**	**27,385.0**	**6.213**	**7.738**	**1,701,300.00**	**2,119,100.00**	**271,440.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC	SCH. - D	487.9	0.0	487.9	4.258	4.500	20,773.54	21,955.85	
SEMINOLE ELEC. HARDEE	JURISDIC	SCH. - D	1,461.8	0.0	1,461.8	3.673	3.879	53,686.00	56,706.64	
PROGRESS ENERGY FLORIDA		SCH. - MA	100.0	0.0	100.0	3.998	6.158	3,998.00	6,158.13	1,850.13
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		SCH. - MA	275.0	0.0	275.0	4.367	6.521	12,009.75	17,933.18	5,070.93
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(35,521.10)	(35,521.10)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	8,315.0	0.0	8,315.0	6.543	8.194	544,022.75	681,309.57	118,500.17
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SEP SCH. - D	7,200.0	0.0	7,200.0	5.184	5.784	373,248.00	416,448.00	
ADJUSTMENTS TO PRIOR MONTHS:										
NEW SMYRNA BEACH	MAY 2006	SEP SCH. - D	(7,440.0)	0.0	(7,440.0)	4.681	5.281	(348,266.40)	(392,906.40)	
NEW SMYRNA BEACH	MAY 2006	SEP SCH. - D	7,440.0	0.0	7,440.0	5.184	5.784	385,689.60	430,329.60	
CALPINE	DEC 2005	OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CALPINE	DEC 2005	OATT	26.0	0.0	26.0	9.916	9.916	2,578.28	2,578.28	
CALPINE	JAN 2006	OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CALPINE	JAN 2006	OATT	16.0	0.0	16.0	7.287	7.287	1,165.90	1,165.90	
CALPINE	MAR 2006	OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CALPINE	MAR 2006	OATT	1.0	0.0	1.0	3.312	3.312	33.12	33.12	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,200.0	0.0	7,200.0	5.704	6.304	410,671.20	453,871.20	
SUB-TOTAL SCHEDULE D POWER SALES			1,949.7	0.0	1,949.7	3.819	4.035	74,459.54	78,662.49	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			8,690.0	0.0	8,690.0	6.445	7.709	560,030.50	669,879.78	89,900.13
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			43.0	0.0	43.0	8.784	8.784	3,777.30	3,777.30	
TOTAL			**17,882.7**	**0.0**	**17,882.7**	**5.866**	**6.745**	**1,048,938.54**	**1,206,190.77**	**89,900.13**
CURRENT MONTH:										
DIFFERENCE			(9,502.3)	0.0	(9,502.3)	(0.347)	(0.993)	(652,361.46)	(912,909.23)	(181,539.87)
DIFFERENCE %			-34.7%	0.0%	-34.7%	-5.6%	-12.8%	-38.3%	-43.1%	-66.9%
PERIOD TO DATE:										
ACTUAL			107,722.9	7.0	107,715.9	4.723	5.676	5,087,881.33	6,113,694.58	585,467.34
ESTIMATED			131,230.0	0.0	131,230.0	5.312	7.454	6,971,200.00	9,781,900.00	2,132,040.00
DIFFERENCE			(23,507.1)	7.0	(23,514.1)	(0.589)	(1.778)	(1,883,318.67)	(3,668,205.42)	(1,546,572.66)
DIFFERENCE %			-17.9%	0.0%	-17.9%	-11.1%	-23.9%	-27.0%	-37.5%	-72.5%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JUNE 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	1,012.0	0.0	666.0	346.0	10.029	10.029	34,700.00
HARDEE POWER PARTNERS		IPP	37,510.0	0.0	0.0	37,510.0	8.112	8.112	3,042,700.00
CALPINE		SCH. - D	11,622.0	0.0	0.0	11,622.0	10.160	10.160	1,180,800.00
VARIOUS		MKT. BASED	105,961.0	0.0	0.0	105,961.0	7.405	7.405	7,846,800.00
OTHER		SCH. - D	89,173.0	0.0	0.0	89,173.0	3.620	3.620	3,228,400.00
TOTAL			**245,278.0**	**0.0**	**666.0**	**244,612.0**	**6.268**	**6.268**	**15,333,400.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	42,861.0	0.0	0.0	42,861.0	7.386	7.386	3,165,652.90
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	35,750.0	0.0	0.0	35,750.0	3.462	3.462	1,237,665.00
CALPINE		SCH. - D	8,795.0	0.0	0.0	8,795.0	9.179	9.179	807,267.02
AUBURNDALE POWER PARTNERS		OATT	1,134.0	0.0	0.0	1,134.0	3.864	3.864	43,822.76
TEC MARKETING		OATT	63.0	0.0	0.0	63.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	MAY 2006	IPP	(40,607.0)	0.0	0.0	(40,607.0)	7.850	7.850	(3,187,592.04)
HARDEE PWR. PART.-NATIVE	MAY 2006	IPP	40,607.0	0.0	0.0	40,607.0	7.712	7.712	3,131,701.72
PROGRESS ENERGY FLORIDA	MAY 2006	SCH. - D	(34,800.0)	0.0	0.0	(34,800.0)	3.629	3.629	(1,262,892.00)
PROGRESS ENERGY FLORIDA	MAY 2006	SCH. - D	34,800.0	0.0	0.0	34,800.0	3.462	3.462	1,204,776.00
CALPINE	MAY 2006	SCH. - D	(17,310.0)	0.0	0.0	(17,310.0)	9.153	9.153	(1,584,430.36)
CALPINE	MAY 2006	SCH. - D	17,299.0	0.0	0.0	17,299.0	8.075	8.075	1,396,907.02
AUBURNDALE POWER PARTNERS	DEC 2005	OATT	(259.0)	0.0	0.0	(259.0)	5.046	5.046	(13,067.87)
AUBURNDALE POWER PARTNERS	DEC 2005	OATT	285.0	0.0	0.0	285.0	5.490	5.490	15,646.15
AUBURNDALE POWER PARTNERS	JAN 2006	OATT	(378.0)	0.0	0.0	(378.0)	3.386	3.386	(12,800.59)
AUBURNDALE POWER PARTNERS	JAN 2006	OATT	394.0	0.0	0.0	394.0	3.545	3.545	13,966.49
AUBURNDALE POWER PARTNERS	MAR 2006	OATT	(850.0)	0.0	0.0	(850.0)	3.461	3.461	(29,420.05)
AUBURNDALE POWER PARTNERS	MAR 2006	OATT	851.0	0.0	0.0	851.0	3.461	3.461	29,453.17
SUB-TOTAL OF ADJUSTMENTS:			32.0	0.0	0.0	32.0	(930.476)	(930.476)	(297,752.36)
TOTAL			**88,635.0**	**0.0**	**0.0**	**88,635.0**	**5.592**	**5.592**	**4,956,675.32**
CURRENT MONTH:									
DIFFERENCE			(156,643.0)	0.0	(666.0)	(155,977.0)	(0.676)	(0.676)	(10,376,724.68)
DIFFERENCE %			-63.9%	0.0%	0.0%	-63.8%	-10.8%	-10.8%	-67.7%
PERIOD TO DATE:									
ACTUAL			350,809.0	0.0	0.0	350,809.0	5.630	5.630	19,750,786.15
ESTIMATED			1,489,687.0	0.0	3,501.0	1,486,186.0	5.715	5.715	84,941,400.00
DIFFERENCE			(1,138,878.0)	0.0	(3,501.0)	(1,135,377.0)	(0.085)	(0.085)	(65,190,613.85)
DIFFERENCE %			-76.5%	0.0%	-100.0%	-76.4%	-1.5%	-1.5%	-76.7%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	36,546.0	0.0	0.0	36,546.0	3.033	3.033	1,108,600.00
TOTAL			**36,546.0**	**0.0**	**0.0**	**36,546.0**	**3.033**	**3.033**	**1,108,600.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	15,863.0	0.0	0.0	15,863.0	2.743	2.743	435,109.61
McKAY BAY REFUSE		COGEN.	13,430.0	0.0	0.0	13,430.0	2.742	2.742	368,188.69
ORANGE COGENERATION L.P		COGEN.	7,337.0	0.0	0.0	7,337.0	2.152	2.152	157,914.38
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	2.0	0.0	0.0	2.0	5.392	5.392	107.83
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	1,997.0	0.0	0.0	1,997.0	4.049	4.049	80,867.83
CF INDUSTRIES INC		COGEN.	607.0	0.0	0.0	607.0	4.900	4.900	29,745.90
IMC-AGRICO-NEW WALES		COGEN.	1,067.0	0.0	0.0	1,067.0	5.090	5.090	54,305.21
IMC-AGRICO-S. PIERCE		COGEN.	2,195.0	0.0	0.0	2,195.0	5.439	5.439	119,394.64
AUBURNDALE POWER PARTNERS		COGEN.	918.0	0.0	0.0	918.0	4.462	4.462	40,964.20
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR JUNE 2006			43,416.0	0.0	0.0	43,416.0	2.963	2.963	1,286,598.29
ADJUSTMENTS FOR THE MONTH OF:	**MAY 2006**								
HILLSBOROUGH COUNTY		COGEN.	(17,113.0)	0.0	0.0	(17,113.0)	2.630	2.630	(450,085.58)
			17,113.0	0.0	0.0	17,113.0	2.758	2.758	471,986.51
McKAY BAY REFUSE		COGEN.	(14,288.0)	0.0	0.0	(14,288.0)	2.631	2.631	(375,848.61)
			14,288.0	0.0	0.0	14,288.0	2.759	2.759	394,145.11
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.425	2.425	(190,215.23)
			7,843.0	0.0	0.0	7,843.0	2.561	2.561	200,837.87
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL			0.0	0.0	0.0	0.0	0.000	0.000	50,820.07
TOTAL			**43,416.0**	**0.0**	**0.0**	**43,416.0**	**3.080**	**3.080**	**1,337,418.36**
CURRENT MONTH:									
DIFFERENCE			6,870.0	0.0	0.0	6,870.0	0.047	0.047	228,818.36
DIFFERENCE %			18.8%	0.0%	0.0%	18.8%	1.6%	1.6%	20.6%
PERIOD TO DATE:									
ACTUAL			261,227.0	0.0	0.0	261,227.0	3.020	3.020	7,888,562.35
ESTIMATED			214,786.0	0.0	0.0	214,786.0	2.954	2.954	6,345,600.00
DIFFERENCE			46,441.0	0.0	0.0	46,441.0	0.065	0.065	1,542,962.35
DIFFERENCE %			21.6%	0.0%	0.0%	21.6%	2.2%	2.2%	24.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:								
VARIOUS		ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:								
PROGRESS ENERGY FLORIDA		SCH. - JC	8,240.0	4.659	383,905.00	5.639	464,692.80	80,787.80
FLA. POWER & LIGHT		SCH. - JC	20,175.0	5.523	1,114,320.00	6.252	1,261,360.25	147,040.25
CITY OF LAKELAND		SCH. - JC	50.0	6.000	3,000.00	12.714	6,357.00	3,357.00
ORLANDO UTIL. COMM		SCH. - JC	1,670.0	9.291	155,160.00	14.350	239,649.35	84,489.35
THE ENERGY AUTHORITY		SCH. - JC	17,910.0	5.285	946,574.00	6.834	1,223,882.02	277,308.02
OKEELANTA		SCH. - JC	89.0	8.542	7,602.00	10.511	9,355.10	1,753.10
CITY OF TALLAHASSEE		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CALPINE		SCH. - JC	6,370.0	5.892	375,329.00	8.084	514,976.79	139,647.79
CARGILL ALLIANT		SCH. - JC	60,741.0	7.107	4,317,021.00	7.883	4,788,428.76	471,407.76
RELIANT		SCH. - JC	6,964.0	4.066	283,170.00	7.260	505,591.79	222,421.79
RAINBOW ENERGY MARKETERS		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - JC	3,360.0	4.059	136,375.00	5.524	185,611.50	49,236.50
ENTERGY-KOCH TRADING		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JC	3,383.0	4.764	161,160.00	6.094	206,160.76	45,000.76
CINCINATTI GAS & ELECTRIC		SCH. - JC	14.0	7.000	980.00	9.070	1,269.80	289.80
SUBTOTAL			128,966.0	6.114	7,884,596.00	7.294	9,407,335.92	1,522,739.92
ADJUSTMENTS TO PRIOR MONTHS:								
CALPINE	MAY 2006	SCH. - JC	(7,361.0)	6.786	(499,541.00)	8.711	(641,241.53)	(141,700.53)
CALPINE	MAY 2006	SCH. - JC	7,359.0	6.788	499,541.00	8.714	641,243.21	141,702.21
SUBTOTAL			(2.0)	0.000	0.00	(0.084)	1.68	1.68
TOTAL			**128,964.0**	**6.114**	**7,884,596.00**	**7.295**	**9,407,337.60**	**1,522,741.60**
CURRENT MONTH:								
DIFFERENCE			128,964.0	6.114	7,884,596.00	7.295	9,407,337.60	1,522,741.60
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:								
ACTUAL			495,038.9	6.838	33,848,349.75	8.549	42,323,212.74	8,474,862.99
ESTIMATED			0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE			495,038.9	6.838	33,848,349.75	8.549	42,323,212.74	8,474,862.99
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JULY 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	80,405,420	78,338,014	2,067,406	2.6%	1,755,647	1,786,814	(31,167)	-1.7%	4.57982	4.38423	0.19559	4.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(10,037)	(6,734)	(3,303)	49.0%	1,755,647 (a)	1,786,814 (a)	(31,167)	-1.7%	(0.00057)	(0.00038)	(0.00019)	51.7%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,755,647 (a)	1,786,814 (a)	(31,167)	-1.7%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	25,159	25,713	(554)	-2.2%	1,755,647 (a)	1,786,814 (a)	(31,167)	-1.7%	0.00143	0.00144	(0.00001)	-0.4%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**80,420,542**	**78,356,993**	**2,063,549**	**2.6%**	**1,755,647**	**1,786,814**	**(31,167)**	**-1.7%**	**4.58068**	**4.38529**	**0.19539**	**4.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	6,014,829	19,911,400	(13,896,571)	-69.8%	94,347	300,290	(205,943)	-68.6%	6.37522	6.63072	(0.25550)	-3.9%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	9,962,221	0	9,962,221	0.0%	150,481	0	150,481	0.0%	6.62025	0.00000	6.62025	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,602,286	1,163,400	438,886	37.7%	49,153	37,769	11,384	30.1%	3.25979	3.08030	0.17949	5.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**17,579,336**	**21,074,800**	**(3,495,464)**	**-16.6%**	**293,981**	**338,059**	**(44,078)**	**-13.0%**	**5.97975**	**6.23406**	**(0.25431)**	**-4.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**2,049,628**	**2,124,873**	**(75,245)**	**-3.5%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	78,844	38,000	40,844	107.5%	2,005	1,443	562	39.0%	3.93178	2.63340	1.29838	49.3%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	328,154	0	328,154	0.0%	7,440	0	7,440	0.0%	4.41067	0.00000	4.41067	0.0%
17. Fuel Cost of Market Base Sales (A6)	0	1,134,600	(1,134,600)	-100.0%	0	18,044	(18,044)	-100.0%	0.00000	6.28796	(6.28796)	-100.0%
18. Gains on Market Based Sales	(1,775)	224,880	(226,655)	-100.8%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**405,223**	**1,397,480**	**(992,257)**	**-71.0%**	**9,445**	**19,487**	**(10,042)**	**-51.5%**	**4.29034**	**7.17134**	**(2.88100)**	**-40.2%**
20. Net Inadvertant Interchange					369	0	369	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					4,722	0	4,722	0.0%				
22. Interchange and Wheeling Losses					4,758	400	4,358	1089.5%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**97,594,655**	**98,034,313**	**(439,658)**	**-0.4%**	**2,040,516**	**2,104,986**	**(64,470)**	**-3.1%**	**4.78284**	**4.65724**	**0.12560**	**2.7%**
24. Net Unbilled	1,401,994 (a)	2,856,473 (a)	(1,454,479)	-50.9%	29,313	61,334	(32,021)	-52.2%	4.78284	4.65724	0.12560	2.7%
25. Company Use	154,008 (a)	144,375 (a)	9,633	6.7%	3,220	3,100	120	3.9%	4.78286	4.65726	0.12560	2.7%
26. T & D Losses	4,033,514 (a)	4,473,887 (a)	(440,373)	-9.8%	84,333	96,063	(11,730)	-12.2%	4.78284	4.65724	0.12560	2.7%
27. System KWH Sales	97,594,655	98,034,313	(439,658)	-0.4%	1,923,650	1,944,489	(20,839)	-1.1%	5.07341	5.04165	0.03176	0.6%
28. Wholesale KWH Sales	(2,857,601)	(2,660,025)	(197,576)	7.4%	(56,325)	(52,761)	(3,564)	6.8%	5.07342	5.04165	0.03176	0.6%
29. Jurisdictional KWH Sales	94,737,054	95,374,288	(637,234)	-0.7%	1,867,325	1,891,728	(24,403)	-1.3%	5.07341	5.04165	0.03176	0.6%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	94,818,528	95,456,310	(637,782)	-0.7%	1,867,325	1,891,728	(24,403)	-1.3%	5.07777	5.04598	0.03179	0.6%
32. Other	0	0	0	0.0%	1,867,325	1,891,728	(24,403)	-1.3%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,318,233)	(1,276,250)	(41,983)	3.3%	1,867,325	1,891,728	(24,403)	-1.3%	(0.07059)	(0.06746)	(0.00313)	4.6%
34. Other	0	0	0	0.0%	1,867,325	1,891,728	(24,403)	-1.3%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,867,325	1,891,728	(24,403)	-1.3%	0.65895	0.65045	0.00850	1.3%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	105,804,980	106,484,745	(679,765)	-0.6%	1,867,325	1,891,728	(24,403)	-1.3%	5.66613	5.62897	0.03716	0.7%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	105,881,160	106,561,414	(680,254)	-0.6%	1,867,325	1,891,728	(24,403)	-1.3%	5.67021	5.63302	0.03719	0.7%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,867,325	1,891,728	(24,403)	-1.3%	0.00326	0.00321	0.00004	1.3%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**105,941,955**	**106,622,209**	**(680,254)**	**-0.6%**	**1,867,325**	**1,891,728**	**(24,403)**	**-1.3%**	**5.67347**	**5.63623**	**0.03723**	**0.7%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.673**	**5.636**	**0.037**	**0.7%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JULY 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	472,341,806	443,519,911	28,821,895	6.5%	10,670,168	10,163,732	506,436	5.0%	4.42675	4.36375	0.06300	1.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(60,950)	(47,138)	(13,812)	29.3%	10,670,168 (a)	10,163,732 (a)	506,436	5.0%	(0.00057)	(0.00046)	(0.00011)	23.2%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	10,670,168 (a)	10,163,732 (a)	506,436	5.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	80,906	94,506	(13,600)	-14.4%	10,670,168 (a)	10,163,732 (a)	506,436	5.0%	0.00076	0.00093	(0.00017)	-18.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**472,361,762**	**443,567,279**	**28,794,483**	**6.5%**	**10,670,168**	**10,163,732**	**506,436**	**5.0%**	**4.42694**	**4.36422**	**0.06272**	**1.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	25,765,614	104,852,800	(79,087,186)	-75.4%	445,156	1,786,476	(1,341,320)	-75.1%	5.78800	5.86925	(0.08126)	-1.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	43,810,571	0	43,810,571	0.0%	645,520	0	645,520	0.0%	6.78687	0.00000	6.78687	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	9,490,849	7,509,000	1,981,849	26.4%	310,380	252,555	57,825	22.9%	3.05782	2.97321	0.08460	2.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**79,067,034**	**112,361,800**	**(33,294,766)**	**-29.6%**	**1,401,056**	**2,039,031**	**(637,975)**	**-31.3%**	**5.64339**	**5.51055**	**0.13284**	**2.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**12,071,224**	**12,202,763**	**(131,539)**	**-1.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	418,809	307,300	111,509	36.3%	10,923	10,548	375	3.6%	3.83437	2.91335	0.92102	31.6%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,085)	0	(21,085)	0.0%	28	0	28	0.0%	(75.30357)	0.00000	(75.30357)	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	2,345,814	0	2,345,814	0.0%	50,870	0	50,870	0.0%	4.61139	0.00000	4.61139	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,751,342	7,836,500	(5,085,158)	-64.9%	55,342	140,169	(84,827)	-60.5%	4.97153	5.59075	(0.61923)	-11.1%
18. Gains on Market Based Sales	583,692	2,356,920	(1,773,228)	-75.2%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**6,078,572**	**10,500,720**	**(4,422,148)**	**-42.1%**	**117,163**	**150,717**	**(33,554)**	**-22.3%**	**5.18813**	**6.96718**	**(1.77904)**	**-25.5%**
20. Net Inadvertant Interchange					(531)	0	(531)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					22,398	0	22,398	0.0%				
22. Interchange and Wheeling Losses					23,697	2,700	20,997	777.7%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**545,350,224**	**545,428,359**	**(78,135)**	**0.0%**	**11,952,231**	**12,049,346**	**(97,115)**	**-0.8%**	**4.56275**	**4.52662**	**0.03613**	**0.8%**
24. Net Unbilled	5,742,233 (a)	10,758,975 (a)	(5,016,742)	-46.6%	85,791	235,005	(149,214)	-63.5%	6.69328	4.57819	2.11509	46.2%
25. Company Use	945,279 (a)	980,672 (a)	(35,393)	-3.6%	20,820	21,700	(880)	-4.1%	4.54024	4.51923	0.02102	0.5%
26. T & D Losses	30,853,932 (a)	21,375,715 (a)	9,478,217	44.3%	697,128	471,741	225,387	47.8%	4.42586	4.53124	(0.10538)	-2.3%
27. System KWH Sales	545,350,224	545,428,359	(78,135)	0.0%	11,148,492	11,320,900	(172,408)	-1.5%	4.89169	4.81789	0.07381	1.5%
28. Wholesale KWH Sales	(20,018,158)	(14,108,912)	(5,909,246)	41.9%	(418,943)	(290,051)	(128,892)	44.4%	4.77825	4.86429	(0.08603)	-1.8%
29. Jurisdictional KWH Sales	525,332,066	531,319,447	(5,987,381)	-1.1%	10,729,549	11,030,849	(301,300)	-2.7%	4.89612	4.81667	0.07946	1.6%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	525,783,851	531,776,383	(5,992,532)	-1.1%	10,729,549	11,030,849	(301,300)	-2.7%	4.90034	4.82081	0.07952	1.6%
32. Other	0	0	0	0.0%	10,729,549	11,030,849	(301,300)	-2.7%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(9,702,393)	(8,933,750)	(768,643)	8.6%	10,729,549	11,030,849	(301,300)	-2.7%	(0.09043)	(0.08099)	(0.00944)	11.7%
34. Other	0	0	0	0.0%	10,729,549	11,030,849	(301,300)	-2.7%	0.00000	0.00000	0.00000	0.0%
35. True-up *	86,132,795	86,132,796	(1)	0.0%	10,729,549	11,030,849	(301,300)	-2.7%	0.80276	0.78084	0.02193	2.8%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	602,214,253	608,975,429	(6,761,176)	-1.1%	10,729,549	11,030,849	(301,300)	-2.7%	5.61267	5.52066	0.09201	1.7%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	602,647,847	609,413,891	(6,766,044)	-1.1%	10,729,549	11,030,849	(301,300)	-2.7%	5.61671	5.52463	0.09208	1.7%
39. GPIF * (Already Adjusted for Taxes)	425,565	425,565	0	0.0%	10,729,549	11,030,849	(301,300)	-2.7%	0.00397	0.00386	0.00011	2.8%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**603,073,412**	**609,839,456**	**(6,766,044)**	**-1.1%**	**10,729,549**	**11,030,849**	**(301,300)**	**-2.7%**	**5.62068**	**5.52849**	**0.09219**	**1.7%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.621**	**5.528**	**0.093**	**1.7%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	80,405,420	78,338,014	2,067,406	2.6%	472,341,806	443,519,911	28,821,895	6.5%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	406,998	1,172,600	(765,602)	-65.3%	5,494,880	8,143,800	(2,648,920)	-32.5%
2a. GAINS FROM MARKET BASED SALES	(1,775)	224,880	(226,655)	-100.8%	583,692	2,356,920	(1,773,228)	-75.2%
3. FUEL COST OF PURCHASED POWER	6,014,829	19,911,400	(13,896,571)	-69.8%	25,765,614	104,852,800	(79,087,186)	-75.4%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,602,286	1,163,400	438,886	37.7%	9,490,849	7,509,000	1,981,849	26.4%
4. ENERGY COST OF ECONOMY PURCHASES	9,962,221	0	9,962,221	0.0%	43,810,571	0	43,810,571	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	97,579,533	98,015,334	(435,801)	-0.4%	545,330,268	545,380,991	(50,723)	0.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(10,037)	(6,734)	(3,303)	49.0%	(60,950)	(47,138)	(13,812)	29.3%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	25,159	25,713	(554)	-2.2%	80,906	94,506	(13,600)	-14.4%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	97,594,655	98,034,313	(439,658)	-0.4%	545,350,224	545,428,359	(78,135)	0.0%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,867,325	1,891,728	(24,403)	-1.3%	10,729,549	11,030,849	(301,300)	-2.7%
2. NONJURISDICTIONAL SALES	56,325	52,761	3,564	6.8%	418,943	290,051	128,892	44.4%
3. TOTAL SALES	1,923,650	1,944,489	(20,839)	-1.1%	11,148,492	11,320,900	(172,408)	-1.5%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9707197	0.9728664	(0.0021467)	-0.2%	0.9624216	0.9743792	(0.0119576)	-1.2%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	100,506,628	102,352,306	(1,845,678)	-1.8%	576,694,160	596,520,505	(19,826,345)	-3.3%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(86,132,795)	(86,132,796)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(425,565)	(425,565)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	88,141,148	89,986,826	(1,845,678)	-2.1%	490,135,800	509,962,144	(19,826,344)	-3.9%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	97,594,655	98,034,313	(439,658)	-0.4%	545,350,224	545,428,359	(78,135)	0.0%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9707197	0.9728664	(0.0021467)	-0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	94,737,054	95,374,288	(637,234)	-0.7%	525,332,066	531,319,447	(5,987,381)	-1.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	94,818,528	95,456,310	(637,782)	-0.7%	525,783,851	531,776,383	(5,992,532)	-1.1%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,318,233)	(1,276,250)	(41,983)	3.3%	(9,702,393)	(8,933,750)	(768,643)	8.6%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	93,500,295	94,180,060	(679,765)	-0.7%	516,081,458	522,842,633	(6,761,175)	-1.3%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(5,359,147)	(4,193,234)	(1,165,913)	27.8%	(25,945,658)	(12,880,489)	(13,065,169)	101.4%
8. INTEREST PROVISION FOR THE MONTH	(899,833)	(303,692)	(596,141)	196.3%	(6,106,216)	(2,828,605)	(3,277,611)	115.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(206,137,843)	(85,040,279)	(121,097,564)	142.4%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(200,092,138)	(77,232,520)	(122,859,618)	159.1%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(206,137,843)	(85,040,279)	(121,097,564)	142.4%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(199,192,305)	(76,928,828)	(122,263,477)	158.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(405,330,148)	(161,969,107)	(243,361,041)	150.3%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(202,665,074)	(80,984,554)	(121,680,520)	150.3%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.290	4.500	0.790	17.6%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.360	4.500	0.860	19.1%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	10.650	9.000	1.650	18.3%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.325	4.500	0.825	18.3%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.444	0.375	0.069	18.4%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(899,833)	(303,692)	(596,141)	196.3%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	186,962	492,226	(305,264)	-62.0%	1,622,830	1,142,769	480,061	42.0%
2	LIGHT OIL	1,174,385	1,012,727	161,658	16.0%	4,387,202	4,312,639	74,563	1.7%
3	COAL	27,976,422	25,893,638	2,082,784	8.0%	171,833,317	162,896,058	8,937,259	5.5%
4	NATURAL GAS	51,067,651	50,939,423	128,228	0.3%	294,498,457	275,168,445	19,330,012	7.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	80,405,420	78,338,014	2,067,406	2.6%	472,341,806	443,519,911	28,821,895	6.5%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,344	6,514	(5,170)	-79.4%	16,115	15,016	1,099	7.3%
9	LIGHT OIL	8,644	7,150	1,494	20.9%	30,339	32,470	(2,131)	-6.6%
10	COAL	1,000,494	968,059	32,435	3.4%	6,525,747	6,214,773	310,974	5.0%
11	NATURAL GAS	745,165	805,091	(59,926)	-7.4%	4,099,241	3,901,473	197,768	5.1%
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)	1,755,647	1,786,814	(31,167)	-1.7%	10,671,442	10,163,732	507,710	5.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	2,331	10,112	(7,781)	-76.9%	26,260	23,315	2,945	12.6%
16	LIGHT OIL (BBL)	13,380	18,279	(4,899)	-26.8%	52,297	88,789	(36,492)	-41.1%
17	COAL (TON)	465,688	440,724	24,964	5.7%	2,985,240	2,795,634	189,606	6.8%
18	NATURAL GAS (MCF)	5,353,827	5,986,314	(632,487)	-10.6%	29,564,785	28,568,517	996,268	3.5%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	14,626	63,492	(48,866)	-77.0%	164,750	146,379	18,371	12.6%
22	LIGHT OIL	76,957	85,033	(8,076)	-9.5%	296,383	366,144	(69,761)	-19.1%
23	COAL	10,985,173	10,553,490	431,683	4.1%	70,133,831	67,062,068	3,071,763	4.6%
24	NATURAL GAS	5,541,211	6,153,895	(612,684)	-10.0%	30,598,445	29,368,178	1,230,267	4.2%
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)	16,617,967	16,855,910	(237,943)	-1.4%	101,193,409	96,942,769	4,250,640	4.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.08%	0.36%	(0.00)	-	0.15%	0.15%	0.00	-
29	LIGHT OIL	0.49%	0.40%	0.00	-	0.28%	0.32%	(0.00)	-
30	COAL	56.99%	54.18%	0.03	-	61.15%	61.15%	0.00	-
31	NATURAL GAS	42.44%	45.06%	(0.03)	-	38.41%	38.39%	0.00	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	80.21	48.68	31.53	64.8%	61.80	49.01	12.78	26.1%
36	LIGHT OIL ($/BBL)	87.77	55.40	32.37	58.4%	83.89	48.57	35.32	72.7%
37	COAL ($/TON)	60.08	58.75	1.32	2.3%	57.56	58.27	(0.71)	-1.2%
38	NATURAL GAS ($/MCF)	9.54	8.51	1.03	12.1%	9.96	9.63	0.33	3.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	12.78	7.75	5.03	64.9%	9.85	7.81	2.04	26.2%
42	LIGHT OIL	15.26	11.91	3.35	28.1%	14.80	11.78	3.02	25.7%
43	COAL	2.55	2.45	0.09	3.8%	2.45	2.43	0.02	0.9%
44	NATURAL GAS	9.22	8.28	0.94	11.3%	9.62	9.37	0.26	2.7%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.84	4.65	0.19	4.1%	4.67	4.58	0.09	2.0%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,882	9,747	1,135	11.6%	10,223	9,748	475	4.9%
49	LIGHT OIL	8,903	11,893	(2,990)	-25.1%	9,769	11,276	(1,507)	-13.4%
50	COAL	10,980	10,902	78	0.7%	10,747	10,791	(44)	-0.4%
51	NATURAL GAS	7,436	7,644	(208)	-2.7%	7,464	7,527	(63)	-0.8%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,465	9,434	31	0.3%	9,483	9,538	(55)	-0.6%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	13.91	7.56	6.35	84.0%	10.07	7.61	2.46	32.3%
56	LIGHT OIL	13.59	14.16	(0.57)	-4.0%	14.46	13.28	1.18	8.9%
57	COAL	2.80	2.67	0.13	4.9%	2.63	2.62	0.01	0.4%
58	NATURAL GAS	6.85	6.33	0.52	8.2%	7.18	7.05	0.13	1.8%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.58	4.38	0.20	4.6%	4.43	4.36	0.07	1.6%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

SCHEDULE A4
PAGE 1 OF 1
REVISED 11/17/06

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	181,812	59.5	64.0	72.4	11,259	COAL	88,483	23,134,160	2,046,979.9	5,187,258	2.85	58.62
B.B.#2	391	273,031	93.9	96.2	93.9	10,396	COAL	121,775	23,308,940	2,838,446.2	7,138,980	2.61	58.62
B.B.#3	414	189,783	61.6	63.0	79.0	10,877	COAL	88,877	23,225,460	2,064,209.2	5,210,356	2.75	58.62
B.B.#4	457	215,560	63.4	73.5	71.1	11,591	COAL	106,357	23,491,600	2,498,496.1	6,235,109	2.89	58.62
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	6,372	5,805,052	36,992.4	541,914	-	85.05
B.B. STATION	1,673	860,186	69.1	73.9	78.7	10,984	-	-	-	-	24,313,617	2.83	-
SEB-PHIL #1(HVY OIL)	17	693	5.5	100.0	71.4	10,882	HVY.OIL	1,202	6,273,540	7,539.7	66,285	9.56	55.15
SEB-PHIL #2(HVY OIL)	17	651	5.1	97.7	71.7	10,882	HVY.OIL	1,129	6,273,540	7,086.2	62,260	9.56	55.15
SEB-PHIL IGNITION	-	-	-	-	-	-	LGT.OIL	178	5,805,052	1,031.2	58,417	-	328.19
SEB-PHILLIPS TOTAL	34	1,344	5.3	98.8	71.6	10,882	-	-	-	-	186,962	13.91	-
POLK #1 GASIFIER	255	140,308	-	-	-	10,955	COAL	60,196	25,534,000	1,537,041.9	3,662,805	2.61	60.85
POLK #1 CT (OIL)	225	8,610	-	-	-	8,810	LGT.OIL	13,190	5,784,167	75,853.1	1,158,225	13.45	87.81
POLK #1 TOTAL	255	148,918	78.5	90.2	84.3	10,831	-	-	-	1,612,895.0	4,821,030	3.24	-
POLK #2 CT (GAS)	150	4,692	-	-	-	11,904	GAS	53,966	1,035,000	55,855.0	518,524	11.05	9.61
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	155	4,692	4.1	100.0	78.0	11,904	-	-	-	55,855.0	518,524	11.05	-
POLK #3 CT (GAS)	150	4,593	-	-	-	12,242	GAS	54,326	1,035,000	56,227.0	527,503	11.48	9.71
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	155	4,593	4.0	100.0	73.5	12,242	-	-	-	56,227.0	527,503	11.48	-
POLK STATION TOTAL	565	158,203	37.6	95.6	79.6	10,904	-	-	-	1,724,977.0	5,867,057	3.71	-
B.B.C.T.#1	14	2	0.0	99.9	0.0	33,200	LGT.OIL	11	5,806,649	66.4	936	46.80	85.09
B.B.C.T.#2	66	19	0.0	100.0	28.8	30,158	LGT.OIL	99	5,806,363	573.0	8,420	44.32	85.05
B.B.C.T.#3	66	13	0.0	100.0	19.7	35,692	LGT.OIL	80	5,806,407	464.0	6,804	52.34	85.05
C.T. TOTAL	146	34	0.0	100.0	21.9	32,453	LGT.OIL	190	5,806,452	1,103.4	16,160	47.53	85.05
COT 1	3	10	0.4	100.0	29.8	20,094	GAS	193	1,035,000	200.0	2,521	25.21	13.06
COT 2	3	16	0.7	100.0	78.8	20,094	GAS	316	1,035,000	327.0	4,127	25.79	13.06
CITY OF TAMPA TOTAL	6	26	0.6	100.0	54.3	20,269	GAS	509	1,035,000	527.0	6,648	25.57	13.06
BAYSIDE ST 1	234	110,274	63.3	98.1	64.6	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	71,467	61.6	97.3	85.6	11,221	GAS	774,789	1,035,000	801,907.0	7,386,635	10.34	9.53
BAYSIDE CT1B	156	67,958	58.6	97.0	83.2	11,336	GAS	744,351	1,035,000	770,403.0	7,096,447	10.44	9.53
BAYSIDE CT1C	156	73,797	63.6	100.0	85.7	10,769	GAS	767,866	1,035,000	794,741.0	7,320,632	9.92	9.53
BAYSIDE UNIT 1 TOTAL	702	323,496	61.9	98.1	78.1	7,317	GAS	2,287,006	1,035,000	2,367,051.0	21,803,714	6.74	9.53
BAYSIDE ST 2	306	141,161	62.0	100.0	62.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	67,387	58.1	94.4	83.8	11,178	GAS	727,796	1,035,000	753,269.0	6,941,144	10.30	9.54
BAYSIDE CT2B	156	65,469	56.4	100.0	84.4	11,399	GAS	721,023	1,035,000	746,259.0	6,876,549	10.50	9.54
BAYSIDE CT2C	156	70,155	60.4	100.0	85.2	11,316	GAS	767,017	1,035,000	793,863.0	7,315,203	10.43	9.54
BAYSIDE CT2D	156	68,186	58.7	100.0	88.3	11,266	GAS	742,184	1,035,000	768,160.0	7,078,366	10.38	9.54
BAYSIDE UNIT 2 TOTAL	930	412,358	59.6	99.1	77.7	7,424	GAS	2,958,020	1,035,000	3,061,551.0	28,211,262	6.84	9.54
BAYSIDE STATION TOTAL	1,632	735,854	60.6	98.7	77.9	7,377	GAS	5,245,026	1,035,000	5,428,602.0	50,014,976	6.80	9.54
SYSTEM	4,056	1,755,647	58.2	88.1	76.4	9,465	-	-	-	16,617,966.7	80,405,420	4.58	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES								
2 UNITS (BBL)	2,487	10,112	(7,625)	-75.4%	28,655	23,315	5,340	22.9%
3 UNIT COST ($/BBL)	57.60	47.78	9.82	20.6%	57.49	47.51	9.98	21.0%
4 AMOUNT ($)	143,254	483,114	(339,860)	-70.3%	1,647,270	1,107,617	539,653	48.7%
5 BURNED								
6 UNITS (BBL)	2,331	10,112	(7,781)	-76.9%	26,260	23,315	2,945	12.6%
7 UNIT COST ($/BBL)	80.21	48.68	31.53	64.8%	61.80	49.01	12.78	26.1%
8 AMOUNT ($)	186,962	492,226	(305,264)	-62.0%	1,622,830	1,142,769	480,061	42.0%
9 ENDING INVENTORY								
10 UNITS (BBL)	17,726	12,118	5,608	46.3%	17,726	12,118	5,608	46.3%
11 UNIT COST ($/BBL)	55.93	47.46	8.47	17.8%	55.93	47.46	8.47	17.8%
12 AMOUNT ($)	991,378	575,132	416,246	72.4%	991,378	575,132	416,246	72.4%
13								
14 DAYS SUPPLY	202	138	64	50.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES								
16 UNITS (BBL)	16,233	18,279	(2,046)	-11.2%	110,958	88,789	22,169	25.0%
17 UNIT COST ($/BBL)	98.31	70.55	27.76	39.4%	87.36	70.41	16.94	24.1%
18 AMOUNT ($)	1,595,906	1,289,583	306,323	23.8%	9,692,894	6,251,812	3,441,082	55.0%
19 BURNED								
20 UNITS (BBL)	13,380	18,279	(4,899)	-26.8%	52,297	88,789	(36,492)	-41.1%
21 UNIT COST ($/BBL)	87.77	55.40	32.37	58.4%	83.89	48.57	35.32	72.7%
22 AMOUNT ($)	1,174,385	1,012,727	161,658	16.0%	4,387,202	4,312,639	74,563	1.7%
23 ENDING INVENTORY								
24 UNITS (BBL)	100,726	85,007	15,719	18.5%	100,726	85,007	15,719	18.5%
25 UNIT COST ($/BBL)	86.24	67.77	18.47	27.3%	86.24	67.77	18.47	27.3%
26 AMOUNT ($)	8,686,576	5,760,689	2,925,887	50.8%	8,686,576	5,760,689	2,925,887	50.8%
27								
28 DAYS SUPPLY: NORMAL	222	187	35	20.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	14	12	2	18.5%	-	-	-	-
COAL[3]								
30 PURCHASES								
31 UNITS (TONS)	425,199	464,500	(39,301)	-8.5%	3,141,770	2,798,800	342,970	12.3%
32 UNIT COST ($/TON)	60.11	57.16	2.95	5.2%	57.76	57.88	(0.12)	-0.2%
33 AMOUNT ($)	25,558,708	26,551,894	(993,186)	-3.7%	181,474,841	162,003,487	19,471,354	12.0%
34 BURNED								
35 UNITS (TONS)	465,688	440,724	24,964	5.7%	2,985,240	2,795,634	189,606	6.8%
36 UNIT COST ($/TON)	60.08	58.75	1.32	2.3%	57.56	58.27	(0.71)	-1.2%
37 AMOUNT ($)	27,976,422	25,893,638	2,082,784	8.0%	171,833,317	162,896,058	8,937,259	5.5%
38 ENDING INVENTORY								
39 UNITS (TONS)	627,919	549,914	78,005	14.2%	627,919	549,914	78,005	14.2%
40 UNIT COST ($/TON)	58.43	57.82	0.60	1.0%	58.43	57.82	0.60	1.0%
41 AMOUNT ($)	36,687,617	31,797,305	4,890,312	15.4%	36,687,617	31,797,305	4,890,312	15.4%
42								
43 DAYS SUPPLY	48	43	5	10.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES								
45 UNITS (MCF)	5,391,276	5,986,314	(595,038)	-9.9%	29,568,817	28,568,517	1,000,300	3.5%
46 UNIT COST ($/MCF)	9.52	8.51	1.01	11.9%	9.92	9.63	0.29	3.0%
47 AMOUNT ($)	51,315,360	50,939,422	375,938	0.7%	293,281,140	275,168,442	18,112,698	6.6%
48 BURNED								
49 UNITS (MCF)	5,353,827	5,986,314	(632,487)	-10.6%	29,564,785	28,568,517	996,268	3.5%
50 UNIT COST ($/MCF)	9.54	8.51	1.03	12.1%	9.96	9.63	0.33	3.4%
51 AMOUNT ($)	51,067,651	50,939,423	128,228	0.3%	294,498,457	275,168,445	19,330,012	7.0%
52 ENDING INVENTORY								
53 UNITS (MCF)	190,298	0	190,298	0.0%	190,298	0	190,298	0.0%
54 UNIT COST ($/MCF)	6.97	0.00	6.97	0.0%	6.97	0.00	6.97	0.0%
55 AMOUNT ($)	1,326,881	0	1,326,881	0.0%	1,326,881	0	1,326,881	0.0%
56								
57 DAYS SUPPLY	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	15,920
LUBE OIL	0
FUEL ANALYSIS	140
TOTAL	16,060

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(6,550)	(557,834)
OTHER USAGE	(429)	(37,002)
TOTAL	(6,979)	(594,836)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	64,026
IGNITION #2 OIL	541,914
IGNITION PROPANE	17,356
AERIAL SURVEY ADJ.	0
ADDITIVES	29,217
GREEN FUEL	0
TOTAL	652,513

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED										
VARIOUS	JURISDIC	SCH - D	1,443.0	0.0	1,443.0	2.633	2.633	38,000.00	38,000.00	
VARIOUS	JURISDIC	SCH - MB	18,044.0	0.0	18,044.0	6.288	8.155	1,134,600.00	1,471,400.00	224,880.00
TOTAL			**19,487.0**	**0.0**	**19,487.0**	**6.017**	**7.746**	**1,172,600.00**	**1,509,400.00**	**224,880.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	587.2	0.0	587.2	4.450	4.726	26,130.01	27,750.05	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,418.1	0.0	1,418.1	3.744	3.989	53,088.75	56,572.41	
PROGRESS ENERGY FLORIDA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SEP SCH. - D	7,440.0	0.0	7,440.0	4.791	5.391	356,450.40	401,090.40	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. PRECO-1	JUNE 2006	SCH. - D	(487.9)	0.0	(487.9)	4.258	4.500	(20,773.54)	(21,955.85)	
SEMINOLE ELEC. PRECO-1	JUNE 2006	SCH. - D	487.9	0.0	487.9	4.239	4.500	20,679.67	21,955.85	
SEMINOLE ELEC. HARDEE	JUNE 2006	SCH. - D	(1,461.8)	0.0	(1,461.8)	3.673	3.879	(53,686.00)	(56,706.64)	
SEMINOLE ELEC. HARDEE	JUNE 2006	SCH. - D	1,461.8	0.0	1,461.8	3.653	3.879	53,404.75	56,706.64	
NEW SMYRNA BEACH	JUNE 2006	SEP SCH. - D	(7,200.0)	0.0	(7,200.0)	5.184	5.784	(373,248.00)	(416,448.00)	
NEW SMYRNA BEACH	JUNE 2006	SEP SCH. - D	7,200.0	0.0	7,200.0	4.791	5.391	344,952.00	388,152.00	
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - MA	(100.0)	0.0	(100.0)	3.998	6.158	(3,998.00)	(6,158.13)	(1,850.13)
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - MA	100.0	0.0	100.0	3.998	6.158	3,998.00	6,158.13	1,829.71
NEW SMYRNA BEACH	JUNE 2006	SCH. - MA	(8,315.0)	0.0	(8,315.0)	6.543	8.194	(544,022.75)	(681,309.57)	(118,500.17)
NEW SMYRNA BEACH	JUNE 2006	SCH. - MA	8,315.0	0.0	8,315.0	6.543	8.194	544,022.75	681,309.57	116,801.88
CITY OF LAKELAND	JUNE 2006	SCH. - MA	(275.0)	0.0	(275.0)	4.367	6.521	(12,009.75)	(17,933.18)	(5,070.93)
CITY OF LAKELAND	JUNE 2006	SCH. - MA	275.0	0.0	275.0	4.367	6.521	12,009.75	17,933.18	5,014.76
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,440.0	0.0	7,440.0	4.411	5.011	328,154.40	372,794.40	
SUB-TOTAL SCHEDULE D POWER SALES			2,005.3	0.0	2,005.3	3.932	4.205	78,843.64	84,322.46	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	(1,774.88)
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			**9,445.3**	**0.0**	**9,445.3**	**4.309**	**4.840**	**406,998.04**	**457,116.86**	**(1,774.88)**
CURRENT MONTH:										
DIFFERENCE			(10,041.7)	0.0	(10,041.7)	(1.708)	(2.906)	(765,601.96)	(1,052,283.14)	(226,654.88)
DIFFERENCE %			-51.5%	0.0%	-51.5%	-28.4%	-37.5%	-65.3%	-69.7%	-100.8%
PERIOD TO DATE:										
ACTUAL			117,168.2	7.0	117,161.2	4.690	5.608	5,494,879.37	6,570,811.44	583,692.46
ESTIMATED			150,717.0	0.0	150,717.0	5.403	7.492	8,143,800.00	11,291,300.00	2,356,920.00
DIFFERENCE			(33,548.8)	7.0	(33,555.8)	(0.713)	(1.884)	(2,648,920.63)	(4,720,488.56)	(1,773,227.54)
DIFFERENCE %			-22.3%	0.0%	-22.3%	-13.2%	-25.1%	-32.5%	-41.8%	-75.2%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JULY 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	2,758.0	0.0	1,622.0	1,136.0	10.167	10.167	115,500.00
HARDEE POWER PARTNERS		IPP	45,853.0	0.0	0.0	45,853.0	8.256	8.256	3,785,500.00
CALPINE		SCH. - D	24,909.0	0.0	0.0	24,909.0	10.205	10.205	2,541,900.00
VARIOUS		MKT BASED	132,011.0	0.0	0.0	132,011.0	7.428	7.428	9,805,700.00
OTHER		SCH. - D	96,381.0	0.0	0.0	96,381.0	3.800	3.800	3,662,800.00
TOTAL			**301,912.0**	**0.0**	**1,622.0**	**300,290.0**	**6.631**	**6.631**	**19,911,400.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	46,316.0	0.0	0.0	46,316.0	6.945	6.945	3,216,444.80
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH - D	37,200.0	0.0	0.0	37,200.0	3.831	3.831	1,425,132.00
CALPINE		SCH. - D	9,672.0	0.0	0.0	9,672.0	9.192	9.192	889,068.91
AUBURNDALE POWER PARTNERS		OATT	1,159.0	0.0	0.0	1,159.0	3.664	3.664	42,471.30
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	JUNE 2006	IPP	(42,861.0)	0.0	0.0	(42,861.0)	7.386	7.386	(3,165,652.90)
HARDEE PWR. PART.-NATIVE	JUNE 2006	IPP	42,861.0	0.0	0.0	42,861.0	7.674	7.674	3,289,302.52
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - D	(35,750.0)	0.0	0.0	(35,750.0)	3.462	3.462	(1,237,665.00)
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - D	35,750.0	0.0	0.0	35,750.0	3.831	3.831	1,369,582.50
CALPINE	MAY 2006	SCH. - D	(17,299.0)	0.0	0.0	(17,299.0)	8.075	8.075	(1,396,907.02)
CALPINE	MAY 2006	SCH. - D	17,299.0	0.0	0.0	17,299.0	8.962	8.962	1,550,351.73
CALPINE	JUNE 2006	SCH. - D	(8,795.0)	0.0	0.0	(8,795.0)	9.179	9.179	(807,287.02)
CALPINE	JUNE 2006	SCH. - D	8,795.0	0.0	0.0	8,795.0	9.551	9.551	839,986.71
SUB-TOTAL OF ADJUSTMENTS			0.0	0.0	0.0	0.0	0.000	0.000	441,711.52
TOTAL			**94,347.0**	**0.0**	**0.0**	**94,347.0**	**6.375**	**6.375**	**6,014,828.53**
CURRENT MONTH:									
DIFFERENCE			(207,565.0)	0.0	(1,622.0)	(205,943.0)	(0.256)	(0.256)	(13,896,571.47)
DIFFERENCE %			-68.8%	0.0%	0.0%	-68.6%	-3.9%	-3.9%	-69.8%
PERIOD TO DATE:									
ACTUAL			445,156.0	0.0	0.0	445,156.0	5.788	5.788	25,765,614.68
ESTIMATED			1,791,599.0	0.0	5,123.0	1,786,476.0	5.869	5.869	104,852,800.00
DIFFERENCE			(1,346,443.0)	0.0	(5,123.0)	(1,341,320.0)	(0.081)	(0.081)	(79,087,185.32)
DIFFERENCE %			-75.2%	0.0%	-100.0%	-75.1%	-1.4%	-1.4%	-75.4%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	37,769.0	0.0	0.0	37,769.0	3.080	3.080	1,163,400.00
TOTAL		**37,769.0**	**0.0**	**0.0**	**37,769.0**	**3.080**	**3.080**	**1,163,400.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	17,082.0	0.0	0.0	17,082.0	2.747	2.747	469,211.87
McKAY BAY REFUSE	COGEN.	13,864.0	0.0	0.0	13,864.0	2.748	2.748	380,950.40
ORANGE COGENERATION L.P	COGEN.	7,843.0	0.0	0.0	7,843.0	2.572	2.572	201,693.68
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	407.0	0.0	0.0	407.0	4.571	4.571	18,605.59
CF INDUSTRIES INC.	COGEN.	951.0	0.0	0.0	951.0	5.485	5.485	52,161.20
IMC-AGRICO-NEW WALES	COGEN.	1,086.0	0.0	0.0	1,086.0	4.488	4.488	48,740.81
IMC-AGRICO-S. PIERCE	COGEN.	6,904.0	0.0	0.0	6,904.0	5.377	5.377	371,249.80
AUBURNDALE POWER PARTNERS	COGEN.	1,016.0	0.0	0.0	1,016.0	4.907	4.907	49,859.58
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR JULY 2006		49,153.0	0.0	0.0	49,153.0	3.240	3.240	1,592,472.93
ADJUSTMENTS FOR THE MONTH OF:	**JUNE 2006**							
HILLSBOROUGH COUNTY	COGEN.	(15,863.0)	0.0	0.0	(15,863.0)	2.743	2.743	(435,109.61)
		15,863.0	0.0	0.0	15,863.0	2.752	2.752	436,580.46
McKAY BAY REFUSE	COGEN.	(13,430.0)	0.0	0.0	(13,430.0)	2.742	2.742	(368,188.69)
		13,430.0	0.0	0.0	13,430.0	2.751	2.751	369,434.07
ORANGE COGENERATION L.P	COGEN.	(7,337.0)	0.0	0.0	(7,337.0)	2.152	2.152	(157,914.38)
		7,337.0	0.0	0.0	7,337.0	2.249	2.249	165,011.37
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	9,813.22
TOTAL		**49,153.0**	**0.0**	**0.0**	**49,153.0**	**3.260**	**3.260**	**1,602,286.15**
CURRENT MONTH:								
DIFFERENCE		11,384.0	0.0	0.0	11,384.0	0.179	0.179	438,886.15
DIFFERENCE %		30.1%	0.0%	0.0%	30.1%	5.8%	5.8%	37.7%
PERIOD TO DATE:								
ACTUAL		310,380.0	0.0	0.0	310,380.0	3.058	3.058	9,490,848.50
ESTIMATED		252,555.0	0.0	0.0	252,555.0	2.973	2.973	7,509,000.00
DIFFERENCE		57,825.0	0.0	0.0	57,825.0	0.085	0.085	1,981,848.50
DIFFERENCE %		22.9%	0.0%	0.0%	22.9%	2.8%	2.8%	26.4%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (5B)-5
ESTIMATED:							
VARIOUS	ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	5,617.0	4.976	279,479.00	5.846	328,386.03	48,907.03
FLA. POWER & LIGHT	SCH. - JC	51,949.0	5.154	2,677,538.00	6.052	3,143,914.55	466,376.55
CITY OF LAKELAND	SCH. - JC	25.0	9.200	2,300.00	10.426	2,606.50	306.50
ORLANDO UTIL. COMM	SCH. - JC	1,245.0	7.685	95,680.00	11.163	138,980.10	43,300.10
THE ENERGY AUTHORITY	SCH. - JC	16,841.0	6.417	1,080,663.00	7.956	1,339,871.37	259,208.37
OKEELANTA	SCH. - JC	455.0	9.531	43,368.00	12.064	54,892.39	11,524.39
CITY OF TALLAHASSEE	SCH. - JC	115.0	9.935	11,425.00	12.714	14,621.10	3,196.10
CALPINE	SCH. - JC	10,269.0	6.952	713,902.00	8.803	903,954.01	190,052.01
CARGILL ALLIANT	SCH. - JC	54,451.0	8.504	4,630,754.00	9.006	4,903,671.63	272,917.63
CARGILL FOR NEW SMYRNA BEACH	SCH. - JC	7,440.0	4.411	328,154.40	4.411	328,154.40	0.00
RELIANT	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
RAINBOW ENERGY MARKETERS	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	1,527.0	4.878	74,490.00	6.208	94,799.57	20,309.57
ENTERGY-KOCH TRADING	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	547.0	4.473	24,468.00	5.097	27,878.85	3,410.85
CINCINATTI GAS & ELECTRIC	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL		150,481.0	6.620	9,962,221.40	7.497	11,281,730.50	1,319,509.10
NO PRIOR MONTH ADJUSTMENTS:							
TOTAL		**150,481.0**	**6.620**	**9,962,221.40**	**7.497**	**11,281,730.50**	**1,319,509.10**
CURRENT MONTH:							
DIFFERENCE		150,481.0	6.620	9,962,221.40	7.497	11,281,730.50	1,319,509.10
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		645,519.9	6.787	43,810,571.15	8.304	53,604,943.24	9,794,372.09
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		645,519.9	6.787	43,810,571.15	8.304	53,604,943.24	9,794,372.09
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

AUGUST 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	83,295,334	79,679,907	3,615,427	4.5%	1,761,685	1,807,111	(45,426)	-2.5%	4.72816	4.40924	0.31892	7.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(10,802)	(6,734)	(4,068)	60.4%	1,761,685 (a)	1,807,111 (a)	(45,426)	-2.5%	(0.00061)	(0.00037)	(0.00024)	64.5%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,761,685 (a)	1,807,111 (a)	(45,426)	-2.5%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	24,595	25,713	(1,118)	-4.3%	1,761,685 (a)	1,807,111 (a)	(45,426)	-2.5%	0.00140	0.00142	(0.00003)	-1.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**83,309,127**	**79,698,886**	**3,610,241**	**4.5%**	**1,761,685**	**1,807,111**	**(45,426)**	**-2.5%**	**4.72895**	**4.41029**	**0.31865**	**7.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	9,465,986	19,341,500	(9,875,514)	-51.1%	125,399	291,702	(166,303)	-57.0%	7.54869	6.63057	0.91813	13.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	16,549,714	0	16,549,714	0.0%	205,322	0	205,322	0.0%	8.06037	0.00000	8.06037	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,767,002	1,181,100	585,902	49.6%	49,890	37,769	12,121	32.1%	3.54180	3.12717	0.41463	13.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**27,782,702**	**20,522,600**	**7,260,102**	**35.4%**	**380,611**	**329,471**	**51,140**	**15.5%**	**7.29950**	**6.22895**	**1.07055**	**17.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**2,142,296**	**2,136,582**	**5,714**	**0.3%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	88,508	64,600	23,908	37.0%	1,984	1,992	(8)	-0.4%	4.46176	3.24297	1.21879	37.6%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	65	0	65	0.0%	1	0	1	0.0%	6.50000	0.00000	6.50000	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	371,479	0	371,479	0.0%	7,440	0	7,440	0.0%	4.99300	0.00000	4.99300	0.0%
17. Fuel Cost of Market Base Sales (A6)	39,212	1,271,400	(1,232,188)	-96.9%	750	19,858	(19,108)	-96.2%	5.22827	6.40246	(1.17419)	-18.3%
18. Gains on Market Based Sales	7,223	242,960	(235,737)	-97.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**506,487**	**1,578,960**	**(1,072,473)**	**-67.9%**	**10,175**	**21,850**	**(11,675)**	**-53.4%**	**4.97776**	**7.22636**	**(2.24860)**	**-31.1%**
20. Net Inadvertant Interchange					308	0	308	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					6,753	0	6,753	0.0%				
22. Interchange and Wheeling Losses					5,054	400	4,654	1163.5%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**110,585,342**	**98,642,526**	**11,942,816**	**12.1%**	**2,134,128**	**2,114,332**	**19,796**	**0.9%**	**5.18176**	**4.66542**	**0.51633**	**11.1%**
24. Net Unbilled	4,614,873 (a)	1,595,761 (a)	3,019,112	189.2%	89,060	34,204	54,856	160.4%	5.18176	4.66542	0.51634	11.1%
25. Company Use	163,744 (a)	144,628 (a)	19,116	13.2%	3,160	3,100	60	1.9%	5.18177	4.66542	0.51635	11.1%
26. T & D Losses	6,097,892 (a)	6,629,986 (a)	(532,094)	-8.0%	117,680	142,109	(24,429)	-17.2%	5.18176	4.66542	0.51633	11.1%
27. System KWH Sales	110,585,342	98,642,526	11,942,816	12.1%	1,924,228	1,934,919	(10,691)	-0.6%	5.74700	5.09802	0.64898	12.7%
28. Wholesale KWH Sales	(3,989,456)	(2,705,568)	(1,283,888)	47.5%	(69,418)	(53,071)	(16,347)	30.8%	5.74701	5.09802	0.64899	12.7%
29. Jurisdictional KWH Sales (Incl adj from Sch A2,Pg2,Line C5a)	106,595,949	95,936,958	10,658,991	11.1%	1,854,810	1,881,848	(27,038)	-1.4%	5.74700	5.09802	0.64898	12.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	106,687,622	96,019,464	10,668,158	11.1%	1,854,810	1,881,848	(27,038)	-1.4%	5.75194	5.10240	0.64954	12.7%
32. Other	0	0	0	0.0%	1,854,810	1,881,848	(27,038)	-1.4%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,273,431)	(1,276,250)	2,819	-0.2%	1,854,810	1,881,848	(27,038)	-1.4%	(0.06866)	(0.06782)	(0.00084)	1.2%
34. Other	0	0	0	0.0%	1,854,810	1,881,848	(27,038)	-1.4%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,854,810	1,881,848	(27,038)	-1.4%	0.66339	0.65386	0.00953	1.5%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	117,718,876	107,047,899	10,670,977	10.0%	1,854,810	1,881,848	(27,038)	-1.4%	6.34668	5.68845	0.65824	11.6%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	117,803,634	107,124,974	10,678,660	10.0%	1,854,810	1,881,848	(27,038)	-1.4%	6.35125	5.69254	0.65871	11.6%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,854,810	1,881,848	(27,038)	-1.4%	0.00328	0.00323	0.00005	1.5%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**117,864,429**	**107,185,769**	**10,678,660**	**10.0%**	**1,854,810**	**1,881,848**	**(27,038)**	**-1.4%**	**6.35453**	**5.69577**	**0.65876**	**11.6%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									6.355	5.696	0.659	11.6%

* Based on Jurisdictional Sales (a) included for informational purposes only

T23

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: AUGUST 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	555,637,140	523,199,818	32,437,322	6.2%	12,431,853	11,970,843	461,010	3.9%	4.46946	4.37062	0.09885	2.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(71,752)	(53,872)	(17,880)	33.2%	12,431,853 (a)	11,970,843 (a)	461,010	3.9%	(0.00058)	(0.00045)	(0.00013)	28.3%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	12,431,853 (a)	11,970,843 (a)	461,010	3.9%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	105,501	120,219	(14,718)	-12.2%	12,431,853 (a)	11,970,843 (a)	461,010	3.9%	0.00085	0.00100	(0.00016)	-15.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**555,670,889**	**523,266,165**	**32,404,724**	**6.2%**	**12,431,853**	**11,970,843**	**461,010**	**3.9%**	**4.46974**	**4.37117**	**0.09856**	**2.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	35,231,600	124,194,300	(88,962,700)	-71.6%	570,555	2,078,178	(1,507,623)	-72.5%	6.17497	5.97611	0.19886	3.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	60,360,285	0	60,360,285	0.0%	850,842	0	850,842	0.0%	7.09418	0.00000	7.09418	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	11,257,851	8,690,100	2,567,751	29.5%	360,270	290,324	69,946	24.1%	3.12484	2.99324	0.13160	4.4%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**106,849,736**	**132,884,400**	**(26,034,664)**	**-19.6%**	**1,781,667**	**2,368,502**	**(586,835)**	**-24.8%**	**5.99718**	**5.61048**	**0.38669**	**6.9%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**14,213,520**	**14,339,345**	**(125,825)**	**-0.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	507,317	371,900	135,417	36.4%	12,906	12,540	366	2.9%	3.93080	2.96571	0.96509	32.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,020)	0	(21,020)	0.0%	29	0	29	0.0%	(72.48276)	0.00000	(72.48276)	0.0%
16. Fuel Cost of Separated Sch. D Sales (A6)	2,717,293	0	2,717,293	0.0%	58,310	0	58,310	0.0%	4.66008	0.00000	4.66008	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,790,554	9,107,900	(6,317,346)	-69.4%	56,092	160,027	(103,935)	-64.9%	4.97496	5.69148	(0.71652)	-12.6%
18. Gains on Market Based Sales	590,915	2,599,880	(2,008,965)	-77.3%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**6,585,059**	**12,079,680**	**(5,494,621)**	**-45.5%**	**127,338**	**172,567**	**(45,229)**	**-26.2%**	**5.17132**	**6.99999**	**(1.82867)**	**-26.1%**
20. Net Inadvertant Interchange					(223)	0	(223)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					29,151	0	29,151	0.0%				
22. Interchange and Wheeling Losses					28,751	3,100	25,651	827.5%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**655,935,566**	**644,070,885**	**11,864,681**	**1.8%**	**14,086,359**	**14,163,678**	**(77,319)**	**-0.5%**	**4.65653**	**4.54734**	**0.10919**	**2.4%**
24. Net Unbilled	10,357,106 (a)	12,354,736 (a)	(1,997,630)	-16.2%	174,851	269,209	(94,358)	-35.1%	5.92339	4.58927	1.33412	29.1%
25. Company Use	1,109,023 (a)	1,125,300 (a)	(16,277)	-1.4%	23,980	24,800	(820)	-3.3%	4.62478	4.53750	0.08728	1.9%
26. T & D Losses	36,951,824 (a)	28,005,701 (a)	8,946,123	31.9%	814,808	613,850	200,958	32.7%	4.53503	4.56230	(0.02727)	-0.6%
27. System KWH Sales	655,935,566	644,070,885	11,864,681	1.8%	13,072,720	13,255,819	(183,099)	-1.4%	5.01759	4.85878	0.15881	3.3%
28. Wholesale KWH Sales	(24,007,614)	(16,814,480)	(7,193,134)	42.8%	(488,361)	(343,122)	(145,239)	42.3%	4.91596	4.90044	0.01552	0.3%
29. Jurisdictional KWH Sales (Incl adj from Sch A2,Pg2,Line C5a)	631,928,015	627,256,405	4,671,610	0.7%	12,584,359	12,912,697	(328,338)	-2.5%	5.02154	4.85767	0.16386	3.4%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	632,471,473	627,795,847	4,675,626	0.7%	12,584,359	12,912,697	(328,338)	-2.5%	5.02585	4.86185	0.16400	3.4%
32. Other	0	0	0	0.0%	12,584,359	12,912,697	(328,338)	-2.5%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(10,975,824)	(10,210,000)	(765,824)	7.5%	12,584,359	12,912,697	(328,338)	-2.5%	(0.08722)	(0.07907)	(0.00815)	10.3%
34. Other	0	0	0	0.0%	12,584,359	12,912,697	(328,338)	-2.5%	0.00000	0.00000	0.00000	0.0%
35. True-up *	98,437,480	98,437,481	(1)	0.0%	12,584,359	12,912,697	(328,338)	-2.5%	0.78222	0.76233	0.01989	2.6%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	719,933,129	716,023,328	3,909,801	0.5%	12,584,359	12,912,697	(328,338)	-2.5%	5.72086	5.54511	0.17575	3.2%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	720,451,481	716,538,865	3,912,616	0.5%	12,584,359	12,912,697	(328,338)	-2.5%	5.72498	5.54910	0.17588	3.2%
39. GPIF * (Already Adjusted for Taxes)	486,360	486,360	0	0.0%	12,584,359	12,912,697	(328,338)	-2.5%	0.00386	0.00377	0.00010	2.6%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**720,937,841**	**717,025,225**	**3,912,616**	**0.5%**	**12,584,359**	**12,912,697**	**(328,338)**	**-2.5%**	**5.72884**	**5.55287**	**0.17598**	**3.2%**
									5.729	5.553	0.176	3.2%

41. Fuel FAC Rounded to the Nearest .001 cents per KWH

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	83,295,334	79,679,907	3,615,427	4.5%	555,637,140	523,199,818	32,437,322	6.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	499,264	1,336,000	(836,736)	-62.6%	5,994,144	9,479,800	(3,485,656)	-36.8%
2a. GAINS FROM MARKET BASED SALES	7,223	242,960	(235,737)	-97.0%	590,915	2,599,880	(2,008,965)	-77.3%
3. FUEL COST OF PURCHASED POWER	9,465,986	19,341,500	(9,875,514)	-51.1%	35,231,600	124,194,300	(88,962,700)	-71.6%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,767,002	1,181,100	585,902	49.6%	11,257,851	8,690,100	2,567,751	29.5%
4. ENERGY COST OF ECONOMY PURCHASES	16,549,714	0	16,549,714	0.0%	60,360,285	0	60,360,285	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	110,571,549	98,623,547	11,948,002	12.1%	655,901,817	644,004,538	11,897,279	1.8%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(10,802)	(6,734)	(4,068)	60.4%	(71,752)	(53,872)	(17,880)	33.2%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	24,595	25,713	(1,118)	-4.3%	105,501	120,219	(14,718)	-12.2%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	110,585,342	98,642,526	11,942,816	12.1%	655,935,566	644,070,885	11,864,681	1.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,854,810	1,881,848	(27,038)	-1.4%	12,584,359	12,912,697	(328,338)	-2.5%
2. NONJURISDICTIONAL SALES	69,418	53,071	16,347	30.8%	488,361	343,122	145,239	42.3%
3. TOTAL SALES	1,924,228	1,934,919	(10,691)	-0.6%	13,072,720	13,255,819	(183,099)	-1.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9639242	0.9725720	(0.0086478)	-0.9%	0.9626427	0.9741154	(0.0114727)	-1.2%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	99,903,961	101,814,693	(1,910,732)	-1.9%	676,598,121	698,335,198	(21,737,077)	-3.1%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(98,437,480)	(98,437,481)	1	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(486,360)	(486,360)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	87,538,481	89,449,213	(1,910,732)	-2.1%	577,674,281	599,411,357	(21,737,076)	-3.6%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	110,585,342	98,642,526	11,942,816	12.1%	655,935,566	644,070,885	11,864,681	1.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9639242	0.9725720	(0.0086478)	-0.9%	NA	NA	-	0.0%
5a. JUNE 2006 THRESHOLD CALC. ADJ. FOR SCHEDULES D & MA SALES	63	0	63	0.0%	63	0	63	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	106,595,949	95,936,958	10,658,991	11.1%	631,928,015	627,256,405	4,671,610	0.7%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	106,687,622	96,019,464	10,668,158	11.1%	632,471,473	627,795,847	4,675,626	0.7%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,273,431)	(1,276,250)	2,819	-0.2%	(10,975,824)	(10,210,000)	(765,824)	7.5%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	105,414,191	94,743,214	10,670,977	11.3%	621,495,649	617,585,847	3,909,802	0.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(17,875,710)	(5,294,001)	(12,581,709)	237.7%	(43,821,368)	(18,174,490)	(25,646,878)	141.1%
8. INTEREST PROVISION FOR THE MONTH	(898,748)	(276,477)	(622,271)	225.1%	(7,004,964)	(3,105,082)	(3,899,882)	125.6%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(200,092,138)	(77,232,520)	(122,859,618)	159.1%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(206,561,911)	(70,498,313)	(136,063,598)	193.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(200,092,138)	(77,232,520)	(122,859,618)	159.1%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(205,663,163)	(70,221,836)	(135,441,327)	192.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(405,755,301)	(147,454,356)	(258,300,945)	175.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(202,877,651)	(73,727,178)	(129,150,473)	175.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.360	4.500	0.860	19.1%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.270	4.500	0.770	17.1%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	10.630	9.000	1.630	18.1%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.315	4.500	0.815	18.1%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.443	0.375	0.068	18.1%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(898,748)	(276,477)	(622,271)	225.1%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	565,966	480,871	85,095	17.7%	2,188,796	1,623,640	565,156	34.8%
2	LIGHT OIL	23,809	1,049,643	(1,025,834)	-97.7%	4,411,011	5,362,282	(951,271)	-17.7%
3	COAL	25,158,195	26,017,698	(859,503)	-3.3%	196,991,512	188,913,756	8,077,756	4.3%
4	NATURAL GAS	57,547,364	52,131,695	5,415,669	10.4%	352,045,821	327,300,140	24,745,681	7.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	83,295,334	79,679,907	3,615,427	4.5%	555,637,140	523,199,818	32,437,322	6.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	5,794	6,330	(536)	-8.5%	21,909	21,346	563	2.6%
9	LIGHT OIL	76	7,337	(7,261)	-99.0%	30,415	39,807	(9,392)	-23.6%
10	COAL	992,834	973,547	19,287	2.0%	7,518,581	7,188,320	330,261	4.6%
11	NATURAL GAS	762,981	819,897	(56,916)	-6.9%	4,862,222	4,721,370	140,852	3.0%
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)	1,761,685	1,807,111	(45,426)	-2.5%	12,433,127	11,970,843	462,284	3.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	8,971	9,826	(855)	-8.7%	35,231	33,141	2,090	6.3%
16	LIGHT OIL (BBL)	268	18,735	(18,467)	-98.6%	52,565	107,524	(54,959)	-51.1%
17	COAL (TON)	454,160	443,131	11,029	2.5%	3,439,400	3,238,765	200,635	6.2%
18	NATURAL GAS (MCF)	5,583,567	6,102,339	(518,772)	-8.5%	35,148,352	34,670,856	477,496	1.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	56,282	61,699	(5,417)	-8.8%	221,032	208,078	12,954	6.2%
22	LIGHT OIL	1,552	87,454	(85,902)	-98.2%	297,936	453,598	(155,662)	-34.3%
23	COAL	10,823,654	10,609,020	214,634	2.0%	80,957,484	77,671,088	3,286,396	4.2%
24	NATURAL GAS	5,778,992	6,273,157	(494,165)	-7.9%	36,377,437	35,641,335	736,102	2.1%
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)	16,660,480	17,031,330	(370,850)	-2.2%	117,853,889	113,974,099	3,879,790	3.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.33%	0.35%	(0.00)	-	0.16%	0.18%	(0.00)	-
29	LIGHT OIL	0.00%	0.41%	(0.00)	-	0.24%	0.33%	(0.00)	-
30	COAL	56.36%	53.87%	0.02	-	60.47%	60.05%	0.00	-
31	NATURAL GAS	43.31%	45.37%	(0.02)	-	39.11%	39.44%	(0.00)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	63.09	48.94	14.15	28.9%	62.13	48.99	13.14	26.8%
36	LIGHT OIL ($/BBL)	88.84	56.03	32.81	58.6%	83.92	49.87	34.04	68.3%
37	COAL ($/TON)	55.40	58.71	(3.32)	-5.7%	57.27	58.33	(1.05)	-1.8%
38	NATURAL GAS ($/MCF)	10.31	8.54	1.76	20.6%	10.02	9.44	0.58	6.1%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	10.06	7.79	2.26	29.0%	9.90	7.80	2.10	26.9%
42	LIGHT OIL	15.34	12.00	3.33	27.8%	14.81	11.82	2.98	25.2%
43	COAL	2.32	2.45	(0.13)	-5.2%	2.43	2.43	0.00	0.0%
44	NATURAL GAS	9.96	8.31	1.65	19.8%	9.68	9.18	0.49	5.4%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	5.00	4.68	0.32	6.9%	4.71	4.59	0.12	2.7%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,714	9,747	(33)	-0.3%	10,089	9,748	341	3.5%
49	LIGHT OIL	20,426	11,920	8,506	71.4%	9,796	11,395	(1,599)	-14.0%
50	COAL	10,902	10,897	5	0.0%	10,768	10,805	(37)	-0.3%
51	NATURAL GAS	7,574	7,651	(77)	-1.0%	7,482	7,549	(67)	-0.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,457	9,425	32	0.3%	9,479	9,521	(42)	-0.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	9.77	7.60	2.17	28.6%	9.99	7.61	2.38	31.3%
56	LIGHT OIL	31.33	14.31	17.02	118.9%	14.50	13.47	1.03	7.6%
57	COAL	2.53	2.67	(0.14)	-5.2%	2.62	2.63	(0.01)	-0.4%
58	NATURAL GAS	7.54	6.36	1.18	18.6%	7.24	6.93	0.31	4.5%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.73	4.41	0.32	7.3%	4.47	4.37	0.10	2.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

SCHEDULE A4
PAGE 1 OF 1

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	137,553	45.0	47.7	70.6	11,482	COAL	67,123	23,529,700	1,579,384.1	3,757,463	2.73	55.98
B.B.#2	391	260,943	89.7	92.0	91.1	10,637	COAL	118,003	23,522,380	2,775,711.4	6,605,664	2.53	55.98
B.B.#3	414	150,751	48.9	51.3	72.3	11,073	COAL	71,539	23,334,420	1,669,321.1	4,004,666	2.66	55.98
B.B.#4	457	266,512	78.4	85.6	78.4	11,274	COAL	128,239	23,430,380	3,004,688.5	7,178,662	2.69	55.98
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	1,117	5,797,907	6,477.1	95,235	-	85.26
B.B. STATION	**1,673**	**815,759**	**65.5**	**69.3**	**77.9**	**11,068**	-	-	-	-	**21,641,690**	**2.65**	-
SEB-PHIL. #1(HVY OIL)	17	2,872	22.7	99.2	84.7	9,714	HVY.OIL	4,446	6,273,540	27,893.4	250,402	8.72	56.32
SEB-PHIL. #2(HVY OIL)	17	2,922	23.1	99.7	84.5	9,714	HVY.OIL	4,525	6,273,540	28,388.1	254,851	8.72	56.32
SEB-PHIL. IGNITION	-	-	-	-	-	-	LGT.OIL	424	5,797,907	2,459.3	60,713	-	143.19
SEB-PHILLIPS TOTAL	**34**	**5,794**	**22.9**	**99.5**	**84.6**	**9,714**	-	-	-	-	**565,966**	**9.77**	-
POLK #1 GASIFIER	255	177,075	-	-	-	10,134	COAL	69,256	25,912,000	1,794,548.5	3,516,505	1.99	50.78
POLK #1 CT (OIL)	225	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #1 TOTAL	**255**	**177,075**	**93.3**	**95.9**	**93.3**	**10,134**	-	-	-	**1,794,548.5**	**3,516,505**	**1.99**	-
POLK #2 CT (GAS)	150	14,499	-	-	-	11,499	GAS	161,092	1,035,000	166,730.0	1,624,738	11.21	10.09
POLK #2 CT (OIL)	160	28	-	-	-	20,462	LGT.OIL	98	5,779,448	569.2	18,474	65.98	188.51
POLK #2 TOTAL	**155**	**14,527**	**12.6**	**100.0**	**76.7**	**11,516**	-	-	-	**167,299.2**	**1,643,212**	**11.31**	-
POLK #3 CT (GAS)	150	16,820	-	-	-	11,897	GAS	193,344	1,035,000	200,111.0	1,938,644	11.53	10.03
POLK #3 CT (OIL)	160	48	-	-	-	20,676	LGT.OIL	170	5,779,468	984.1	5,335	11.11	31.38
POLK #3 TOTAL	**155**	**16,868**	**14.6**	**100.0**	**75.2**	**11,922**	-	-	-	**201,095.1**	**1,943,979**	**11.52**	-
POLK STATION TOTAL	**565**	**208,470**	**49.6**	**98.2**	**83.8**	**10,375**	-	-	-	**2,162,942.8**	**7,103,696**	**3.41**	-
B.B.C.T.#1	14	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**146**	**0**	**0.0**	**100.0**	**0.0**	**0**	**LGT.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
COT 1	3	235	10.5	99.8	96.0	11,572	GAS	2,629	1,035,000	2,720.9	7,293	3.10	2.77
COT 2	3	224	10.0	98.2	86.4	11,572	GAS	2,503	1,035,000	2,590.8	6,944	3.10	2.77
CITY OF TAMPA TOTAL	**6**	**459**	**10.3**	**99.0**	**91.2**	**11,572**	**GAS**	**5,132**	**1,035,000**	**5,311.6**	**14,237**	**3.10**	**2.77**
BAYSIDE ST 1	234	98,761	56.7	99.9	56.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	32,355	27.9	46.0	87.6	11,156	GAS	348,748	1,035,000	360,954.0	3,627,444	11.21	10.40
BAYSIDE CT1B	156	78,173	67.4	100.0	83.9	11,430	GAS	863,297	1,035,000	893,512.0	8,979,440	11.49	10.40
BAYSIDE CT1C	156	79,970	68.9	100.0	83.3	10,866	GAS	839,573	1,035,000	868,958.0	8,732,679	10.92	10.40
BAYSIDE UNIT 1 TOTAL	**702**	**289,259**	**55.4**	**88.0**	**75.6**	**7,341**	**GAS**	**2,051,618**	**1,035,000**	**2,123,424.0**	**21,339,563**	**7.38**	**10.40**
BAYSIDE ST 2	306	151,070	66.4	99.0	67.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	67,088	57.8	100.0	84.2	11,172	GAS	724,165	1,035,000	749,511.0	7,448,549	11.10	10.29
BAYSIDE CT2B	156	74,635	64.3	100.0	85.2	11,357	GAS	818,944	1,035,000	847,607.0	8,423,418	11.29	10.29
BAYSIDE CT2C	156	74,282	64.0	99.8	84.3	11,358	GAS	815,130	1,035,000	843,660.0	8,384,189	11.29	10.29
BAYSIDE CT2D	156	74,869	64.5	100.0	84.3	11,255	GAS	814,142	1,035,000	842,637.0	8,374,026	11.18	10.29
BAYSIDE UNIT 2 TOTAL	**930**	**441,944**	**63.9**	**99.7**	**78.7**	**7,429**	**GAS**	**3,172,381**	**1,035,000**	**3,283,415.0**	**32,630,182**	**7.38**	**10.29**
BAYSIDE STATION TOTAL	**1,632**	**731,203**	**60.2**	**94.7**	**77.4**	**7,394**	**GAS**	**5,223,999**	**1,035,000**	**5,406,839.0**	**53,969,745**	**7.38**	**10.33**
SYSTEM	**4,056**	**1,761,685**	**58.4**	**84.9**	**75.8**	**9,457**	-	-	-	**16,660,480.0**	**83,295,334**	**4.73**	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:

B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,913	9,826	1,087	11.1%	39,568	33,141	6,427	19.4%
3 UNIT COST ($/BBL)	62.47	47.93	14.54	30.3%	58.86	47.63	11.23	23.6%
4 AMOUNT ($)	681,746	470,985	210,761	44.7%	2,329,016	1,578,602	750,414	47.5%
5 BURNED:								
6 UNITS (BBL)	8,971	9,826	(855)	-8.7%	35,231	33,141	2,090	6.3%
7 UNIT COST ($/BBL)	63.09	48.94	14.15	28.9%	62.13	48.99	13.14	26.8%
8 AMOUNT ($)	565,966	480,871	85,095	17.7%	2,188,796	1,623,640	565,156	34.8%
9 ENDING INVENTORY:								
10 UNITS (BBL)	19,668	12,118	7,550	62.3%	19,668	12,118	7,550	62.3%
11 UNIT COST ($/BBL)	58.24	47.67	10.57	22.2%	58.24	47.67	10.57	22.2%
12 AMOUNT ($)	1,145,433	577,698	567,735	98.3%	1,145,433	577,698	567,735	98.3%
13								
14 DAYS SUPPLY:	178	110	68	60.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	6,201	18,735	(12,534)	-66.9%	117,159	107,524	9,635	9.0%
17 UNIT COST ($/BBL)	95.09	70.80	24.29	34.3%	87.77	70.48	17.29	24.5%
18 AMOUNT ($)	589,655	1,326,530	(736,875)	-55.5%	10,282,549	7,578,342	2,704,207	35.7%
19 BURNED:								
20 UNITS (BBL)	268	18,735	(18,467)	-98.6%	52,565	107,524	(54,959)	-51.1%
21 UNIT COST ($/BBL)	88.84	56.03	32.81	58.6%	83.92	49.87	34.04	68.3%
22 AMOUNT ($)	23,809	1,049,643	(1,025,834)	-97.7%	4,411,011	5,362,282	(951,271)	-17.7%
23 ENDING INVENTORY:								
24 UNITS (BBL)	104,693	85,007	19,686	23.2%	104,693	85,007	19,686	23.2%
25 UNIT COST ($/BBL)	86.75	68.13	18.63	27.3%	86.75	68.13	18.63	27.3%
26 AMOUNT ($)	9,082,529	5,791,252	3,291,277	56.8%	9,082,529	5,791,252	3,291,277	56.8%
27								
28 DAYS SUPPLY: NORMAL	221	180	41	20.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	12	3	23.2%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	487,231	444,500	42,731	9.6%	3,629,001	3,243,300	385,701	11.9%
32 UNIT COST ($/TON)	57.26	58.02	(0.76)	-1.3%	57.69	57.90	(0.21)	-0.4%
33 AMOUNT ($)	27,898,210	25,788,913	2,109,297	8.2%	209,373,051	187,792,400	21,580,651	11.5%
34 BURNED:								
35 UNITS (TONS)	454,160	443,131	11,029	2.5%	3,439,400	3,238,765	200,635	6.2%
36 UNIT COST ($/TON)	55.40	58.71	(3.32)	-5.7%	57.27	58.33	(1.05)	-1.8%
37 AMOUNT ($)	25,158,195	26,017,698	(859,503)	-3.3%	196,991,512	188,913,756	8,077,756	4.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	660,990	551,283	109,707	19.9%	660,990	551,283	109,707	19.9%
40 UNIT COST ($/TON)	57.72	57.86	(0.14)	-0.2%	57.72	57.86	(0.14)	-0.2%
41 AMOUNT ($)	38,152,987	31,897,929	6,255,058	19.6%	38,152,987	31,897,929	6,255,058	19.6%
42								
43 DAYS SUPPLY:	50	42	8	20.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	5,551,092	6,102,339	(551,247)	-9.0%	35,119,909	34,670,856	449,053	1.3%
46 UNIT COST ($/MCF)	10.36	8.54	1.81	21.2%	9.99	9.44	0.55	5.8%
47 AMOUNT ($)	57,491,895	52,131,695	5,360,200	10.3%	350,773,035	327,300,137	23,472,898	7.2%
48 BURNED:								
49 UNITS (MCF)	5,583,567	6,102,339	(518,772)	-8.5%	35,148,352	34,670,856	477,496	1.4%
50 UNIT COST ($/MCF)	10.31	8.54	1.76	20.6%	10.02	9.44	0.58	6.1%
51 AMOUNT ($)	57,547,364	52,131,695	5,415,669	10.4%	352,045,821	327,300,140	24,745,681	7.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	157,823	0	157,823	0.0%	157,823	0	157,823	0.0%
54 UNIT COST ($/MCF)	8.06	0.00	8.06	0.0%	8.06	0.00	8.06	0.0%
55 AMOUNT ($)	1,271,412	0	1,271,412	0.0%	1,271,412	0	1,271,412	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	38,275
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	38,275

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(1,541)	(133,510)
OTHER USAGE	(425)	(36,383)
TOTAL	(1,966)	(169,893)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	53,932
IGNITION #2 OIL	95,235
IGNITION PROPANE	0
AERIAL SURVEY ADJ.	(1,508,386)
ADDITIVES	84,574
GREEN FUEL	0
TOTAL	(1,274,645)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,992.0	0.0	1,992.0	3.243	3.243	64,600.00	64,600.00	
VARIOUS	JURISDIC.	SCH. - MB	19,858.0	0.0	19,858.0	6.402	8.224	1,271,400.00	1,633,200.00	242,960.00
TOTAL			21,850.0	0.0	21,850.0	6.114	7.770	1,336,000.00	1,697,800.00	242,960.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	710.9	10.7	700.2	5.292	5.590	37,056.69	39,138.32	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,278.5	0.0	1,278.5	4.024	4.259	51,451.42	54,445.99	
PROGRESS ENERGY FLORIDA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	400.0	0.0	400.0	4.248	5.707	16,992.00	22,827.05	5,743.81
CITY OF LAKELAND		SCH. - MA	150.0	0.0	150.0	6.805	7.916	10,207.50	11,873.65	1,567.69
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	200.0	0.0	200.0	6.006	6.985	12,012.00	13,969.52	1,716.90
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LESS 20% - THRESHHOLD EXCESS		SCH. - MA								(1,805.68)
AUBURNDALE POWER PARTNERS		OATT	1.0	0.0	1.0	6.502	6.502	65.02	65.02	
NEW SMYRNA BEACH		SEP SCH. - D	7,440.0	0.0	7,440.0	4.892	5.492	363,964.80	408,604.80	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. HARDEE	JULY 2006	SCH. - D	(1,418.1)	0.0	(1,418.1)	3.744	3.989	(53,088.75)	(56,572.41)	
SEMINOLE ELEC. HARDEE	JULY 2006	SCH. - D	1,423.1	0.0	1,423.1	3.731	3.975	53,088.75	56,572.41	
NEW SMYRNA BEACH	JULY 2006	SEP SCH. - D	(7,440.0)	0.0	(7,440.0)	4.791	5.391	(356,450.40)	(401,090.40)	
NEW SMYRNA BEACH	JULY 2006	SEP SCH. - D	7,440.0	0.0	7,440.0	4.892	5.492	363,964.80	408,604.80	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,440.0	0.0	7,440.0	4.993	5.593	371,479.20	416,119.20	
SUB-TOTAL SCHEDULE D POWER SALES			1,994.4	10.7	1,983.7	4.462	4.718	88,508.11	93,584.31	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			750.0	0.0	750.0	5.228	6.489	39,211.50	48,670.22	7,222.72
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			1.0	0.0	1.0	6.502	6.502	65.02	65.02	
TOTAL			10,185.4	10.7	10,174.7	4.907	5.489	499,263.83	558,438.75	7,222.72
CURRENT MONTH:										
DIFFERENCE			(11,664.6)	10.7	(11,675.3)	(1.207)	(2.281)	(836,736.17)	(1,139,361.25)	(235,737.28)
DIFFERENCE %			-53.4%	0.0%	-53.4%	-19.7%	-29.4%	-62.6%	-67.1%	-97.0%
PERIOD TO DATE:										
ACTUAL			127,353.6	17.7	127,335.9	4.707	5.599	5,994,143.20	7,129,250.19	590,915.18
ESTIMATED			172,567.0	0.0	172,567.0	5.493	7.527	9,479,800.00	12,989,100.00	2,599,880.00
DIFFERENCE			(45,213.4)	17.7	(45,231.1)	(0.786)	(1.928)	(3,485,656.80)	(5,859,849.81)	(2,008,964.82)
DIFFERENCE %			-26.2%	0.0%	-26.2%	-14.3%	-25.6%	-36.8%	-45.1%	-77.3%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF AUGUST 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	2,862.0	0.0	1,634.0	1,228.0	10.391	10.391	127,600.00
HARDEE POWER PARTNERS		IPP	44,175.0	0.0	0.0	44,175.0	8.290	8.290	3,662,100.00
CALPINE		SCH. - D	24,921.0	0.0	0.0	24,921.0	10.242	10.242	2,552,400.00
VARIOUS		MKT. BASED	124,169.0	0.0	0.0	124,169.0	7.455	7.455	9,256,600.00
OTHER		SCH. - D	97,209.0	0.0	0.0	97,209.0	3.850	3.850	3,742,800.00
TOTAL			**293,336.0**	**0.0**	**1,634.0**	**291,702.0**	**6.631**	**6.631**	**19,341,500.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	65,472.0	0.0	0.0	65,472.0	8.397	8.397	5,497,548.49
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	36,300.0	0.0	0.0	36,300.0	3.608	3.608	1,309,704.00
CALPINE		SCH. - D	22,240.0	0.0	0.0	22,240.0	11.502	11.502	2,557,972.92
CALPINE		OATT	1,413.0	0.0	0.0	1,413.0	4.315	4.315	60,973.49
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	JULY 2006	IPP	(46,316.0)	0.0	0.0	(46,316.0)	6.945	6.945	(3,216,444.80)
HARDEE PWR. PART.-NATIVE	JULY 2006	IPP	46,290.0	0.0	0.0	46,290.0	7.211	7.211	3,337,988.04
PROGRESS ENERGY FLORIDA	JULY 2006	SCH. - D	(37,200.0)	0.0	0.0	(37,200.0)	3.831	3.831	(1,425,132.00)
PROGRESS ENERGY FLORIDA	JULY 2006	SCH. - D	37,200.0	0.0	0.0	37,200.0	3.608	3.608	1,342,176.00
CALPINE	JULY 2006	SCH. - D	(9,672.0)	0.0	0.0	(9,672.0)	9.192	9.192	(889,068.91)
CALPINE	JULY 2006	SCH. - D	9,672.0	0.0	0.0	9,672.0	9.205	9.205	890,269.16
SUB-TOTAL OF ADJUSTMENTS:			(26.0)	0.0	0.0	(26.0)	(153.029)	(153.029)	39,787.49
TOTAL			**125,399.0**	**0.0**	**0.0**	**125,399.0**	**7.549**	**7.549**	**9,465,986.39**
CURRENT MONTH:									
DIFFERENCE			(167,937.0)	0.0	(1,634.0)	(166,303.0)	0.918	0.918	(9,875,513.61)
DIFFERENCE %			-57.3%	0.0%	0.0%	-57.0%	13.9%	13.9%	-51.1%
PERIOD TO DATE:									
ACTUAL			570,555.0	0.0	0.0	570,555.0	6.175	6.175	35,231,601.07
ESTIMATED			2,084,935.0	0.0	6,757.0	2,078,178.0	5.976	5.976	124,194,300.00
DIFFERENCE			(1,514,380.0)	0.0	(6,757.0)	(1,507,623.0)	0.199	0.199	(88,962,698.93)
DIFFERENCE %			-72.6%	0.0%	-100.0%	-72.5%	3.3%	3.3%	-71.6%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	37,769.0	0.0	0.0	37,769.0	3.127	3.127	1,181,100.00
TOTAL			**37,769.0**	**0.0**	**0.0**	**37,769.0**	**3.127**	**3.127**	**1,181,100.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	15,643.0	0.0	0.0	15,643.0	2.670	2.670	417,601.88
McKAY BAY REFUSE		COGEN.	13,646.0	0.0	0.0	13,646.0	2.668	2.668	364,136.93
ORANGE COGENERATION L.P.		COGEN.	7,843.0	0.0	0.0	7,843.0	2.486	2.486	194,977.40
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	3.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	1,029.0	0.0	0.0	1,029.0	6.249	6.249	64,301.45
CF INDUSTRIES INC.		COGEN.	1,058.0	0.0	0.0	1,058.0	6.768	6.768	71,607.28
IMC-AGRICO-NEW WALES		COGEN.	739.0	0.0	0.0	739.0	6.947	6.947	51,339.74
IMC-AGRICO-S. PIERCE		COGEN.	8,946.0	0.0	0.0	8,946.0	6.396	6.396	572,174.98
AUBURNDALE POWER PARTNERS		COGEN.	986.0	0.0	0.0	986.0	6.609	6.609	65,168.62
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR AUGUST 2006			49,890.0	0.0	0.0	49,890.0	3.611	3.611	1,801,311.28
ADJUSTMENTS FOR THE MONTH OF:	**JULY 2006**								
HILLSBOROUGH COUNTY		COGEN.	(17,082.0)	0.0	0.0	(17,082.0)	2.747	2.747	(469,211.87)
			17,082.0	0.0	0.0	17,082.0	2.655	2.655	453,516.30
McKAY BAY REFUSE		COGEN.	(13,864.0)	0.0	0.0	(13,864.0)	2.748	2.748	(380,950.40)
			13,864.0	0.0	0.0	13,864.0	2.656	2.656	368,209.12
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.572	2.572	(201,693.68)
			7,843.0	0.0	0.0	7,843.0	2.471	2.471	193,815.38
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	(1,086.0)	0.0	0.0	(1,086.0)	4.488	4.488	(48,740.81)
			1,086.0	0.0	0.0	1,086.0	4.673	4.673	50,746.64
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL			0.0	0.0	0.0	0.0	0.000	0.000	(34,309.32)
TOTAL			**49,890.0**	**0.0**	**0.0**	**49,890.0**	**3.542**	**3.542**	**1,767,001.96**
CURRENT MONTH:									
DIFFERENCE			12,121.0	0.0	0.0	12,121.0	0.415	0.415	585,901.96
DIFFERENCE %			32.1%	0.0%	0.0%	32.1%	13.3%	13.3%	49.6%
PERIOD TO DATE:									
ACTUAL			360,270.0	0.0	0.0	360,270.0	3.125	3.125	11,257,850.46
ESTIMATED			290,324.0	0.0	0.0	290,324.0	2.993	2.993	8,690,100.00
DIFFERENCE			69,946.0	0.0	0.0	69,946.0	0.132	0.132	2,567,750.46
DIFFERENCE %			24.1%	0.0%	0.0%	24.1%	4.4%	4.4%	29.5%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	885.0	8.963	79,325.00	11.908	105,382.90	26,057.90
FLA. POWER & LIGHT	SCH. - JC	82,705.0	6.887	5,696,205.00	8.446	6,985,038.34	1,288,833.34
CITY OF LAKELAND	SCH. - JC	745.0	9.134	68,050.00	12.674	94,424.30	26,374.30
ORLANDO UTIL. COMM.	SCH. - JC	1,080.0	7.663	82,760.00	10.279	111,010.60	28,250.60
THE ENERGY AUTHORITY	SCH. - JC	27,776.3	8.267	2,296,296.01	10.970	3,046,975.29	750,679.28
OKEELANTA	SCH. - JC	20.0	9.700	1,940.00	11.429	2,285.80	345.80
CITY OF TALLAHASSEE	SCH. - JC	95.0	10.947	10,400.00	19.378	18,408.85	8,008.85
CALPINE	SCH. - JC	7,903.0	7.723	610,367.00	11.254	889,411.33	279,044.33
CARGILL ALLIANT	SCH. - JC	59,949.0	8.398	5,034,227.00	9.490	5,689,172.16	654,945.16
CARGILL FOR NEW SMYRNA BEACH	SCH. - JC	7,440.0	4.993	371,479.20	4.993	371,479.20	0.00
RELIANT	SCH. - JC	14,646.3	14.186	2,077,766.72	15.683	2,296,953.94	219,187.22
RAINBOW ENERGY MARKETERS	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	2,077.0	10.635	220,898.00	12.423	258,027.97	37,129.97
ENTERGY-KOCH TRADING	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CINCINATTI GAS & ELECTRIC	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL		205,321.6	8.060	16,549,713.93	9.677	19,868,570.68	3,318,856.75
NO PRIOR MONTH ADJUSTMENTS:							
TOTAL		**205,321.6**	**8.060**	**16,549,713.93**	**9.677**	**19,868,570.68**	**3,318,856.75**
CURRENT MONTH:							
DIFFERENCE		205,321.6	8.060	16,549,713.93	9.677	19,868,570.68	3,318,856.75
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		850,841.5	7.094	60,360,285.08	8.635	73,473,513.92	13,113,228.84
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		850,841.5	7.094	60,360,285.08	8.635	73,473,513.92	13,113,228.84
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

SEPTEMBER 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	71,680,875	71,780,397	(99,522)	-0.1%	1,601,845	1,628,898	(27,053)	-1.7%	4.47489	4.40668	0.06821	1.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(9,677)	(6,734)	(2,943)	43.7%	1,601,845 (a)	1,628,898 (a)	(27,053)	-1.7%	(0.00060)	(0.00041)	(0.00019)	46.1%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,601,845 (a)	1,628,898 (a)	(27,053)	-1.7%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	21,026	38,443	(17,417)	-45.3%	1,601,845 (a)	1,628,898 (a)	(27,053)	-1.7%	0.00131	0.00236	(0.00105)	-44.4%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**71,692,224**	**71,812,106**	**(119,882)**	**-0.2%**	**1,601,845**	**1,628,898**	**(27,053)**	**-1.7%**	**4.47560**	**4.40863**	**0.06697**	**1.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	6,615,804	21,747,800	(15,131,996)	-69.6%	121,637	328,807	(207,170)	-63.0%	5.43897	6.61415	(1.17518)	-17.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	8,755,425	0	8,755,425	0.0%	144,605	0	144,605	0.0%	6.05472	0.00000	6.05472	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,595,686	1,131,500	464,186	41.0%	52,934	36,546	16,388	44.8%	3.01448	3.09610	(0.08162)	-2.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**16,966,915**	**22,879,300**	**(5,912,385)**	**-25.8%**	**319,176**	**365,353**	**(46,177)**	**-12.6%**	**5.31585**	**6.26225**	**(0.94640)**	**-15.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,921,021**	**1,994,251**	**(73,230)**	**-3.7%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	59,040	34,200	24,840	72.6%	1,922	1,335	587	44.0%	3.07196	2.56180	0.51016	19.9%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sales (A6)	411,955	0	411,955	0.0%	7,200	0	7,200	0.0%	5.72160	0.00000	5.72160	0.0%
17. Fuel Cost of Market Base Sales (A6)	5,829	772,900	(767,071)	-99.2%	205	11,932	(11,727)	-98.3%	2.84341	6.47754	(3.63412)	-56.1%
18. Gains on Market Based Sales	1,996	130,800	(128,804)	-98.5%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**478,820**	**937,900**	**(459,080)**	**-48.9%**	**9,327**	**13,267**	**(3,940)**	**-29.7%**	**5.13370**	**7.06942**	**(1.93572)**	**-27.4%**
20. Net Inadvertant Interchange					(442)	0	(442)	0.0%				
21. Wheeling Rec'd less Wheeling Delv'd.					9,022	0	9,022	0.0%				
22. Interchange and Wheeling Losses					4,584	300	4,284	1428.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**88,180,319**	**93,753,506**	**(5,573,187)**	**-5.9%**	**1,915,690**	**1,980,684**	**(64,994)**	**-3.3%**	**4.60306**	**4.73339**	**(0.13033)**	**-2.8%**
24. Net Unbilled	(4,968,725) (a)	(4,816,225) (a)	(152,500)	3.2%	(107,944)	(101,750)	(6,194)	6.1%	4.60306	4.73339	(0.13033)	-2.8%
25. Company Use	139,519 (a)	146,735 (a)	(7,216)	-4.9%	3,031	3,100	(69)	-2.2%	4.60307	4.73339	(0.13032)	-2.8%
26. T & D Losses	5,340,053 (a)	4,277,518 (a)	1,062,535	24.8%	116,011	90,369	25,642	28.4%	4.60306	4.73339	(0.13033)	-2.8%
27. System KWH Sales	88,180,319	93,753,506	(5,573,187)	-5.9%	1,904,592	1,988,965	(84,373)	-4.2%	4.62988	4.71368	(0.08380)	-1.8%
28. Wholesale KWH Sales	(2,373,834)	(2,429,106)	55,272	-2.3%	(51,272)	(51,533)	261	-0.5%	4.62988	4.71369	(0.08381)	-1.8%
29. Jurisdictional KWH Sales	85,806,485	91,324,400	(5,517,915)	-6.0%	1,853,320	1,937,432	(84,112)	-4.3%	4.62988	4.71368	(0.08380)	-1.8%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	85,880,279	91,402,939	(5,522,660)	-6.0%	1,853,320	1,937,432	(84,112)	-4.3%	4.63386	4.71774	(0.08388)	-1.8%
32. Other	0	0	0	0.0%	1,853,320	1,937,432	(84,112)	-4.3%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,063,551)	(1,276,250)	212,699	-16.7%	1,853,320	1,937,432	(84,112)	-4.3%	(0.05739)	(0.06587)	0.00849	-12.9%
34. Other	0	0	0	0.0%	1,853,320	1,937,432	(84,112)	-4.3%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,853,320	1,937,432	(84,112)	-4.3%	0.66393	0.63510	0.02882	4.5%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	97,121,413	102,431,374	(5,309,961)	-5.2%	1,853,320	1,937,432	(84,112)	-4.3%	5.24040	5.28697	(0.04656)	-0.9%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	97,191,340	102,505,125	(5,313,785)	-5.2%	1,853,320	1,937,432	(84,112)	-4.3%	5.24417	5.29077	(0.04660)	-0.9%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,853,320	1,937,432	(84,112)	-4.3%	0.00328	0.00314	0.00014	4.5%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**97,252,135**	**102,565,920**	**(5,313,785)**	**-5.2%**	**1,853,320**	**1,937,432**	**(84,112)**	**-4.3%**	**5.24745**	**5.29391**	**(0.04646)**	**-0.9%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.247**	**5.294**	**(0.047)**	**-0.9%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: SEPTEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	627,318,015	594,980,215	32,337,800	5.4%	14,033,698	13,599,741	433,957	3.2%	4.47008	4.37494	0.09515	2.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(81,429)	(60,606)	(20,823)	34.4%	14,033,698 (a)	13,599,741 (a)	433,957	3.2%	(0.00058)	(0.00045)	(0.00013)	30.2%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	14,033,698 (a)	13,599,741 (a)	433,957	3.2%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	126,527	158,662	(32,135)	-20.3%	14,033,698 (a)	13,599,741 (a)	433,957	3.2%	0.00090	0.00117	(0.00027)	-22.7%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**627,363,113**	**595,078,271**	**32,284,842**	**5.4%**	**14,033,698**	**13,599,741**	**433,957**	**3.2%**	**4.47040**	**4.37566**	**0.09475**	**2.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	41,847,404	145,942,100	(104,094,696)	-71.3%	692,192	2,406,985	(1,714,793)	-71.2%	6.04564	6.06327	(0.01764)	-0.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	69,115,710	0	69,115,710	0.0%	995,447	0	995,447	0.0%	6.94318	0.00000	6.94318	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	12,853,537	9,821,600	3,031,937	30.9%	413,204	326,870	86,334	26.4%	3.11070	3.00474	0.10596	3.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**123,816,651**	**155,763,700**	**(31,947,049)**	**-20.5%**	**2,100,843**	**2,733,855**	**(633,012)**	**-23.2%**	**5.89367**	**5.69758**	**0.19608**	**3.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**16,134,541**	**16,333,596**	**(199,055)**	**-1.2%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	566,357	406,100	160,257	39.5%	14,828	13,875	953	6.9%	3.81948	2.92685	0.89264	30.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,020)	0	(21,020)	0.0%	29	0	29	0.0%	(72.48276)	0.00000	(72.48276)	0.0%
16. Fuel Cost of Sch. D Sales (A6)	3,129,248	0	3,129,248	0.0%	65,510	0	65,510	0.0%	4.77675	0.00000	4.77675	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,796,383	9,880,800	(7,084,417)	-71.7%	56,297	171,959	(115,662)	-67.3%	4.96720	5.74602	(0.77882)	-13.6%
18. Gains on Market Based Sales	592,911	2,730,680	(2,137,769)	-78.3%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**7,063,879**	**13,017,580**	**(5,953,701)**	**-45.7%**	**136,665**	**185,834**	**(49,169)**	**-26.5%**	**5.16875**	**7.00495**	**(1.83620)**	**-26.2%**
20. Net Inadvertant Interchange					(665)	0	(665)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					38,173	0	38,173	0.0%				
22. Interchange and Wheeling Losses					33,335	3,400	29,935	880.4%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**744,115,885**	**737,824,391**	**6,291,494**	**0.9%**	**16,002,049**	**16,144,362**	**(142,313)**	**-0.9%**	**4.65013**	**4.57017**	**0.07996**	**1.7%**
24. Net Unbilled	5,388,381 (a)	7,538,511 (a)	(2,150,130)	-28.5%	66,907	167,459	(100,552)	-60.0%	8.05354	4.50171	3.55183	78.9%
25. Company Use	1,248,542 (a)	1,272,035 (a)	(23,493)	-1.8%	27,011	27,900	(889)	-3.2%	4.62235	4.55927	0.06308	1.4%
26. T & D Losses	42,291,877 (a)	32,283,219 (a)	10,008,658	31.0%	930,819	704,219	226,600	32.2%	4.54351	4.58426	(0.04075)	-0.9%
27. System KWH Sales	744,115,885	737,824,391	6,291,494	0.9%	14,977,312	15,244,784	(267,472)	-1.8%	4.96829	4.83985	0.12844	2.7%
28. Wholesale KWH Sales	(26,381,448)	(19,243,586)	(7,137,862)	37.1%	(539,633)	(394,655)	(144,978)	36.7%	4.88878	4.87605	0.01272	0.3%
29. Jurisdictional KWH Sales (Incl adj from Sch A2,Pg2,Line C5a)	717,734,500	718,580,805	(846,305)	-0.1%	14,437,679	14,850,129	(412,450)	-2.8%	4.97126	4.83889	0.13237	2.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	718,351,752	719,198,786	(847,034)	-0.1%	14,437,679	14,850,129	(412,450)	-2.8%	4.97553	4.84305	0.13249	2.7%
32. Other	0	0	0	0.0%	14,437,679	14,850,129	(412,450)	-2.8%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(12,039,375)	(11,486,250)	(553,125)	4.8%	14,437,679	14,850,129	(412,450)	-2.8%	(0.08339)	(0.07735)	(0.00604)	7.8%
34. Other	0	0	0	0.0%	14,437,679	14,850,129	(412,450)	-2.8%	0.00000	0.00000	0.00000	0.0%
35. True-up *	110,742,165	110,742,167	(2)	0.0%	14,437,679	14,850,129	(412,450)	-2.8%	0.76704	0.74573	0.02130	2.9%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	817,054,542	818,454,703	(1,400,161)	-0.2%	14,437,679	14,850,129	(412,450)	-2.8%	5.65918	5.51143	0.14775	2.7%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	817,642,821	819,043,990	(1,401,169)	-0.2%	14,437,679	14,850,129	(412,450)	-2.8%	5.66326	5.51540	0.14786	2.7%
39. GPIF * (Already Adjusted for Taxes)	547,155	547,155	0	0.0%	14,437,679	14,850,129	(412,450)	-2.8%	0.00379	0.00368	0.00011	2.9%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**818,189,976**	**819,591,145**	**(1,401,169)**	**-0.2%**	**14,437,679**	**14,850,129**	**(412,450)**	**-2.8%**	**5.66705**	**5.51908**	**0.14797**	**2.7%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.667**	**5.519**	**0.148**	**2.7%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	71,680,875	71,780,397	(99,522)	-0.1%	627,318,015	594,980,215	32,337,800	5.4%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	476,824	807,100	(330,276)	-40.9%	6,470,968	10,286,900	(3,815,932)	-37.1%
2a. GAINS FROM MARKET BASED SALES	1,996	130,800	(128,804)	-98.5%	592,911	2,730,680	(2,137,769)	-78.3%
3. FUEL COST OF PURCHASED POWER	6,615,804	21,747,800	(15,131,996)	-69.6%	41,847,404	145,942,100	(104,094,696)	-71.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,595,686	1,131,500	464,186	41.0%	12,853,537	9,821,600	3,031,937	30.9%
4. ENERGY COST OF ECONOMY PURCHASES	8,755,425	0	8,755,425	0.0%	69,115,710	0	69,115,710	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	88,168,970	93,721,797	(5,552,827)	-5.9%	744,070,787	737,726,335	6,344,452	0.9%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(9,677)	(6,734)	(2,943)	43.7%	(81,429)	(60,606)	(20,823)	34.4%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	21,026	38,443	(17,417)	-45.3%	126,527	158,662	(32,135)	-20.3%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	88,180,319	93,753,506	(5,573,187)	-5.9%	744,115,885	737,824,391	6,291,494	0.9%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,853,320	1,937,432	(84,112)	-4.3%	14,437,679	14,850,129	(412,450)	-2.8%
2. NONJURISDICTIONAL SALES	51,272	51,533	(261)	-0.5%	539,633	394,655	144,978	36.7%
3. TOTAL SALES	1,904,592	1,988,965	(84,373)	-4.2%	14,977,312	15,244,784	(267,472)	-1.8%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9730798	0.9740905	(0.0010107)	-0.1%	0.9639700	0.9741121	(0.0101421)	-1.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	99,761,089	104,835,518	(5,074,429)	-4.8%	776,359,210	803,170,716	(26,811,506)	-3.3%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(110,742,165)	(110,742,167)	2	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(547,155)	(547,155)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	87,395,609	92,470,038	(5,074,429)	-5.5%	665,069,890	691,881,395	(26,811,505)	-3.9%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	88,180,319	93,753,506	(5,573,187)	-5.9%	744,115,885	737,824,391	6,291,494	0.9%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9730798	0.9740905	(0.0010107)	-0.1%	NA	NA	-	0.0%
5a. Other	0	0	0	0.0%	63	0	63	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	85,806,485	91,324,400	(5,517,915)	-6.0%	717,734,500	718,580,805	(846,305)	-0.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	85,880,279	91,402,939	(5,522,660)	-6.0%	718,351,752	719,198,786	(847,034)	-0.1%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,063,551)	(1,276,250)	212,699	-16.7%	(12,039,375)	(11,486,250)	(553,125)	4.8%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	84,816,728	90,126,689	(5,309,961)	-5.9%	706,312,377	707,712,536	(1,400,159)	-0.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	2,578,881	2,343,349	235,532	10.1%	(41,242,487)	(15,831,142)	(25,411,346)	160.5%
8. INTEREST PROVISION FOR THE MONTH	(874,137)	(236,904)	(637,233)	269.0%	(7,879,101)	(3,341,986)	(4,537,115)	135.8%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(206,561,911)	(70,498,313)	(136,063,598)	193.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(192,552,482)	(56,087,183)	(136,465,299)	243.3%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(206,561,911)	(70,498,313)	(136,063,598)	193.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(191,678,345)	(55,850,279)	(135,828,066)	243.2%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(398,240,256)	(126,348,592)	(271,891,664)	215.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(199,120,128)	(63,174,296)	(135,945,832)	215.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.270	4.500	0.770	17.1%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.260	4.500	0.760	16.9%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	10.530	9.000	1.530	17.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.265	4.500	0.765	17.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.439	0.375	0.064	17.1%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(874,137)	(236,904)	(637,233)	269.0%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	103,178	501,297	(398,119)	-79.4%	2,291,974	2,124,937	167,037	7.9%
2	LIGHT OIL	196,851	710,189	(513,338)	-72.3%	4,607,862	6,072,471	(1,464,609)	-24.1%
3	COAL	26,353,634	22,706,643	3,646,991	16.1%	223,345,146	211,620,399	11,724,747	5.5%
4	NATURAL GAS	45,027,212	47,862,268	(2,835,056)	-5.9%	397,073,033	375,162,408	21,910,625	5.8%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	71,680,875	71,780,397	(99,522)	-0.1%	627,318,015	594,980,215	32,337,800	5.4%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	836	6,585	(5,749)	-87.3%	22,745	27,931	(5,186)	-18.6%
9	LIGHT OIL	854	5,314	(4,460)	-83.9%	31,269	45,121	(13,852)	-30.7%
10	COAL	971,098	853,253	117,845	13.8%	8,489,679	8,041,573	448,106	5.6%
11	NATURAL GAS	629,057	763,746	(134,689)	-17.6%	5,491,279	5,485,116	6,163	0.1%
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)	1,601,845	1,628,898	(27,053)	-1.7%	14,034,972	13,599,741	435,231	3.2%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	1,593	10,226	(8,633)	-84.4%	36,824	43,367	(6,543)	-15.1%
16	LIGHT OIL (BBL)	2,241	13,449	(11,208)	-83.3%	54,806	120,973	(66,167)	-54.7%
17	COAL (TON)	449,104	383,032	66,072	17.2%	3,888,504	3,621,797	266,707	7.4%
18	NATURAL GAS (MCF)	4,632,389	5,603,693	(971,304)	-17.3%	39,780,741	40,274,549	(493,808)	-1.2%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	9,994	64,204	(54,210)	-84.4%	231,026	272,282	(41,256)	-15.2%
22	LIGHT OIL	12,433	58,867	(46,434)	-78.9%	310,369	512,465	(202,096)	-39.4%
23	COAL	10,652,478	9,208,540	1,443,938	15.7%	91,609,963	86,879,628	4,730,335	5.4%
24	NATURAL GAS	4,785,258	5,760,668	(975,410)	-16.9%	41,162,695	41,402,003	(239,308)	-0.6%
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)	15,460,163	15,092,279	367,884	2.4%	133,314,052	129,066,378	4,247,674	3.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.05%	0.40%	(0.00)	-	0.16%	0.21%	(0.00)	-
29	LIGHT OIL	0.05%	0.33%	(0.00)	-	0.22%	0.33%	(0.00)	-
30	COAL	60.62%	52.38%	0.08	-	60.49%	59.13%	0.01	-
31	NATURAL GAS	39.27%	46.89%	(0.08)	-	39.13%	40.33%	(0.01)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	64.77	49.02	15.75	32.1%	62.24	49.00	13.24	27.0%
36	LIGHT OIL ($/BBL)	87.84	52.81	35.03	66.3%	84.08	50.20	33.88	67.5%
37	COAL ($/TON)	58.68	59.28	(0.60)	-1.0%	57.44	58.43	(0.99)	-1.7%
38	NATURAL GAS ($/MCF)	9.72	8.54	1.18	13.8%	9.98	9.32	0.67	7.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	10.32	7.81	2.52	32.2%	9.92	7.80	2.12	27.1%
42	LIGHT OIL	15.83	12.06	3.77	31.2%	14.85	11.85	3.00	25.3%
43	COAL	2.47	2.47	0.01	0.3%	2.44	2.44	0.00	0.1%
44	NATURAL GAS	9.41	8.31	1.10	13.3%	9.65	9.06	0.58	6.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.64	4.76	(0.12)	-2.5%	4.71	4.61	0.10	2.1%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	11,955	9,750	2,205	22.6%	10,157	9,748	409	4.2%
49	LIGHT OIL	14,558	11,078	3,480	31.4%	9,926	11,358	(1,432)	-12.6%
50	COAL	10,970	10,792	178	1.6%	10,791	10,804	(13)	-0.1%
51	NATURAL GAS	7,607	7,543	64	0.8%	7,496	7,548	(52)	-0.7%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,651	9,265	386	4.2%	9,499	9,490	9	0.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	12.34	7.61	4.73	62.2%	10.08	7.61	2.47	32.5%
56	LIGHT OIL	23.05	13.36	9.69	72.5%	14.74	13.46	1.28	9.5%
57	COAL	2.71	2.66	0.05	1.9%	2.63	2.63	0.00	0.0%
58	NATURAL GAS	7.16	6.27	0.89	14.2%	7.23	6.84	0.39	5.7%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.47	4.41	0.06	1.4%	4.47	4.37	0.10	2.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	219,697	74.2	78.4	74.2	11,263	COAL	105,417	23,473,840	2,474,541.8	6,269,732	2.85	59.48
B.B.#2	391	142,137	50.5	51.2	71.8	10,656	COAL	64,589	23,449,760	1,514,596.5	3,841,465	2.70	59.48
B.B.#3	414	218,934	73.4	76.9	76.2	10,911	COAL	101,633	23,503,500	2,388,731.2	6,044,677	2.76	59.48
B.B.#4	457	243,347	74.0	83.1	76.1	11,329	COAL	118,373	23,288,820	2,756,767.5	7,040,298	2.89	59.48
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	2,065	5,807,630	11,993.3	176,045	-	85.25
B.B. STATION	**1,673**	**824,115**	**68.4**	**72.9**	**74.7**	**11,084**	-	-	-	-	**23,372,217**	**2.84**	-
SEB-PHIL. #1(HVY OIL)	17	448	3.7	100.0	63.2	11,955	HVY.OIL	854	6,273,540	5,360.7	48,087	10.73	56.31
SEB-PHIL. #2(HVY OIL)	17	388	3.2	99.6	65.4	11,955	HVY.OIL	739	6,273,540	4,633.4	41,612	10.72	56.31
SEB-PHIL. IGNITION	-	-	-	-	-	-	LGT.OIL	130	5,807,630	752.1	13,479	-	103.68
SEB-PHILLIPS TOTAL	**34**	**836**	**3.4**	**99.8**	**64.3**	**11,955**	-	-	-	-	**103,178**	**12.34**	-
POLK #1 GASIFIER	255	146,983	-	-	-	10,327	COAL	59,092	25,686,000	1,517,841.2	2,981,417	2.03	50.45
POLK #1 CT (OIL)	225	854	-	-	-	14,564	LGT.OIL	2,241	5,780,693	12,432.4	196,851	23.05	87.84
POLK #1 TOTAL	**255**	**147,837**	**80.5**	**87.6**	**86.9**	**10,351**	-	-	-	**1,530,273.6**	**3,178,268**	**2.15**	-
POLK #2 CT (GAS)	150	11,327	-	-	-	11,404	GAS	125,049	1,033,000	129,176.0	1,206,034	10.65	9.64
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	(9,749)	0.00	0.00
POLK #2 TOTAL	**155**	**11,327**	**10.1**	**100.0**	**76.9**	**11,404**	-	-	-	**129,176.0**	**1,196,285**	**10.56**	-
POLK #3 CT (GAS)	150	12,346	-	-	-	12,009	GAS	143,524	1,033,000	148,260.3	1,383,331	11.20	9.64
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	9,749	0.00	0.00
POLK #3 TOTAL	**155**	**12,346**	**11.1**	**100.0**	**77.4**	**12,009**	-	-	-	**148,260.3**	**1,393,080**	**11.28**	-
POLK STATION TOTAL	**565**	**171,510**	**42.2**	**94.4**	**81.5**	**10,540**	-	-	-	**1,807,709.9**	**5,767,633**	**3.36**	-
B.B.C.T.#1	14	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**146**	**0**	**0.0**	**100.0**	**0.0**	**0**	**LGT.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
COT 1	3	309	14.3	99.7	93.1	14,526	GAS	4,345	1,033,000	4,488.6	39,478	12.78	9.09
COT 2	3	296	13.7	100.0	87.8	14,526	GAS	4,162	1,033,000	4,299.4	37,815	12.78	9.09
CITY OF TAMPA TOTAL	**6**	**605**	**14.0**	**99.8**	**90.5**	**14,526**	**GAS**	**8,507**	**1,033,000**	**8,788.0**	**77,293**	**12.78**	**9.09**
BAYSIDE ST 1	234	66,933	39.7	84.5	47.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	0	0.0	0.0	0.0	0	GAS	0	1,033,000	0.0	0	0.00	0.00
BAYSIDE CT1B	156	60,299	53.7	83.1	80.0	11,633	GAS	679,022	1,033,000	701,430.0	6,601,963	10.95	9.72
BAYSIDE CT1C	156	65,912	58.7	84.5	79.2	11,045	GAS	704,728	1,033,000	727,984.0	6,851,897	10.40	9.72
BAYSIDE UNIT 1 TOTAL	**702**	**193,144**	**38.2**	**65.4**	**51.1**	**7,401**	**GAS**	**1,383,750**	**1,033,000**	**1,429,414.0**	**13,453,860**	**6.97**	**9.72**
BAYSIDE ST 2	306	141,269	64.1	98.4	65.2	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	59,480	53.0	100.0	82.9	11,211	GAS	645,556	1,033,000	666,859.0	6,279,831	10.56	9.73
BAYSIDE CT2B	156	70,466	62.7	100.0	82.6	11,444	GAS	780,673	1,033,000	806,435.0	7,594,221	10.78	9.73
BAYSIDE CT2C	156	78,333	69.7	99.9	82.5	11,414	GAS	865,511	1,033,000	894,073.0	8,419,507	10.75	9.73
BAYSIDE CT2D	156	62,087	55.3	98.3	82.7	11,311	GAS	679,819	1,033,000	702,253.0	6,613,135	10.65	9.73
BAYSIDE UNIT 2 TOTAL	**930**	**411,635**	**61.5**	**99.2**	**76.9**	**7,457**	**GAS**	**2,971,559**	**1,033,000**	**3,069,620.0**	**28,906,694**	**7.02**	**9.73**
BAYSIDE STATION TOTAL	**1,632**	**604,779**	**51.5**	**84.7**	**65.8**	**7,439**	**GAS**	**4,355,309**	**1,033,000**	**4,499,034.0**	**42,360,554**	**7.00**	**9.73**
SYSTEM	**4,056**	**1,601,845**	**54.9**	**81.9**	**69.3**	**9,651**	-	-	-	**15,460,163.0**	**71,680,875**	**4.47**	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	1,884	10,226	(8,342)	-81.6%	41,452	43,367	(1,915)	-4.4%
3 UNIT COST ($/BBL)	56.18	47.96	8.22	17.1%	58.74	47.71	11.03	23.1%
4 AMOUNT ($)	105,839	490,402	(384,563)	-78.4%	2,434,855	2,069,004	365,851	17.7%
5 BURNED:								
6 UNITS (BBL)	1,593	10,226	(8,633)	-84.4%	36,824	43,367	(6,543)	-15.1%
7 UNIT COST ($/BBL)	64.77	49.02	15.75	32.1%	62.24	49.00	13.24	27.0%
8 AMOUNT ($)	103,178	501,297	(398,119)	-79.4%	2,291,974	2,124,937	167,037	7.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	19,959	12,118	7,841	64.7%	19,959	12,118	7,841	64.7%
11 UNIT COST ($/BBL)	58.13	47.80	10.33	21.6%	58.13	47.80	10.33	21.6%
12 AMOUNT ($)	1,160,187	579,279	580,908	100.3%	1,160,187	579,279	580,908	100.3%
13								
14 DAYS SUPPLY:	148	90	58	60.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	2,839	13,449	(10,610)	-78.9%	119,998	120,973	(975)	-0.8%
17 UNIT COST ($/BBL)	76.33	70.85	5.48	7.7%	87.50	70.52	16.97	24.1%
18 AMOUNT ($)	216,713	952,901	(736,188)	-77.3%	10,499,262	8,531,243	1,968,019	23.1%
19 BURNED:								
20 UNITS (BBL)	2,241	13,449	(11,208)	-83.3%	54,806	120,973	(66,167)	-54.7%
21 UNIT COST ($/BBL)	87.84	52.81	35.03	66.3%	84.08	50.20	33.88	67.5%
22 AMOUNT ($)	196,851	710,189	(513,338)	-72.3%	4,607,862	6,072,471	(1,464,609)	-24.1%
23 ENDING INVENTORY:								
24 UNITS (BBL)	102,599	85,007	17,592	20.7%	102,599	85,007	17,592	20.7%
25 UNIT COST ($/BBL)	86.47	68.40	18.07	26.4%	86.47	68.40	18.07	26.4%
26 AMOUNT ($)	8,871,377	5,814,056	3,057,321	52.6%	8,871,377	5,814,056	3,057,321	52.6%
27								
28 DAYS SUPPLY: NORMAL	215	178	37	20.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	12	3	20.7%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	337,691	354,700	(17,009)	-4.8%	3,966,692	3,598,000	368,692	10.2%
32 UNIT COST ($/TON)	60.72	59.42	1.30	2.2%	57.95	58.05	(0.10)	-0.2%
33 AMOUNT ($)	20,504,386	21,077,494	(573,108)	-2.7%	229,877,437	208,869,894	21,007,543	10.1%
34 BURNED:								
35 UNITS (TONS)	449,104	383,032	66,072	17.2%	3,888,504	3,621,797	266,707	7.4%
36 UNIT COST ($/TON)	58.68	59.28	(0.60)	-1.0%	57.44	58.43	(0.99)	-1.7%
37 AMOUNT ($)	26,353,634	22,706,643	3,646,991	16.1%	223,345,146	211,620,399	11,724,747	5.5%
38 ENDING INVENTORY:								
39 UNITS (TONS)	549,577	522,951	26,626	5.1%	549,577	522,951	26,626	5.1%
40 UNIT COST ($/TON)	58.18	58.46	(0.28)	-0.5%	58.18	58.46	(0.28)	-0.5%
41 AMOUNT ($)	31,972,947	30,572,155	1,400,792	4.6%	31,972,947	30,572,155	1,400,792	4.6%
42								
43 DAYS SUPPLY:	42	40	2	0.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	4,666,348	5,603,693	(937,345)	-16.7%	39,786,257	40,274,549	(488,292)	-1.2%
46 UNIT COST ($/MCF)	9.60	8.54	1.06	12.4%	9.94	9.32	0.63	6.7%
47 AMOUNT ($)	44,781,228	47,862,268	(3,081,040)	-6.4%	395,554,263	375,162,405	20,391,858	5.4%
48 BURNED:								
49 UNITS (MCF)	4,632,389	5,603,693	(971,304)	-17.3%	39,780,741	40,274,549	(493,808)	-1.2%
50 UNIT COST ($/MCF)	9.72	8.54	1.18	13.8%	9.98	9.32	0.67	7.2%
51 AMOUNT ($)	45,027,212	47,862,268	(2,835,056)	-5.9%	397,073,033	375,162,408	21,910,625	5.8%
52 ENDING INVENTORY:								
53 UNITS (MCF)	191,782	0	191,782	0.0%	191,782	0	191,782	0.0%
54 UNIT COST ($/MCF)	5.35	0.00	5.35	0.0%	5.35	0.00	5.35	0.0%
55 AMOUNT ($)	1,025,428	0	1,025,428	0.0%	1,025,428	0	1,025,428	0.0%
56								
57 DAYS SUPPLY:	2	0	2	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	12,093
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	12,093

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(2,195)	(188,138)
OTHER USAGE	(497)	(42,876)
TOTAL	(2,692)	(231,014)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	61,696
IGNITION #2 OIL	176,045
IGNITION PROPANE	15,424
AERIAL SURVEY ADJ.	(691,857)
ADDITIVES	107,900
GREEN FUEL	0
TOTAL	(330,792)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,335.0	0.0	1,335.0	2.562	2.562	34,200.00	34,200.00	
VARIOUS	JURISDIC.	SCH. - MB	11,932.0	0.0	11,932.0	6.478	8.138	772,900.00	971,000.00	130,800.00
TOTAL			13,267.0	0.0	13,267.0	6.084	7.577	807,100.00	1,005,200.00	130,800.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	695.2	2.5	692.7	3.507	3.745	24,290.57	25,944.74	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,228.5	0.0	1,228.5	2.829	3.016	34,749.07	37,050.96	
PROGRESS ENERGY FLORIDA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	150.0	0.0	150.0	2.607	4.643	3,911.07	6,963.76	2,745.19
CITY OF LAKELAND		SCH. - MA	20.0	0.0	20.0	3.631	4.665	726.20	932.97	144.77
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(584.03)	(584.03)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE FOR SEMINOLE ELEC. CO-OP*		SCH. - MA	35.0	0.0	35.0	3.406	3.854	1,192.10	1,348.83	150.78
LESS 20% - THRESHHOLD EXCESS		SCH. - MA								(461.18)
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - D	7,200.0	0.0	7,200.0	5.300	5.900	381,600.00	424,800.00	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. PRECO-1	AUGUST 2006	SCH. - D	(710.9)	(10.7)	(700.2)	5.292	5.590	(37,056.69)	(39,138.32)	
SEMINOLE ELEC. PRECO-1	AUGUST 2006	SCH. - D	710.9	10.0	700.9	5.287	5.584	37,056.69	39,138.32	
NEW SMYRNA BEACH	AUGUST 2006	SEP SCH. - D	(7,440.0)	0.0	(7,440.0)	4.892	5.492	(363,964.80)	(408,604.80)	
NEW SMYRNA BEACH	AUGUST 2006	SEP SCH. - D	7,440.0	0.0	7,440.0	5.300	5.900	394,320.00	438,960.00	
SUB-TOTAL SEP SCHEDULE D POWER SALES			7,200.0	0.0	7,200.0	5.722	6.322	411,955.20	455,155.20	
SUB-TOTAL SCHEDULE D POWER SALES			1,923.7	1.8	1,921.9	3.072	3.278	59,039.64	62,995.70	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			205.0	0.0	205.0	2.844	4.225	5,829.37	8,661.53	1,995.53
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			9,328.7	1.8	9,326.9	5.112	5.648	476,824.21	526,812.43	1,995.53
CURRENT MONTH:										
DIFFERENCE			(3,938.3)	1.8	(3,940.1)	(0.972)	(1.929)	(330,275.79)	(478,387.57)	(128,804.47)
DIFFERENCE %			-29.7%	0.0%	-29.7%	-16.0%	-25.5%	-40.9%	-47.6%	-98.5%
PERIOD TO DATE:										
ACTUAL			136,682.3	19.5	136,662.8	4.735	5.602	6,470,967.41	7,656,062.62	592,910.71
ESTIMATED			185,834.0	0.0	185,834.0	5.536	7.531	10,286,900.00	13,994,300.00	2,730,680.00
DIFFERENCE			(49,151.7)	19.5	(49,171.2)	(0.801)	(1.929)	(3,815,932.59)	(6,338,237.38)	(2,137,769.29)
DIFFERENCE %			-26.4%	0.0%	-26.5%	-14.5%	-25.6%	-37.1%	-45.3%	-78.3%

* SEC 60% PROFIT OR $226.17 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	3,039.0	0.0	1,926.0	1,113.0	10.072	10.072	112,100.00
HARDEE POWER PARTNERS		IPP	41,152.0	0.0	0.0	41,152.0	8.225	8.225	3,384,700.00
CALPINE		SCH. - D	18,791.0	0.0	0.0	18,791.0	10.245	10.245	1,925,200.00
VARIOUS		MKT. BASED	174,729.0	0.0	0.0	174,729.0	7.256	7.256	12,679,000.00
OTHER		SCH. - D	93,022.0	0.0	0.0	93,022.0	3.920	3.920	3,646,800.00
TOTAL			**330,733.0**	**0.0**	**1,926.0**	**328,807.0**	**6.614**	**6.614**	**21,747,800.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	67,408.0	0.0	0.0	67,408.0	5.837	5.837	3,934,446.85
HARDEE PWR. PART.-OTHERS		IPP	35.0	0.0	0.0	35.0	3.423	3.423	1,198.05
PROGRESS ENERGY FLORIDA		SCH. - D	35,550.0	0.0	0.0	35,550.0	3.716	3.716	1,321,038.00
CALPINE		SCH. - D	17,156.0	0.0	0.0	17,156.0	7.280	7.280	1,249,035.03
CALPINE		OATT	1,488.0	0.0	0.0	1,488.0	2.943	2.943	43,797.85
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	AUGUST 2006	IPP	(65,472.0)	0.0	0.0	(65,472.0)	8.397	8.397	(5,497,548.49)
HARDEE PWR. PART.-NATIVE	AUGUST 2006	IPP	65,472.0	0.0	0.0	65,472.0	8.451	8.451	5,532,995.11
PROGRESS ENERGY FLORIDA	AUGUST 2006	SCH. - D	(36,300.0)	0.0	0.0	(36,300.0)	3.608	3.608	(1,309,704.00)
PROGRESS ENERGY FLORIDA	AUGUST 2006	SCH. - D	36,300.0	0.0	0.0	36,300.0	3.716	3.716	1,348,908.00
CALPINE	AUGUST 2006	SCH. - D	(22,240.0)	0.0	0.0	(22,240.0)	11.502	11.502	(2,557,972.92)
CALPINE	AUGUST 2006	SCH. - D	22,240.0	0.0	0.0	22,240.0	11.464	11.464	2,549,608.92
CALPINE	AUGUST 2006	OATT	(1,413.0)	0.0	0.0	(1,413.0)	4.315	4.315	(60,973.49)
CALPINE	AUGUST 2006	OATT	1,413.0	0.0	0.0	1,413.0	4.315	4.315	60,975.03
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	66,288.16
TOTAL			**121,637.0**	**0.0**	**0.0**	**121,637.0**	**5.439**	**5.439**	**6,615,803.94**
CURRENT MONTH:									
DIFFERENCE			(209,096.0)	0.0	(1,926.0)	(207,170.0)	(1.175)	(1.175)	(15,131,996.06)
DIFFERENCE %			-63.2%	0.0%	0.0%	-63.0%	-17.8%	-17.8%	-69.6%
PERIOD TO DATE:									
ACTUAL			692,192.0	0.0	0.0	692,192.0	6.046	6.046	41,847,405.01
ESTIMATED			2,415,668.0	0.0	8,683.0	2,406,985.0	6.063	6.063	145,942,100.00
DIFFERENCE			(1,723,476.0)	0.0	(8,683.0)	(1,714,793.0)	(0.017)	(0.017)	(104,094,694.99)
DIFFERENCE %			-71.3%	0.0%	-100.0%	-71.2%	-0.3%	-0.3%	-71.3%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	36,546.0	0.0	0.0	36,546.0	3.096	3.096	1,131,500.00
TOTAL		**36,546.0**	**0.0**	**0.0**	**36,546.0**	**3.096**	**3.096**	**1,131,500.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	17,142.0	0.0	0.0	17,142.0	2.572	2.572	440,944.92
McKAY BAY REFUSE	COGEN.	13,372.0	0.0	0.0	13,372.0	2.571	2.571	343,741.35
ORANGE COGENERATION L.P.	COGEN.	7,590.0	0.0	0.0	7,590.0	2.378	2.378	180,503.23
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	1.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	1,462.0	0.0	0.0	1,462.0	4.001	4.001	58,495.76
CF INDUSTRIES INC.	COGEN.	612.0	0.0	0.0	612.0	4.547	4.547	27,830.38
IMC-AGRICO-NEW WALES	COGEN.	876.0	0.0	0.0	876.0	4.212	4.212	36,893.46
IMC-AGRICO-S. PIERCE	COGEN.	10,977.0	0.0	0.0	10,977.0	4.593	4.593	504,157.39
AUBURNDALE POWER PARTNERS	COGEN.	903.0	0.0	0.0	903.0	4.029	4.029	36,382.32
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR SEPTEMBER 2006		52,934.0	0.0	0.0	52,934.0	3.077	3.077	1,628,949.81
ADJUSTMENTS FOR THE MONTH OF:	**AUGUST 2006**							
HILLSBOROUGH COUNTY	COGEN.	(15,643.0)	0.0	0.0	(15,643.0)	2.670	2.670	(417,601.88)
		15,643.0	0.0	0.0	15,643.0	2.582	2.582	403,863.24
McKAY BAY REFUSE	COGEN.	(13,646.0)	0.0	0.0	(13,646.0)	2.668	2.668	(364,136.93)
		13,646.0	0.0	0.0	13,646.0	2.581	2.581	352,168.17
ORANGE COGENERATION L.P.	COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.486	2.486	(194,977.40)
		7,843.0	0.0	0.0	7,843.0	2.390	2.390	187,410.22
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	(739.0)	0.0	0.0	(739.0)	6.947	6.947	(51,339.74)
		739.0	0.0	0.0	739.0	6.947	6.947	51,339.64
IMC-AGRICO-S. PIERCE	COGEN.	(8,946.0)	0.0	0.0	(8,946.0)	6.396	6.396	(572,174.98)
		8,946.0	0.0	0.0	8,946.0	6.396	6.396	572,185.36
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	(33,264.30)
TOTAL		**52,934.0**	**0.0**	**0.0**	**52,934.0**	**3.014**	**3.014**	**1,595,685.51**
CURRENT MONTH:								
DIFFERENCE		16,388.0	0.0	0.0	16,388.0	(0.082)	(0.082)	464,185.51
DIFFERENCE %		44.8%	0.0%	0.0%	44.8%	-2.6%	-2.6%	41.0%
PERIOD TO DATE:								
ACTUAL		413,204.0	0.0	0.0	413,204.0	3.111	3.111	12,853,535.97
ESTIMATED		326,870.0	0.0	0.0	326,870.0	3.005	3.005	9,821,600.00
DIFFERENCE		86,334.0	0.0	0.0	86,334.0	0.106	0.106	3,031,935.97
DIFFERENCE %		26.4%	0.0%	0.0%	26.4%	3.5%	3.5%	30.9%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:								
VARIOUS		ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:								
PROGRESS ENERGY FLORIDA		SCH. - JC	2,185.0	5.128	112,045.00	6.198	135,425.50	23,380.50
FLA. POWER & LIGHT		SCH. - JC	39,286.3	5.257	2,065,101.93	6.176	2,426,240.81	361,138.88
CITY OF LAKELAND		SCH. - JC	150.0	4.967	7,450.00	9.559	14,339.00	6,889.00
ORLANDO UTIL. COMM.		SCH. - JC	6,658.0	7.390	492,045.00	10.975	730,688.54	238,643.54
THE ENERGY AUTHORITY		SCH. - JC	23,878.0	5.365	1,280,963.00	7.709	1,840,696.99	559,733.99
OKEELANTA		SCH. - JC	429.0	8.602	36,901.00	12.635	54,204.37	17,303.37
CITY OF TALLAHASSEE		SCH. - JC	110.0	8.459	9,305.00	10.267	11,293.70	1,988.70
CALPINE		SCH. - JC	9,792.0	5.739	561,937.00	8.203	803,196.18	241,259.18
CARGILL ALLIANT		SCH. - JC	26,932.0	7.649	2,059,981.00	7.945	2,139,787.01	79,806.01
CARGILL FOR NEW SMYRNA BEACH		SCH. - JC	7,220.0	5.706	411,955.20	5.706	411,955.20	0.00
RELIANT		SCH. - JC	24,016.0	6.216	1,492,908.82	6.545	1,571,758.72	78,849.90
RAINBOW ENERGY MARKETERS		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - JC	3,855.0	5.508	212,330.00	6.871	264,883.80	52,553.80
ENTERGY-KOCH TRADING		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CINCINATTI GAS & ELECTRIC		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL			144,511.3	6.050	8,742,922.95	7.200	10,404,469.82	1,661,546.87
PRIOR MONTH ADJUSTMENTS:								
RELIANT	AUGUST 2006	SCH. - JC	(14,646.3)	14.186	(2,077,766.72)	15.683	(2,296,953.94)	(219,187.22)
RELIANT	AUGUST 2006	SCH. - JC	14,740.3	14.181	2,090,268.72	15.668	2,309,455.94	219,187.22
SUBTOTAL			94.0	13.300	12,502.00	13.300	12,502.00	0.00
TOTAL			**144,605.3**	**6.055**	**8,755,424.95**	**7.204**	**10,416,971.82**	**1,661,546.87**
CURRENT MONTH:								
DIFFERENCE			144,605.3	6.055	8,755,424.95	7.204	10,416,971.82	1,661,546.87
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:								
ACTUAL			995,446.8	6.943	69,115,710.03	8.427	83,890,485.74	14,774,775.71
ESTIMATED			0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE			995,446.8	6.943	69,115,710.03	8.427	83,890,485.74	14,774,775.71
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

OCTOBER 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	76,275,167	62,146,292	14,128,875	22.7%	1,503,536	1,456,738	46,798	3.2%	5.07305	4.26613	0.80693	18.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,642)	(6,734)	(1,908)	28.3%	1,503,536 (a)	1,456,738 (a)	46,798	3.2%	(0.00057)	(0.00046)	(0.00011)	24.3%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,503,536 (a)	1,456,738 (a)	46,798	3.2%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	25,503	25,713	(210)	-0.8%	1,503,536 (a)	1,456,738 (a)	46,798	3.2%	0.00170	0.00177	(0.00007)	-3.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**76,292,028**	**62,165,271**	**14,126,757**	**22.7%**	**1,503,536**	**1,456,738**	**46,798**	**3.2%**	**5.07417**	**4.26743**	**0.80674**	**18.9%**
6. Fuel Cost of Purchased Power - Firm (A7)	5,145,908	20,078,000	(14,932,092)	-74.4%	77,705	348,602	(270,897)	-77.7%	6.62236	5.75958	0.86279	15.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	6,661,664	0	6,661,664	0.0%	100,929	0	100,929	0.0%	6.60035	0.00000	6.60035	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	2,013,536	1,149,900	863,636	75.1%	57,188	37,769	19,419	51.4%	3.52091	3.04456	0.47635	15.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**13,821,108**	**21,227,900**	**(7,406,792)**	**-34.9%**	**235,822**	**386,371**	**(150,549)**	**-39.0%**	**5.86082**	**5.49418**	**0.36665**	**6.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,739,358**	**1,843,109**	**(103,751)**	**-5.6%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	102,623	50,500	52,123	103.2%	1,999	1,589	410	25.8%	5.13474	3.17810	1.95664	61.6%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sales (A6)	307,976	0	307,976	0.0%	7,450	0	7,450	0.0%	4.13391	0.00000	4.13391	0.0%
17. Fuel Cost of Market Base Sales (A6)	51,182	779,800	(728,618)	-93.4%	1,226	12,215	(10,989)	-90.0%	4.17471	6.38395	(2.20924)	-34.6%
18. Gains on Market Based Sales	10,507	124,560	(114,053)	-91.6%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**472,288**	**954,860**	**(482,572)**	**-50.5%**	**10,675**	**13,804**	**(3,129)**	**-22.7%**	**4.42424**	**6.91727**	**(2.49303)**	**-36.0%**
20. Net Inadvertant Interchange					(736)	0	(736)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					5,976	0	5,976	0.0%				
22. Interchange and Wheeling Losses					3,065	300	2,765	921.7%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**89,640,848**	**82,438,311**	**7,202,537**	**8.7%**	**1,730,858**	**1,829,005**	**(98,147)**	**-5.4%**	**5.17898**	**4.50728**	**0.67171**	**14.9%**
24. Net Unbilled	(4,212,119) (a)	(1,672,290) (a)	(2,539,829)	151.9%	(81,331)	(37,102)	(44,229)	119.2%	5.17898	4.50728	0.67171	14.9%
25. Company Use	153,401 (a)	139,726 (a)	13,675	9.8%	2,962	3,100	(138)	-4.5%	5.17897	4.50729	0.67168	14.9%
26. T & D Losses	2,966,211 (a)	2,601,284 (a)	364,927	14.0%	57,274	57,713	(439)	-0.8%	5.17898	4.50728	0.67171	14.9%
27. System KWH Sales	89,640,848	82,438,311	7,202,537	8.7%	1,751,953	1,805,294	(53,341)	-3.0%	5.11662	4.56648	0.55015	12.0%
28. Wholesale KWH Sales	(2,562,507)	(2,269,494)	(293,013)	12.9%	(50,082)	(49,699)	(383)	0.8%	5.11662	4.56648	0.55014	12.0%
29. Jurisdictional KWH Sales (Incl adj from Sch A2,Pg2,Line C5a)	87,078,278	80,168,817	6,909,461	8.6%	1,701,871	1,755,595	(53,724)	-3.1%	5.11662	4.56648	0.55014	12.0%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	87,153,165	80,237,762	6,915,403	8.6%	1,701,871	1,755,595	(53,724)	-3.1%	5.12102	4.57040	0.55062	12.0%
32. Other	0	0	0	0.0%	1,701,871	1,755,595	(53,724)	-3.1%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,116,327)	(1,276,250)	159,923	-12.5%	1,701,871	1,755,595	(53,724)	-3.1%	(0.06559)	(0.07270)	0.00710	-9.8%
34. Other	0	0	0	0.0%	1,701,871	1,755,595	(53,724)	-3.1%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,701,871	1,755,595	(53,724)	-3.1%	0.72301	0.70088	0.02213	3.2%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	98,341,523	91,266,197	7,075,326	7.8%	1,701,871	1,755,595	(53,724)	-3.1%	5.77844	5.19859	0.57985	11.2%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	98,412,329	91,331,909	7,080,420	7.8%	1,701,871	1,755,595	(53,724)	-3.1%	5.78260	5.20233	0.58027	11.2%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,701,871	1,755,595	(53,724)	-3.1%	0.00357	0.00346	0.00011	3.2%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**98,473,124**	**91,392,704**	**7,080,420**	**7.7%**	**1,701,871**	**1,755,595**	**(53,724)**	**-3.1%**	**5.78617**	**5.20579**	**0.58038**	**11.1%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.786**	**5.206**	**0.580**	**11.1%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: OCTOBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	703,593,182	657,126,507	46,466,675	7.1%	15,537,234	15,056,479	480,755	3.2%	4.52843	4.36441	0.16402	3.8%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(90,071)	(67,340)	(22,731)	33.8%	15,537,234 (a)	15,056,479 (a)	480,755	3.2%	(0.00058)	(0.00045)	(0.00013)	29.6%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	15,537,234 (a)	15,056,479 (a)	480,755	3.2%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	152,030	184,375	(32,345)	-17.5%	15,537,234 (a)	15,056,479 (a)	480,755	3.2%	0.00098	0.00122	(0.00025)	-20.1%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**703,655,141**	**657,243,542**	**46,411,599**	**7.1%**	**15,537,234**	**15,056,479**	**480,755**	**3.2%**	**4.52883**	**4.36519**	**0.16364**	**3.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	46,993,312	166,020,100	(119,026,788)	-71.7%	769,897	2,755,587	(1,985,690)	-72.1%	6.10384	6.02485	0.07899	1.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	75,777,374	0	75,777,374	0.0%	1,096,376	0	1,096,376	0.0%	6.91162	0.00000	6.91162	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	14,867,073	10,971,500	3,895,573	35.5%	470,392	364,639	105,753	29.0%	3.16057	3.00887	0.15170	5.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**137,637,759**	**176,991,600**	**(39,353,841)**	**-22.2%**	**2,336,665**	**3,120,226**	**(783,561)**	**-25.1%**	**5.89035**	**5.67240**	**0.21795**	**3.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**17,873,899**	**18,176,705**	**(302,806)**	**-1.7%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	668,980	456,600	212,380	46.5%	16,827	15,464	1,363	8.8%	3.97571	2.95266	1.02304	34.6%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,020)	0	(21,020)	0.0%	29	0	29	0.0%	(72.48276)	0.00000	(72.48276)	0.0%
16. Fuel Cost of Sch. D Sales (A6)	3,437,224	0	3,437,224	0.0%	72,960	0	72,960	0.0%	4.71111	0.00000	4.71111	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,847,565	10,660,600	(7,813,035)	-73.3%	57,523	184,174	(126,651)	-68.8%	4.95031	5.78833	(0.83802)	-14.5%
18. Gains on Market Based Sales	603,418	2,855,240	(2,251,822)	-78.9%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**7,536,167**	**13,972,440**	**(6,436,273)**	**-46.1%**	**147,340**	**199,638**	**(52,298)**	**-26.2%**	**5.11481**	**6.99889**	**(1.88407)**	**-26.9%**
20. Net Inadvertant Interchange					(1,401)	0	(1,401)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					44,149	0	44,149	0.0%				
22. Interchange and Wheeling Losses					36,400	3,700	32,700	883.8%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**833,756,733**	**820,262,702**	**13,494,031**	**1.6%**	**17,732,907**	**17,973,367**	**(240,460)**	**-1.3%**	**4.70175**	**4.56377**	**0.13798**	**3.0%**
24. Net Unbilled	1,176,262 (a)	5,866,221 (a)	(4,689,959)	-79.9%	(14,424)	130,357	(144,781)	-111.1%	(8.15489)	4.50012	(12.65501)	-281.2%
25. Company Use	1,401,943 (a)	1,411,761 (a)	(9,818)	-0.7%	29,973	31,000	(1,027)	-3.3%	4.67735	4.55407	0.12329	2.7%
26. T & D Losses	45,258,088 (a)	34,884,503 (a)	10,373,585	29.7%	988,093	761,932	226,161	29.7%	4.58035	4.57843	0.00192	0.0%
27. System KWH Sales	833,756,733	820,262,702	13,494,031	1.6%	16,729,265	17,050,078	(320,813)	-1.9%	4.98382	4.81090	0.17292	3.6%
28. Wholesale KWH Sales	(28,943,955)	(21,513,080)	(7,430,875)	34.5%	(589,715)	(444,354)	(145,361)	32.7%	4.90813	4.84143	0.06670	1.4%
29. Jurisdictional KWH Sales (Incl adj from Sch A2,Pg2,Line C5a)	804,812,778	798,749,622	6,063,156	0.8%	16,139,550	16,605,724	(466,174)	-2.8%	4.98659	4.81009	0.17650	3.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	805,504,917	799,436,548	6,068,369	0.8%	16,139,550	16,605,724	(466,174)	-2.8%	4.99088	4.81422	0.17665	3.7%
32. Other	0	0	0	0.0%	16,139,550	16,605,724	(466,174)	-2.8%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(13,155,702)	(12,762,500)	(393,202)	3.1%	16,139,550	16,605,724	(466,174)	-2.8%	(0.08151)	(0.07686)	(0.00466)	6.1%
34. Other	0	0	0	0.0%	16,139,550	16,605,724	(466,174)	-2.8%	0.00000	0.00000	0.00000	0.0%
35. True-up *	123,046,850	123,046,852	(2)	0.0%	16,139,550	16,605,724	(466,174)	-2.8%	0.76239	0.74099	0.02140	2.9%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	915,396,065	909,720,900	5,675,165	0.6%	16,139,550	16,605,724	(466,174)	-2.8%	5.67176	5.47836	0.19340	3.5%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	916,055,150	910,375,899	5,679,251	0.6%	16,139,550	16,605,724	(466,174)	-2.8%	5.67584	5.48230	0.19354	3.5%
39. GPIF * (Already Adjusted for Taxes)	607,950	607,950	0	0.0%	16,139,550	16,605,724	(466,174)	-2.8%	0.00377	0.00366	0.00011	2.9%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**916,663,100**	**910,983,849**	**5,679,251**	**0.6%**	**16,139,550**	**16,605,724**	**(466,174)**	**-2.8%**	**5.67961**	**5.48596**	**0.19365**	**3.5%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.680**	**5.486**	**0.194**	**3.5%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	76,275,167	62,146,292	14,128,875	22.7%	703,593,182	657,126,507	46,466,675	7.1%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	461,781	830,300	(368,519)	-44.4%	6,932,749	11,117,200	(4,184,451)	-37.6%
2a. GAINS FROM MARKET BASED SALES	10,507	124,560	(114,053)	-91.6%	603,418	2,855,240	(2,251,822)	-78.9%
3. FUEL COST OF PURCHASED POWER	5,145,908	20,078,000	(14,932,092)	-74.4%	46,993,312	166,020,100	(119,026,788)	-71.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	2,013,536	1,149,900	863,636	75.1%	14,867,073	10,971,500	3,895,573	35.5%
4. ENERGY COST OF ECONOMY PURCHASES	6,661,664	0	6,661,664	0.0%	75,777,374	0	75,777,374	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	89,623,987	82,419,332	7,204,655	8.7%	833,694,774	820,145,667	13,549,107	1.7%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,642)	(6,734)	(1,908)	28.3%	(90,071)	(67,340)	(22,731)	33.8%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	25,503	25,713	(210)	-0.8%	152,030	184,375	(32,345)	-17.5%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	89,640,848	82,438,311	7,202,537	8.7%	833,756,733	820,262,702	13,494,031	1.6%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,701,871	1,755,595	(53,724)	-3.1%	16,139,550	16,605,724	(466,174)	-2.8%
2. NONJURISDICTIONAL SALES	50,082	49,699	383	0.8%	589,715	444,354	145,361	32.7%
3. TOTAL SALES	1,751,953	1,805,294	(53,341)	-3.0%	16,729,265	17,050,078	(320,813)	-1.9%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9714136	0.9724704	(0.0010568)	-0.1%	0.9647495	0.9739383	(0.0091888)	-0.9%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	91,607,924	94,959,629	(3,351,705)	-3.5%	867,967,134	898,130,345	(30,163,211)	-3.4%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(123,046,850)	(123,046,852)	2	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(607,950)	(607,950)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	79,242,444	82,594,149	(3,351,705)	-4.1%	744,312,334	774,475,543	(30,163,209)	-3.9%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	89,640,848	82,438,311	7,202,537	8.7%	833,756,733	820,262,702	13,494,031	1.6%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9714136	0.9724704	(0.0010568)	-0.1%	NA	NA	-	0.0%
5a. JUNE 2006 THRESHOLD CALC. ADJ. FOR SCHEDULES D & MA SALES	(63)	0	(63)	0.0%	0	0	0	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	87,078,278	80,168,817	6,909,461	8.6%	804,812,778	798,749,622	6,063,156	0.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	87,153,165	80,237,762	6,915,403	8.6%	805,504,917	799,436,548	6,068,369	0.8%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,116,327)	(1,276,250)	159,923	-12.5%	(13,155,702)	(12,762,500)	(393,202)	3.1%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	86,036,838	78,961,512	7,075,326	9.0%	792,349,215	786,674,048	5,675,167	0.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(6,794,394)	3,632,637	(10,427,031)	-287.0%	(48,036,881)	(12,198,505)	(35,838,376)	293.8%
8. INTEREST PROVISION FOR THE MONTH	(833,210)	(180,444)	(652,766)	361.8%	(8,712,311)	(3,522,430)	(5,189,881)	147.3%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(192,552,482)	(56,087,183)	(136,465,299)	243.3%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(187,875,401)	(40,330,305)	(147,545,096)	365.8%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(192,552,482)	(56,087,183)	(136,465,299)	243.3%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(187,042,191)	(40,149,861)	(146,892,330)	365.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(379,594,673)	(96,237,044)	(283,357,629)	294.4%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(189,797,337)	(48,118,522)	(141,678,815)	294.4%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.260	4.500	0.760	16.9%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.270	4.500	0.770	17.1%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	10.530	9.000	1.530	17.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.265	4.500	0.765	17.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.439	0.375	0.064	17.1%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(833,210)	(180,444)	(652,766)	361.8%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	266,566	252,917	13,649	5.4%	2,558,540	2,377,854	180,686	7.6%
2	LIGHT OIL	1,562,048	591,846	970,202	163.9%	6,169,910	6,664,317	(494,407)	-7.4%
3	COAL	22,139,708	21,460,187	679,521	3.2%	245,484,854	233,080,586	12,404,268	5.3%
4	NATURAL GAS	52,306,845	39,841,342	12,465,503	31.3%	449,379,878	415,003,750	34,376,128	8.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	76,275,167	62,146,292	14,128,875	22.7%	703,593,182	657,126,507	46,466,675	7.1%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	2,522	3,274	(752)	-23.0%	25,267	31,205	(5,938)	-19.0%
9	LIGHT OIL	10,026	4,577	5,449	119.1%	41,295	49,698	(8,403)	-16.9%
10	COAL	783,891	811,170	(27,279)	-3.4%	9,273,570	8,852,743	420,827	4.8%
11	NATURAL GAS	707,097	637,717	69,380	10.9%	6,198,376	6,122,833	75,543	1.2%
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)	1,503,536	1,456,738	46,798	3.2%	15,538,508	15,056,479	482,029	3.2%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	4,257	5,083	(826)	-16.3%	41,081	48,450	(7,369)	-15.2%
16	LIGHT OIL (BBL)	18,312	11,295	7,017	62.1%	73,118	132,268	(59,150)	-44.7%
17	COAL (TON)	364,548	359,389	5,159	1.4%	4,253,052	3,981,186	271,866	6.8%
18	NATURAL GAS (MCF)	5,154,510	4,639,177	515,333	11.1%	44,935,251	44,913,726	21,525	0.0%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	26,704	31,918	(5,214)	-16.3%	257,730	304,200	(46,470)	-15.3%
22	LIGHT OIL	105,595	48,812	56,783	116.3%	415,963	561,277	(145,314)	-25.9%
23	COAL	8,586,917	8,663,010	(76,093)	-0.9%	100,196,880	95,542,638	4,654,242	4.9%
24	NATURAL GAS	5,309,146	4,769,069	540,077	11.3%	46,471,841	46,171,072	300,769	0.7%
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)	14,028,362	13,512,809	515,553	3.8%	147,342,414	142,579,187	4,763,227	3.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.17%	0.22%	(0.00)	-	0.16%	0.21%	(0.00)	-
29	LIGHT OIL	0.67%	0.31%	0.00	-	0.27%	0.33%	(0.00)	-
30	COAL	52.14%	55.68%	(0.04)	-	59.68%	58.80%	0.01	-
31	NATURAL GAS	47.03%	43.78%	0.03	-	39.89%	40.67%	(0.01)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	62.62	49.76	12.86	25.8%	62.28	49.08	13.20	26.9%
36	LIGHT OIL ($/BBL)	85.30	52.40	32.90	62.8%	84.38	50.38	34.00	67.5%
37	COAL ($/TON)	60.73	59.71	1.02	1.7%	57.72	58.55	(0.83)	-1.4%
38	NATURAL GAS ($/MCF)	10.15	8.59	1.56	18.2%	10.00	9.24	0.76	8.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	9.98	7.92	2.06	26.0%	9.93	7.82	2.11	27.0%
42	LIGHT OIL	14.79	12.13	2.67	22.0%	14.83	11.87	2.96	24.9%
43	COAL	2.58	2.48	0.10	4.1%	2.45	2.44	0.01	0.4%
44	NATURAL GAS	9.85	8.35	1.50	17.9%	9.67	8.99	0.68	7.6%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	5.44	4.60	0.84	18.2%	4.78	4.61	0.17	3.6%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,588	9,749	839	8.6%	10,200	9,748	452	4.6%
49	LIGHT OIL	10,532	10,665	(133)	-1.2%	10,073	11,294	(1,221)	-10.8%
50	COAL	10,954	10,680	274	2.6%	10,805	10,792	13	0.1%
51	NATURAL GAS	7,508	7,478	30	0.4%	7,497	7,541	(44)	-0.6%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,330	9,276	54	0.6%	9,482	9,470	12	0.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	10.57	7.73	2.84	36.7%	10.13	7.62	2.51	32.9%
56	LIGHT OIL	15.58	12.93	2.65	20.5%	14.94	13.41	1.53	11.4%
57	COAL	2.82	2.65	0.17	6.4%	2.65	2.63	0.02	0.8%
58	NATURAL GAS	7.40	6.25	1.15	18.4%	7.25	6.78	0.47	6.9%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	5.07	4.27	0.80	18.7%	4.53	4.36	0.17	3.9%

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	46,321	15.1	15.5	77.0	11,353	COAL	22,444	23,431,920	525,906.0	1,353,282	2.92	60.30
B.B.#2	391	220,423	75.7	77.9	75.7	10,559	COAL	97,375	23,902,560	2,327,522.5	5,871,316	2.66	60.30
B.B.#3	414	147,686	47.9	49.4	69.0	10,950	COAL	68,364	23,655,360	1,617,175.0	4,122,071	2.79	60.30
B.B.#4	457	270,241	79.4	85.2	79.5	10,968	COAL	131,260	22,581,580	2,964,057.7	7,914,443	2.93	60.30
B.B. IGNITION	0	0	0	0	0	0	LGT.OIL	1,769	5,801,578	10,262.8	150,800	-	85.25
B.B. STATION	1,673	684,671	54.9	57.5	75.4	10,859	-	-	-	-	19,411,912	2.84	-
SEB-PHIL. #1(HVY OIL)	17	1,279	10.1	100.0	82.3	10,588	HVY.OIL	2,158	6,273,540	13,538.7	121,499	9.50	56.30
SEB-PHIL. #2(HVY OIL)	17	1,243	9.8	100.0	81.0	10,589	HVY.OIL	2,099	6,273,540	13,165.5	118,178	9.51	56.30
SEB-PHIL. IGNITION	0	0	0	0	0	0	LGT.OIL	224	5,801,578	1,299.0	26,889	-	120.04
SEB-PHILLIPS TOTAL	34	2,522	10.0	100.0	81.7	10,589	-	-	-	-	266,566	10.57	-
POLK #1 GASIFIER	255	99,220	-	-	-	11,613	COAL	45,105	25,546,000	1,152,256.2	2,727,796	2.75	60.48
POLK #1 CT (OIL)	225	8,769	-	-	-	9,673	LGT.OIL	14,721	5,778,960	84,817.4	1,255,999	14.32	85.32
POLK #1 TOTAL	255	107,989	56.8	69.5	73.4	11,456	-	-	-	1,237,073.6	3,983,795	3.69	-
POLK #2 CT (GAS)	150	11,008	-	-	-	11,851	GAS	126,653	1,030,000	130,453.0	1,285,852	11.68	10.15
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	155	11,008	9.5	100.0	77.0	11,851	-	-	-	130,453.0	1,285,852	11.68	-
POLK #3 CT (GAS)	150	10,886	-	-	-	12,336	GAS	130,377	1,030,000	134,288.0	1,327,410	12.19	10.18
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	155	10,886	9.4	100.0	76.1	12,336	-	-	-	134,288.0	1,327,410	12.19	-
POLK STATION TOTAL	565	129,883	30.9	86.2	75.1	11,563	-	-	-	1,501,814.6	6,597,057	5.08	-
B.B.C.T.#1	14	57	0.5	100.0	81.4	19,123	LGT.OIL	189	5,779,775	1,090.0	16,108	28.26	85.23
B.B.C.T.#2	66	650	1.3	97.5	100.0	15,837	LGT.OIL	1,779	5,787,792	10,293.8	151,618	23.33	85.23
B.B.C.T.#3	66	550	1.1	96.5	59.5	17,079	LGT.OIL	1,623	5,787,792	9,393.5	138,323	25.15	85.23
C.T. TOTAL	146	1,257	1.2	97.3	79.9	16,529	LGT.OIL	3,591	5,787,388	20,777.3	306,049	24.35	85.23
COT 1	3	224	10.0	100.0	84.3	9,093	GAS	1,973	1,030,000	2,032.7	17,337	7.74	8.79
COT 2	3	236	10.6	98.9	96.7	9,093	GAS	2,088	1,030,000	2,150.3	18,348	7.77	8.79
CITY OF TAMPA TOTAL	6	460	10.3	99.5	90.5	9,093	GAS	4,061	1,030,000	4,183.0	35,685	7.76	8.79
BAYSIDE ST 1	234	86,670	49.7	100.0	49.7	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	0	0.0	0.0	0.0	0	GAS	0	1,030,000	0.0	0	0.00	0.00
BAYSIDE CT1B	156	86,816	74.7	100.0	84.4	11,394	GAS	960,367	1,030,000	989,178.0	9,718,510	11.19	10.12
BAYSIDE CT1C	156	77,919	67.0	100.0	85.2	10,750	GAS	813,205	1,030,000	837,601.0	8,229,293	10.56	10.12
BAYSIDE UNIT 1 TOTAL	702	251,405	48.1	77.8	54.3	7,266	GAS	1,773,572	1,030,000	1,826,779.0	17,947,803	7.14	10.12
BAYSIDE ST 2	306	147,782	64.8	100.0	64.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	82,006	70.6	98.3	84.1	11,164	GAS	888,882	1,030,000	915,549.0	9,034,588	11.02	10.16
BAYSIDE CT2B	156	68,530	59.0	100.0	85.4	11,343	GAS	754,708	1,030,000	777,349.0	7,670,845	11.19	10.16
BAYSIDE CT2C	156	59,275	51.0	98.6	85.6	11,301	GAS	650,354	1,030,000	669,865.0	6,610,192	11.15	10.16
BAYSIDE CT2D	156	75,745	65.2	100.0	84.9	11,231	GAS	825,903	1,030,000	850,680.0	8,394,470	11.08	10.16
BAYSIDE UNIT 2 TOTAL	930	433,338	62.5	99.5	78.3	7,416	GAS	3,119,847	1,030,000	3,213,443.0	31,710,095	7.32	10.16
BAYSIDE STATION TOTAL	1,632	684,743	56.3	90.2	68.0	7,361	GAS	4,893,419	1,030,000	5,040,222.0	49,657,898	7.25	10.15
SYSTEM	4,056	1,503,536	49.8	76.5	72.6	9,330	-	-	-	14,028,362.3	76,275,167	5.07	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:

B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	0	5,083	(5,083)	-100.0%	41,452	48,450	(6,998)	-14.4%
3 UNIT COST ($/BBL)	0.00	47.93	(47.93)	-100.0%	58.74	47.73	11.01	23.1%
4 AMOUNT ($)	0	243,606	(243,606)	-100.0%	2,434,855	2,312,610	122,245	5.3%
5 BURNED:								
6 UNITS (BBL)	4,257	5,083	(826)	-16.3%	41,081	48,450	(7,369)	-15.2%
7 UNIT COST ($/BBL)	62.62	49.76	12.86	25.8%	62.28	49.08	13.20	26.9%
8 AMOUNT ($)	266,566	252,917	13,649	5.4%	2,558,540	2,377,854	180,686	7.6%
9 ENDING INVENTORY:								
10 UNITS (BBL)	15,702	12,118	3,584	29.6%	15,702	12,118	3,584	29.6%
11 UNIT COST ($/BBL)	58.01	47.84	10.17	21.3%	58.01	47.84	10.17	21.3%
12 AMOUNT ($)	910,897	579,722	331,175	57.1%	910,897	579,722	331,175	57.1%
13								
14 DAYS SUPPLY:	97	75	22	30.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	13,533	11,295	2,238	19.8%	133,531	132,268	1,263	1.0%
17 UNIT COST ($/BBL)	76.28	70.81	5.47	7.7%	86.36	70.55	15.81	22.4%
18 AMOUNT ($)	1,032,349	799,827	232,522	29.1%	11,531,611	9,331,070	2,200,541	23.6%
19 BURNED:								
20 UNITS (BBL)	18,312	11,295	7,017	62.1%	73,118	132,268	(59,150)	-44.7%
21 UNIT COST ($/BBL)	85.30	52.40	32.90	62.8%	84.38	50.38	34.00	67.5%
22 AMOUNT ($)	1,562,048	591,846	970,202	163.9%	6,169,910	6,664,317	(494,407)	-7.4%
23 ENDING INVENTORY:								
24 UNITS (BBL)	94,911	85,007	9,904	11.7%	94,911	85,007	9,904	11.7%
25 UNIT COST ($/BBL)	85.28	68.60	16.67	24.3%	85.28	68.60	16.67	24.3%
26 AMOUNT ($)	8,093,879	5,831,888	2,261,991	38.8%	8,093,879	5,831,888	2,261,991	38.8%
27								
28 DAYS SUPPLY: NORMAL	197	177	20	10.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	14	12	1	11.7%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	341,432	353,500	(12,068)	-3.4%	4,308,124	3,951,500	356,624	9.0%
32 UNIT COST ($/TON)	60.20	59.63	0.58	1.0%	58.13	58.19	(0.06)	-0.1%
33 AMOUNT ($)	20,555,782	21,078,527	(522,745)	-2.5%	250,433,219	229,948,421	20,484,798	8.9%
34 BURNED:								
35 UNITS (TONS)	364,548	359,389	5,159	1.4%	4,253,052	3,981,186	271,866	6.8%
36 UNIT COST ($/TON)	60.73	59.71	1.02	1.7%	57.72	58.55	(0.83)	-1.4%
37 AMOUNT ($)	22,139,708	21,460,187	679,521	3.2%	245,484,854	233,080,586	12,404,268	5.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	526,461	517,062	9,399	1.8%	526,461	517,062	9,399	1.8%
40 UNIT COST ($/TON)	58.27	58.92	(0.65)	-1.1%	58.27	58.92	(0.65)	-1.1%
41 AMOUNT ($)	30,678,696	30,465,364	213,332	0.7%	30,678,696	30,465,364	213,332	0.7%
42								
43 DAYS SUPPLY:	40	40	0	0.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	5,010,644	4,639,177	371,467	8.0%	44,796,901	44,913,726	(116,825)	-0.3%
46 UNIT COST ($/MCF)	10.29	8.59	1.71	19.9%	9.98	9.24	0.74	8.0%
47 AMOUNT ($)	51,581,669	39,841,342	11,740,327	29.5%	447,135,932	415,003,747	32,132,185	7.7%
48 BURNED:								
49 UNITS (MCF)	5,154,510	4,639,177	515,333	11.1%	44,935,251	44,913,726	21,525	0.0%
50 UNIT COST ($/MCF)	10.15	8.59	1.56	18.2%	10.00	9.24	0.76	8.2%
51 AMOUNT ($)	52,306,845	39,841,342	12,465,503	31.3%	449,379,878	415,003,750	34,376,128	8.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	47,916	0	47,916	0.0%	47,916	0	47,916	0.0%
54 UNIT COST ($/MCF)	6.27	0.00	6.27	0.0%	6.27	0.00	6.27	0.0%
55 AMOUNT ($)	300,252	0	300,252	0.0%	300,252	0	300,252	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,276
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	17,276

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(1,974)	(168,076)
OTHER USAGE	(935)	(79,723)
TOTAL	(2,909)	(247,799)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	79,273
IGNITION #2 OIL	150,800
IGNITION PROPANE	21,226
AERIAL SURVEY ADJ.	0
ADDITIVES	38,376
GREEN FUEL	0
TOTAL	289,675

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,589.0	0.0	1,589.0	3.178	3.178	50,500.00	50,500.00	
VARIOUS	JURISDIC.	SCH. - MB	12,215.0	0.0	12,215.0	6.384	7.936	779,800.00	969,400.00	124,560.00
TOTAL			13,804.0	0.0	13,804.0	6.015	7.388	830,300.00	1,019,900.00	124,560.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	840.2	7.0	833.2	7.592	7.922	63,253.05	66,004.46	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,165.4	0.0	1,165.4	3.346	3.576	38,994.93	41,672.84	
PROGRESS ENERGY FLORIDA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	900.0	0.0	900.0	4.007	4.806	36,060.00	43,257.88	5,334.88
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	124.0	0.0	124.0	4.214	7.131	5,224.80	8,843.02	3,361.54
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	202.0	0.0	202.0	4.900	6.206	9,897.98	12,536.20	2,220.08
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(1.61)	(1.61)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LESS 20% - THRESHHOLD EXCESS		SCH. - MA								(2,182.97)
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - D	7,450.0	0.0	7,450.0	4.707	5.307	350,671.50	395,371.50	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. PRECO-1	SEPTEMBER 2006	SCH. - D	(695.2)	(2.5)	(692.7)	3.507	3.745	(24,290.57)	(25,944.74)	
SEMINOLE ELEC. PRECO-1	SEPTEMBER 2006	SCH. - D	695.2	2.5	692.7	3.507	3.745	24,290.57	25,944.74	
NEW SMYRNA BEACH	SEPTEMBER 2006	SCH. - D	(7,200.0)	0.0	(7,200.0)	5.300	5.900	(381,600.00)	(424,800.00)	
NEW SMYRNA BEACH	SEPTEMBER 2006	SCH. - D	7,200.0	0.0	7,200.0	4.707	5.307	338,904.00	382,104.00	
SEMINOLE ELEC. PRECO-1	JUNE 2006	SCH. - D	(487.9)	0.0	(487.9)	4.239	4.500	(20,679.67)	(21,955.85)	
SEMINOLE ELEC. PRECO-1	JUNE 2006	SCH. - D	487.9	0.0	487.9	4.258	4.500	20,773.54	21,955.85	
SEMINOLE ELEC. HARDEE	JUNE 2006	SCH. - D	(1,461.8)	0.0	(1,461.8)	3.653	3.879	(53,404.75)	(56,706.64)	
SEMINOLE ELEC. HARDEE	JUNE 2006	SCH. - D	1,461.8	0.0	1,461.8	3.673	3.879	53,686.00	56,706.64	
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - MA	(100.0)	0.0	(100.0)	3.998	6.158	(3,998.00)	(6,158.13)	(1,829.71)
PROGRESS ENERGY FLORIDA	JUNE 2006	SCH. - MA	100.0	0.0	100.0	3.998	6.158	3,998.00	6,158.13	1,850.13
CITY OF LAKELAND	JUNE 2006	SCH. - MA	(275.0)	0.0	(275.0)	4.367	6.521	(12,009.75)	(17,933.18)	(5,014.76)
CITY OF LAKELAND	JUNE 2006	SCH. - MA	275.0	0.0	275.0	4.367	6.521	12,009.75	17,933.18	5,070.93
NEW SMYRNA BEACH	JUNE 2006	SCH. - MA	(8,315.0)	0.0	(8,315.0)	6.543	8.194	(544,022.75)	(681,309.57)	(118,801.88)
NEW SMYRNA BEACH	JUNE 2006	SCH. - MA	8,315.0	0.0	8,315.0	6.543	8.194	544,022.75	681,309.57	118,500.17
SUB-TOTAL SCHEDULE D POWER SALES			7,450.0	0.0	7,450.0	4.134	4.734	307,975.50	352,675.50	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,005.6	7.0	1,998.6	5.135	5.388	102,623.10	107,677.10	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			1,226.0	0.0	1,226.0	4.175	5.272	51,182.78	64,635.49	10,506.80
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			10,681.6	7.0	10,674.6	4.326	4.918	461,781.38	524,988.09	10,506.80
CURRENT MONTH:										
DIFFERENCE			(3,122.4)	7.0	(3,129.4)	(1.689)	(2.470)	(368,518.62)	(494,911.91)	(114,053.20)
DIFFERENCE %			-22.6%	0.0%	-22.7%	-28.1%	-33.4%	-44.4%	-48.5%	-91.6%
PERIOD TO DATE:										
ACTUAL			147,383.9	26.5	147,337.4	4.705	5.553	6,932,748.79	8,181,050.71	603,417.51
ESTIMATED			199,638.0	0.0	199,638.0	5.569	7.521	11,117,200.00	15,014,200.00	2,855,240.00
DIFFERENCE			(52,274.1)	26.5	(52,300.6)	(0.864)	(1.968)	(4,184,451.21)	(6,833,149.29)	(2,251,822.49)
DIFFERENCE %			-26.2%	0.0%	-26.2%	-15.5%	-26.2%	-37.6%	-45.5%	-78.9%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF OCTOBER 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	1,173.0	0.0	763.0	410.0	10.122	10.122	41,500.00
HARDEE POWER PARTNERS		IPP	14,132.0	0.0	0.0	14,132.0	8.508	8.508	1,202,400.00
CALPINE		SCH. - D	3,964.0	0.0	0.0	3,964.0	10.298	10.298	408,200.00
VARIOUS		MKT. BASED	233,661.0	0.0	0.0	233,661.0	6.317	6.317	14,761,100.00
OTHER		SCH. - D	96,435.0	0.0	0.0	96,435.0	3.800	3.800	3,664,800.00
TOTAL			**349,365.0**	**0.0**	**763.0**	**348,602.0**	**5.760**	**5.760**	**20,078,000.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	25,241.0	0.0	0.0	25,241.0	10.274	10.274	2,593,185.73
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	36,500.0	0.0	0.0	36,500.0	3.757	3.757	1,371,305.00
CALPINE		SCH. - D	14,598.0	0.0	0.0	14,598.0	7.603	7.603	1,109,851.99
CALPINE		OATT	1,266.0	0.0	0.0	1,266.0	3.880	3.880	49,117.99
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. PWR. & LIGHT		EMERG.	100.0	0.0	0.0	100.0	18.544	18.544	18,544.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	SEPT. 2006	IPP	(67,408.0)	0.0	0.0	(67,408.0)	5.837	5.837	(3,934,446.85)
HARDEE PWR. PART.-NATIVE	SEPT. 2006	IPP	67,408.0	0.0	0.0	67,408.0	5.821	5.821	3,923,774.38
PROGRESS ENERGY FLORIDA	SEPT. 2006	SCH. - D	(35,550.0)	0.0	0.0	(35,550.0)	3.716	3.716	(1,321,038.00)
PROGRESS ENERGY FLORIDA	SEPT. 2006	SCH. - D	35,550.0	0.0	0.0	35,550.0	3.757	3.757	1,335,613.50
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	3,903.03
TOTAL			**77,705.0**	**0.0**	**0.0**	**77,705.0**	**6.622**	**6.622**	**5,145,907.74**
CURRENT MONTH:									
DIFFERENCE			(271,660.0)	0.0	(763.0)	(270,897.0)	0.862	0.862	(14,932,092.26)
DIFFERENCE %			-77.8%	0.0%	0.0%	-77.7%	15.0%	15.0%	-74.4%
PERIOD TO DATE:									
ACTUAL			769,897.0	0.0	0.0	769,897.0	6.104	6.104	46,993,312.75
ESTIMATED			2,765,033.0	0.0	9,446.0	2,755,587.0	6.025	6.025	166,020,100.00
DIFFERENCE			(1,995,136.0)	0.0	(9,446.0)	(1,985,690.0)	0.079	0.079	(119,026,787.25)
DIFFERENCE %			-72.2%	0.0%	-100.0%	-72.1%	1.3%	1.3%	-71.7%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	37,769.0	0.0	0.0	37,769.0	3.045	3.045	1,149,900.00
TOTAL		**37,769.0**	**0.0**	**0.0**	**37,769.0**	**3.045**	**3.045**	**1,149,900.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	17,454.0	0.0	0.0	17,454.0	2.726	2.726	475,807.85
McKAY BAY REFUSE	COGEN.	13,959.0	0.0	0.0	13,959.0	2.726	2.726	380,530.88
ORANGE COGENERATION L.P.	COGEN.	5,497.0	0.0	0.0	5,497.0	2.543	2.543	139,813.13
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	6,893.0	0.0	0.0	6,893.0	4.032	4.032	277,910.97
CF INDUSTRIES INC.	COGEN.	1,621.0	0.0	0.0	1,621.0	4.985	4.985	80,804.21
IMC-AGRICO-NEW WALES	COGEN.	1,036.0	0.0	0.0	1,036.0	4.927	4.927	51,043.09
IMC-AGRICO-S. PIERCE	COGEN.	10,574.0	0.0	0.0	10,574.0	5.188	5.188	548,556.76
AUBURNDALE POWER PARTNERS	COGEN.	153.0	0.0	0.0	153.0	3.165	3.165	4,842.18
CUTRALE CITRUS	COGEN.	1.0	0.0	0.0	1.0	4.174	4.174	41.74
SUBTOTAL FOR OCTOBER 2006		57,188.0	0.0	0.0	57,188.0	3.426	3.426	1,959,350.81
ADJUSTMENTS FOR THE MONTH OF:	**SEPTEMBER 2006**							
HILLSBOROUGH COUNTY	COGEN.	(17,142.0)	0.0	0.0	(17,142.0)	2.572	2.572	(440,944.92)
		17,142.0	0.0	0.0	17,142.0	2.712	2.712	464,959.79
McKAY BAY REFUSE	COGEN.	(13,372.0)	0.0	0.0	(13,372.0)	2.571	2.571	(343,741.35)
		13,372.0	0.0	0.0	13,372.0	2.710	2.710	362,333.35
ORANGE COGENERATION L.P.	COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	2.378	2.378	(180,503.23)
		7,590.0	0.0	0.0	7,590.0	2.531	2.531	192,081.95
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	54,185.59
TOTAL		**57,188.0**	**0.0**	**0.0**	**57,188.0**	**3.521**	**3.521**	**2,013,536.40**
CURRENT MONTH:								
DIFFERENCE		19,419.0	0.0	0.0	19,419.0	0.476	0.476	863,636.40
DIFFERENCE %		51.4%	0.0%	0.0%	51.4%	15.6%	15.6%	75.1%
PERIOD TO DATE:								
ACTUAL		470,392.0	0.0	0.0	470,392.0	3.161	3.161	14,867,072.37
ESTIMATED		364,639.0	0.0	0.0	364,639.0	3.009	3.009	10,971,500.00
DIFFERENCE		105,753.0	0.0	0.0	105,753.0	0.152	0.152	3,895,572.37
DIFFERENCE %		29.0%	0.0%	0.0%	29.0%	5.0%	5.0%	35.5%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:								
VARIOUS		ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:								
PROGRESS ENERGY FLORIDA		SCH. - JC	3,400.0	6.233	211,925.00	8.519	289,645.50	77,720.50
FLA. POWER & LIGHT		SCH. - JC	32,552.0	5.330	1,735,005.50	6.354	2,068,293.60	333,288.10
CITY OF LAKELAND		SCH. - JC	1,959.1	6.271	122,864.22	7.977	156,269.82	33,405.60
ORLANDO UTIL. COMM.		SCH. - JC	2,715.9	16.362	444,384.02	17.163	466,136.12	21,752.10
THE ENERGY AUTHORITY		SCH. - JC	21,276.2	7.567	1,610,043.37	8.848	1,882,487.85	272,444.48
OKEELANTA		SCH. - JC	507.0	7.680	38,937.00	9.616	48,751.70	9,814.70
CITY OF TALLAHASSEE		SCH. - JC	40.0	8.300	3,320.00	9.457	3,782.80	462.80
CALPINE		SCH. - JC	5,865.0	6.634	389,077.14	8.429	494,341.56	105,264.42
CARGILL ALLIANT		SCH. - JC	4,534.0	4.862	220,452.00	5.449	247,044.85	26,592.85
CARGILL FOR NEW SMYRNA BEACH		SCH. - JC	7,450.0	4.134	307,975.50	4.134	307,975.50	0.00
RELIANT		SCH. - JC	4,558.4	11.581	527,888.39	11.604	528,960.23	1,071.84
RAINBOW ENERGY MARKETERS		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - JC	16,100.0	6.525	1,050,550.00	7.966	1,282,455.25	231,905.25
ENTERGY-KOCH TRADING		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CINCINATTI GAS & ELECTRIC		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL			100,957.6	6.599	6,662,422.14	7.702	7,776,144.78	1,113,722.64
PRIOR MONTH ADJUSTMENTS:								
CARGILL ALLIANT	SEPT. 2006	SCH. - JC	(26,932.0)	7.649	(2,059,981.00)	7.945	(2,139,787.01)	(79,806.01)
CARGILL ALLIANT	SEPT. 2006	SCH. - JC	26,952.0	7.649	2,061,601.00	7.945	2,141,407.01	79,806.01
CARGILL FOR NEW SMYR BCH	SEPT. 2006	SCH. - JC	(7,220.0)	5.706	(411,955.20)	5.706	(411,955.20)	0.00
CARGILL FOR NEW SMYR BCH	SEPT. 2006	SCH. - JC	7,200.0	5.722	411,955.20	5.722	411,955.20	0.00
RELIANT	SEPT. 2006	SCH. - JC	(24,016.0)	6.216	(1,492,908.82)	6.545	(1,571,758.72)	(78,849.90)
RELIANT	SEPT. 2006	SCH. - JC	23,987.0	6.214	1,490,530.82	6.536	1,567,772.67	77,241.85
SUBTOTAL			(29.0)	2.614	(758.00)	8.159	(2,366.05)	(1,608.05)
TOTAL			**100,928.6**	**6.600**	**6,661,664.14**	**7.702**	**7,773,778.73**	**1,112,114.59**
CURRENT MONTH:								
DIFFERENCE			100,928.6	6.600	6,661,664.14	7.702	7,773,778.73	1,112,114.59
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:								
ACTUAL			1,096,375.4	6.912	75,777,374.17	8.361	91,664,264.47	15,886,890.30
ESTIMATED			0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE			1,096,375.4	6.912	75,777,374.17	8.361	91,664,264.47	15,886,890.30
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

NOVEMBER 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	58,394,677	50,225,576	8,169,101	16.3%	1,291,409	1,271,563	19,846	1.6%	4.52178	3.94991	0.57187	14.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,247)	(6,734)	(513)	7.6%	1,291,409 (a)	1,271,563 (a)	19,846	1.6%	(0.00056)	(0.00053)	(0.00003)	6.0%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,291,409 (a)	1,271,563 (a)	19,846	1.6%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	24,239	25,713	(1,474)	-5.7%	1,291,409 (a)	1,271,563 (a)	19,846	1.6%	0.00188	0.00202	(0.00015)	-7.2%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**58,411,669**	**50,244,555**	**8,167,114**	**16.3%**	**1,291,409**	**1,271,563**	**19,846**	**1.6%**	**4.52310**	**3.95140**	**0.57169**	**14.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	1,830,325	14,442,000	(12,611,675)	-87.3%	61,672	259,142	(197,470)	-76.2%	2.96784	5.57301	(2.60517)	-46.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	6,897,924	0	6,897,924	0.0%	98,294	0	98,294	0.0%	7.01765	0.00000	7.01765	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	2,479,908	1,034,700	1,445,208	139.7%	55,180	34,638	20,542	59.3%	4.49422	2.98718	1.50703	50.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**11,208,157**	**15,476,700**	**(4,268,543)**	**-27.6%**	**215,146**	**293,780**	**(78,634)**	**-26.8%**	**5.20956**	**5.26813**	**(0.05857)**	**-1.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,506,555**	**1,565,343**	**(58,788)**	**-3.8%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	112,502	31,500	81,002	257.1%	1,745	1,207	538	44.6%	6.44563	2.60978	3.83585	147.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sales (A6)	425,339	0	425,339	0.0%	7,200	0	7,200	0.0%	5.90749	0.00000	5.90749	0.0%
17. Fuel Cost of Market Base Sales (A6)	463,061	934,300	(471,239)	-50.4%	9,567	15,926	(6,359)	-39.9%	4.84019	5.86651	(1.02632)	-17.5%
18. Gains on Market Based Sales	73,742	155,440	(81,698)	-52.6%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**1,074,644**	**1,121,240**	**(46,596)**	**-4.2%**	**18,512**	**17,133**	**1,379**	**8.0%**	**5.80512**	**6.54433**	**(0.73921)**	**-11.3%**
20. Net Inadvertant Interchange					392	0	392	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					2,906	0	2,906	0.0%				
22. Interchange and Wheeling Losses					3,962	300	3,662	1220.7%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**68,545,182**	**64,600,015**	**3,945,167**	**6.1%**	**1,487,379**	**1,547,910**	**(60,531)**	**-3.9%**	**4.60845**	**4.17337**	**0.43508**	**10.4%**
24. Net Unbilled	(4,289,780) (a)	(4,878,920) (a)	589,140	-12.1%	(93,085)	(116,906)	23,821	-20.4%	4.60845	4.17337	0.43508	10.4%
25. Company Use	121,663 (a)	129,374 (a)	(7,711)	-6.0%	2,640	3,100	(460)	-14.8%	4.60845	4.17335	0.43509	10.4%
26. T & D Losses	5,061,373 (a)	4,141,360 (a)	920,013	22.2%	109,828	99,233	10,595	10.7%	4.60845	4.17337	0.43508	10.4%
27. System KWH Sales	68,545,182	64,600,015	3,945,167	6.1%	1,467,996	1,562,483	(94,487)	-6.0%	4.66930	4.13445	0.53486	12.9%
28. Wholesale KWH Sales	(2,495,085)	(1,453,424)	(1,041,661)	71.7%	(53,436)	(35,154)	(18,282)	52.0%	4.66930	4.13445	0.53485	12.9%
29. Jurisdictional KWH Sales	66,050,097	63,146,591	2,903,506	4.6%	1,414,560	1,527,329	(112,769)	-7.4%	4.66930	4.13445	0.53486	12.9%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	66,106,900	63,200,897	2,906,003	4.6%	1,414,560	1,527,329	(112,769)	-7.4%	4.67332	4.13800	0.53532	12.9%
32. Other	0	0	0	0.0%	1,414,560	1,527,329	(112,769)	-7.4%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(1,360,915)	(1,276,250)	(84,665)	6.6%	1,414,560	1,527,329	(112,769)	-7.4%	(0.09621)	(0.08356)	(0.01265)	15.1%
34. Other	0	0	0	0.0%	1,414,560	1,527,329	(112,769)	-7.4%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,685	12,304,685	(0)	0.0%	1,414,560	1,527,329	(112,769)	-7.4%	0.86986	0.80563	0.06423	8.0%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	77,050,670	74,229,332	2,821,338	3.8%	1,414,560	1,527,329	(112,769)	-7.4%	5.44697	4.86007	0.58690	12.1%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	77,106,146	74,282,777	2,823,369	3.8%	1,414,560	1,527,329	(112,769)	-7.4%	5.45089	4.86357	0.58732	12.1%
39. GPIF * (Already Adjusted for Taxes)	60,795	60,795	0	0.0%	1,414,560	1,527,329	(112,769)	-7.4%	0.00430	0.00398	0.00032	8.0%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**77,166,941**	**74,343,572**	**2,823,369**	**3.8%**	**1,414,560**	**1,527,329**	**(112,769)**	**-7.4%**	**5.45519**	**4.86755**	**0.58764**	**12.1%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									5.455	4.868	0.587	12.1%

* Based on Jurisdictional Sales (a) included for informational purposes only

174

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: NOVEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	761,987,859	707,352,083	54,635,776	7.7%	16,828,643	16,328,042	500,601	3.1%	4.52792	4.33213	0.19579	4.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(97,318)	(74,074)	(23,244)	31.4%	16,828,643 (a)	16,328,042 (a)	500,601	3.1%	(0.00058)	(0.00045)	(0.00012)	27.5%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	16,828,643 (a)	16,328,042 (a)	500,601	3.1%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	176,269	210,088	(33,819)	-16.1%	16,828,643 (a)	16,328,042 (a)	500,601	3.1%	0.00105	0.00129	(0.00024)	-18.6%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**762,066,810**	**707,488,097**	**54,578,713**	**7.7%**	**16,828,643**	**16,328,042**	**500,601**	**3.1%**	**4.52839**	**4.33296**	**0.19543**	**4.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	48,823,637	180,462,100	(131,638,463)	-72.9%	831,569	3,014,729	(2,183,160)	-72.4%	5.87127	5.98601	(0.11475)	-1.9%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	82,675,298	0	82,675,298	0.0%	1,194,670	0	1,194,670	0.0%	6.92035	0.00000	6.92035	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	17,346,981	12,006,200	5,340,781	44.5%	525,572	399,277	126,295	31.6%	3.30059	3.00699	0.29361	9.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**148,845,916**	**192,468,300**	**(43,622,384)**	**-22.7%**	**2,551,811**	**3,414,006**	**(862,195)**	**-25.3%**	**5.83295**	**5.63761**	**0.19534**	**3.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**19,380,454**	**19,742,048**	**(361,594)**	**-1.8%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	781,482	488,100	293,382	60.1%	18,572	16,671	1,901	11.4%	4.20783	2.92784	1.27999	43.7%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,020)	0	(21,020)	0.0%	29	0	29	0.0%	(72.48276)	0.00000	(72.48276)	0.0%
16. Fuel Cost of Sch. D Sales (A6)	3,862,563	0	3,862,563	0.0%	80,160	0	80,160	0.0%	4.81857	0.00000	4.81857	0.0%
17. Fuel Cost of Market Base Sales (A6)	3,310,626	11,594,900	(8,284,274)	-71.4%	67,090	200,100	(133,010)	-66.5%	4.93460	5.79455	(0.85995)	-14.8%
18. Gains on Market Based Sales	677,160	3,010,680	(2,333,520)	-77.5%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**8,610,811**	**15,093,680**	**(6,482,869)**	**-43.0%**	**165,852**	**216,771**	**(50,919)**	**-23.5%**	**5.19186**	**6.96296**	**(1.77110)**	**-25.4%**
20. Net Inadvertant Interchange					(1,009)	0	(1,009)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					47,055	0	47,055	0.0%				
22. Interchange and Wheeling Losses					40,362	4,000	36,362	909.1%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**902,301,915**	**884,862,717**	**17,439,198**	**2.0%**	**19,220,286**	**19,521,277**	**(300,991)**	**-1.5%**	**4.69453**	**4.53281**	**0.16172**	**3.6%**
24. Net Unbilled	(3,113,518) (a)	987,301 (a)	(4,100,819)	-415.4%	(107,509)	13,451	(120,960)	-899.3%	2.89605	7.33998	(4.44393)	-60.5%
25. Company Use	1,523,606 (a)	1,541,135 (a)	(17,529)	-1.1%	32,613	34,100	(1,487)	-4.4%	4.67178	4.51946	0.15232	3.4%
26. T & D Losses	50,319,461 (a)	39,025,863 (a)	11,293,598	28.9%	1,097,921	861,165	236,756	27.5%	4.58316	4.53175	0.05141	1.1%
27. System KWH Sales	902,301,915	884,862,717	17,439,198	2.0%	18,197,261	18,612,561	(415,300)	-2.2%	4.95845	4.75412	0.20433	4.3%
28. Wholesale KWH Sales	(31,439,040)	(22,966,504)	(8,472,536)	36.9%	(643,151)	(479,508)	(163,643)	34.1%	4.88828	4.78960	0.09869	2.1%
29. Jurisdictional KWH Sales	870,862,875	861,896,213	8,966,662	1.0%	17,554,110	18,133,053	(578,943)	-3.2%	4.96102	4.75318	0.20784	4.4%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	871,611,817	862,637,445	8,974,372	1.0%	17,554,110	18,133,053	(578,943)	-3.2%	4.96529	4.75727	0.20802	4.4%
32. Other	0	0	0	0.0%	17,554,110	18,133,053	(578,943)	-3.2%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(14,516,617)	(14,038,750)	(477,867)	3.4%	17,554,110	18,133,053	(578,943)	-3.2%	(0.08270)	(0.07742)	(0.00528)	6.8%
34. Other	0	0	0	0.0%	17,554,110	18,133,053	(578,943)	-3.2%	0.00000	0.00000	0.00000	0.0%
35. True-up *	135,351,535	135,351,537	(2)	0.0%	17,554,110	18,133,053	(578,943)	-3.2%	0.77105	0.74644	0.02462	3.3%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	992,446,735	983,950,232	8,496,503	0.9%	17,554,110	18,133,053	(578,943)	-3.2%	5.65364	5.42628	0.22736	4.2%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	993,161,296	984,658,676	8,502,620	0.9%	17,554,110	18,133,053	(578,943)	-3.2%	5.65771	5.43019	0.22752	4.2%
39. GPIF * (Already Adjusted for Taxes)	668,745	668,745	0	0.0%	17,554,110	18,133,053	(578,943)	-3.2%	0.00381	0.00369	0.00012	3.3%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**993,830,041**	**985,327,421**	**8,502,620**	**0.9%**	**17,554,110**	**18,133,053**	**(578,943)**	**-3.2%**	**5.66152**	**5.43388**	**0.22764**	**4.2%**
									5.662	5.434	0.228	4.2%

41. Fuel FAC Rounded to the Nearest .001 cents per KWH

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	58,394,677	50,225,576	8,169,101	16.3%	761,987,859	707,352,083	54,635,776	7.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,000,902	965,800	35,102	3.6%	7,933,651	12,083,000	(4,149,349)	-34.3%
2a. GAINS FROM MARKET BASED SALES	73,742	155,440	(81,698)	-52.6%	677,160	3,010,680	(2,333,520)	-77.5%
3. FUEL COST OF PURCHASED POWER	1,830,325	14,442,000	(12,611,675)	-87.3%	48,823,637	180,462,100	(131,638,463)	-72.9%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	2,479,908	1,034,700	1,445,208	139.7%	17,346,981	12,006,200	5,340,781	44.5%
4. ENERGY COST OF ECONOMY PURCHASES	6,897,924	0	6,897,924	0.0%	82,675,298	0	82,675,298	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	68,528,190	64,581,036	3,947,154	6.1%	902,222,964	884,726,703	17,496,261	2.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,247)	(6,734)	(513)	7.6%	(97,318)	(74,074)	(23,244)	31.4%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	24,239	25,713	(1,474)	-5.7%	176,269	210,088	(33,819)	-16.1%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	68,545,182	64,600,015	3,945,167	6.1%	902,301,915	884,862,717	17,439,198	2.0%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,414,560	1,527,329	(112,769)	-7.4%	17,554,110	18,133,053	(578,943)	-3.2%
2. NONJURISDICTIONAL SALES	53,436	35,154	18,282	52.0%	643,151	479,508	163,643	34.1%
3. TOTAL SALES	1,467,996	1,562,483	(94,487)	-6.0%	18,197,261	18,612,561	(415,300)	-2.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9635994	0.9775012	(0.0139018)	-1.4%	0.9646567	0.9742374	(0.0095807)	-1.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	76,102,733	82,581,541	(6,478,808)	-7.8%	944,069,867	980,711,886	(36,642,019)	-3.7%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,685)	(12,304,685)	0	0.0%	(135,351,535)	(135,351,537)	2	0.0%
2b. INCENTIVE PROVISION	(60,795)	(60,795)	0	0.0%	(668,745)	(668,745)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	63,737,253	70,216,061	(6,478,808)	-9.2%	808,049,587	844,691,604	(36,642,017)	-4.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	68,545,182	64,600,015	3,945,167	6.1%	902,301,915	884,862,717	17,439,198	2.0%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9635994	0.9775012	(0.0139018)	-1.4%	NA	NA	-	0.0%
5a. JUNE 2006 THRESHOLD CALC. ADJ. FOR SCHEDULES D & MA SALES	0	0	0	0.0%	0	0	0	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	66,050,097	63,146,591	2,903,506	4.6%	870,862,875	861,896,213	8,966,662	1.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	66,106,900	63,200,897	2,906,003	4.6%	871,611,817	862,637,445	8,974,372	1.0%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(1,360,915)	(1,276,250)	(84,665)	6.6%	(14,516,617)	(14,038,750)	(477,867)	3.4%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	64,745,985	61,924,647	2,821,338	4.6%	857,095,200	848,598,695	8,496,505	1.0%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(1,008,732)	8,291,414	(9,300,146)	-112.2%	(49,045,613)	(3,907,091)	(45,138,522)	1155.3%
8. INTEREST PROVISION FOR THE MONTH	(798,156)	(112,621)	(685,535)	608.7%	(9,510,467)	(3,635,051)	(5,875,416)	161.6%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(187,875,401)	(40,330,305)	(147,545,096)	365.8%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,685	12,304,685	(0)	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(177,377,604)	(19,846,827)	(157,530,777)	793.7%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(187,875,401)	(40,330,305)	(147,545,096)	365.8%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(176,579,448)	(19,734,206)	(156,845,242)	794.8%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(364,454,849)	(60,064,511)	(304,390,338)	506.8%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(182,227,425)	(30,032,256)	(152,195,169)	506.8%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.270	4.500	0.770	17.1%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.250	4.500	0.750	16.7%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	10.520	9.000	1.520	16.9%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.260	4.500	0.760	16.9%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.438	0.375	0.063	16.8%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(798,156)	(112,621)	(685,535)	608.7%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	139,723	48,960	90,763	185.4%	2,698,263	2,426,814	271,449	11.2%
2	LIGHT OIL	380,042	325,128	54,914	16.9%	6,549,952	6,989,445	(439,493)	-6.3%
3	COAL	19,967,757	22,728,087	(2,760,330)	-12.1%	265,452,611	255,808,673	9,643,938	3.8%
4	NATURAL GAS	37,907,155	27,123,401	10,783,754	39.8%	487,287,033	442,127,151	45,159,882	10.2%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	58,394,677	50,225,576	8,169,101	16.3%	761,987,859	707,352,083	54,635,776	7.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,315	611	704	115.2%	26,582	31,816	(5,234)	-16.5%
9	LIGHT OIL	2,313	2,560	(247)	-9.6%	43,608	52,258	(8,650)	-16.6%
10	COAL	748,472	852,589	(104,117)	-12.2%	10,022,042	9,705,332	316,710	3.3%
11	NATURAL GAS	539,309	415,803	123,506	29.7%	6,737,685	6,538,636	199,049	3.0%
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)	1,291,409	1,271,563	19,846	1.6%	16,829,917	16,328,042	501,875	3.1%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	2,218	947	1,271	134.2%	43,299	49,397	(6,098)	-12.3%
16	LIGHT OIL (BBL)	4,513	8,226	(3,713)	-45.1%	77,631	140,494	(62,863)	-44.7%
17	COAL (TON)	334,216	384,540	(50,324)	-13.1%	4,587,268	4,365,726	221,542	5.1%
18	NATURAL GAS (MCF)	3,907,735	3,027,272	880,463	29.1%	48,842,986	47,940,998	901,988	1.9%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	13,912	5,951	7,961	133.8%	271,642	310,151	(38,509)	-12.4%
22	LIGHT OIL	25,695	27,120	(1,425)	-5.3%	441,658	588,397	(146,739)	-24.9%
23	COAL	7,875,742	9,161,291	(1,285,549)	-14.0%	108,072,622	104,703,929	3,368,693	3.2%
24	NATURAL GAS	4,024,967	3,112,128	912,839	29.3%	50,496,808	49,283,200	1,213,608	2.5%
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)	11,940,316	12,306,490	(366,174)	-3.0%	159,282,730	154,885,677	4,397,053	2.8%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.10%	0.05%	0.00	-	0.16%	0.19%	(0.00)	-
29	LIGHT OIL	0.18%	0.20%	(0.00)	-	0.26%	0.32%	(0.00)	-
30	COAL	57.96%	67.05%	(0.09)	-	59.55%	59.44%	0.00	-
31	NATURAL GAS	41.76%	32.70%	0.09	-	40.03%	40.05%	(0.00)	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	63.00	51.70	11.29	21.8%	62.32	49.13	13.19	26.8%
36	LIGHT OIL ($/BBL)	84.21	39.52	44.69	113.1%	84.37	49.75	34.62	69.6%
37	COAL ($/TON)	59.75	59.10	0.64	1.1%	57.87	58.59	(0.73)	-1.2%
38	NATURAL GAS ($/MCF)	9.70	8.96	0.74	8.3%	9.98	9.22	0.75	8.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	10.04	8.23	1.82	22.1%	9.93	7.82	2.11	26.9%
42	LIGHT OIL	14.79	11.99	2.80	23.4%	14.83	11.88	2.95	24.8%
43	COAL	2.54	2.48	0.05	2.2%	2.46	2.44	0.01	0.5%
44	NATURAL GAS	9.42	8.72	0.70	8.1%	9.65	8.97	0.68	7.6%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.89	4.08	0.81	19.8%	4.78	4.57	0.22	4.8%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,579	9,740	839	8.6%	10,219	9,748	471	4.8%
49	LIGHT OIL	11,109	10,594	515	4.9%	10,128	11,259	(1,131)	-10.0%
50	COAL	10,522	10,745	(223)	-2.1%	10,783	10,788	(5)	0.0%
51	NATURAL GAS	7,463	7,485	(22)	-0.3%	7,495	7,537	(42)	-0.6%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,246	9,678	(432)	-4.5%	9,464	9,486	(22)	-0.2%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	10.63	8.01	2.62	32.7%	10.15	7.63	2.52	33.0%
56	LIGHT OIL	16.43	12.70	3.73	29.4%	15.02	13.37	1.65	12.3%
57	COAL	2.67	2.67	0.00	0.0%	2.65	2.64	0.01	0.4%
58	NATURAL GAS	7.03	6.52	0.51	7.8%	7.23	6.76	0.47	7.0%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	4.52	3.95	0.57	14.4%	4.53	4.33	0.20	4.6%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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)[2]	(L) AS BURNED FUEL COST ($)[1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B.#2	391	195,720	69.5	72.4	90.2	10,344	COAL	85,525	23,672,500	2,024,590.6	5,089,275	2.60	59.51
B.B.#3	414	227,275	76.2	81.4	81.9	10,524	COAL	103,826	23,036,320	2,391,769.0	6,178,300	2.72	59.51
B.B.#4	457	180,613	54.9	59.5	85.0	11,082	COAL	88,180	22,698,380	2,001,543.1	5,247,265	2.91	59.51
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	2,097	5,803,164	12,166.3	178,722	-	85.23
B.B. STATION	**1,673**	**603,608**	**50.1**	**53.3**	**64.6**	**10,633**	-	-	-	-	16,693,562	2.77	-
SEB-PHIL. #1(HVY OIL)	17	663	5.4	96.6	62.6	10,580	HVY.OIL	1,119	6,273,540	7,017.5	61,373	9.26	54.85
SEB-PHIL. #2(HVY OIL)	17	652	5.3	100.0	92.3	10,580	HVY.OIL	1,099	6,273,540	6,894.8	60,277	9.24	54.85
SEB-PHIL. IGNITION	-	-	-	-	-	-	LGT.OIL	123	5,803,164	823.4	18,073	-	146.93
SEB-PHILLIPS TOTAL	**34**	**1,315**	**5.4**	**98.3**	**77.5**	**10,580**	-	-	-	-	139,723	10.63	-
POLK #1 GASIFIER	255	144,864	-	-	-	10,063	COAL	56,685	25,718,000	1,457,839.2	3,274,195	2.26	57.76
POLK #1 CT (OIL)	225	2,266	-	-	-	10,865	LGT.OIL	4,327	5,792,795	24,617.6	364,145	16.07	84.16
POLK #1 TOTAL	**255**	**147,130**	**80.1**	**94.2**	**86.6**	**10,076**	-	-	-	**1,482,456.8**	**3,638,340**	**2.47**	-
POLK #2 CT (GAS)	150	2,412	-	-	-	12,745	GAS	29,846	1,030,000	30,741.0	317,946	13.18	10.65
POLK #2 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**2,412**	**2.2**	**100.0**	**68.2**	**12,745**	-	-	-	**30,741.0**	**317,946**	**13.18**	-
POLK #3 CT (GAS)	150	2,630	-	-	-	11,779	GAS	30,077	1,030,000	30,979.0	320,986	12.20	10.67
POLK #3 CT (OIL)	160	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**2,630**	**2.4**	**100.0**	**67.1**	**11,779**	-	-	-	**30,979.0**	**320,986**	**12.20**	-
POLK STATION TOTAL	**565**	**152,172**	**37.4**	**97.4**	**76.2**	**10,148**	-	-	-	**1,544,176.8**	**4,277,272**	**2.81**	-
B.B.C.T.#1	14	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	35	0.1	100.0	53.0	19,346	LGT.OIL	117	5,774,518	677.1	10,000	28.57	85.47
B.B.C.T.#3	66	12	0.0	100.0	18.2	33,308	LGT.OIL	69	5,774,487	399.7	5,897	49.14	85.46
C.T. TOTAL	**146**	**47**	**0.0**	**100.0**	**32.2**	**22,911**	**LGT.OIL**	**186**	**5,774,346**	**1,076.8**	**15,897**	**33.82**	**85.47**
COT 1	3	16	0.7	100.0	58.4	16,469	GAS	257	1,030,000	264.3	2,444	15.28	9.51
COT 2	3	16	0.7	100.0	58.5	16,469	GAS	255	1,030,000	262.7	2,425	15.16	9.51
CITY OF TAMPA TOTAL	**6**	**32**	**0.7**	**100.0**	**58.5**	**16,469**	**GAS**	**512**	**1,030,000**	**527.0**	**4,869**	**15.22**	**9.51**
BAYSIDE ST 1	234	61,720	36.6	100.0	43.1	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	156	13,072	11.6	39.6	52.0	11,440	GAS	145,193	1,030,000	149,549.0	1,410,231	10.79	9.71
BAYSIDE CT1B	156	60,498	53.9	100.0	80.9	11,492	GAS	675,016	1,030,000	695,267.0	6,556,298	10.84	9.71
BAYSIDE CT1C	156	42,079	37.5	55.4	80.8	10,946	GAS	447,194	1,030,000	460,610.0	4,343,508	10.32	9.71
BAYSIDE UNIT 1 TOTAL	**702**	**177,369**	**35.1**	**76.7**	**61.8**	**7,360**	**GAS**	**1,267,403**	**1,030,000**	**1,305,426.0**	**12,310,037**	**6.94**	**9.71**
BAYSIDE ST 2	306	122,155	55.4	100.0	55.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	156	60,794	54.1	99.9	82.1	11,218	GAS	662,108	1,030,000	681,971.0	6,404,050	10.53	9.67
BAYSIDE CT2B	156	63,009	56.1	100.0	81.4	11,449	GAS	700,392	1,030,000	721,404.0	6,774,342	10.75	9.67
BAYSIDE CT2C	156	48,619	43.3	82.9	81.7	11,399	GAS	538,063	1,030,000	554,205.0	5,204,261	10.70	9.67
BAYSIDE CT2D	156	62,289	55.5	96.1	82.9	11,233	GAS	679,334	1,030,000	699,714.0	6,570,664	10.55	9.67
BAYSIDE UNIT 2 TOTAL	**930**	**356,866**	**53.3**	**96.5**	**73.3**	**7,446**	**GAS**	**2,579,897**	**1,030,000**	**2,657,294.0**	**24,953,317**	**6.99**	**9.67**
BAYSIDE STATION TOTAL	**1,632**	**534,235**	**45.5**	**88.0**	**68.4**	**7,418**	**GAS**	**3,847,300**	**1,030,000**	**3,962,720.0**	**37,263,354**	**6.98**	**9.69**
SYSTEM	**4,056**	**1,291,409**	**44.2**	**75.5**	**66.6**	**9,246**	-	-	-	**11,940,315.6**	**58,394,677**	**4.52**	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

[3] Includes (19) bbls adjustment for October 2006.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	3,732	947	2,785	294.1%	45,184	49,397	(4,213)	-8.5%
3 UNIT COST ($/BBL)	48.75	46.87	1.88	4.0%	57.91	47.72	10.20	21.4%
4 AMOUNT ($)	181,922	44,386	137,536	309.9%	2,616,777	2,356,996	259,781	11.0%
5 BURNED:								
6 UNITS (BBL)	2,218	947	1,271	134.2%	43,299	49,397	(6,098)	-12.3%
7 UNIT COST ($/BBL)	63.00	51.70	11.29	21.8%	62.32	49.13	13.19	26.8%
8 AMOUNT ($)	139,723	48,960	90,763	185.4%	2,698,263	2,426,814	271,449	11.2%
9 ENDING INVENTORY:								
10 UNITS (BBL)	17,216	12,118	5,098	42.1%	17,216	12,118	5,098	42.1%
11 UNIT COST ($/BBL)	56.05	47.77	8.28	17.3%	56.05	47.77	8.28	17.3%
12 AMOUNT ($)	964,984	578,871	386,113	66.7%	964,984	578,871	386,113	66.7%
13								
14 DAYS SUPPLY:	90	63	27	40.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	6,575	8,226	(1,651)	-20.1%	140,106	140,494	(388)	-0.3%
17 UNIT COST ($/BBL)	76.23	68.96	7.26	10.5%	85.88	70.45	15.43	21.9%
18 AMOUNT ($)	501,186	567,289	(66,103)	-11.7%	12,032,797	9,898,359	2,134,438	21.6%
19 BURNED:								
20 UNITS (BBL)	4,513	8,226	(3,713)	-45.1%	77,631	140,494	(62,863)	-44.7%
21 UNIT COST ($/BBL)	84.21	39.52	44.69	113.1%	84.37	49.75	34.62	69.6%
22 AMOUNT ($)	380,042	325,128	54,914	16.9%	6,549,952	6,989,445	(439,493)	-6.3%
23 ENDING INVENTORY:								
24 UNITS (BBL)	94,334	85,007	9,327	11.0%	94,334	85,007	9,327	11.0%
25 UNIT COST ($/BBL)	84.70	68.63	16.07	23.4%	84.70	68.63	16.07	23.4%
26 AMOUNT ($)	7,990,246	5,834,288	2,155,958	37.0%	7,990,246	5,834,288	2,155,958	37.0%
27								
28 DAYS SUPPLY: NORMAL	192	173	19	10.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	13	12	1	11.0%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	433,202	400,800	32,402	8.1%	4,741,326	4,352,300	389,026	8.9%
32 UNIT COST ($/TON)	59.78	56.92	2.85	5.0%	58.28	58.08	0.20	0.4%
33 AMOUNT ($)	25,895,033	22,815,123	3,079,910	13.5%	276,328,252	252,763,544	23,564,708	9.3%
34 BURNED:								
35 UNITS (TONS)	334,216	384,540	(50,324)	-13.1%	4,587,268	4,365,726	221,542	5.1%
36 UNIT COST ($/TON)	59.75	59.10	0.64	1.1%	57.87	58.59	(0.73)	-1.2%
37 AMOUNT ($)	19,967,757	22,728,087	(2,760,330)	-12.1%	265,452,611	255,808,673	9,643,938	3.8%
38 ENDING INVENTORY:								
39 UNITS (TONS)	625,447	533,322	92,125	17.3%	625,447	533,322	92,125	17.3%
40 UNIT COST ($/TON)	58.91	57.91	1.01	1.7%	58.91	57.91	1.01	1.7%
41 AMOUNT ($)	36,846,246	30,882,953	5,963,293	19.3%	36,846,246	30,882,953	5,963,293	19.3%
42								
43 DAYS SUPPLY:	47	41	6	20.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	3,992,432	3,027,272	965,160	31.9%	48,789,333	47,940,998	848,335	1.8%
46 UNIT COST ($/MCF)	9.67	8.96	0.71	7.9%	9.96	9.22	0.73	8.0%
47 AMOUNT ($)	38,599,274	27,123,401	11,475,873	42.3%	485,735,206	442,127,148	43,608,058	9.9%
48 BURNED:								
49 UNITS (MCF)	3,907,735	3,027,272	880,463	29.1%	48,842,986	47,940,998	901,988	1.9%
50 UNIT COST ($/MCF)	9.70	8.96	0.74	8.3%	9.98	9.22	0.75	8.2%
51 AMOUNT ($)	37,907,155	27,123,401	10,783,754	39.8%	487,287,033	442,127,151	45,159,882	10.2%
52 ENDING INVENTORY:								
53 UNITS (MCF)	132,613	0	132,613	0.0%	132,613	0	132,613	0.0%
54 UNIT COST ($/MCF)	7.48	0.00	7.48	0.0%	7.48	0.00	7.48	0.0%
55 AMOUNT ($)	992,371	0	992,371	0.0%	992,371	0	992,371	0.0%
56								
57 DAYS SUPPLY:	1	0	1	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	11,888
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	11,888

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(2,238)	(190,610)
OTHER USAGE	(401)	(34,167)
TOTAL	(2,639)	(224,777)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	5,541
IGNITION #2 OIL	178,722
IGNITION PROPANE	5,796
AERIAL SURVEY ADJ.	0
ADDITIVES	50,215
GREEN FUEL	0
TOTAL	240,274

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,207.0	0.0	1,207.0	2.610	2.610	31,500.00	31,500.00	
VARIOUS	JURISDIC	SCH. - MB	15,926.0	0.0	15,926.0	5.867	7.397	934,300.00	1,178,100.00	155,440.00
TOTAL			17,133.0	0.0	17,133.0	5.637	7.060	965,800.00	1,209,600.00	155,440.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	791.1	5.6	785.5	6.412	6.791	50,370.14	53,345.20	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	959.9	0.0	959.9	6.476	6.875	62,159.94	65,990.99	
PROGRESS ENERGY FLORIDA		SCH. - MA	850.0	0.0	850.0	4.478	5.954	38,061.25	50,612.38	10,434.63
FLA. PWR. & LIGHT		SCH. - MA	8,166.0	0.0	8,166.0	4.861	6.017	396,985.85	491,322.33	75,408.34
CITY OF LAKELAND		SCH. - MA	50.0	0.0	50.0	4.175	4.658	2,087.50	2,329.06	87.06
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	200.0	0.0	200.0	4.531	6.496	9,061.75	12,991.26	3,464.51
THE ENERGY AUTHORITY		SCH. - MA	31.0	0.0	31.0	4.916	5.954	1,523.96	1,845.75	257.62
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(24,393.00)	(24,393.00)
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	270.0	0.0	270.0	5.682	15.965	15,340.50	43,105.23	26,918.73
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LESS 20% - THRESHHOLD EXCESS		SCH. - MA								(18,435.58)
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - D	7,200.0	0.0	7,200.0	5.297	5.897	381,384.00	424,584.00	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. HARDEE	OCTOBER 2006	SCH. - D	(1,165.4)	0.0	(1,165.4)	3.346	3.576	(38,994.93)	(41,672.64)	
SEMINOLE ELEC. HARDEE	OCTOBER 2006	SCH. - D	1,165.4	0.0	1,165.4	3.344	3.576	38,966.65	41,672.64	
NEW SMYRNA BEACH	OCTOBER 2006	SCH. - D	(7,450.0)	0.0	(7,450.0)	4.707	5.307	(350,671.50)	(395,371.50)	
NEW SMYRNA BEACH	OCTOBER 2006	SCH. - D	7,450.0	0.0	7,450.0	5.297	5.897	394,626.50	439,326.50	
SUB-TOTAL SCHEDULE D POWER SALES			7,200.0	0.0	7,200.0	5.907	6.507	425,339.00	468,539.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			1,751.0	5.6	1,745.4	6.446	6.837	112,501.80	119,336.19	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			9,567.0	0.0	9,567.0	4.840	6.040	463,060.81	577,813.01	73,742.31
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			18,518.0	5.6	18,512.4	5.407	6.297	1,000,901.61	1,165,688.20	73,742.31
CURRENT MONTH:										
DIFFERENCE			1,385.0	5.6	1,379.4	(0.230)	(0.763)	35,101.61	(43,911.80)	(81,697.69)
DIFFERENCE %			8.1%	0.0%	8.1%	-4.1%	-10.8%	3.6%	-3.6%	-52.6%
PERIOD TO DATE:										
ACTUAL			165,881.9	32.1	165,849.8	4.784	5.636	7,933,650.40	9,346,738.91	677,159.82
ESTIMATED			216,771.0	0.0	216,771.0	5.574	7.484	12,083,000.00	16,223,800.00	3,010,680.00
DIFFERENCE			(50,889.1)	32.1	(50,921.2)	(0.790)	(1.848)	(4,149,349.60)	(6,877,061.09)	(2,333,520.18)
DIFFERENCE %			-23.5%	0.0%	-23.5%	-14.2%	-24.7%	-34.3%	-42.4%	-77.5%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF NOVEMBER 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	129.0	0.0	95.0	34.0	10.294	10.294	3,500.00
HARDEE POWER PARTNERS		IPP	2,910.0	0.0	0.0	2,910.0	12.344	12.344	359,200.00
CALPINE		SCH. - D	912.0	0.0	0.0	912.0	10.768	10.768	98,200.00
VARIOUS		MKT. BASED	164,652.0	0.0	0.0	164,652.0	6.328	6.328	10,418,900.00
OTHER		SCH. - D	90,634.0	0.0	0.0	90,634.0	3.930	3.930	3,562,200.00
TOTAL			**259,237.0**	**0.0**	**95.0**	**259,142.0**	**5.573**	**5.573**	**14,442,000.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	25,737.0	0.0	0.0	25,737.0	3.048	3.048	784,514.81
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	33,450.0	0.0	0.0	33,450.0	3.064	3.064	1,024,908.00
CALPINE		SCH. - D	1,174.0	0.0	0.0	1,174.0	10.852	10.852	127,405.87
CALPINE		OATT	1,311.0	0.0	0.0	1,311.0	6.986	6.986	91,580.49
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. PWR. & LIGHT		EMERG.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	OCT. 2006	IPP	(25,241.0)	0.0	0.0	(25,241.0)	10.274	10.274	(2,593,185.73)
HARDEE PWR. PART.-NATIVE	OCT. 2006	IPP	25,241.0	0.0	0.0	25,241.0	10.491	10.491	2,648,046.85
PROGRESS ENERGY FLORIDA	OCT. 2006	SCH. - D	(36,500.0)	0.0	0.0	(36,500.0)	3.757	3.757	(1,371,305.00)
PROGRESS ENERGY FLORIDA	OCT. 2006	SCH. - D	36,500.0	0.0	0.0	36,500.0	3.064	3.064	1,118,360.00
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	(198,083.88)
TOTAL			**61,672.0**	**0.0**	**0.0**	**61,672.0**	**2.968**	**2.968**	**1,830,325.29**
CURRENT MONTH:									
DIFFERENCE			(197,565.0)	0.0	(95.0)	(197,470.0)	(2.605)	(2.605)	(12,611,674.71)
DIFFERENCE %			-76.2%	0.0%	0.0%	-76.2%	-46.7%	-46.7%	-87.3%
PERIOD TO DATE:									
ACTUAL			831,569.0	0.0	0.0	831,569.0	5.871	5.871	48,823,638.04
ESTIMATED			3,024,270.0	0.0	9,541.0	3,014,729.0	5.986	5.986	180,462,100.00
DIFFERENCE			(2,192,701.0)	0.0	(9,541.0)	(2,183,160.0)	(0.115)	(0.115)	(131,638,461.96)
DIFFERENCE %			-72.5%	0.0%	-100.0%	-72.4%	-1.9%	-1.9%	-72.9%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	34,638.0	0.0	0.0	34,638.0	2.987	2.987	1,034,700.00
TOTAL		**34,638.0**	**0.0**	**0.0**	**34,638.0**	**2.987**	**2.987**	**1,034,700.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	17,077.0	0.0	0.0	17,077.0	2.906	2.906	496,324.45
McKAY BAY REFUSE	COGEN.	13,533.0	0.0	0.0	13,533.0	2.904	2.904	393,019.41
ORANGE COGENERATION L.P.	COGEN.	4,830.0	0.0	0.0	4,830.0	2.662	2.662	128,556.54
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	5,999.0	0.0	0.0	5,999.0	6.988	6.988	419,185.69
CF INDUSTRIES INC.	COGEN.	1,316.0	0.0	0.0	1,316.0	7.974	7.974	104,941.77
IMC-AGRICO-NEW WALES	COGEN.	1,091.0	0.0	0.0	1,091.0	7.411	7.411	80,855.67
IMC-AGRICO-S. PIERCE	COGEN.	10,461.0	0.0	0.0	10,461.0	7.386	7.386	772,685.04
AUBURNDALE POWER PARTNERS	COGEN.	873.0	0.0	0.0	873.0	5.016	5.016	43,785.41
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR NOVEMBER 2006		55,180.0	0.0	0.0	55,180.0	4.421	4.421	2,439,353.98
ADJUSTMENTS FOR THE MONTH OF:	**OCTOBER 2006**							
HILLSBOROUGH COUNTY	COGEN.	(17,454.0)	0.0	0.0	(17,454.0)	2.726	2.726	(475,807.85)
		17,454.0	0.0	0.0	17,454.0	2.833	2.833	494,555.30
McKAY BAY REFUSE	COGEN.	(13,959.0)	0.0	0.0	(13,959.0)	2.726	2.726	(380,530.88)
		13,959.0	0.0	0.0	13,959.0	2.835	2.835	395,674.26
ORANGE COGENERATION L.P.	COGEN.	(5,497.0)	0.0	0.0	(5,497.0)	2.543	2.543	(139,813.13)
		5,497.0	0.0	0.0	5,497.0	2.665	2.665	146,476.23
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	40,553.93
TOTAL		**55,180.0**	**0.0**	**0.0**	**55,180.0**	**4.494**	**4.494**	**2,479,907.91**
CURRENT MONTH:								
DIFFERENCE		20,542.0	0.0	0.0	20,542.0	1.507	1.507	1,445,207.91
DIFFERENCE %		59.3%	0.0%	0.0%	59.3%	50.5%	50.5%	139.7%
PERIOD TO DATE:								
ACTUAL		525,572.0	0.0	0.0	525,572.0	3.301	3.301	17,346,980.28
ESTIMATED		399,277.0	0.0	0.0	399,277.0	3.007	3.007	12,006,200.00
DIFFERENCE		126,295.0	0.0	0.0	126,295.0	0.294	0.294	5,340,780.28
DIFFERENCE %		31.6%	0.0%	0.0%	31.6%	9.8%	9.8%	44.5%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	9,803.0	5.294	518,959.50	6.813	667,837.65	148,878.15
FLA. POWER & LIGHT	SCH. - JC	21,180.0	6.688	1,416,485.00	8.771	1,857,708.10	441,223.10
CITY OF LAKELAND	SCH. - JC	1,189.0	7.970	94,761.00	9.687	115,175.30	20,414.30
ORLANDO UTIL. COMM.	SCH. - JC	525.0	4.143	21,750.00	6.149	32,280.50	10,530.50
THE ENERGY AUTHORITY	SCH. - JC	20,250.0	6.873	1,391,761.97	8.961	1,814,692.36	422,930.39
OKEELANTA	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF TALLAHASSEE	SCH. - JC	135.0	6.444	8,700.00	7.998	10,796.85	2,096.85
CALPINE	SCH. - JC	1,468.0	5.490	80,598.50	6.828	100,230.41	19,631.91
CARGILL ALLIANT	SCH. - JC	16,965.0	7.152	1,213,378.00	7.198	1,221,117.82	7,739.82
CARGILL FOR NEW SMYRNA BEACH	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
RELIANT	SCH. - JC	17,603.0	8.230	1,448,757.38	8.292	1,459,697.76	10,940.38
RAINBOW ENERGY MARKETERS	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP	SCH. - JC	9,176.0	7.659	702,773.00	9.080	833,212.62	130,439.62
ENTERGY-KOCH TRADING	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CINCINATTI GAS & ELECTRIC	SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL		98,294.0	7.018	6,897,924.35	8.254	8,112,749.37	1,214,825.02
NO PRIOR MONTH ADJUSTMENTS:							
TOTAL		**98,294.0**	**7.018**	**6,897,924.35**	**8.254**	**8,112,749.37**	**1,214,825.02**
CURRENT MONTH:							
DIFFERENCE		98,294.0	7.018	6,897,924.35	8.254	8,112,749.37	1,214,825.02
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		1,194,669.4	6.920	82,675,298.52	8.352	99,777,013.84	17,101,715.32
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		1,194,669.4	6.920	82,675,298.52	8.352	99,777,013.84	17,101,715.32
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

DECEMBER 2006

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	53,532,953	50,130,903	3,402,050	6.8%	1,347,455	1,291,224	56,231	4.4%	3.97289	3.88243	0.09046	2.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,652)	(6,734)	(918)	13.6%	1,347,455 (a)	1,291,224 (a)	56,231	4.4%	(0.00057)	(0.00052)	(0.00005)	8.9%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	1,347,455 (a)	1,291,224 (a)	56,231	4.4%	0.00000	0.00000	0.00000	0.0%
4c. Incremental Hedging O&M Costs	34,380	25,713	8,667	33.7%	1,347,455 (a)	1,291,224 (a)	56,231	4.4%	0.00255	0.00199	0.00056	28.1%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**53,559,681**	**50,149,882**	**3,409,799**	**6.8%**	**1,347,455**	**1,291,224**	**56,231**	**4.4%**	**3.97488**	**3.88390**	**0.09097**	**2.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	4,041,747	19,076,500	(15,034,753)	-78.8%	64,399	356,910	(292,511)	-82.0%	6.27610	5.34490	0.93120	17.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	4,723,194	0	4,723,194	0.0%	76,626	0	76,626	0.0%	6.16396	0.00000	6.16396	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,158,064	1,084,100	73,964	6.8%	50,147	35,798	14,349	40.1%	2.30934	3.02838	(0.71904)	-23.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**9,923,005**	**20,160,600**	**(10,237,595)**	**-50.8%**	**191,172**	**392,708**	**(201,536)**	**-51.3%**	**5.19062**	**5.13374**	**0.05688**	**1.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,538,627**	**1,683,932**	**(145,305)**	**-8.6%**	**0**			
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	17,174	20,700	(3,526)	-17.0%	1,723	893	830	93.0%	0.99652	2.31803	(1.32151)	-57.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Sales (A6)	308,892	0	308,892	0.0%	7,440	0	7,440	0.0%	4.15177	0.00000	4.15177	0.0%
17. Fuel Cost of Market Base Sales (A6)	134,086	629,800	(495,714)	-78.7%	3,090	10,946	(7,856)	-71.8%	4.33935	5.75370	(1.41435)	-24.6%
18. Gains on Market Based Sales	17,913	135,840	(117,927)	-86.8%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**478,065**	**786,340**	**(308,275)**	**-39.2%**	**12,253**	**11,839**	**414**	**3.5%**	**3.90162**	**6.64195**	**(2.74033)**	**-41.3%**
20. Net Inadvertant Interchange					(194)	0	(194)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					711	0	711	0.0%				
22. Interchange and Wheeling Losses					871	200	671	335.5%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**63,004,621**	**69,524,142**	**(6,519,521)**	**-9.4%**	**1,526,020**	**1,671,893**	**(145,873)**	**-8.7%**	**4.12869**	**4.15841**	**(0.02972)**	**-0.7%**
24. Net Unbilled	(1,703,291) (a)	(419,376) (a)	(1,283,915)	306.1%	(41,255)	(10,085)	(31,170)	309.1%	4.12869	4.15841	(0.02972)	-0.7%
25. Company Use	118,370 (a)	128,911 (a)	(10,541)	-8.2%	2,867	3,100	(233)	-7.5%	4.12871	4.15842	(0.02971)	-0.7%
26. T & D Losses	2,375,028 (a)	4,587,390 (a)	(2,212,362)	-48.2%	57,525	110,316	(52,791)	-47.9%	4.12869	4.15841	(0.02972)	-0.7%
27. System KWH Sales	63,004,621	69,524,142	(6,519,521)	-9.4%	1,506,883	1,568,562	(61,679)	-3.9%	4.18112	4.43235	(0.25123)	-5.7%
28. Wholesale KWH Sales	(1,707,860)	(1,379,214)	(328,646)	23.8%	(40,847)	(31,117)	(9,730)	31.3%	4.18111	4.43235	(0.25123)	-5.7%
29. Jurisdictional KWH Sales	61,296,761	68,144,928	(6,848,167)	-10.0%	1,466,036	1,537,445	(71,409)	-4.6%	4.18112	4.43235	(0.25123)	-5.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	61,349,476	68,203,533	(6,854,057)	-10.0%	1,466,036	1,537,445	(71,409)	-4.6%	4.18472	4.43616	(0.25144)	-5.7%
32. Other	0	0	0	0.0%	1,466,036	1,537,445	(71,409)	-4.6%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(798,185)	(1,276,250)	478,065	-37.5%	1,466,036	1,537,445	(71,409)	-4.6%	(0.05445)	(0.08301)	0.02857	-34.4%
34. Other	0	0	0	0.0%	1,466,036	1,537,445	(71,409)	-4.6%	0.00000	0.00000	0.00000	0.0%
35. True-up *	12,304,687	12,304,685	2	0.0%	1,466,036	1,537,445	(71,409)	-4.6%	0.83932	0.80033	0.03898	4.9%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	72,855,978	79,231,968	(6,375,990)	-8.0%	1,466,036	1,537,445	(71,409)	-4.6%	4.96959	5.15348	(0.18389)	-3.6%
37. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	72,908,434	79,289,015	(6,380,581)	-8.0%	1,466,036	1,537,445	(71,409)	-4.6%	4.97317	5.15719	(0.18402)	-3.6%
39. GPIF * (Already Adjusted for Taxes)	60,789	60,789	0	0.0%	1,466,036	1,537,445	(71,409)	-4.6%	0.00415	0.00395	0.00019	4.9%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**72,969,223**	**79,349,804**	**(6,380,581)**	**-8.0%**	**1,466,036**	**1,537,445**	**(71,409)**	**-4.6%**	**4.97732**	**5.16114**	**(0.18383)**	**-3.6%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**4.977**	**5.161**	**(0.184)**	**-3.6%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: DECEMBER 2006

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	815,520,812	757,482,986	58,037,826	7.7%	18,176,098	17,619,266	556,832	3.2%	4.48678	4.29917	0.18760	4.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(104,970)	(80,808)	(24,162)	29.9%	18,176,098 (a)	17,619,266 (a)	556,832	3.2%	(0.00058)	(0.00046)	(0.00012)	25.9%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	18,176,098 (a)	17,619,266 (a)	556,832	3.2%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments to Fuel Cost	210,649	235,801	(25,152)	-10.7%	18,176,098 (a)	17,619,266 (a)	556,832	3.2%	0.00116	0.00134	(0.00018)	-13.4%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**815,626,491**	**757,637,979**	**57,988,512**	**7.7%**	**18,176,098**	**17,619,266**	**556,832**	**3.2%**	**4.48736**	**4.30005**	**0.18730**	**4.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	52,865,384	199,538,600	(146,673,216)	-73.5%	895,968	3,371,639	(2,475,671)	-73.4%	5.90037	5.91815	(0.01778)	-0.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	87,398,492	0	87,398,492	0.0%	1,271,296	0	1,271,296	0.0%	6.87476	0.00000	6.87476	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	18,505,045	13,090,300	5,414,745	41.4%	575,719	435,075	140,644	32.3%	3.21425	3.00875	0.20550	6.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**158,768,921**	**212,628,900**	**(53,859,979)**	**-25.3%**	**2,742,983**	**3,806,714**	**(1,063,731)**	**-27.9%**	**5.78818**	**5.58563**	**0.20256**	**3.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**20,919,081**	**21,425,980**	**(506,899)**	**-2.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	798,656	508,800	289,856	57.0%	20,296	17,564	2,732	15.6%	3.93514	2.89683	1.03830	35.8%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(21,020)	0	(21,020)	0.0%	29	0	29	0.0%	(72.48276)	0.00000	(72.48276)	0.0%
16. Fuel Cost of Sch. D Sales (A6)	4,171,455	0	4,171,455	0.0%	87,600	0	87,600	0.0%	4.76193	0.00000	4.76193	0.0%
17. Fuel Cost of Market Base Sales (A6)	3,444,712	12,224,700	(8,779,988)	-71.8%	70,180	211,046	(140,866)	-66.7%	4.90840	5.79243	(0.88404)	-15.3%
18. Gains on Market Based Sales	695,073	3,146,520	(2,451,447)	-77.9%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**9,088,876**	**15,880,020**	**(6,791,144)**	**-42.8%**	**178,105**	**228,610**	**(50,505)**	**-22.1%**	**5.10310**	**6.94634**	**(1.84324)**	**-26.5%**
20. Net Inadvertant Interchange					(1,203)	0	(1,203)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					47,766	0	47,766	0.0%				
22. Interchange and Wheeling Losses					41,233	4,200	37,033	881.7%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**965,306,536**	**954,386,859**	**10,919,677**	**1.1%**	**20,746,306**	**21,193,170**	**(446,864)**	**-2.1%**	**4.65291**	**4.50328**	**0.14963**	**3.3%**
24. Net Unbilled	(4,816,809) (a)	567,925 (a)	(5,384,734)	-948.1%	(148,764)	3,366	(152,130)	-4519.6%	3.23789	16.87240	(13.63451)	-80.8%
25. Company Use	1,641,976 (a)	1,670,046 (a)	(28,070)	-1.7%	35,480	37,200	(1,720)	-4.6%	4.62789	4.48937	0.13852	3.1%
26. T & D Losses	52,694,489 (a)	43,613,253 (a)	9,081,236	20.8%	1,155,446	971,481	183,965	18.9%	4.56053	4.48936	0.07118	1.6%
27. System KWH Sales	965,306,536	954,386,859	10,919,677	1.1%	19,704,144	20,181,123	(476,979)	-2.4%	4.89900	4.72911	0.16990	3.6%
28. Wholesale KWH Sales	(33,146,900)	(24,345,718)	(8,801,182)	36.2%	(683,998)	(510,625)	(173,373)	34.0%	4.84605	4.76783	0.07822	1.6%
29. Jurisdictional KWH Sales	932,159,636	930,041,141	2,118,495	0.2%	19,020,146	19,670,498	(650,352)	-3.3%	4.90091	4.72810	0.17281	3.7%
30. Jurisdictional Loss Multiplier									1.00086	1.00086	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	932,961,293	930,840,978	2,120,315	0.2%	19,020,146	19,670,498	(650,352)	-3.3%	4.90512	4.73217	0.17295	3.7%
32. Other	0	0	0	0.0%	19,020,146	19,670,498	(650,352)	-3.3%	0.00000	0.00000	0.00000	0.0%
33. Waterborne Transportation Disallowance Per FPSC Decision 9/21/04	(15,314,802)	(15,315,000)	198	0.0%	19,020,146	19,670,498	(650,352)	-3.3%	(0.08052)	(0.07786)	(0.00266)	3.4%
34. Other	0	0	0	0.0%	19,020,146	19,670,498	(650,352)	-3.3%	0.00000	0.00000	0.00000	0.0%
35. True-up *	147,656,222	147,656,222	0	0.0%	19,020,146	19,670,498	(650,352)	-3.3%	0.77631	0.75065	0.02567	3.4%
36. Total Jurisdictional Fuel Cost (Excl. GPIF)	1,065,302,713	1,063,182,200	2,120,513	0.2%	19,020,146	19,670,498	(650,352)	-3.3%	5.60092	5.40496	0.19596	3.6%
37. Revenue Tax Factor	0	0							1.00072	1.00072	0.00000	0.0%
38. Fuel Cost Adjusted for Taxes (Excl. GPIF)	1,066,069,730	1,063,947,691	2,122,039	0.2%	19,020,146	19,670,498	(650,352)	-3.3%	5.60495	5.40885	0.19610	3.6%
39. GPIF * (Already Adjusted for Taxes)	729,534	729,534	0	0.0%	19,020,146	19,670,498	(650,352)	-3.3%	0.00384	0.00371	0.00013	3.4%
40. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**1,066,799,264**	**1,064,677,225**	**2,122,039**	**0.2%**	**19,020,146**	**19,670,498**	**(650,352)**	**-3.3%**	**5.60879**	**5.41256**	**0.19623**	**3.6%**
41. Fuel FAC Rounded to the Nearest .001 cents per KWH									**5.609**	**5.413**	**0.196**	**3.6%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	53,532,953	50,130,903	3,402,050	6.8%	815,520,812	757,482,986	58,037,826	7.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	460,152	650,500	(190,348)	-29.3%	8,393,803	12,733,500	(4,339,697)	-34.1%
2a. GAINS FROM MARKET BASED SALES	17,913	135,840	(117,927)	-86.8%	695,073	3,146,520	(2,451,447)	-77.9%
3. FUEL COST OF PURCHASED POWER	4,041,747	19,076,500	(15,034,753)	-78.8%	52,865,384	199,538,600	(146,673,216)	-73.5%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,158,064	1,084,100	73,964	6.8%	18,505,045	13,090,300	5,414,745	41.4%
4. ENERGY COST OF ECONOMY PURCHASES	4,723,194	0	4,723,194	0.0%	87,398,492	0	87,398,492	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	62,977,893	69,505,163	(6,527,270)	-9.4%	965,200,857	954,231,866	10,968,991	1.1%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,652)	(6,734)	(918)	13.6%	(104,970)	(80,808)	(24,162)	29.9%
6b. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	34,380	25,713	8,667	33.7%	210,649	235,801	(25,152)	-10.7%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	63,004,621	69,524,142	(6,519,521)	-9.4%	965,306,536	954,386,859	10,919,677	1.1%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,466,036	1,537,445	(71,409)	-4.6%	19,020,146	19,670,498	(650,352)	-3.3%
2. NONJURISDICTIONAL SALES	40,847	31,117	9,730	31.3%	683,998	510,625	173,373	34.0%
3. TOTAL SALES	1,506,883	1,568,562	(61,679)	-3.9%	19,704,144	20,181,123	(476,979)	-2.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9728931	0.9801621	(0.0072690)	-0.7%	0.9652866	0.9746979	(0.0094113)	-1.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	78,600,381	83,123,151	(4,522,770)	-5.4%	1,022,670,248	1,063,835,037	(41,164,789)	-3.9%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(12,304,687)	(12,304,685)	(2)	0.0%	(147,656,222)	(147,656,222)	0	0.0%
2b. INCENTIVE PROVISION	(60,789)	(60,789)	0	0.0%	(729,534)	(729,534)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	66,234,905	70,757,677	(4,522,772)	-6.4%	874,284,492	915,449,281	(41,164,789)	-4.5%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	63,004,621	69,524,142	(6,519,521)	-9.4%	965,306,536	954,386,859	10,919,677	1.1%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9728931	0.9801621	(0.0072690)	-0.7%	NA	NA	-	0.0%
5a. JUNE 2006 THRESHOLD CALC. ADJ. FOR SCHEDULES D & MA SALES	0	0	0	0.0%	0	0	0	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	61,296,761	68,144,928	(6,848,167)	-10.0%	932,159,636	930,041,141	2,118,495	0.2%
6a. JURISDIC. LOSS MULTIPLIER	1.00086	1.00086	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	61,349,476	68,203,533	(6,854,057)	-10.0%	932,961,293	930,840,978	2,120,315	0.2%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	0	0	0	0.0%	0	0	0	0.0%
6e. WATERBORNE TRANSP. DISALLOWANCE PER FPSC DECISION 9/21/04	(798,185)	(1,276,250)	478,065	-37.5%	(15,314,802)	(15,315,000)	198	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	60,551,291	66,927,283	(6,375,992)	-9.5%	917,646,491	915,525,978	2,120,513	0.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	5,683,614	3,830,394	1,853,220	48.4%	(43,361,999)	(76,697)	(43,285,302)	56436.8%
8. INTEREST PROVISION FOR THE MONTH	(737,520)	(44,172)	(693,348)	1569.7%	(10,247,987)	(3,679,223)	(6,568,764)	178.5%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(177,377,604)	(19,846,827)	(157,530,777)	793.7%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	12,304,687	12,304,685	2	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(160,126,823)	(3,755,920)	(156,370,903)	4163.3%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(177,377,604)	(19,846,827)	(157,530,777)	793.7%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 - C6f)	(159,389,303)	(3,711,748)	(155,677,555)	4194.2%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(336,766,907)	(23,558,575)	(313,208,332)	1329.5%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(168,383,454)	(11,779,288)	(156,604,166)	1329.5%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.250	4.500	0.750	16.7%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.270	4.500	0.770	17.1%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	10.520	9.000	1.520	16.9%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	5.260	4.500	0.760	16.9%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.438	0.375	0.063	16.8%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(737,520)	(44,172)	(693,348)	1569.7%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	201,025	4,693	196,332	4183.5%	2,899,288	2,431,507	467,781	19.2%
2	LIGHT OIL	200,966	603,220	(402,254)	-66.7%	6,750,918	7,592,665	(841,747)	-11.1%
3	COAL	27,019,398	24,235,372	2,784,026	11.5%	292,472,009	280,044,045	12,427,964	4.4%
4	NATURAL GAS	26,111,564	25,287,618	823,946	3.3%	513,398,597	467,414,769	45,983,828	9.8%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	53,532,953	50,130,903	3,402,050	6.8%	815,520,812	757,482,986	58,037,826	7.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,980	53	1,927	3635.8%	28,562	31,869	(3,307)	-10.4%
9	LIGHT OIL	1,034	4,778	(3,744)	-78.4%	44,642	57,036	(12,394)	-21.7%
10	COAL	946,537	910,719	35,818	3.9%	10,968,579	10,616,051	352,528	3.3%
11	NATURAL GAS	397,904	375,674	22,230	5.9%	7,135,589	6,914,310	221,279	3.2%
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)	1,347,455	1,291,224	56,231	4.4%	18,177,372	17,619,266	558,106	3.2%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	3,208	83	3,125	3765.1%	46,507	49,480	(2,973)	-6.0%
16	LIGHT OIL (BBL)	2,400	11,912	(9,512)	-79.9%	80,031	152,406	(72,375)	-47.5%
17	COAL (TON)	432,694	409,700	22,994	5.6%	5,019,962	4,775,426	244,536	5.1%
18	NATURAL GAS (MCF)	2,899,343	2,723,634	175,709	6.5%	51,742,329	50,664,632	1,077,697	2.1%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	20,125	520	19,605	3770.2%	291,767	310,671	(18,904)	-6.1%
22	LIGHT OIL	11,417	49,938	(38,521)	-77.1%	453,076	638,335	(185,259)	-29.0%
23	COAL	10,269,980	9,780,730	489,250	5.0%	118,342,601	114,484,659	3,857,942	3.4%
24	NATURAL GAS	2,986,323	2,799,989	186,334	6.7%	53,483,131	52,083,189	1,399,942	2.7%
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)	13,287,845	12,631,177	656,668	5.2%	172,570,575	167,516,854	5,053,721	3.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.15%	0.00%	0.00	-	0.16%	0.18%	(0.00)	-
29	LIGHT OIL	0.08%	0.37%	(0.00)	-	0.25%	0.32%	(0.00)	-
30	COAL	70.25%	70.53%	(0.00)	-	60.34%	60.25%	0.00	-
31	NATURAL GAS	29.53%	29.09%	0.00	-	39.26%	39.24%	0.00	-
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%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	62.66	56.54	6.12	10.8%	62.34	49.14	13.20	26.9%
36	LIGHT OIL ($/BBL)	83.74	50.64	33.10	65.4%	84.35	49.82	34.54	69.3%
37	COAL ($/TON)	62.44	59.15	3.29	5.6%	58.26	58.64	(0.38)	-0.6%
38	NATURAL GAS ($/MCF)	9.01	9.28	(0.28)	-3.0%	9.92	9.23	0.70	7.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	9.99	9.03	0.96	10.7%	9.94	7.83	2.11	27.0%
42	LIGHT OIL	17.60	12.08	5.52	45.7%	14.90	11.89	3.01	25.3%
43	COAL	2.63	2.48	0.15	6.2%	2.47	2.45	0.03	1.0%
44	NATURAL GAS	8.74	9.03	(0.29)	-3.2%	9.60	8.97	0.62	7.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	4.03	3.97	0.06	1.5%	4.73	4.52	0.20	4.5%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,164	9,811	353	3.6%	10,215	9,748	467	4.8%
49	LIGHT OIL	11,042	10,452	590	5.6%	10,149	11,192	(1,043)	-9.3%
50	COAL	10,850	10,740	110	1.0%	10,789	10,784	5	0.0%
51	NATURAL GAS	7,505	7,453	52	0.7%	7,495	7,533	(38)	-0.5%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,861	9,782	79	0.8%	9,494	9,508	(14)	-0.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	10.15	8.85	1.30	14.7%	10.15	7.63	2.52	33.0%
56	LIGHT OIL	19.44	12.62	6.82	54.0%	15.12	13.31	1.81	13.6%
57	COAL	2.85	2.66	0.19	7.1%	2.67	2.64	0.03	1.1%
58	NATURAL GAS	6.56	6.73	(0.17)	-2.5%	7.19	6.76	0.43	6.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.97	3.88	0.09	2.3%	4.49	4.30	0.19	4.4%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

SCHEDULE A4
PAGE 1 OF 1

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET 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) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	411	106,667	34.9	36.6	81.7	10,840	COAL	49,070	23,564,540	1,156,312.0	2,984,498	2.80	60.82
B.B.#2	391	253,907	87.3	95.8	87.3	10,493	COAL	113,011	23,575,500	2,664,290.8	6,873,469	2.71	60.82
B.B.#3	433	173,066	53.7	56.4	64.0	11,132	COAL	81,690	23,583,020	1,926,496.9	4,968,487	2.87	60.82
B.B.#4	462	260,905	75.9	82.5	83.9	11,152	COAL	126,122	23,069,060	2,909,516.0	7,670,897	2.94	60.82
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	9,425	5,800,187	54,668.2	803,483	-	85.25
B.B. STATION	**1,697**	**794,545**	**62.9**	**67.8**	**79.1**	**10,895**	-	-	-	-	**23,300,834**	**2.93**	-
SEB-PHIL. #1(HVY OIL)	18	1,013	7.6	100.0	72.9	10,164	HVY.OIL	1,641	6,273,540	10,295.1	90,015	8.89	54.85
SEB-PHIL. #2(HVY OIL)	18	967	7.2	100.0	72.3	10,164	HVY.OIL	1,567	6,273,540	9,829.6	85,956	8.89	54.85
SEB-PHIL. IGNITION	-	-	-	-	-	-	LGT.OIL	188	5,800,187	1,087.8	25,054	-	133.27
SEB-PHILLIPS TOTAL	**36**	**1,980**	**7.4**	**100.0**	**72.6**	**10,164**	-	-	-	-	**201,025**	**10.15**	-
POLK #1 GASIFIER	260	151,992	-	-	-	10,615	COAL	62,801	25,690,000	1,613,363.9	3,718,564	2.45	59.21
POLK #1 CT (OIL)	245	1,034	-	-	-	11,046	LGT.OIL	2,400	5,792,501	11,417.5	200,966	19.44	83.74
POLK #1 TOTAL	**260**	**153,026**	**79.1**	**83.8**	**89.3**	**10,618**	-	-	-	**1,624,781.4**	**3,919,530**	**2.56**	-
POLK #2 CT (GAS)	175	2,630	-	-	-	13,354	GAS	34,097	1,030,000	35,120.0	137,502	5.23	4.03
POLK #2 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**180**	**2,630**	**2.0**	**91.5**	**57.1**	**13,354**	-	-	-	**35,120.0**	**137,502**	**5.23**	-
POLK #3 CT (GAS)	175	5,961	-	-	-	12,219	GAS	70,718	1,030,000	72,840.0	754,599	12.66	10.67
POLK #3 CT (OIL)	184	0	-	-	-	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**180**	**5,961**	**4.5**	**91.5**	**60.3**	**12,219**	-	-	-	**72,840.0**	**754,599**	**12.66**	-
POLK STATION TOTAL	**620**	**161,617**	**35.0**	**88.3**	**71.5**	**10,721**	-	-	-	**1,732,741.4**	**4,811,631**	**2.98**	-
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	80	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**175**	**0**	**0.0**	**100.0**	**0.0**	**0**	**LGT.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
COT 1	3	23	1.0	100.0	58.8	16,467	GAS	371	1,030,000	382.3	4,079	17.73	10.99
COT 2	3	7	0.3	89.7	56.8	16,467	GAS	108	1,030,000	111.7	1,187	16.96	10.99
CITY OF TAMPA TOTAL	**6**	**30**	**0.7**	**94.9**	**57.8**	**16,467**	**GAS**	**479**	**1,030,000**	**494.0**	**5,266**	**17.55**	**10.99**
BAYSIDE ST 1	244	75,442	41.6	100.0	64.2	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	183	54,215	39.8	87.4	78.7	11,450	GAS	602,662	1,030,000	620,742.0	5,761,547	10.63	9.56
BAYSIDE CT1B	183	41,889	30.8	100.0	69.2	11,612	GAS	472,259	1,030,000	486,427.0	4,514,873	10.78	9.56
BAYSIDE CT1C	183	40,860	30.0	100.0	68.6	10,995	GAS	436,192	1,030,000	449,277.0	4,170,067	10.21	9.56
BAYSIDE UNIT 1 TOTAL	**793**	**212,406**	**36.0**	**98.0**	**69.7**	**7,328**	**GAS**	**1,511,113**	**1,030,000**	**1,556,446.0**	**14,446,487**	**6.80**	**9.56**
BAYSIDE ST 2	316	60,852	25.9	53.0	48.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	183	23,217	17.1	56.7	70.0	11,188	GAS	252,184	1,030,000	259,749.0	2,116,586	9.12	8.39
BAYSIDE CT2B	183	26,784	19.7	57.0	74.8	11,329	GAS	294,612	1,030,000	303,450.0	2,472,685	9.23	8.39
BAYSIDE CT2C	183	29,621	21.8	47.7	67.7	11,442	GAS	329,044	1,030,000	338,915.0	2,761,673	9.32	8.39
BAYSIDE CT2D	183	36,403	26.7	56.0	63.0	11,519	GAS	407,096	1,030,000	419,309.0	3,416,766	9.39	8.39
BAYSIDE UNIT 2 TOTAL	**1,048**	**176,877**	**22.7**	**53.9**	**62.8**	**7,471**	**GAS**	**1,282,936**	**1,030,000**	**1,321,423.0**	**10,767,710**	**6.09**	**8.39**
BAYSIDE STATION TOTAL	**1,841**	**389,283**	**28.4**	**72.9**	**65.8**	**7,393**	**GAS**	**2,794,049**	**1,030,000**	**2,877,869.0**	**25,214,197**	**6.48**	**9.02**
SYSTEM	**4,375**	**1,347,455**	**41.4**	**74.4**	**69.2**	**9,861**	-	-	-	**13,287,844.8**	**53,532,953**	**3.97**	-

Footnotes:

[1] As burned fuel cost system total inludes ignition oil.

[2] Fuel burned (MM BTU) system total exludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
COT = CITY OF TAMPA

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES								
2 UNITS (BBL)	0	83	(83)	-100.0%	45,184	49,480	(4,296)	-8.7%
3 UNIT COST ($/BBL)	0.00	48.42	(48.42)	-100.0%	59.00	47.72	11.28	23.7%
4 AMOUNT ($)	49,201	4,019	45,182	1124.2%	2,665,978	2,361,015	304,963	12.9%
5 BURNED:								
6 UNITS (BBL)	3,208	83	3,125	3765.1%	46,507	49,480	(2,973)	-6.0%
7 UNIT COST ($/BBL)	62.66	56.54	6.12	10.8%	62.34	49.14	13.20	26.9%
8 AMOUNT ($)	201,025	4,693	196,332	4183.5%	2,899,288	2,431,507	467,781	19.2%
9 ENDING INVENTORY:								
10 UNITS (BBL)	14,008	12,118	1,890	15.6%	14,008	12,118	1,890	15.6%
11 UNIT COST ($/BBL)	59.17	47.77	11.40	23.9%	59.17	47.77	11.40	23.9%
12 AMOUNT ($)	828,872	578,925	249,947	43.2%	828,872	578,925	249,947	43.2%
13								
14 DAYS SUPPLY	62	54	8	20.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	3,114	11,912	(8,798)	-73.9%	143,220	152,406	(9,186)	-6.0%
17 UNIT COST ($/BBL)	76.98	71.57	5.42	7.6%	85.69	70.54	15.15	21.5%
18 AMOUNT ($)	239,724	852,483	(612,759)	-71.9%	12,272,521	10,750,842	1,521,679	14.2%
19 BURNED:								
20 UNITS (BBL)	2,400	11,912	(9,512)	-79.9%	80,031	152,406	(72,375)	-47.5%
21 UNIT COST ($/BBL)	83.74	50.64	33.10	65.4%	84.35	49.82	34.54	69.3%
22 AMOUNT ($)	200,966	603,220	(402,254)	-66.7%	6,750,918	7,592,665	(841,747)	-11.1%
23 ENDING INVENTORY:								
24 UNITS (BBL)	84,750	85,007	(257)	-0.3%	84,750	85,007	(257)	-0.3%
25 UNIT COST ($/BBL)	84.39	68.94	15.45	22.4%	84.39	68.94	15.45	22.4%
26 AMOUNT ($)	7,151,806	5,860,260	1,291,546	22.0%	7,151,806	5,860,260	1,291,546	22.0%
27								
28 DAYS SUPPLY: NORMAL	171	172	(1)	0.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	12	(0)	-0.3%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	213,205	409,600	(196,395)	-47.9%	4,954,531	4,761,900	192,631	4.0%
32 UNIT COST ($/TON)	60.20	58.96	1.24	2.1%	58.36	58.15	0.21	0.4%
33 AMOUNT ($)	12,835,755	24,151,171	(11,315,416)	-46.9%	289,164,007	276,914,715	12,249,292	4.4%
34 BURNED:								
35 UNITS (TONS)	432,694	409,700	22,994	5.6%	5,019,962	4,775,426	244,536	5.1%
36 UNIT COST ($/TON)	62.44	59.15	3.29	5.6%	58.26	58.64	(0.38)	-0.6%
37 AMOUNT ($)	27,019,398	24,235,372	2,784,026	11.5%	292,472,009	280,044,045	12,427,964	4.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	405,958	533,222	(127,264)	-23.9%	405,958	533,222	(127,264)	-23.9%
40 UNIT COST ($/TON)	57.99	58.36	(0.37)	-0.6%	57.99	58.36	(0.37)	-0.6%
41 AMOUNT ($)	23,542,293	31,118,370	(7,576,077)	-24.3%	23,542,293	31,118,370	(7,576,077)	-24.3%
42								
43 DAYS SUPPLY:	31	41	(10)	-30.0%	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF) **	2,943,395	2,723,634	219,761	8.1%	51,732,728	50,664,632	1,068,096	2.1%
46 UNIT COST ($/MCF)	9.01	9.28	(0.28)	-3.0%	9.90	9.23	0.68	7.3%
47 AMOUNT ($)	26,506,555	25,287,618	1,218,937	4.8%	512,241,761	467,414,766	44,826,995	9.6%
48 BURNED:								
49 UNITS (MCF)	2,899,343	2,723,634	175,709	6.5%	51,742,329	50,664,632	1,077,697	2.1%
50 UNIT COST ($/MCF)	9.01	9.28	(0.28)	-3.0%	9.92	9.23	0.70	7.6%
51 AMOUNT ($)	26,111,564	25,287,618	823,946	3.3%	513,398,597	467,414,769	45,983,828	9.8%
52 ENDING INVENTORY:								
53 UNITS (MCF)	176,665	0	176,665	0.0%	176,665	0	176,665	0.0%
54 UNIT COST ($/MCF)	7.85	0.00	7.85	0.0%	7.85	0.00	7.85	0.0%
55 AMOUNT ($)	1,387,362	0	1,387,362	0.0%	1,387,362	0	1,387,362	0.0%
56								
57 DAYS SUPPLY:	2	0	2	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

SCHEDULE A5
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

** *Includes prior months adjustments of 15,966 mcf for Bayside & Polk.*

(1) RECONCILIATION - *HEAVY OIL*

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	15,712
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	15,712

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(9,613)	(819,195)
OTHER USAGE	(685)	(58,003)
TOTAL	(10,298)	(877,198)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	11,371
IGNITION #2 OIL	803,483
IGNITION PROPANE	8,408
AERIAL SURVEY ADJ.	0
ADDITIVES	56,428
GREEN FUEL	0
TOTAL	879,690

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	893.0	0.0	893.0	2.318	2.318	20,700.00	20,700.00	
VARIOUS	JURISDIC.	SCH - MB	10,946.0	0.0	10,946.0	5.754	7.610	629,800.00	833,000.00	135,840.00
TOTAL			11,839.0	0.0	11,839.0	5.495	7.211	650,500.00	853,700.00	135,840.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	726.4	0.0	726.4	3.880	4.111	28,186.27	29,864.32	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	997.0	0.0	997.0	3.522	3.745	35,116.07	37,336.66	
PROGRESS ENERGY FLORIDA		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	880.0	0.0	880.0	4.695	5.121	41,314.45	45,063.48	1,021.03
CITY OF LAKELAND		SCH. - MA	250.0	0.0	250.0	2.985	4.095	7,461.89	10,236.86	2,348.47
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CAROLINA POWER & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CALPEA		SCH. - MA	1,960.0	0.0	1,960.0	4.371	5.645	85,679.72	110,641.85	19,022.23
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENASKA POWER CORP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CINCINNATI GAS & ELECTRIC		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LESS 20% - THRESHHOLD EXCESS		SCH. - MA								(4,478.35)
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - D	7,440.0	0.0	7,440.0	4.715	5.315	350,796.00	395,436.00	
ADJUSTMENTS TO PRIOR MONTHS:										
SEMINOLE ELEC. PRECO-1	NOVEMBER 2006	SCH. - D	(791.1)	(5.6)	(785.5)	6.412	6.791	(50,370.14)	(53,345.20)	
SEMINOLE ELEC. PRECO-1	NOVEMBER 2006	SCH. - D	791.1	5.6	785.5	3.931	4.182	30,875.35	32,852.08	
SEMINOLE ELEC. HARDEE	NOVEMBER 2006	SCH. - D	(959.9)	0.0	(959.9)	6.476	6.875	(62,159.94)	(65,990.99)	
SEMINOLE ELEC. HARDEE	NOVEMBER 2006	SCH. - D	959.9	0.0	959.9	3.701	3.940	35,526.68	37,817.81	
FLA. PWR. & LIGHT	NOVEMBER 2006	SCH. - MA	(8,166.0)	0.0	(8,166.0)	4.861	6.017	(396,985.85)	(491,322.33)	(75,408.34)
FLA. PWR. & LIGHT	NOVEMBER 2006	SCH. - MA	8,166.0	0.0	8,166.0	4.857	6.012	396,628.49	490,964.97	75,408.34
NEW SMYRNA BEACH	NOVEMBER 2006	SCH. - MA	(270.0)	0.0	(270.0)	5.682	15.965	(15,340.50)	(43,105.23)	(26,918.73)
NEW SMYRNA BEACH	NOVEMBER 2006	SCH. - MA	270.0	0.0	270.0	5.677	15.960	15,327.23	43,091.96	26,918.73
NEW SMYRNA BEACH	NOVEMBER 2006	SCH. - D	(7,200.0)	0.0	(7,200.0)	5.297	5.897	(381,384.00)	(424,584.00)	
NEW SMYRNA BEACH	NOVEMBER 2006	SCH. - D	7,200.0	0.0	7,200.0	4.715	5.315	339,480.00	382,680.00	
SUB-TOTAL SCHEDULE D POWER SALES			7,440.0	0.0	7,440.0	4.152	4.752	308,892.00	353,532.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			1,723.4	0.0	1,723.4	0.997	1.075	17,174.29	18,534.68	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			3,090.0	0.0	3,090.0	4.339	5.358	134,085.43	165,571.56	17,913.38
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			12,253.4	0.0	12,253.4	3.755	4.388	460,151.72	537,638.24	17,913.38
CURRENT MONTH:										
DIFFERENCE			414.4	0.0	414.4	(1.740)	(2.823)	(190,348.28)	(316,061.76)	(117,926.62)
DIFFERENCE %			3.5%	0.0%	3.5%	-31.7%	-39.1%	-29.3%	-37.0%	-86.8%
PERIOD TO DATE:										
ACTUAL			178,135.3	32.1	178,103.2	4.713	5.550	8,393,802.12	9,884,377.15	695,073.20
ESTIMATED			228,610.0	0.0	228,610.0	5.570	7.470	12,733,500.00	17,077,500.00	3,146,520.00
DIFFERENCE			(50,474.7)	32.1	(50,506.8)	(0.857)	(1.920)	(4,339,697.88)	(7,193,122.85)	(2,451,446.80)
DIFFERENCE %			-22.1%	0.0%	-22.1%	-15.4%	-25.7%	-34.1%	-42.1%	-77.9%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF DECEMBER 2006.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	4.0	0.0	3.0	1.0	10.000	10.000	100.00
HARDEE POWER PARTNERS		IPP	1,061.0	0.0	0.0	1,061.0	20.377	20.377	216,200.00
CALPINE		SCH. - D	3,089.0	0.0	0.0	3,089.0	11.140	11.140	344,100.00
VARIOUS		MKT. BASED	260,868.0	0.0	0.0	260,868.0	5.833	5.833	15,216,900.00
OTHER		SCH. - D	91,891.0	0.0	0.0	91,891.0	3.590	3.590	3,299,200.00
TOTAL			**356,913.0**	**0.0**	**3.0**	**356,910.0**	**5.345**	**5.345**	**19,076,500.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	31,612.0	0.0	0.0	31,612.0	8.655	8.655	2,735,918.30
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	30,500.0	0.0	0.0	30,500.0	3.322	3.322	1,013,210.00
CALPINE		SCH. - D	1,950.0	0.0	0.0	1,950.0	9.677	9.677	188,709.89
CALPINE		OATT	337.0	0.0	0.0	337.0	3.477	3.477	11,718.78
AUBURNDALE POWER PARTNERS		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TEC MARKETING		OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. PWR. & LIGHT		EMERG.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	NOV. 2006	IPP	(25,737.0)	0.0	0.0	(25,737.0)	3.048	3.048	(784,514.81)
HARDEE PWR. PART.-NATIVE	NOV. 2006	IPP	25,737.0	0.0	0.0	25,737.0	3.224	3.224	829,851.73
PROGRESS ENERGY FLORIDA	NOV. 2006	SCH. - D	(33,450.0)	0.0	0.0	(33,450.0)	3.064	3.064	(1,024,908.00)
PROGRESS ENERGY FLORIDA	NOV. 2006	SCH. - D	33,450.0	0.0	0.0	33,450.0	3.322	3.322	1,111,209.00
CALPINE	NOV. 2006	SCH. - D	(1,174.0)	0.0	0.0	(1,174.0)	10.852	10.852	(127,405.67)
CALPINE	NOV. 2006	SCH. - D	1,174.0	0.0	0.0	1,174.0	10.885	10.885	127,786.35
CALPINE	NOV. 2006	OATT	(1,311.0)	0.0	0.0	(1,311.0)	6.986	6.986	(91,580.49)
CALPINE	NOV. 2006	OATT	1,311.0	0.0	0.0	1,311.0	3.948	3.948	51,752.50
SUB-TOTAL OF ADJUSTMENTS:			0.0	0.0	0.0	0.0	0.000	0.000	92,190.41
TOTAL			**64,399.0**	**0.0**	**0.0**	**64,399.0**	**6.276**	**6.276**	**4,041,747.38**
CURRENT MONTH:									
DIFFERENCE			(292,514.0)	0.0	(3.0)	(292,511.0)	0.931	0.931	(15,034,752.62)
DIFFERENCE %			-82.0%	0.0%	0.0%	-82.0%	17.4%	17.4%	-78.8%
PERIOD TO DATE:									
ACTUAL			895,968.0	0.0	0.0	895,968.0	5.900	5.900	52,865,385.42
ESTIMATED			3,381,183.0	0.0	9,544.0	3,371,639.0	5.918	5.918	199,538,600.00
DIFFERENCE			(2,485,215.0)	0.0	(9,544.0)	(2,475,671.0)	(0.018)	(0.018)	(146,673,214.58)
DIFFERENCE %			-73.5%	0.0%	-100.0%	-73.4%	-0.3%	-0.3%	-73.5%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	35,798.0	0.0	0.0	35,798.0	3.028	3.028	1,084,100.00
TOTAL		**35,798.0**	**0.0**	**0.0**	**35,798.0**	**3.028**	**3.028**	**1,084,100.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	16,805.0	0.0	0.0	16,805.0	2.784	2.784	467,779.70
McKAY BAY REFUSE	COGEN.	13,919.0	0.0	0.0	13,919.0	3.184	3.184	443,121.58
ORANGE COGENERATION L.P	COGEN.	3,680.0	0.0	0.0	3,680.0	2.615	2.615	96,222.66
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	2,942.0	0.0	0.0	2,942.0	3.600	3.600	105,925.59
CF INDUSTRIES INC.	COGEN.	626.0	0.0	0.0	626.0	4.978	4.978	31,160.95
IMC-AGRICO-NEW WALES	COGEN.	1,102.0	0.0	0.0	1,102.0	4.694	4.694	51,725.84
IMC-AGRICO-S. PIERCE	COGEN.	10,048.0	0.0	0.0	10,048.0	4.752	4.752	477,462.93
AUBURNDALE POWER PARTNERS	COGEN.	1,025.0	0.0	0.0	1,025.0	3.466	3.466	35,527.13
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL FOR DECEMBER 2006		50,147.0	0.0	0.0	50,147.0	3.408	3.408	1,708,926.38
ADJUSTMENTS FOR THE MONTH OF:	**NOVEMBER 2006**							
HILLSBOROUGH COUNTY	COGEN.	(17,077.0)	0.0	0.0	(17,077.0)	2.906	2.906	(496,324.45)
		17,077.0	0.0	0.0	17,077.0	2.779	2.779	474,572.94
McKAY BAY REFUSE	COGEN.	(13,533.0)	0.0	0.0	(13,533.0)	2.904	2.904	(393,019.41)
		13,533.0	0.0	0.0	13,533.0	2.777	2.777	375,844.36
ORANGE COGENERATION L.P.	COGEN.	(4,830.0)	0.0	0.0	(4,830.0)	2.662	2.662	(128,556.54)
		4,830.0	0.0	0.0	4,830.0	2.589	2.589	125,053.15
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	(5,999.0)	0.0	0.0	(5,999.0)	6.988	6.988	(419,185.69)
		5,999.0	0.0	0.0	5,999.0	4.407	4.407	264,386.91
CF INDUSTRIES INC.	COGEN.	(1,316.0)	0.0	0.0	(1,316.0)	7.974	7.974	(104,941.77)
		1,316.0	0.0	0.0	1,316.0	5.242	5.242	68,987.56
IMC-AGRICO-NEW WALES	COGEN.	(1,091.0)	0.0	0.0	(1,091.0)	7.411	7.411	(80,855.67)
		1,091.0	0.0	0.0	1,091.0	4.764	4.764	51,972.65
IMC-AGRICO-S. PIERCE	COGEN.	(10,461.0)	0.0	0.0	(10,461.0)	7.386	7.386	(772,685.04)
		10,461.0	0.0	0.0	10,461.0	4.732	4.732	494,986.93
AUBURNDALE POWER PARTNERS	COGEN.	(873.0)	0.0	0.0	(873.0)	5.016	5.016	(43,785.41)
		873.0	0.0	0.0	873.0	3.744	3.744	32,686.67
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUBTOTAL		0.0	0.0	0.0	0.0	0.000	0.000	(550,862.81)
TOTAL		**50,147.0**	**0.0**	**0.0**	**50,147.0**	**2.309**	**2.309**	**1,158,063.57**
CURRENT MONTH:								
DIFFERENCE		14,349.0	0.0	0.0	14,349.0	(0.719)	(0.719)	73,963.57
DIFFERENCE %		40.1%	0.0%	0.0%	40.1%	-23.7%	-23.7%	6.8%
PERIOD TO DATE:								
ACTUAL		575,719.0	0.0	0.0	575,719.0	3.214	3.214	18,505,043.85
ESTIMATED		435,075.0	0.0	0.0	435,075.0	3.009	3.009	13,090,300.00
DIFFERENCE		140,644.0	0.0	0.0	140,644.0	0.206	0.206	5,414,743.85
DIFFERENCE %		32.3%	0.0%	0.0%	32.3%	6.8%	6.8%	41.4%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2006

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (5B)-5
ESTIMATED:								
VARIOUS		ECON	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:								
PROGRESS ENERGY FLORIDA		SCH. - JC	6,497.0	5.970	387,865.00	8.321	540,620.84	152,755.84
FLA. POWER & LIGHT		SCH. - JC	16,225.0	6.562	1,064,680.00	9.427	1,529,575.63	464,895.63
CITY OF LAKELAND		SCH. - JC	1,675.0	6.521	109,220.00	10.538	176,507.65	67,287.65
ORLANDO UTIL. COMM.		SCH. - JC	2,665.0	8.326	221,885.00	11.388	303,478.65	81,593.65
THE ENERGY AUTHORITY		SCH. - JC	39,769.0	5.627	2,237,943.00	7.184	2,856,884.34	618,941.34
OKEELANTA		SCH. - JC	280.0	7.488	20,965.00	10.946	30,647.40	9,682.40
CITY OF TALLAHASSEE		SCH. - JC	158.0	7.708	12,179.00	12.770	20,177.24	7,998.24
CALPINE		SCH. - JC	545.0	6.237	33,990.00	11.811	64,369.70	30,379.70
CARGILL ALLIANT		SCH. - JC	1,195.0	8.100	96,793.00	11.795	140,944.91	44,151.91
CARGILL FOR NEW SMYRNA BEACH		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
RELIANT		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
RAINBOW ENERGY MARKETERS		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - JC	7,617.0	7.227	550,470.00	9.312	709,331.56	158,861.56
ENTERGY-KOCH TRADING		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
CINCINATTI GAS & ELECTRIC		SCH. - JC	0.0	0.000	0.00	0.000	0.00	0.00
SUBTOTAL			76,626.0	6.181	4,735,990.00	8.316	6,372,537.92	1,636,547.92
PRIOR MONTH ADJUSTMENTS:								
RELIANT	NOV. 2006	SCH. - JC	(17,603.0)	8.230	(1,448,757.38)	8.292	(1,459,697.76)	(10,940.38)
RELIANT	NOV. 2006	SCH. - JC	17,603.0	8.157	1,435,960.96	8.220	1,446,901.34	10,940.38
SUBTOTAL			0.0	0.000	(12,796.42)	0.000	(12,796.42)	0.00
TOTAL			**76,626.0**	**6.164**	**4,723,193.58**	**8.300**	**6,359,741.50**	**1,636,547.92**
CURRENT MONTH:								
DIFFERENCE			76,626.0	6.164	4,723,193.58	8.300	6,359,741.50	1,636,547.92
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:								
ACTUAL			1,271,295.4	6.875	87,398,492.10	8.349	106,136,755.34	18,738,263.24
ESTIMATED			0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE			1,271,295.4	6.875	87,398,492.10	8.349	106,136,755.34	18,738,263.24
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2006 - DECEMBER 2006

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:									
VARIOUS	JURISDIC. SCH. - D	17,564.0	0.0	17,564.0	2.897	2.897	508,800.00	508,800.00	
VARIOUS	JURISDIC. SCH. - MB	211,046.0	0.0	211,046.0	5.792	7.851	12,224,700.00	16,568,700.00	3,146,520.00
TOTAL		**228,610.0**	**0.0**	**228,610.0**	**5.570**	**7.470**	**12,733,500.00**	**17,077,500.00**	**3,146,520.00**
ACTUAL:									
SEMINOLE ELEC. PRECO-1	JURISDIC. SCH. - D	7,626.5	32.1	7,594.4	4.536	4.783	344,449.39	363,245.92	
SEMINOLE ELEC. HARDEE	JURISDIC. SCH. - D	12,699.8	0.0	12,699.8	3.576	3.787	454,205.71	480,883.61	
CALPEA	SCH. - MA	2,160.0	0.0	2,160.0	4.523	5.769	97,691.72	124,611.37	20,739.13
CARGILL ALLIANT	SCH. - MA	3,498.0	0.0	3,498.0	2.904	3.625	101,591.62	126,793.69	20,883.78
CINCINNATI GAS & ELECTRIC	SCH. - MA	1,935.0	0.0	1,935.0	2.486	3.037	48,106.39	58,765.64	9,426.37
CITY OF LAKELAND	SCH. - MA	2,130.0	0.0	2,130.0	4.766	6.537	101,515.59	139,247.83	30,027.73
CITY OF TALLAHASSEE	SCH. - MA	30.0	0.0	30.0	4.147	5.865	1,244.10	1,759.45	411.85
COBB ELECTRIC MEMBERSHIP CORP	SCH. - MA	3,005.0	0.0	3,005.0	4.206	5.480	126,380.83	164,660.19	32,616.89
FLA. PWR. & LIGHT	SCH. - MA	29,221.0	0.0	29,221.0	4.667	5.928	1,363,602.85	1,732,268.04	274,531.91
NEW SMYRNA BEACH	SCH. - MA	14,075.0	0.0	14,075.0	6.173	8.126	868,907.68	1,143,753.78	239,521.75
PROGRESS ENERGY FLORIDA	SCH. - MA	9,415.0	0.0	9,415.0	5.636	7.176	530,615.39	675,591.37	115,717.23
SEMINOLE ELEC. CO-OP	SCH. - MA	2,550.0	0.0	2,550.0	4.129	6.352	105,300.04	161,987.71	49,229.72
TENASKA POWER CORP	SCH. - MA	420.0	0.0	420.0	6.999	10.560	29,396.75	44,353.53	13,626.78
THE ENERGY AUTHORITY	SCH. - MA	1,586.0	0.0	1,586.0	3.994	5.703	63,344.55	90,452.66	22,773.72
TEC WHOLESALE MARKETING	SCH. - MA						0.00	(107,696.79)	(107,696.79)
HARDEE FOR PROGRESS ENERGY FLORIDA*	SCH. - MA	120.0	0.0	120.0	4.851	5.261	5,820.65	6,313.56	476.11
HARDEE FOR SEMINOLE ELEC. CO-OP*	SCH. - MA	35.0	0.0	35.0	3.406	3.854	1,192.10	1,348.83	150.78
LESS 20% - THRESHHOLD EXCESS									(27,363.76)
AUBURNDALE POWER PARTNERS	OATT	(14.0)	0.0	(14.0)	177.118	177.118	(24,796.54)	(24,796.54)	
CALPINE	OATT	43.0	0.0	43.0	8.784	8.784	3,777.30	3,777.30	
NEW SMYRNA BEACH	SCH. - D	87,600.0	0.0	87,600.0	4.762	5.362	4,171,456.00	4,697,056.00	
SUB-TOTAL SCHEDULE D POWER SALES		87,600.0	0.0	87,600.0	4.762	5.362	4,171,456.00	4,697,056.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		20,326.3	32.1	20,294.2	3.935	4.159	798,655.10	844,129.53	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.		70,180.0	0.0	70,180.0	4.908	6.219	3,444,710.26	4,364,210.86	695,073.20
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.		29.0	0.0	29.0	(72.480)	(72.480)	(21,019.24)	(21,019.24)	
TOTAL		**178,135.3**	**32.1**	**178,103.2**	**4.713**	**5.550**	**8,393,802.12**	**9,884,377.15**	**695,073.20**
DIFFERENCE		(50,474.7)	32.1	(50,506.8)	(0.857)	(1.920)	(4,339,697.88)	(7,193,122.85)	(2,451,446.80)
DIFFERENCE %		-22.1%	0.0%	-22.1%	-15.4%	-25.7%	-34.1%	-42.1%	-77.9%

* SEC 60% PROFIT OR $940.35 HAS BEEN EXCLUDED.

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2006 - DECEMBER 2006

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF JANUARY 2006 THROUGH DECEMBER 2006

(1) PURCHASED FROM		(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) (A) FUEL COST	(7) (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	SCH. - J	15,702.0	0.0	9,544.0	6,158.0	9.742	9.742	599,900.00
HARDEE POWER PARTNERS	IPP	226,755.0	0.0	0.0	226,755.0	8.586	8.586	19,469,300.00
CALPINE	SCH. - D	93,163.0	0.0	0.0	93,163.0	10.254	10.254	9,552,700.00
VARIOUS	MKT. BASED	2,027,654.0	0.0	0.0	2,027,654.0	6.512	6.512	132,031,400.00
OTHER	SCH. - D	1,017,909.0	0.0	0.0	1,017,909.0	3.722	3.722	37,885,300.00
TOTAL		**3,381,183.0**	**0.0**	**9,544.0**	**3,371,639.0**	**5.918**	**5.918**	**199,538,600.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	389,442.0	0.0	0.0	389,442.0	7.764	7.764	30,236,407.79
HARDEE PWR. PART.-OTHERS	IPP	155.0	0.0	0.0	155.0	4.539	4.539	7,035.50
PROGRESS ENERGY FLORIDA	SCH. - D	400,965.0	0.0	0.0	400,965.0	3.401	3.401	13,637,149.75
CALPINE	SCH. - D	92,884.0	0.0	0.0	92,884.0	9.157	9.157	8,505,599.78
CALPINE	OATT	5,815.0	0.0	0.0	5,815.0	3.738	3.738	217,362.15
AUBURNDALE POWER PARTNERS	OATT	6,468.0	0.0	0.0	6,468.0	3.761	3.761	243,286.45
TEC MARKETING	OATT	139.0	0.0	0.0	139.0	0.000	0.000	0.00
FLA. PWR. & LIGHT	EMERG.	100.0	0.0	0.0	100.0	18.544	18.544	18,544.00
TOTAL		**895,968.0**	**0.0**	**0.0**	**895,968.0**	**5.900**	**5.900**	**52,865,385.42**
DIFFERENCE		(2,485,215.0)	0.0	(9,544.0)	(2,475,671.0)	(0.018)	(0.018)	(146,673,214.58)
DIFFERENCE %		-73.5%	0.0%	-100.0%	-73.4%	-0.3%	-0.3%	-73.5%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2006 - DECEMBER 2006

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF JANUARY 2006 THROUGH DECEMBER 2006

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	435,075.0	0.0	0.0	435,075.0	3.009	3.009	13,090,300.00
TOTAL		**435,075.0**	**0.0**	**0.0**	**435,075.0**	**3.009**	**3.009**	**13,090,300.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	196,241.0	0.0	0.0	196,241.0	2.685	2.685	5,268,868.23
McKAY BAY REFUSE	COGEN.	162,420.0	0.0	0.0	162,420.0	2.716	2.716	4,412,003.42
ORANGE COGENERATION L.P.	COGEN.	76,291.0	0.0	0.0	76,291.0	2.491	2.491	1,900,548.97
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	4.00
CARGILL GREEN BAY	COGEN.	309.0	0.0	0.0	309.0	7.258	7.258	22,427.88
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	26,123.0	0.0	0.0	26,123.0	4.254	4.254	1,111,313.87
CF INDUSTRIES INC.	COGEN.	12,371.0	0.0	0.0	12,371.0	5.187	5.187	641,669.63
IMC-AGRICO-NEW WALES	COGEN.	13,815.0	0.0	0.0	13,815.0	5.101	5.101	704,679.94
IMC-AGRICO-S. PIERCE	COGEN.	76,519.0	0.0	0.0	76,519.0	5.145	5.145	3,936,898.60
AUBURNDALE POWER PARTNERS	COGEN.	11,629.0	0.0	0.0	11,629.0	4.356	4.356	506,587.57
CUTRALE CITRUS	COGEN.	1.0	0.0	0.0	1.0	4.174	4.174	41.74
TOTAL		**575,719.0**	**0.0**	**0.0**	**575,719.0**	**3.214**	**3.214**	**18,505,043.85**
DIFFERENCE		140,644.0	0.0	0.0	140,644.0	0.206	0.206	5,414,743.85
DIFFERENCE %		32.3%	0.0%	0.0%	32.3%	6.8%	6.8%	41.4%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2006 - DECEMBER 2006

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF JANUARY 2006 THROUGH DECEMBER 2006

(1)	(2)	(3)	(4)	(5)	(6) COST IF GENERATED		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACTION COSTS CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(A) CENTS PER KWH	(B) TOTAL COST	FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
PROGRESS ENERGY FLORIDA	SCH. - JC	72,153.4	5.561	4,012,656.50	7.105	5,126,854.70	1,114,198.20
FLA. POWER & LIGHT	SCH. - JC	412,324.3	6.147	25,344,802.31	7.692	31,714,468.61	6,369,666.30
CITY OF LAKELAND	SCH. - JC	16,054.1	7.235	1,161,589.72	10.067	1,616,094.06	454,504.34
ORLANDO UTIL. COMM.	SCH. - JC	34,180.9	9.713	3,320,029.02	11.575	3,956,409.56	636,380.54
THE ENERGY AUTHORITY	SCH. - JC	236,504.9	6.750	15,964,236.25	8.722	20,628,258.44	4,664,022.19
OKEELANTA	SCH. - JC	6,778.0	7.788	527,850.00	10.222	692,868.09	165,018.09
CITY OF TALLAHASSEE	SCH. - JC	1,943.0	8.380	162,819.00	11.591	225,219.74	62,400.74
CALPINE	SCH. - JC	64,652.0	7.060	4,564,635.64	9.055	5,854,362.94	1,289,727.30
CARGILL ALLIANT	SCH. - JC	250,444.1	7.758	19,429,349.62	8.557	21,430,228.25	2,000,878.63
CARGILL FOR NEW SMYRNA BEACH	SCH. - JC	29,530.0	4.807	1,419,564.30	4.807	1,419,564.30	0.00
RELIANT	SCH. - JC	83,143.7	9.047	7,522,317.89	10.105	8,401,264.59	878,946.70
RAINBOW ENERGY MARKETERS	SCH. - JC	14.0	5.600	784.00	11.966	1,675.24	891.24
SEMINOLE ELEC. CO-OP	SCH. - JC	50,167.0	6.555	3,288,431.00	8.251	4,139,479.02	851,048.02
ENTERGY-KOCH TRADING	SCH. - JC	0.0	0.000	(23,853.15)	0.000	(12,789.15)	11,064.00
COBB ELECTRIC MEMBERSHIP CORP	SCH. - JC	11,030.0	4.737	522,509.00	6.368	702,399.15	179,890.15
CINCINATTI GAS & ELECTRIC	SCH. - JC	2,376.0	7.608	180,771.00	10.118	240,397.80	59,626.80
TOTAL		**1,271,295.4**	**6.875**	**87,398,492.10**	**8.349**	**106,136,755.34**	**18,738,263.24**
DIFFERENCE		1,271,295.4	6.875	87,398,492.10	8.349	106,136,755.34	18,738,263.24
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2006 - DECEMBER 2006

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL PURCHASES AND SALES
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

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
HILLSBOROUGH COUNTY	1/10/1985	3/1/2010	QF
HARDEE POWER PARTNERS	1/1/1993	12/31/2012	LT
PROGRESS ENERGY FLORIDA	1/1/2006	3/31/2007	LT
SEMINOLE ELECTRIC	06/01/92	**	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	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	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
HILLSBOROUGH COUNTY	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
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	377.0	377.0	377.0	377.0	377.0	377.0	377.0	377.0	377.0	377.0	377.0	377.0
PROGRESS ENERGY FLORIDA	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
CALPINE	0.0	0.0	0.0	0.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
SEMINOLE ELECTRIC	3.2	5.2	4.2	5.6	5.6	6.4	5.5	6.4	6.4	6.4	5.8	5.8

CAPACITY YEAR 2006	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
MCKAY BAY REFUSE	$263,035	$263,035	$263,035	$263,035	$263,035	$263,035	$263,035	$263,035	$268,770	$268,770	$268,770	$268,770	$3,179,360
HILLSBOROUGH COUNTY	$846,630	$846,630	$846,630	$846,630	$937,710	$892,170	$892,170	$892,170	$892,170	$892,170	$892,170	$892,170	$10,569,420
ORANGE COGEN LP	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$724,960	$8,699,520
TOTAL COGENERATION	**$1,834,625**	**$1,834,625**	**$1,834,625**	**$1,834,625**	**$1,925,705**	**$1,880,165**	**$1,880,165**	**$1,880,165**	**$1,885,900**	**$1,885,900**	**$1,885,900**	**$1,885,900**	**$22,448,300**
HARDEE POWER PARTNERS	[redacted]												
PROGRESS ENERGY FLORIDA - D													
CALPINE - D													
CITY OF TALLAHASSEE - JC													
OKEELANTA - JC													
THE ENERGY AUTHORITY - JC													
RELIANT ENERGY SERVICES - JC													
ORLANDO UTILITIES - JC													
FLORIDA POWER & LIGHT - JC													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
HARDEE PWR PART. TO PROGRESS ENERGY FLORIDA - OATT													
CALPEA - MA													
COBB ELECTRIC MEMBERSHIP - MA													
CAROLINA POWER & LIGHT - MA													
CARGILL ALLIANT - MA													
CITY OF TALLAHASSEE - MA													
PROGRESS ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
SEMINOLE ELECTRIC - MA													
THE ENERGY AUTHORITY - MA													
TEC WHOLESALE MARKETING - MA													
TENASKA POWER CORP. - MA													
CINCINNATI GAS & ELECTRIC - MA													
NEW SMYRNA BEACH - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$ 2,470,186**	**$ 2,467,647**	**$ 2,461,760**	**$ 2,689,292**	**$ 3,021,104**	**$ 3,049,966**	**$ 3,022,731**	**$ 3,109,508**	**$ 3,988,237**	**$ 3,107,417**	**$ 3,209,496**	**$ 3,442,813**	**$ 36,040,157**
TOTAL CAPACITY	**$ 4,304,811**	**$ 4,302,272**	**$ 4,296,385**	**$ 4,523,917**	**$ 4,946,809**	**$ 4,930,131**	**$ 4,902,896**	**$ 4,989,673**	**$ 5,874,137**	**$ 4,993,317**	**$ 5,095,396**	**$ 5,328,713**	**$ 58,488,457**

DOCKET NO. 070001-EI
CCR 2006 FINAL TRUE-UP
EXHIBIT CA-1
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER)RECOVERY FOR

JANUARY 2006 - DECEMBER 2006

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 35
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-1)
DATE 11-010-07

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

1.	End-of-Period True-up: Over/(Under) Recovery	($3,627,197)
2.	Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-06-1057-FOF-EI For the January 2006 Through December 2006 Period	(960,951)
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2008 Through December 2008 Period	**($2,666,246)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	Total
1 UNIT POWER CAPACITY CHARGES	1,711,084	1,695,490	1,695,490	1,682,168	1,703,282	1,703,282	1,703,282	1,703,282	1,703,282	1,703,282	1,703,282	1,703,282	20,410,488
2 CAPACITY PAYMENTS TO COGENERATORS	1,834,625	1,834,625	1,834,625	1,834,625	1,925,705	1,880,165	1,880,165	1,880,165	1,885,900	1,885,900	1,885,900	1,885,900	22,448,300
3 EMERGENCY CAPACITY CHARGES	865,000	865,000	865,000	1,108,213	1,435,161	1,515,223	1,354,413	1,435,161	2,332,906	1,435,908	1,599,618	1,819,903	16,631,506
4 INCREMENTAL SECURITY O&M COSTS	39,116	13,100	46,444	18,913	48,531	53,812	49,967	86,854	71,416	53,684	54,744	50,987	587,570
5 (CAPACITY REVENUES)	(105,898)	(92,843)	(98,729)	(101,086)	(117,339)	(168,538)	(34,964)	(28,935)	(47,950)	(31,773)	(93,403)	(80,372)	(1,001,830)
6 TOTAL CAPACITY DOLLARS	4,343,927	4,315,372	4,342,830	4,542,833	4,995,340	4,983,944	4,952,863	5,076,527	5,945,554	5,047,001	5,150,141	5,379,700	59,076,034
7 JURISDICTIONAL PERCENTAGE	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
8 JURISDICTIONAL CAPACITY DOLLARS	4,188,294	4,160,762	4,187,236	4,380,073	4,816,368	4,805,380	4,775,412	4,894,647	5,732,538	4,866,178	4,965,623	5,186,957	56,959,468
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	4,201,800	3,848,120	3,677,992	3,913,972	4,487,616	5,143,290	5,465,574	5,424,091	5,389,905	4,887,928	3,996,265	4,105,925	54,542,478
10 PRIOR PERIOD TRUE-UP PROVISION	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(79,776)	(957,312)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	4,122,024	3,768,344	3,598,216	3,834,196	4,407,840	5,063,514	5,385,798	5,344,315	5,310,129	4,808,152	3,916,489	4,026,149	53,585,166
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(66,270)	(392,418)	(589,020)	(545,877)	(408,528)	258,134	610,386	449,668	(422,409)	(58,026)	(1,049,134)	(1,160,808)	(3,374,302)
13 INTEREST PROVISION FOR PERIOD	(4,064)	(4,754)	(6,506)	(8,814)	(10,695)	(11,079)	(9,234)	(6,551)	(6,110)	(6,842)	(8,931)	(13,461)	(97,041)
14 2005 ADJUSTMENT (RETAIL/WHSL) INCL INTEREST					612								612
15 INTEREST ADJUSTMENT FOR JUNE 2006							340						340
16 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,114,118)	(1,104,676)	(1,422,072)	(1,937,822)	(2,412,737)	(2,751,572)	(2,424,741)	(1,743,473)	(1,220,580)	(1,569,323)	(1,554,415)	(2,532,704)	(1,114,118)
17 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	79,776	79,776	79,776	79,776	79,776	79,776	79,776	79,776	79,776	79,776	79,776	79,776	957,312
18 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 17)	(1,104,676)	(1,422,072)	(1,937,822)	(2,412,737)	(2,751,572)	(2,424,741)	(1,743,473)	(1,220,580)	(1,569,323)	(1,554,415)	(2,532,704)	(3,627,197)	**(3,627,197)**

DOCKET NO. 070001-EI
CCR 2006 FINAL TRUE UP
EXHIBIT CA-1, PAGE 2 OF 4
DOCUMENT NO. 1

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	Total
1 BEGINNING TRUE-UP AMOUNT	(1,114,118)	(1,104,676)	(1,422,072)	(1,937,822)	(2,412,737)	(2,751,572)	(2,424,741)	(1,743,473)	(1,220,580)	(1,569,323)	(1,554,415)	(2,532,704)	(1,114,118)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(1,100,612)	(1,417,318)	(1,931,316)	(2,403,923)	(2,741,489)	(2,413,662)	(1,734,579)	(1,214,029)	(1,563,213)	(1,547,573)	(2,523,773)	(3,613,736)	(3,531,108)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(2,214,730)	(2,521,994)	(3,353,388)	(4,341,745)	(5,154,226)	(5,165,234)	(4,159,320)	(2,957,502)	(2,783,793)	(3,116,896)	(4,078,188)	(6,146,440)	(4,645,226)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(1,107,365)	(1,260,997)	(1,676,694)	(2,170,873)	(2,577,113)	(2,582,617)	(2,079,660)	(1,478,751)	(1,391,897)	(1,558,448)	(2,039,094)	(3,073,220)	(2,322,613)
5 INTEREST RATE % - 1ST DAY OF MONTH	4.300	4.510	4.530	4.780	4.960	5.010	5.290	5.360	5.270	5.260	5.270	5.250	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	4.510	4.530	4.780	4.960	5.010	5.290	5.360	5.270	5.260	5.270	5.250	5.270	NA
7 TOTAL (LINE 5 + LINE 6)	8.810	9.040	9.310	9.740	9.970	10.300	10.650	10.630	10.530	10.530	10.520	10.520	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	4.405	4.520	4.655	4.870	4.985	5.150	5.325	5.315	5.265	5.265	5.260	5.260	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.367	0.377	0.388	0.406	0.415	0.429	0.444	0.443	0.439	0.439	0.438	0.438	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(4,064)	(4,754)	(6,506)	(8,814)	(10,695)	(11,079)	(9,234)	(6,551)	(6,110)	(6,842)	(8,931)	(13,461)	(97,041)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2006 THROUGH DECEMBER 2006

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$20,410,488	$35,360,393	($14,949,905)	-42.28%
2 CAPACITY PAYMENTS TO COGENERATORS	22,448,300	22,798,370	(350,070)	-1.54%
3 EMERGENCY CAPACITY CHARGES	16,631,506	0	16,631,506	0.00%
4 INCREMENTAL SECURITY O&M COSTS	587,570	604,656	(17,086)	-3.00%
5 (CAPACITY REVENUES)	(1,001,830)	(1,353,937)	352,107	-26.01%
6 TOTAL CAPACITY DOLLARS	$59,076,034	$57,409,482	$1,666,552	2.90%
7 JURISDICTIONAL PERCENTAGE	96.41722%	96.41722%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$56,959,468	$55,352,630	$1,606,838	2.90%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	54,542,478	55,569,975	(1,027,497)	-1.85%
10 PRIOR PERIOD TRUE-UP PROVISION	(957,312)	(957,312)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$53,585,166	$54,612,663	($1,027,497)	-1.88%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($3,374,302)	($739,967)	($2,634,335)	356.01%
13 INTEREST PROVISION FOR PERIOD	(97,041)	(64,790)	(32,251)	49.78%
14 2005 ADJUSTMENT (RETAIL/WHSL) INCL INTEREST	612	612	0	0.00%
15 INTEREST ADJUSTMENT FOR JUNE 2006	340	0	340	0.00%
16 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,114,118)	(1,114,118)	0	0.00%
17 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	957,312	957,312	0	0.00%
18 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 17)	($3,627,197)	($960,951)	($2,666,246)	277.46%

DOCKET NO. 070001-EI
FAC 2006 FINAL TRUE-UP
EXHIBIT CA-1
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY

FOR

JANUARY 2006 - DECEMBER 2006

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2006 THROUGH DECEMBER 2006

1 TOTAL FUEL COSTS FOR THE PERIOD	$965,306,536
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS) *	917,646,491
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	874,284,492
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	(43,361,999)
5 INTEREST	(10,247,987)
6 TRUE-UP COLLECTED	147,656,222
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/05)	(254,173,059)
8 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7)	(160,126,823)
9 PROJECTED UNDER-RECOVERY PER PROJECTION FILED 9/1/06 (SCHEDULE E1-A LINE 3)	(157,776,979)
10 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)	**($2,349,844)**

* Includes Waterborne Coal Transportation disallowance of $15,314,802 per Order No. PSC-04-0999-FOF-EI.

DOCKET NO. 070001-EI
FAC 2006 FINAL TRUE-UP
EXHIBIT CA-1
DOCUMENT NO. 3

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2006 - DECEMBER 2006

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2006 THROUGH DECEMBER 2006

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$815,520,812	$757,482,986	$58,037,826	7.7
	2. FUEL COST OF POWER SOLD	8,393,803	12,733,500	(4,339,697)	(34.1)
	2a. GAINS FROM MARKET BASED SALES	695,073	3,146,520	(2,451,447)	(77.9)
	3. FUEL COST OF PURCHASED POWER	52,865,384	199,538,600	(146,673,216)	(73.5)
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	18,505,045	13,090,300	5,414,745	41.4
	4. ENERGY COST OF ECONOMY PURCHASES	87,398,492	0	87,398,492	0.0
	6a. ADJ. TO FUEL COST (FT. MEADE/WAUCHULA)	(104,970)	(80,808)	(24,162)	29.9
	6b. ADJ. TO FUEL COST	0	0	0	0.0
	6c. INCREMENTAL HEDGING O&M COSTS	210,649	235,801	(25,152)	(10.7)
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. SUM OF LINES A1 THRU 6c	$965,306,536	$954,386,859	$10,919,677	1.1
C	1. JURISDICTIONAL FUEL REVENUE	$1,022,670,248	$1,063,835,037	($41,164,789)	(3.9)
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	a. TRUE-UP PROVISION	(147,656,222)	(147,656,222)	0	0.0
	b. INCENTIVE PROVISION	(729,534)	(729,534)	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2b)	874,284,492	915,449,281	(41,164,789)	(4.5)
	6B.JURISDICTIONAL FUEL COST	932,961,293	930,840,978	2,120,315	0.2
	6D.OTHER JURISD. ADJUSTMENTS	0	0	0	0.0
	6E.WATERBORNE COAL TRANSPORTATION DISALLOWANCE PER FPSC DECISION ON 9/21/04	(15,314,802)	(15,315,000)	198	0.0
	6F.OTHER	0	0	0	0.0
	6G.OTHER	0	0	0	0.0
	6H.JURISD. TOTAL FUEL & NET PWR. TRANS.	917,646,491	915,525,978	2,120,513	0.2
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6H)	(43,361,999)	(76,697)	(43,285,302)	56,436.8
	8. INTEREST PROVISION - THIS PERIOD	(10,247,987)	(3,679,223)	(6,568,764)	178.5
	9.TOTAL TRUE-UP AMOUNT FOR PERIOD	($53,609,986)	($3,755,920)	($49,854,066)	1,327.3
	10.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2006)	(254,173,059)	(147,656,222)	(106,516,837)	72.1
	11.TRUE-UP COLLECTED (REFUNDED)	147,656,222	147,656,222	0	0.0
	12.END OF PERIOD TOTAL NET TRUE-UP (LINE C9 through C11)	($160,126,823)	($3,755,920)	($156,370,903)	4,163.3

Line numbers reference Schedule A-2 included in Document No. 4

Docket No. 070001-EI
FAC 2007 Actual/Estimated True-Up
Exhibit No. ____ (CA-2)
Document No. 1

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY
ACTUAL / ESTIMATED
JANUARY 2007 THROUGH DECEMBER 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 36
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-2)
DATE 11-06-07

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

BATES PAGE NO.	DESCRIPTION	PERIOD
13	Schedule E1-B Calculation of Estimated True-Up	(JAN. 2007 - DEC. 2007)
14	Schedule E2 Cost Recovery Clause Calculation	(")
15-16	Schedule E3 Generating System Comparative Data	(")
17-18	Schedule E5 Inventory Analysis	(")
19	Schedule E6 Power Sold	(")
20-21	Schedule E7 Purchased Power	(")
22	Schedule E8 Energy Payment to Qualifying Facilities	(")
23	Schedule E9 Economy Energy Purchases	(")

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL
A. 1.	Fuel Cost of System Net Generation	59,381,927	65,475,257	62,491,151	66,039,299	76,553,714	78,178,991	84,251,810	89,480,920	84,868,471	71,636,907	63,924,542	77,788,505	880,071,494
2.	Fuel Cost of Power Sold (1)	1,163,068	810,332	955,639	859,309	540,195	489,202	485,700	679,900	782,700	1,069,300	1,446,300	581,400	9,863,045
3.	Fuel Cost of Purchased Power	2,781,714	3,206,152	2,758,323	3,236,613	6,442,129	6,539,332	7,005,000	7,819,300	6,374,000	4,982,900	1,779,700	284,700	53,209,863
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	1,637,467	1,765,337	1,668,018	1,887,853	2,120,569	1,846,445	1,829,500	2,038,800	1,943,800	1,928,100	1,810,600	1,994,200	22,470,689
4.	Energy Cost of Economy Purchases	5,180,527	8,730,048	6,834,498	7,436,323	11,061,602	8,025,722	3,251,100	2,709,200	6,681,800	6,315,900	1,289,000	5,052,300	72,568,020
5.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(8,643)	(8,241)	(8,442)	(8,643)	(10,502)	(11,206)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(110,547)
5a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
5b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**67,809,924**	**78,358,221**	**72,787,909**	**77,732,136**	**95,627,317**	**94,090,082**	**95,842,565**	**101,359,175**	**99,076,226**	**83,785,362**	**67,348,397**	**84,529,160**	**1,018,346,474**
(1)	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,527,746	1,389,646	1,387,116	1,429,774	1,548,480	1,697,396	1,918,945	1,928,655	1,965,321	1,760,861	1,506,618	1,471,115	19,531,673
2.	Non-Jurisdictional MWH Sales	38,980	58,901	43,070	65,305	62,030	59,289	72,735	78,930	75,834	70,607	57,249	48,178	731,108
3.	**TOTAL SALES (LINE B1+B2)**	**1,566,726**	**1,448,547**	**1,430,186**	**1,495,079**	**1,610,510**	**1,756,685**	**1,991,680**	**2,007,585**	**2,041,155**	**1,831,468**	**1,563,867**	**1,519,293**	**20,262,781**
4.	**Jurisdictional % of Total Sales**	**0.9751201**	**0.9593379**	**0.9698850**	**0.9563200**	**0.9614843**	**0.9662495**	**0.9634806**	**0.9606841**	**0.9628475**	**0.9614479**	**0.9633927**	**0.9682892**	-
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	89,050,798	81,088,575	80,892,226	83,520,142	90,693,922	99,390,841	113,111,560	113,685,147	115,853,585	103,757,295	88,735,111	86,631,625	1,146,410,827
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,082)	(13,148,077)	(157,776,979)
2a.	Incentive Provision	8,316	8,316	8,316	8,316	8,316	8,316	8,316	8,316	8,316	8,316	8,316	8,315	99,791
2b.	Waterborne Transp. Disallowance Per FPSC Decision 9/21/04	1,340,445	761,058	1,398,399	1,483,969	1,462,467	1,407,882	1,276,282	1,276,282	1,276,282	1,276,282	1,276,282	1,276,282	15,511,912
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**77,251,477**	**68,709,867**	**69,150,859**	**71,864,345**	**79,016,623**	**87,658,957**	**101,248,076**	**101,821,663**	**103,990,101**	**91,893,811**	**76,871,627**	**74,768,145**	**1,004,245,551**
4.	Total Fuel and Net Power Transactions (Line A6)	67,809,924	78,358,221	72,787,909	77,732,136	95,627,317	94,090,082	95,842,565	101,359,175	99,076,226	83,785,362	67,348,397	84,529,160	1,018,346,474
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	66,122,820	75,172,010	70,595,902	74,336,797	91,944,164	90,914,494	92,342,452	97,374,148	95,395,297	80,555,260	64,882,954	81,848,673	981,484,971
5a.	Jurisdictional Loss Multiplier	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	-
5b.	Jurisdictional Sales Adjusted for Line Losses	66,180,347	75,237,410	70,657,320	74,401,470	92,024,155	90,993,590	92,422,790	97,458,864	95,478,291	80,625,343	64,939,402	81,919,881	982,338,863
5c.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**66,180,347**	**75,237,410**	**70,657,320**	**74,401,470**	**92,024,155**	**90,993,590**	**92,422,790**	**97,458,864**	**95,478,291**	**80,625,343**	**64,939,402**	**81,919,881**	**982,338,863**
7.	Over/(Under) Recovery	11,071,130	(6,527,543)	(1,506,461)	(2,537,125)	(13,007,532)	(3,334,633)	8,825,286	4,362,799	8,511,810	11,268,468	11,932,225	(7,151,736)	21,906,688
8.	Interest Provision(1)	(649,796)	(583,622)	(455,857)	(499,448)	(478,090)	(459,431)	(400,598)	(320,044)	(231,808)	(127,355)	(14,591)	56,508	(4,164,132)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**17,742,556**

(1)Includes interest adjustment in March 2007of ($90,328) for prior periods.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Actual						Estimated						TOTAL
		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	PERIOD
1.	Fuel Cost of System Net Generation	59,381,927	65,475,257	62,491,151	66,039,299	76,553,714	78,178,991	84,251,810	89,480,920	84,868,471	71,636,907	63,924,542	77,788,505	880,071,494
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	1,163,068	810,332	955,639	859,309	540,195	489,202	485,700	679,900	782,700	1,069,300	1,446,300	581,400	9,863,045
4.	Fuel Cost of Purchased Power	2,781,714	3,206,152	2,758,323	3,236,613	6,442,129	6,539,332	7,005,000	7,819,300	6,374,000	4,982,900	1,779,700	284,700	53,209,863
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	1,637,467	1,765,337	1,668,018	1,887,853	2,120,569	1,846,445	1,829,500	2,038,800	1,943,800	1,928,100	1,810,600	1,994,200	22,470,689
7.	Energy Cost of Schedule J Purchases	5,180,527	8,730,048	6,834,498	7,436,323	11,061,602	8,025,722	3,251,100	2,709,200	6,681,800	6,315,900	1,289,000	5,052,300	72,568,020
8.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(8,643)	(8,241)	(8,442)	(8,643)	(10,502)	(11,206)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(110,547)
8a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
8b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**67,809,924**	**78,358,221**	**72,787,909**	**77,732,136**	**95,627,317**	**94,090,082**	**95,842,565**	**101,359,175**	**99,076,226**	**83,785,362**	**67,348,397**	**84,529,160**	**1,018,346,474**
10.	Jurisdictional MWH Sold	1,527,746	1,389,646	1,387,116	1,429,774	1,548,480	1,697,396	1,918,945	1,928,655	1,965,321	1,760,861	1,506,618	1,471,115	19,531,673
11.	Jurisdictional % of Total Sales	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9634806	0.9606841	0.9628475	0.9614479	0.9633927	0.9682892	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	66,122,820	75,172,010	70,595,902	74,336,797	91,944,164	90,914,494	92,342,452	97,374,148	95,395,297	80,555,260	64,882,954	81,848,673	981,484,971
13.	Jurisdictional Loss Multiplier	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	66,180,347	75,237,410	70,657,320	74,401,470	92,024,155	90,993,590	92,422,790	97,458,864	95,478,291	80,625,343	64,939,402	81,919,881	982,338,863
15.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
17.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
18.	**JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 14+15+16+17)**	**66,180,347**	**75,237,410**	**70,657,320**	**74,401,470**	**92,024,155**	**90,993,590**	**92,422,790**	**97,458,864**	**95,478,291**	**80,625,343**	**64,939,402**	**81,919,881**	**982,338,863**
19.	Waterborne Transp. Disallowance Per FPSC Decision 9/21/04	(1,340,445)	(761,058)	(1,398,399)	(1,483,969)	(1,462,467)	(1,407,882)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(15,511,912)
20.	Cost Per kWh Sold (Cents/kWh)	4.2442	5.3594	4.9930	5.0999	5.8484	5.2778	4.7498	4.9870	4.7932	4.5063	4.2256	5.4818	4.9500
21.	True-up (Cents/kWh) [2]	0.8606	0.9461	0.9479	0.9196	0.8491	0.7746	0.6852	0.6817	0.6690	0.7467	0.8727	0.8937	0.8206
22.	Total (Cents/kWh) (Line 20+21)	5.1048	6.3055	5.9409	6.0195	6.6975	6.0524	5.4350	5.6687	5.4622	5.2530	5.0983	6.3755	5.7706
23.	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
24.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	5.1085	6.3100	5.9452	6.0238	6.7023	6.0568	5.4389	5.6728	5.4661	5.2568	5.1020	6.3801	5.7747
25.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0005)	(0.0006)	(0.0006)	(0.0006)	(0.0005)	(0.0005)	(0.0004)	(0.0004)	(0.0004)	(0.0005)	(0.0006)	(0.0006)	(0.0005)
26.	**TOTAL RECOVERY FACTOR (LINE 24+25)**	**5.1080**	**6.3094**	**5.9446**	**6.0232**	**6.7018**	**6.0563**	**5.4385**	**5.6724**	**5.4657**	**5.2563**	**5.1014**	**6.3795**	**5.7742**
27.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**5.108**	**6.309**	**5.945**	**6.023**	**6.702**	**6.056**	**5.439**	**5.672**	**5.466**	**5.256**	**5.101**	**6.380**	**5.774**

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

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2007 THROUGH JUNE 2007

SCHEDULE E3

	ACTUAL					
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	83,645	395,450	103,719	146,928	591,465	384,127
2. LIGHT OIL	320,940	428,448	498,209	342,274	790,377	631,215
3. COAL	27,857,386	15,279,400	17,693,349	18,342,073	21,866,255	25,494,652
4. NATURAL GAS	31,119,956	49,371,959	44,195,874	47,208,024	53,305,617	51,668,997
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**59,381,927**	**65,475,257**	**62,491,151**	**66,039,299**	**76,553,714**	**78,178,991**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	645	4,379	928	1,437	6,102	3,645
9. LIGHT OIL	2,556	3,146	2,865	1,582	5,100	4,267
10. COAL	1,013,965	578,992	668,752	672,993	735,592	934,156
11. NATURAL GAS	368,421	655,412	661,841	691,729	777,738	739,071
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,385,587**	**1,241,929**	**1,334,386**	**1,367,741**	**1,524,532**	**1,681,139**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	1,246	6,805	1,625	2,427	9,344	5,834
16. LIGHT OIL (BBL)	3,834	5,119	5,935	4,008	9,188	7,296
17. COAL (TON)	467,222	265,756	290,997	304,170	343,945	428,793
18. NATURAL GAS (MCF)	2,693,027	4,660,390	4,718,745	4,970,364	5,667,381	5,331,316
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	7,815	42,695	10,194	15,223	58,622	36,601
22. LIGHT OIL	22,184	29,271	32,407	19,873	51,955	39,262
23. COAL	10,541,756	6,356,695	7,097,513	7,372,386	8,173,462	10,176,438
24. NATURAL GAS	2,779,205	4,804,811	4,865,026	5,129,995	5,859,493	5,512,581
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,350,960**	**11,233,472**	**12,005,140**	**12,537,477**	**14,143,532**	**15,764,882**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.05	0.35	0.07	0.11	0.40	0.22
29. LIGHT OIL	0.18	0.25	0.21	0.12	0.33	0.25
30. COAL	73.18	46.63	50.12	49.20	48.26	55.57
31. NATURAL GAS	26.59	52.77	49.60	50.57	51.01	43.96
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 ($/BBL)	67.13	58.11	63.83	60.54	63.30	65.84
36. LIGHT OIL ($/BBL)	83.71	83.70	83.94	85.40	86.02	86.52
37. COAL ($/TON)	59.62	57.49	60.80	60.30	63.57	59.46
38. NATURAL GAS ($/MCF)	11.56	10.59	9.37	9.50	9.41	9.69
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	10.70	9.26	10.17	9.65	10.09	10.49
42. LIGHT OIL	14.47	14.64	15.37	17.22	15.21	16.08
43. COAL	2.64	2.40	2.49	2.49	2.68	2.51
44. NATURAL GAS	11.20	10.28	9.08	9.20	9.10	9.37
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)	**4.45**	**5.83**	**5.21**	**5.27**	**5.41**	**4.96**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	12,116	9,750	10,985	10,594	9,607	10,041
49. LIGHT OIL	8,679	9,304	11,311	12,562	10,187	9,201
50. COAL	10,397	10,979	10,613	10,955	11,111	10,894
51. NATURAL GAS	7,544	7,331	7,351	7,416	7,534	7,459
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,636**	**9,045**	**8,997**	**9,167**	**9,277**	**9,378**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	12.97	9.03	11.18	10.22	9.69	10.54
56. LIGHT OIL	12.56	13.62	17.39	21.64	15.50	14.79
57. COAL	2.75	2.64	2.65	2.73	2.97	2.73
58. NATURAL GAS	8.45	7.53	6.68	6.82	6.85	6.99
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)	**4.29**	**5.27**	**4.68**	**4.83**	**5.02**	**4.65**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2007 THROUGH DECEMBER 2007

SCHEDULE E3

	Estimated						
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	647,854	696,943	745,815	665,803	108,546	16,840	4,587,135
2. LIGHT OIL	828,256	840,213	691,159	666,587	531,168	657,219	7,226,065
3. COAL	28,213,436	28,759,912	26,382,723	28,026,719	26,603,792	22,020,343	286,540,040
4. NATURAL GAS	54,562,264	59,183,852	57,048,774	42,277,798	36,681,036	55,094,103	581,718,254
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**84,251,810**	**89,480,920**	**84,868,471**	**71,636,907**	**63,924,542**	**77,788,505**	**880,071,494**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	7,176	8,056	9,067	8,336	1,288	200	51,259
9. LIGHT OIL	5,450	5,574	4,661	4,583	3,695	4,632	48,111
10. COAL	1,072,090	1,077,080	982,874	1,033,590	978,748	807,190	10,556,022
11. NATURAL GAS	878,100	916,268	822,464	609,609	484,394	687,666	8,292,713
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,962,816**	**2,006,978**	**1,819,066**	**1,656,118**	**1,468,125**	**1,499,688**	**18,948,105**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	11,095	12,535	14,079	12,946	1,995	309	80,240
16. LIGHT OIL (BBL)	13,558	13,866	11,604	11,813	9,695	10,904	106,820
17. COAL (TON)	485,342	485,870	440,421	460,491	436,192	353,941	4,763,140
18. NATURAL GAS (MCF)	6,586,400	6,890,000	5,995,500	4,405,700	3,489,500	4,909,200	60,317,523
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	69,669	78,707	88,404	81,293	12,530	1,940	503,693
22. LIGHT OIL	59,059	60,504	49,690	48,603	39,136	49,088	501,033
23. COAL	11,517,216	11,568,976	10,501,476	10,975,506	10,378,003	8,495,146	113,154,572
24. NATURAL GAS	6,770,759	7,083,090	6,163,100	4,529,062	3,587,083	5,046,756	62,130,961
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**18,416,703**	**18,791,277**	**16,802,670**	**15,634,464**	**14,016,752**	**13,592,930**	**176,290,259**
GENERATION MIX (% MWH)	0.65	0.68	0.76	0.78	0.34	0.32	0.52
28. HEAVY OIL	0.37	0.40	0.50	0.50	0.09	0.01	0.27
29. LIGHT OIL	0.28	0.28	0.26	0.28	0.25	0.31	0.25
30. COAL	54.61	53.67	54.03	62.41	66.67	53.83	55.71
31. NATURAL GAS	44.74	45.65	45.21	36.81	32.99	45.85	43.77
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 ($/BBL)	58.39	55.60	52.97	51.43	54.41	54.50	57.17
36. LIGHT OIL ($/BBL)	61.09	60.60	59.56	56.43	54.79	60.27	67.65
37. COAL ($/TON)	58.13	59.19	59.90	60.86	60.99	62.21	60.16
38. NATURAL GAS ($/MCF)	8.28	8.59	9.52	9.60	10.51	11.22	9.64
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	9.30	8.85	8.44	8.19	8.66	8.68	9.11
42. LIGHT OIL	14.02	13.89	13.91	13.71	13.57	13.39	14.42
43. COAL	2.45	2.49	2.51	2.55	2.56	2.59	2.53
44. NATURAL GAS	8.06	8.36	9.26	9.33	10.23	10.92	9.36
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)	**4.57**	**4.76**	**5.05**	**4.58**	**4.56**	**5.72**	**4.99**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,709	9,770	9,750	9,752	9,728	9,700	9,826
49. LIGHT OIL	10,837	10,855	10,661	10,605	10,592	10,598	10,414
50. COAL	10,743	10,741	10,684	10,619	10,603	10,524	10,719
51. NATURAL GAS	7,711	7,730	7,493	7,429	7,405	7,339	7,492
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,383**	**9,363**	**9,237**	**9,440**	**9,547**	**9,064**	**9,304**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	9.03	8.65	8.23	7.99	8.43	8.42	8.95
56. LIGHT OIL	15.20	15.07	14.83	14.54	14.38	14.19	15.02
57. COAL	2.63	2.67	2.68	2.71	2.72	2.73	2.71
58. NATURAL GAS	6.21	6.46	6.94	6.94	7.57	8.01	7.01
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**	**4.46**	**4.67**	**4.33**	**4.35**	**5.19**	**4.64**

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS SCHEDULE E5
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2007 THROUGH JUNE 2007

	ACTUAL					
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	6,721	0	0	11,985	9,892
3. UNIT COST ($/BBL)	0.00	48.21	0.00	0.00	62.89	60.48
4. AMOUNT ($)	0	324,012	0	0	753,732	598,296
5. BURNED:						
6. UNITS (BBL)	1,246	6,805	1,625	2,427	9,344	5,834
7. UNIT COST ($/BBL)	67.13	58.11	63.83	60.54	63.30	65.84
8. AMOUNT ($)	83,645	395,450	103,719	146,928	591,465	384,127
9. ENDING INVENTORY:						
10. UNITS (BBL)	12,762	12,678	11,053	8,626	11,267	15,325
11. UNIT COST ($/BBL)	59.30	55.58	55.59	55.65	60.42	60.20
12. AMOUNT ($)	756,811	704,622	614,397	480,007	680,792	922,504
13. DAYS SUPPLY:	477	386	268	164	192	220
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	2,925	356	24,560	22,768	9,230	31,146
16. UNIT COST ($/BBL)	4.49	79.70	85.29	92.82	89.59	93.13
17. AMOUNT ($)	13,136	28,373	2,094,790	2,113,291	826,948	2,900,502
18. BURNED:						
19. UNITS (BBL)	3,834	5,119	5,935	4,008	9,188	7,296
20. UNIT COST ($/BBL)	83.71	83.70	83.94	85.40	86.02	86.52
21. AMOUNT ($)	320,940	428,448	498,209	342,274	790,377	631,215
22. ENDING INVENTORY:						
23. UNITS (BBL)	81,104	71,313	85,854	97,464	83,113	101,727
24. UNIT COST ($/BBL)	81.70	81.68	82.58	84.74	85.23	87.40
25. AMOUNT ($)	6,626,439	5,825,133	7,090,189	8,259,573	7,083,430	8,891,262
26. DAYS SUPPLY: NORMAL	230	203	244	272	229	279
27. DAYS SUPPLY: EMERGENCY	12	10	12	14	12	15
COAL						
28. PURCHASES:						
29. UNITS (TONS)	405,559	217,235	392,177	441,176	469,702	477,441
30. UNIT COST ($/TON)	58.71	61.26	60.34	57.31	57.88	58.22
31. AMOUNT ($)	23,810,194	13,307,807	23,664,795	25,285,853	27,184,546	27,795,956
32. BURNED:						
33. UNITS (TONS)	467,222	265,756	290,997	304,170	343,945	428,793
34. UNIT COST ($/TON)	59.62	57.49	60.80	60.30	63.57	59.46
35. AMOUNT ($)	27,857,386	15,279,400	17,693,349	18,342,073	21,866,255	25,494,652
36. ENDING INVENTORY:						
37. UNITS (TONS)	344,295	295,774	396,954	533,960	659,717	708,365
38. UNIT COST ($/TON)	57.50	56.30	57.90	57.23	57.05	57.08
39. AMOUNT ($)	19,796,018	16,651,051	22,984,233	30,559,018	37,634,259	40,430,159
40. DAYS SUPPLY:	28	23	31	41	50	54
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	2,571,639	4,722,576	4,669,654	5,100,164	5,678,818	5,327,874
43. UNIT COST ($/MCF)	11.71	10.60	9.35	9.47	9.40	9.69
44. AMOUNT ($)	30,124,524	50,042,885	43,643,145	48,281,994	53,404,937	51,636,345
45. BURNED:						
46. UNITS (MCF)	2,693,027	4,660,390	4,718,745	4,970,364	5,667,381	5,331,316
47. UNIT COST ($/MCF)	11.56	10.59	9.37	9.50	9.41	9.69
48. AMOUNT ($)	31,119,956	49,371,959	44,195,874	47,208,024	53,305,617	51,668,997
49. ENDING INVENTORY:						
50. UNITS (MCF)	55,277	117,463	68,372	198,172	209,609	206,167
51. UNIT COST ($/MCF)	7.09	9.05	7.46	7.99	8.03	8.01
52. AMOUNT ($)	391,930	1,062,856	510,127	1,584,097	1,683,417	1,650,765
53. DAYS SUPPLY:	0	1	0	1	1	1
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.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS SCHEDULE E5

TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JULY 2007 THROUGH DECEMBER 2007

	Estimated						
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	11,095	12,535	14,079	12,946	1,995	309	81,557
3. UNIT COST ($/BBL)	52.52	51.26	49.19	48.31	50.07	51.58	53.15
4. AMOUNT ($)	582,682	642,566	692,542	625,429	99,887	15,937	4,335,083
5. BURNED:							
6. UNITS (BBL)	11,095	12,535	14,079	12,946	1,995	309	80,240
7. UNIT COST ($/BBL)	58.39	55.60	52.97	51.43	54.41	54.50	57.17
8. AMOUNT ($)	647,854	696,943	745,815	665,803	108,546	16,840	4,587,135
9. ENDING INVENTORY:							
10. UNITS (BBL)	15,325	15,325	15,325	15,325	15,325	15,325	15,325
11. UNIT COST ($/BBL)	56.97	54.40	51.91	50.26	50.24	50.27	50.27
12. AMOUNT ($)	873,093	833,727	795,478	770,244	769,907	770,312	770,312
13. DAYS SUPPLY:	73	87	110	147	153	153	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	13,558	13,866	11,604	11,813	9,695	10,904	162,425
16. UNIT COST ($/BBL)	70.55	72.52	73.45	72.92	73.77	74.02	81.12
17. AMOUNT ($)	956,565	1,005,611	852,364	861,397	715,213	807,118	13,175,308
18. BURNED:							
19. UNITS (BBL)	13,558	13,866	11,604	11,813	9,695	10,904	106,820
20. UNIT COST ($/BBL)	61.09	60.60	59.56	56.43	54.79	60.27	67.65
21. AMOUNT ($)	828,256	840,213	691,159	666,587	531,168	657,219	7,226,065
22. ENDING INVENTORY:							
23. UNITS (BBL)	101,727	101,727	101,727	101,727	101,727	101,727	101,727
24. UNIT COST ($/BBL)	85.75	84.50	83.58	82.65	82.03	81.46	81.46
25. AMOUNT ($)	8,723,507	8,596,182	8,501,901	8,408,003	8,344,216	8,286,703	8,286,703
26. DAYS SUPPLY: NORMAL	260	256	254	251	246	248	-
27. DAYS SUPPLY: EMERGENCY	15	15	15	15	15	15	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	480,600	441,600	414,400	451,400	347,600	237,000	4,775,890
30. UNIT COST ($/TON)	57.67	60.22	60.46	61.61	60.60	62.13	59.47
31. AMOUNT ($)	27,716,715	26,595,340	25,052,934	27,810,103	21,064,579	14,725,261	284,014,083
32. BURNED:							
33. UNITS (TONS)	485,342	485,870	440,421	460,491	436,192	353,941	4,763,140
34. UNIT COST ($/TON)	58.13	59.19	59.90	60.86	60.99	62.21	60.16
35. AMOUNT ($)	28,213,436	28,759,912	26,382,723	28,026,719	26,603,792	22,020,343	286,540,040
36. ENDING INVENTORY:							
37. UNITS (TONS)	703,623	659,353	633,332	624,241	535,649	418,708	418,708
38. UNIT COST ($/TON)	57.35	58.55	59.45	60.63	60.98	61.41	61.41
39. AMOUNT ($)	40,352,023	38,603,213	37,651,981	37,847,169	32,661,700	25,711,300	25,711,300
40. DAYS SUPPLY:	47	45	47	50	48	38	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	6,586,400	6,890,000	5,995,500	4,405,700	3,489,500	4,909,200	60,347,025
43. UNIT COST ($/MCF)	8.28	8.59	9.52	9.60	10.51	11.22	9.64
44. AMOUNT ($)	54,562,267	59,183,850	57,048,775	42,277,798	36,681,039	55,094,102	581,981,660
45. BURNED:							
46. UNITS (MCF)	6,586,400	6,890,000	5,995,500	4,405,700	3,489,500	4,909,200	60,317,523
47. UNIT COST ($/MCF)	8.28	8.59	9.52	9.60	10.51	11.22	9.64
48. AMOUNT ($)	54,562,264	59,183,852	57,048,774	42,277,798	36,681,036	55,094,103	581,718,254
49. ENDING INVENTORY:							
50. UNITS (MCF)	0	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0	-
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.

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ACTUAL										
Jan-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	3.729	4.329	277,437.60	322,077.60	
	SEMINOLE JURISD.	SCH. -D	1,797.5	0.0	1,797.5	3.212	3.394	57,738.75	61,013.10	
	VARIOUS JURISD.	MKT. BASE	17,456.0	0.0	17,456.0	3.857	4.988	673,234.75	870,676.74	154,656.68
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		26,693.5	0.0	26,693.5	3.778	4.697	1,008,411.10	1,253,767.44	154,656.68
ACTUAL										
Feb-07	NSB	SCH. -D	6,720.0	0.0	6,720.0	4.844	5.444	325,490.40	365,810.40	
	SEMINOLE JURISD.	SCH. -D	1,563.5	0.0	1,563.5	2.723	2.968	42,573.62	46,411.14	
	VARIOUS JURISD.	MKT. BASE	6,350.0	0.0	6,350.0	6.068	7.248	385,330.85	460,240.84	56,937.58
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		14,633.5	0.0	14,633.5	5.148	5.962	753,394.87	872,462.38	56,937.58
ACTUAL										
Mar-07	NSB	SCH. -D	7,430.0	0.0	7,430.0	6.408	7.008	476,122.60	520,702.60	
	SEMINOLE JURISD.	SCH. -D	1,789.5	0.0	1,789.5	4.016	4.260	71,862.87	76,236.14	
	VARIOUS JURISD.	MKT. BASE	6,575.0	0.0	6,575.0	5.370	6.510	353,051.30	428,035.87	54,602.07
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		15,794.5	0.0	15,794.5	5.705	6.489	901,036.77	1,024,974.61	54,602.07
ACTUAL										
Apr-07	NSB	SCH. -D	7,200.0	0.0	7,200.0	3.972	4.187	293,139.60	336,339.60	
	SEMINOLE JURISD.	SCH. -D	1,705.5	0.0	1,705.5	5.649	6.640	67,750.69	71,402.00	
	VARIOUS JURISD.	MKT. BASE	7,885.0	0.0	7,885.0	0.000	0.000	445,441.39	523,602.49	52,977.25
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	4.802	5.547	0.00	0.00	
	TOTAL		16,790.5	0.0	16,790.5	4.802	5.547	806,331.68	931,344.09	52,977.25
ACTUAL										
May-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	5.270	5.870	392,112.00	436,752.00	
	SEMINOLE JURISD.	SCH. -D	1,950.7	0.0	1,950.7	3.993	4.204	77,894.23	82,009.92	
	VARIOUS JURISD.	MKT. BASE	1,060.0	0.0	1,060.0	5.637	6.952	59,757.45	73,686.98	10,431.53
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		10,450.7	0.0	10,450.7	5.069	5.669	529,763.68	592,448.90	10,431.53
ACTUAL										
Jun-07	NSB	SCH. -D	7,200.0	0.0	7,200.0	5.617	6.217	404,457.60	447,657.60	
	SEMINOLE JURISD.	SCH. -D	2,051.8	0.0	2,051.8	4.130	4.343	84,744.07	89,107.75	
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		9,251.8	0.0	9,251.8	5.288	5.802	489,201.67	536,765.35	0.00
ESTIMATED										
Jul-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	4.292	5.051	319,300.00	375,800.00	
	SEMINOLE JURISD.	SCH. -D	1,609.0	0.0	1,609.0	2.331	2.846	37,500.00	45,800.00	
	VARIOUS JURISD.	MKT. BASE	1,260.0	0.0	1,260.0	5.921	9.929	74,600.00	125,100.00	
	TOTAL		10,309.0	0.0	10,309.0	4.185	5.303	431,400.00	546,700.00	54,300.00
ESTIMATED										
Aug-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	4.458	5.218	331,700.00	388,200.00	
	SEMINOLE JURISD.	SCH. -D	1,619.0	0.0	1,619.0	2.292	2.860	37,100.00	46,300.00	
	VARIOUS JURISD.	MKT. BASE	2,955.0	0.0	2,955.0	6.403	10.572	189,200.00	312,400.00	
	TOTAL		12,014.0	0.0	12,014.0	4.645	6.217	558,000.00	746,900.00	121,900.00
ESTIMATED										
Sep-07	NSB	SCH. -D	7,200.0	0.0	7,200.0	4.665	5.429	335,900.00	390,900.00	
	SEMINOLE JURISD.	SCH. -D	1,560.0	0.0	1,560.0	2.186	2.756	34,100.00	43,000.00	
	VARIOUS JURISD.	MKT. BASE	6,552.0	0.0	6,552.0	2.839	6.516	186,000.00	426,900.00	
	TOTAL		15,312.0	0.0	15,312.0	3.631	5.622	556,000.00	860,800.00	226,700.00
ESTIMATED										
Oct-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	4.327	5.085	321,900.00	378,300.00	
	SEMINOLE JURISD.	SCH. -D	1,599.0	0.0	1,599.0	2.376	2.871	38,000.00	45,900.00	
	VARIOUS JURISD.	MKT. BASE	11,498.0	0.0	11,498.0	2.726	6.455	313,400.00	742,200.00	
	TOTAL		20,537.0	0.0	20,537.0	3.278	5.680	673,300.00	1,166,400.00	396,000.00
ESTIMATED										
Nov-07	NSB	SCH. -D	7,200.0	0.0	7,200.0	4.354	5.118	313,500.00	368,500.00	
	SEMINOLE JURISD.	SCH. -D	1,472.0	0.0	1,472.0	2.357	2.846	34,700.00	41,900.00	
	VARIOUS JURISD.	MKT. BASE	16,235.0	0.0	16,235.0	2.742	7.090	445,200.00	1,151,000.00	
	TOTAL		24,907.0	0.0	24,907.0	3.185	6.269	793,400.00	1,561,400.00	652,900.00
ESTIMATED										
Dec-07	NSB	SCH. -D	7,440.0	0.0	7,440.0	5.187	5.946	385,900.00	442,400.00	
	SEMINOLE JURISD.	SCH. -D	1,560.0	0.0	1,560.0	2.173	2.891	33,900.00	45,100.00	
	VARIOUS JURISD.	MKT. BASE	1,973.0	0.0	1,973.0	3.284	7.973	64,800.00	157,300.00	
	TOTAL		10,973.0	0.0	10,973.0	4.416	5.876	484,600.00	644,800.00	96,800.00
Jan-07	NSB	SCH. -D	87,590.0	0.0	87,590.0	4.769	5.450	4,176,959.80	4,773,439.80	
THRU	SEMINOLE JURISD.	SCH. -D	20,277.5	0.0	20,277.5	3.047	3.423	617,864.23	694,180.05	
Dec-07	VARIOUS JURISD.	MKT. BASE	79,799.0	0.0	79,799.0	3.998	6.606	3,190,015.74	5,271,142.92	1,878,205.11
	VARIOUS JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL		187,666.5	0.0	187,666.5	4.255	5.722	7,984,839.77	10,738,762.77	1,878,205.11

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2007 THROUGH JUNE 2007

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL									
Jan-07									
	HPP	IPP	(1,730.0)	0.0	0.0	(1,730.0)	(95.451)	(95.451)	1,651,306.34
	PEF	SCH. D	29,150.0	0.0	0.0	29,150.0	3.752	3.752	1,093,628.00
	VARIOUS	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	1,125.0	0.0	0.0	1,125.0	3.269	3.269	36,779.68
	TOTAL		**28,545.0**	**0.0**	**0.0**	**28,545.0**	**9.745**	**9.745**	**2,781,714.02**
ACTUAL									
Feb-07									
	HPP	IPP	11,331.0	0.0	0.0	11,331.0	18.337	18.337	2,077,760.38
	PEF	SCH. D	32,900.0	0.0	0.0	32,900.0	3.347	3.347	1,101,219.00
	VARIOUS	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	560.0	0.0	0.0	560.0	4.852	4.852	27,172.31
	TOTAL		**44,791.0**	**0.0**	**0.0**	**44,791.0**	**7.158**	**7.158**	**3,206,151.69**
ACTUAL									
Mar-07									
	HPP	IPP	24,598.0	0.0	0.0	24,598.0	5.617	5.617	1,381,623.49
	PEF	SCH. D	36,450.0	0.0	0.0	36,450.0	3.731	3.731	1,359,879.00
	VARIOUS	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	406.0	0.0	0.0	406.0	4.143	4.143	16,820.45
	TOTAL		**61,454.0**	**0.0**	**0.0**	**61,454.0**	**4.488**	**4.488**	**2,758,322.94**
ACTUAL									
Apr-07									
	HPP	IPP	1,727.0	0.0	0.0	1,727.0	14.746	14.746	254,664.16
	PEF	SCH. D	49,350.0	0.0	0.0	49,350.0	3.607	3.607	1,780,245.00
	VARIOUS	SCH. D	10,357.0	0.0	0.0	10,357.0	10.926	10.926	1,131,586.54
	VARIOUS	OATT	1,562.0	0.0	0.0	1,562.0	4.489	4.489	70,117.10
	TOTAL		**62,996.0**	**0.0**	**0.0**	**62,996.0**	**5.138**	**5.138**	**3,236,612.80**
ACTUAL									
May-07									
	HPP	IPP	42,664.0	0.0	0.0	42,664.0	8.392	8.392	3,580,271.63
	PEF	SCH. D	54,075.0	0.0	0.0	54,075.0	3.843	3.843	2,078,049.75
	VARIOUS	SCH. D	6,475.0	0.0	0.0	6,475.0	10.705	10.705	693,148.18
	VARIOUS	OATT	2,067.0	0.0	0.0	2,067.0	4.386	4.386	90,659.01
	TOTAL		**105,281.0**	**0.0**	**0.0**	**105,281.0**	**6.119**	**6.119**	**6,442,128.57**
ACTUAL									
Jun-07									
	HPP	IPP	45,619.0	0.0	0.0	45,619.0	8.199	8.199	3,740,227.29
	PEF	SCH. D	51,350.0	0.0	0.0	51,350.0	3.643	3.643	1,870,590.25
	VARIOUS	SCH. D	8,135.0	0.0	0.0	8,135.0	10.610	10.610	863,127.29
	VARIOUS	OATT	1,480.0	0.0	0.0	1,480.0	4.418	4.418	65,387.00
	TOTAL		**106,584.0**	**0.0**	**0.0**	**106,584.0**	**6.135**	**6.135**	**6,539,331.83**

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2007 THROUGH DECEMBER 2007

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ESTIMATED Jul-07									
	HPP	IPP	55,236.0	0.0	0.0	55,236.0	7.702	7.702	4,254,300.00
	PEF	SCH. D	47,688.0	0.0	0.0	47,688.0	3.865	3.865	1,843,200.00
	VARIOUS	SCH. D	8,793.0	0.0	0.0	8,793.0	10.321	10.321	907,500.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**111,717.0**	**0.0**	**0.0**	**111,717.0**	**6.270**	**6.270**	**7,005,000.00**
ESTIMATED Aug-07									
	HPP	IPP	56,960.0	0.0	0.0	56,960.0	8.081	8.081	4,603,100.00
	PEF	SCH. D	49,454.0	0.0	0.0	49,454.0	3.965	3.965	1,960,800.00
	VARIOUS	SCH. D	12,181.0	0.0	0.0	12,181.0	10.306	10.306	1,255,400.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**118,595.0**	**0.0**	**0.0**	**118,595.0**	**6.593**	**6.593**	**7,819,300.00**
ESTIMATED Sep-07									
	HPP	IPP	51,139.0	0.0	0.0	51,139.0	8.442	8.442	4,317,300.00
	PEF	SCH. D	46,854.0	0.0	0.0	46,854.0	4.025	4.025	1,885,900.00
	VARIOUS	SCH. D	1,409.0	0.0	0.0	1,409.0	12.122	12.122	170,800.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**99,402.0**	**0.0**	**0.0**	**99,402.0**	**6.412**	**6.412**	**6,374,000.00**
ESTIMATED Oct-07									
	HPP	IPP	39,461.0	0.0	0.0	39,461.0	8.498	8.498	3,353,400.00
	PEF	SCH. D	44,155.0	0.0	0.0	44,155.0	3.635	3.635	1,605,000.00
	VARIOUS	SCH. D	183.0	0.0	0.0	183.0	13.388	13.388	24,500.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**83,799.0**	**0.0**	**0.0**	**83,799.0**	**5.946**	**5.946**	**4,982,900.00**
ESTIMATED Nov-07									
	HPP	IPP	491.0	0.0	0.0	491.0	33.564	33.564	164,800.00
	PEF	SCH. D	41,141.0	0.0	0.0	41,141.0	3.925	3.925	1,614,800.00
	VARIOUS	SCH. D	1.0	0.0	0.0	1.0	10.000	10.000	100.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**41,633.0**	**0.0**	**0.0**	**41,633.0**	**4.275**	**4.275**	**1,779,700.00**
ESTIMATED Dec-07									
	HPP	IPP	740.0	0.0	0.0	740.0	28.932	28.932	214,100.00
	PEF	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. D	519.0	0.0	0.0	519.0	13.603	13.603	70,600.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**1,259.0**	**0.0**	**0.0**	**1,259.0**	**22.613**	**22.613**	**284,700.00**
Jan-07	HPP	IPP	328,236.0	0.0	0.0	328,236.0	9.016	9.016	29,592,853.29
THRU	PEF	SCH. D	482,567.0	0.0	0.0	482,567.0	3.770	3.770	18,193,311.00
Dec-07	VARIOUS	SCH. D	48,053.0	0.0	0.0	48,053.0	10.648	10.648	5,116,762.01
	VARIOUS	OATT	7,200.0	0.0	0.0	7,200.0	4.263	4.263	306,935.55
	TOTAL		**866,056.0**	**0.0**	**0.0**	**866,056.0**	**6.144**	**6.144**	**53,209,861.85**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

SCHEDULE E8

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	Jan-07	VARIOUS	CO-GEN.	52,086.0	0.0	0.0	52,086.0	3.144	3.144	1,637,466.82
ACTUAL	Feb-07	VARIOUS	CO-GEN.	46,211.0	0.0	0.0	46,211.0	3.820	3.820	1,765,336.88
ACTUAL	Mar-07	VARIOUS	CO-GEN.	50,740.0	0.0	0.0	50,740.0	3.287	3.287	1,668,017.63
ACTUAL	Apr-07	VARIOUS	CO-GEN.	47,691.0	0.0	0.0	47,691.0	3.959	3.959	1,887,852.67
ACTUAL	May-07	VARIOUS	CO-GEN.	55,762.0	0.0	0.0	55,762.0	3.803	3.803	2,120,569.34
ACTUAL	Jun-07	VARIOUS	CO-GEN.	50,427.0	0.0	0.0	50,427.0	3.662	3.662	1,846,444.98
ESTIMATED	Jul-07	VARIOUS	CO-GEN.	51,019.0	0.0	0.0	51,019.0	3.586	3.586	1,829,500.00
ESTIMATED	Aug-07	VARIOUS	CO-GEN.	51,019.0	0.0	0.0	51,019.0	3.996	3.996	2,038,800.00
ESTIMATED	Sep-07	VARIOUS	CO-GEN.	49,356.0	0.0	0.0	49,356.0	3.938	3.938	1,943,800.00
ESTIMATED	Oct-07	VARIOUS	CO-GEN.	51,019.0	0.0	0.0	51,019.0	3.779	3.779	1,928,100.00
ESTIMATED	Nov-07	VARIOUS	CO-GEN.	47,448.0	0.0	0.0	47,448.0	3.816	3.816	1,810,600.00
ESTIMATED	Dec-07	VARIOUS	CO-GEN.	49,048.0	0.0	0.0	49,048.0	4.066	4.066	1,994,200.00
	TOTAL			**601,826.0**	**0.0**	**0.0**	**601,826.0**	**3.734**	**3.734**	**22,470,688.32**

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

SCHEDULE E9

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	COST IF GENERATED (A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
ACTUAL	Jan-07	VARIOUS	SCH. - J	96,240.0	0.0	96,240.0	5.383	5,180,527.10	6.287	6,050,441.07	869,913.97
ACTUAL	Feb-07	VARIOUS	SCH. - J	136,667.0	0.0	136,667.0	6.388	8,730,048.47	7.744	10,583,037.52	1,852,989.05
ACTUAL	Mar-07	VARIOUS	SCH. - J	120,265.0	0.0	120,265.0	5.683	6,834,498.46	6.645	7,991,889.78	1,157,391.32
ACTUAL	Apr-07	VARIOUS	SCH. - J	116,045.0	0.0	116,045.0	6.408	7,436,323.06	7.223	8,381,690.48	945,367.42
ACTUAL	May-07	VARIOUS	SCH. - J	157,610.0	0.0	157,610.0	7.018	11,061,601.67	8.599	13,552,296.48	2,490,694.81
ACTUAL	Jun-07	VARIOUS	SCH. - J	123,733.0	0.0	123,733.0	6.486	8,025,721.68	8.046	9,955,520.31	1,929,798.63
ESTIMATED	Jul-07	VARIOUS	SCH. - J	39,009.0	130.0	38,879.0	8.334	3,251,100.00	8.334	3,251,100.00	0.00
ESTIMATED	Aug-07	VARIOUS	SCH. - J	30,813.0	302.0	30,511.0	8.792	2,709,200.00	8.792	2,709,200.00	0.00
ESTIMATED	Sep-07	VARIOUS	SCH. - J	79,681.0	451.0	79,230.0	8.386	6,681,800.00	8.386	6,681,800.00	0.00
ESTIMATED	Oct-07	VARIOUS	SCH. - J	81,912.0	88.0	81,824.0	7.711	6,315,900.00	7.711	6,315,900.00	0.00
ESTIMATED	Nov-07	VARIOUS	SCH. - J	16,544.0	3.0	16,541.0	7.791	1,289,000.00	7.791	1,289,000.00	0.00
ESTIMATED	Dec-07	VARIOUS	SCH. - J	68,304.0	1.0	68,303.0	7.397	5,052,300.00	7.397	5,052,300.00	0.00
	TOTAL			**1,066,823.0**	**975.0**	**1,065,848.0**	**6.802**	**72,568,020.44**	**7.669**	**81,814,175.64**	**9,246,155.20**

Docket No. 070001-EI
CCR 2007 Actual/Estimated True-Up
Exhibit No. ____ (CA-2)
Document No. 2

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
ACTUAL / ESTIMATED
JANUARY 2007 THROUGH DECEMBER 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 37
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-2)
DATE 11-06-07

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2007 THROUGH DECEMBER 2007

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2006 THROUGH DECEMBER 2006	($2,666,246)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2007 THROUGH DECEMBER 2007	($21,130,338)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2008 THROUGH DECEMBER 2008	($23,796,584)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	Total
1 UNIT POWER CAPACITY CHARGES	3,758,735	4,511,191	4,370,882	4,468,362	4,592,495	5,121,210	4,810,000	4,810,000	3,704,000	3,704,000	3,704,000	2,272,000	49,826,875
2 CAPACITY PAYMENTS TO COGENERATORS	1,940,790	1,940,790	1,940,790	1,940,790	2,036,323	1,989,090	2,088,900	2,088,900	1,956,300	2,088,900	1,956,300	2,088,900	24,056,773
3 SECURITY COSTS	44,849	21,614	51,962	47,001	59,713	85,686	91,174	171,711	107,179	69,171	64,665	191,167	1,005,892
4 (UNIT POWER CAPACITY REVENUES)	(91,599)	(60,695)	(58,200)	(63,128)	(46,071)	(40,849)	(48,500)	(51,000)	(56,500)	(63,000)	(66,900)	(47,300)	(693,742)
5 TOTAL CAPACITY DOLLARS	5,652,775	6,412,900	6,305,434	6,393,025	6,642,460	7,155,137	6,941,574	7,019,611	5,710,979	5,799,071	5,658,065	4,504,767	74,195,798
6 SEPARATION FACTOR	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
7 JURISDICTIONAL CAPACITY DOLLARS	5,464,393	6,199,186	6,095,301	6,179,973	6,421,096	6,916,687	6,710,241	6,785,678	5,520,657	5,605,813	5,469,506	4,354,642	71,723,173
8 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	4,014,584	3,685,923	3,635,941	3,763,126	4,118,461	4,598,441	5,257,215	5,284,195	5,392,118	4,749,580	3,996,123	3,885,203	52,380,910
9 PRIOR PERIOD TRUE-UP PROVISION	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,079)	(80,082)	(960,951)
10 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,934,505	3,605,844	3,555,862	3,683,047	4,038,382	4,518,362	5,177,136	5,204,116	5,312,039	4,669,501	3,916,044	3,805,121	51,419,959
11 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 10 - Line 7)	(1,529,888)	(2,593,342)	(2,539,439)	(2,496,926)	(2,382,714)	(2,398,325)	(1,533,105)	(1,581,562)	(208,618)	(936,312)	(1,553,462)	(549,521)	(20,303,214)
12 INTEREST PROVISION FOR MONTH	(19,106)	(27,825)	(38,837)	(49,638)	(60,191)	(70,736)	(81,131)	(89,895)	(94,039)	(96,725)	(102,503)	(107,421)	(838,047)
13 INTEREST ADJUSTMENT FOR PRIOR PERIODS			10,923										10,923
14 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(3,627,197)	(5,096,112)	(7,637,200)	(10,124,474)	(12,590,959)	(14,953,785)	(17,342,767)	(18,876,924)	(20,468,302)	(20,690,880)	(21,643,838)	(23,219,724)	(3,627,197)
15 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	80,079	80,079	80,079	80,079	80,079	80,079	80,079	80,079	80,079	80,079	80,079	80,082	960,951
16 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	(5,096,112)	(7,637,200)	(10,124,474)	(12,590,959)	(14,953,785)	(17,342,767)	(18,876,924)	(20,468,302)	(20,690,880)	(21,643,838)	(23,219,724)	(23,796,584)	**(23,796,584)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	Total
1 BEGINNING TRUE-UP AMOUNT	(3,627,197)	(5,096,112)	(7,637,200)	(10,124,474)	(12,590,959)	(14,953,785)	(17,342,767)	(18,876,924)	(20,468,302)	(20,690,880)	(21,643,838)	(23,219,724)	(3,627,197)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(5,077,006)	(7,609,375)	(10,096,560)	(12,541,321)	(14,893,594)	(17,272,031)	(18,795,793)	(20,378,407)	(20,596,841)	(21,547,113)	(23,117,221)	(23,689,163)	(22,969,460)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(8,704,203)	(12,705,487)	(17,733,760)	(22,665,795)	(27,484,553)	(32,225,816)	(36,138,560)	(39,255,331)	(41,065,143)	(42,237,993)	(44,761,059)	(46,908,887)	(26,596,657)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(4,352,102)	(6,352,744)	(8,866,880)	(11,332,898)	(13,742,277)	(16,112,908)	(18,069,280)	(19,627,666)	(20,532,572)	(21,118,997)	(22,380,530)	(23,454,444)	(13,298,329)
5 INTEREST RATE % - 1ST DAY OF MONTH	5.270	5.260	5.260	5.260	5.260	5.260	5.280	5.500	5.500	5.500	5.500	5.500	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	5.260	5.260	5.260	5.260	5.260	5.280	5.500	5.500	5.500	5.500	5.500	5.500	NA
7 TOTAL (LINE 5 + LINE 6)	10.530	10.520	10.520	10.520	10.520	10.540	10.780	11.000	11.000	11.000	11.000	11.000	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	5.265	5.260	5.260	5.260	5.260	5.270	5.390	5.500	5.500	5.500	5.500	5.500	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.439	0.438	0.438	0.438	0.438	0.439	0.449	0.458	0.458	0.458	0.458	0.458	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(19,106)	(27,825)	(38,837)	(49,638)	(60,191)	(70,736)	(81,131)	(89,895)	(94,039)	(96,725)	(102,503)	(107,421)	(838,047)

2007 Incremental Security O&M Expenses

Calculation of 2007 Incremental Security O&M Expenses:

Based on Security Expenses at Locations Where Post-9/11 Guards Patrol and Expenses to Comply with Post-9/11 NERC Cyber Security Standards

		2007 Act/Est
Adjusted Baseline Amount Developed in 2006	$	2,218,979
Multiplied by 2006 Growth Factor		1.0063
2007 Baseline Security O&M Expenses Adjusted for Energy Sales Growth		2,232,959
Total Security O&M Expenses at Locations Where Post-9/11 Guards Patrol	$	3,517,431
Plus Incremental NERC Cyber Security Expenses		263,323
Less Baseline Adjusted for Energy Sales Growth		(2,232,959)
		1,547,795
Base Rate Items that Were Removed		
O&M Savings Associated with Critical Intervention Incremental Expense and Operational Changes		(470,334)
Savings Due to Reduction in Capital Spending		(71,568)
Recoverable Incremental Security O&M Expense [1]	$	1,005,893
Retail Jurisdictional Separation Factor		0.9666743
2007 Recoverable Retail Incremental Security O&M Expense	**$**	**972,371**

[1] All incremental security O&M expense is for guard services and NERC cyber security standards.

CAPACITY COSTS
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2007 THROUGH DECEMBER 2007

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	QF = QUALIFYING FACILITY
HILLSBOROUGH COUNTY	1/10/1985	3/1/2010	QF	LT = LONG TERM
HARDEE POWER PARTNERS	1/1/1993	12/31/2012	LT	ST = SHORT TERM
PROGRESS ENERGY FLORIDA	1/1/2006	11/30/2007	LT	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
SEMINOLE ELECTRIC	6/1/1992	**	LT	
CALPINE	5/1/2006	4/30/2011	LT	
RELIANT	2/1/2007	8/31/2007	ST	

CONTRACT	ACT JANUARY MW	ACT FEBRUARY MW	ACT MARCH MW	ACT APRIL MW	ACT MAY MW	ACT JUNE MW	EST JULY MW	EST AUGUST MW	EST SEPTEMBER MW	EST OCTOBER MW	EST NOVEMBER MW	EST DECEMBER MW
MCKAY BAY REFUSE	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
HILLSBOROUGH COUNTY	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
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	377.0	377.0	377.0	377.0	377.0	377.0	441.0	441.0	441.0	441.0	441.0	441.0
PROGRESS ENERGY FLORIDA	50.0	50.0	50.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
SEMINOLE ELECTRIC	6.0	5.1	5.9	6.1	6.1	5.8	6.1	6.1	6.1	6.1	6.1	6.1
CALPINE	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
RELIANT	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0				

CAPACITY YEAR 2007	ACT JANUARY ($)	ACT FEBRUARY ($)	ACT MARCH ($)	ACT APRIL ($)	ACT MAY ($)	ACT JUNE ($)	EST JULY ($)	EST AUGUST ($)	EST SEPTEMBER ($)	EST OCTOBER ($)	EST NOVEMBER ($)	EST DECEMBER ($)	TOTAL ($)
MCKAY BAY REFUSE	277,660.00	277,660.00	277,660.00	277,660.00	276,593.20	277,660.00	310,600.00	310,600.00	290,900.00	310,600.00	290,900.00	310,600.00	$3,489,093.20
HILLSBOROUGH COUNTY	892,170.00	892,170.00	892,170.00	892,170.00	988,770.00	940,470.00	975,300.00	975,300.00	913,400.00	975,300.00	913,400.00	975,300.00	$11,225,920.00
ORANGE COGEN LP	770,960.00	770,960.00	770,960.00	770,960.00	770,960.00	770,960.00	803,000.00	803,000.00	752,000.00	803,000.00	752,000.00	803,000.00	$9,341,760.00
TOTAL COGENERATION	**$1,940,790.00**	**$1,940,790.00**	**$1,940,790.00**	**$1,940,790.00**	**$2,036,323.20**	**$1,989,090.00**	**$2,088,900.00**	**$2,088,900.00**	**$1,956,300.00**	**$2,088,900.00**	**$1,956,300.00**	**$2,088,900.00**	**$24,056,773.20**
HARDEE POWER PARTNERS	[redacted]												
PROGRESS ENERGY FLORIDA - D													
CALPINE - D													
CITY OF TALLAHASSEE - JC													
OKEELANTA - JC													
RELIANT ENERGY SERVICES - JC													
ORLANDO UTILITIES - JC													
FLORIDA POWER & LIGHT - JC													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED SALES													
CALPEA - MA													
CARGILL ALLIANT - MA													
PROGRESS ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
ORLANDO UTILITIES - MA													
REEDY CREEK - MA													
SEMINOLE ELECTRIC - MA													
THE ENERGY AUTHORITY - MA													
TEC WHOLESALE MARKETING - MA													
NEW SMYRNA BEACH - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$3,667,136.21**	**$4,450,495.94**	**$4,312,681.95**	**$4,405,233.70**	**$4,546,424.66**	**$5,080,360.68**	**$4,616,500.00**	**$4,614,000.00**	**$3,502,500.00**	**$3,496,000.00**	**$3,492,100.00**	**$2,079,700.00**	**$48,263,133.14**
TOTAL CAPACITY	**$5,607,926.21**	**$6,391,285.94**	**$6,253,471.95**	**$6,346,023.70**	**$6,582,747.86**	**$7,069,450.68**	**$6,705,400.00**	**$6,702,900.00**	**$5,458,800.00**	**$5,584,900.00**	**$5,448,400.00**	**$4,168,600.00**	**$72,319,906.34**

Docket No. 070001-EI
FAC 2008 Projection Filing
Exhibit CA-3
Document No. 2

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY
JANUARY 2008 - DECEMBER 2008

SCHEDULES E1 THROUGH E10
SCHEDULE E12
SCHEDULE H1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 38
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-3)
DATE 11-06-07

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2008 - DEC. 2008)
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	Schedule E6 Power Sold	(")
25-26	Schedule E7 Purchased Power	(")
27	Schedule E8 Energy Payment to Qualifying Facilities	(")
28	Schedule E9 Economy Energy Purchases	(")
29	Schedule E10 Residential Bill Comparison	(")
30	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2005-2008)

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	942,046,990	19,586,497	4.80968
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(109,740)	19,586,497 (1)	(0.00056)
4b.	Adjustments to Fuel Cost	0	19,586,497 (1)	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)**	**941,937,250**	**19,586,497**	**4.80912**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	53,895,600	574,898	9.37481
7.	Energy Cost of Economy Purchases (E9)	107,048,900	1,361,559	7.86223
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	29,106,500	659,244	4.41513
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**190,051,000**	**2,595,701**	**7.32176**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		22,182,198	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	586,000	10,813	5.41940
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,657,600	124,156	4.55685
14.	Gains on Sales	2,187,300	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**8,430,900**	**134,969**	**6.24655**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		2,600	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**1,123,557,350**	**22,044,629**	**5.09674**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,834,826 (1)	36,000	0.00874
22.	T & D Losses	52,196,401 (1)	1,024,113	0.24874
23.	System MWH Sales	1,123,557,350	20,984,516	5.35422
24.	Wholesale MWH Sales	(34,136,855)	(637,279)	5.35666
25.	Jurisdictional MWH Sales	1,089,420,495	20,347,237	5.35414
26.	Jurisdictional Loss Multiplier			1.00087
27.	Jurisdictional MWH Sales Adjusted for Line Loss	1,090,368,291	20,347,237	5.35880
28.	Waterborne Coal Transportation Contract Adj. (WCT) (2)	(15,315,380)	20,347,237	(0.07527)
29.	True-up (3)	(15,392,712)	20,347,237	(0.07565)
30.	Total Jurisdictional Fuel Cost (Excl. GPIF and Incl. WCT)	1,059,660,199	20,347,237	5.20788
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	1,060,423,154	20,347,237	5.21163
33.	GPIF Adjusted for Taxes (3)	1,439,819	20,347,237	0.00708
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	1,061,862,973	20,347,237	5.21871
35.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**5.219**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Represents WCT adjustment for 2007 required by FPSC Order No. PSC-04-0999-FOF-EI.
(3) Calculation Based on Jurisdictional KWH Sales

CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2007 - December 2007 (6 months actual, 6 months estimated)	$17,742,556
2.	FINAL TRUE-UP (January 2006 - December 2006) (Per True-Up filed March 1, 2007)	(2,349,844)
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2008 through December 2008 (Schedule E1, line 28)	$15,392,712
4.	JURISDICTIONAL MWH SALES (Projected January 2008 through December 2008)	20,347,237
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**-0.0757**

SCHEDULE E1-C

INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2008 through December 2008)	$1,439,819	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2007 through December 2007)	$15,392,712	
2.	TOTAL SALES (January 2008 through December 2008)	20,347,237	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0071**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0757)**	Cents/kWh

SCHEDULE E1-D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

1. COST RATIO
   ON-PEAK COST / OFF-PEAK COST = $\frac{6.297}{4.633}$ = 1.3592

2. SALES/GENERATION

   34.18 % ON-PEAK

   65.82 % OFF-PEAK

3. FORMULA
   FUEL ADJUSTMENT FACTOR ADJUSTED FOR TAX AND GPIF = (% ON-PEAK GENERATION * COST RATIO * OFF-PEAK FACTOR) + (% OFF-PEAK GENERATION * OFF-PEAK FACTOR)

5.2187	=	0.3418	*	1.3592	Y +	0.6582	Y
5.2187	=	1.1228	*	Y			
4.6479	=	Y					

   where Y = OFF-PEAK FACTOR and

X	=	1.3592	Y	
X	=	1.3592	*	4.6479
X	=	6.3174		

   where X = ON-PEAK FACTOR

4. **FUEL COST (CENTS/KWH)**	**ON-PEAK**	**OFF-PEAK**
	6.3174	**4.6479**
5. **FUEL FACTOR (CENTS/KWH, NEAREST 0.001)**	**6.317**	**4.648**

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

SCHEDULE E1-E

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS,GS,TS	5.219	1.0042	**5.241**
A1*	SL-2, OL-1&3	5.219	N/A	**4.920**
B	GSD,GSLD,SBF	5.219	1.0004	**5.221**
C	IS-1&3,SBI-1&3	5.219	0.9742	**5.084**
A	RST,GST			
	ON-PEAK	6.317	1.0042	**6.344**
	OFF-PEAK	4.648	1.0042	**4.668**
B	GSDT, EV-X, GSLDT, SBFT			
	ON-PEAK	6.317	1.0004	**6.320**
	OFF-PEAK	4.648	1.0004	**4.650**
C	IST-1&3, SBIT-1&3			
	ON-PEAK	6.317	0.9742	**6.154**
	OFF-PEAK	4.648	0.9742	**4.528**

* GROUP A1 IS BASED ON GROUP A, 15% ON-PEAK AND 85% OFF-PEAK

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

SCHEDULE E2

	(a) Jan-08	(b) Feb-08	(c) Mar-08	(d) Apr-08	(e) May-08	(f) ESTIMATED Jun-08	(g) Jul-08	(h) Aug-08	(i) Sep-08	(j) Oct-08	(k) Nov-08	(l) Dec-08	(m) TOTAL PERIOD
1. Fuel Cost of System Net Generation	62,896,108	68,533,200	60,578,472	56,121,828	85,928,229	88,359,661	101,470,838	103,612,964	89,878,999	79,720,616	68,255,914	76,690,161	942,046,990
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	452,100	871,300	93,600	490,900	878,000	797,100	715,600	848,700	1,558,500	631,700	652,700	440,700	8,430,900
4. Fuel Cost of Purchased Power	2,303,400	1,529,000	3,227,000	4,146,700	5,409,300	6,401,900	9,209,800	10,166,200	5,862,000	2,157,200	1,708,400	1,774,700	53,895,600
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	2,363,000	2,122,700	2,185,400	2,392,100	2,339,700	2,417,700	2,597,600	2,813,900	2,996,400	2,369,900	2,156,500	2,351,600	29,106,500
7. Energy Cost of Economy Purchases	22,624,500	8,030,900	13,044,400	16,033,000	4,243,400	9,005,100	5,481,500	5,198,300	10,458,100	4,457,400	3,043,700	5,428,600	107,048,900
8a. Adj. to Fuel Cost (Ft. Meade/Wauchula Wheeling)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(9,145)	(109,740)
8b. Adj. To Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9. TOTAL FUEL & NET POWER TRANSACTIONS	**89,725,763**	**79,335,355**	**78,932,527**	**78,193,583**	**97,033,484**	**105,378,116**	**118,034,993**	**120,933,519**	**107,627,854**	**88,064,271**	**74,502,669**	**85,795,216**	**1,123,557,350**
10. Jurisdictional MWH Sold	1,609,833	1,457,852	1,419,115	1,492,171	1,657,376	1,892,473	1,976,060	1,972,363	1,961,934	1,796,186	1,557,051	1,554,823	20,347,237
11. Jurisdictional % of Total Sales	0.9586032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
12. Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	86,908,661	76,777,583	76,445,789	75,652,761	94,071,663	102,234,170	114,544,167	116,992,284	104,245,606	85,299,035	72,397,671	83,851,105	1,089,420,495
13. Jurisdictional Loss Multiplier	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	1.00087	
14. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 12 * Line 13)	86,984,272	76,844,379	76,512,297	75,718,579	94,153,505	102,323,114	114,643,820	117,094,067	104,336,300	85,373,245	72,460,657	83,924,055	1,090,368,290
15. Waterborne Coal Transportation Contract Adj. (WCT) (Per FPSC Order No. PSC-04-0999-FOF-EI)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,282)	(1,276,278)	(15,315,380)
16. JURISD. TOTAL FUEL & NET PWR. TRANS. (Incl. Waterborne Coal Transportation Contract Adj.)	**85,707,990**	**75,568,097**	**75,236,015**	**74,442,297**	**92,877,223**	**101,046,832**	**113,367,538**	**115,817,785**	**103,060,018**	**84,096,963**	**71,184,375**	**82,647,777**	**1,075,052,910**
17. Cost Per kWh Sold (Cents/kWh)	5.3240	5.1835	5.3016	4.9889	5.6039	5.3394	5.7370	5.8720	5.2530	4.6820	4.5717	5.3156	5.2835
18. True-up (Cents/kWh) (2)	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757	-0.0757
19. Total (Cents/kWh) (Line 17+18)	5.2483	5.1078	5.2259	4.9132	5.5282	5.2637	5.6613	5.7963	5.1773	4.6063	4.4960	5.2399	5.2078
20. 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
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	5.2521	5.1115	5.2297	4.9167	5.5322	5.2675	5.6654	5.8005	5.1810	4.6096	4.4992	5.2437	5.2115
22. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**5.2592**	**5.1186**	**5.2368**	**4.9238**	**5.5393**	**5.2746**	**5.6725**	**5.8076**	**5.1881**	**4.6167**	**4.5063**	**5.2508**	**5.2186**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**5.259**	**5.119**	**5.237**	**4.924**	**5.539**	**5.275**	**5.673**	**5.808**	**5.188**	**4.617**	**4.506**	**5.251**	**5.219**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH JUNE 2008

SCHEDULE E3

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	158,113	133,494	254,212	511,014	231,090	723,396
2. LIGHT OIL	670,369	206,215	465,038	621,669	691,870	697,616
3. COAL	22,374,244	18,468,037	21,510,561	26,502,356	28,459,367	27,804,296
4. NATURAL GAS	39,693,382	49,725,454	38,348,661	28,486,789	56,545,902	59,134,353
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**62,896,108**	**68,533,200**	**60,578,472**	**56,121,828**	**85,928,229**	**88,359,661**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	1,816	1,488	2,835	5,664	2,457	7,944
9. LIGHT OIL	4,799	1,493	3,369	4,501	5,070	5,122
10. COAL	802,325	660,305	762,623	933,852	1,002,582	978,875
11. NATURAL GAS	490,459	660,035	560,068	400,107	825,668	845,428
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,299,399**	**1,323,321**	**1,328,895**	**1,344,124**	**1,835,777**	**1,837,369**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	2,814	2,302	4,390	8,739	3,803	12,277
16. LIGHT OIL (BBL)	12,333	6,301	9,749	12,670	13,765	13,971
17. COAL (TON)	356,437	295,515	340,215	417,074	449,124	440,290
18. NATURAL GAS (MCF)	3,553,400	4,715,000	4,038,400	2,899,200	6,088,000	6,297,400
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	35,332	28,908	55,130	109,744	47,762	154,170
22. LIGHT OIL	50,894	15,843	35,701	47,831	54,308	54,994
23. COAL	8,505,126	6,999,599	8,092,833	9,908,243	10,662,946	10,450,183
24. NATURAL GAS	3,652,851	4,847,080	4,151,525	2,980,215	6,258,529	6,473,679
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,244,203**	**11,891,430**	**12,335,189**	**13,046,033**	**17,023,545**	**17,133,026**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.14	0.11	0.21	0.42	0.13	0.43
29. LIGHT OIL	0.37	0.11	0.25	0.33	0.28	0.28
30. COAL	61.74	49.90	57.39	69.48	54.61	53.28
31. NATURAL GAS	37.75	49.88	42.15	29.77	44.98	46.01
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 ($/BBL)	56.19	57.99	57.91	58.48	60.77	58.92
36. LIGHT OIL ($/BBL)	54.36	32.73	47.70	49.07	50.26	49.93
37. COAL ($/TON)	62.77	62.49	63.23	63.54	63.37	63.15
38. NATURAL GAS ($/MCF)	11.17	10.55	9.50	9.83	9.29	9.39
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	4.48	4.62	4.61	4.66	4.84	4.69
42. LIGHT OIL	13.17	13.02	13.03	13.00	12.74	12.69
43. COAL	2.63	2.64	2.66	2.67	2.67	2.66
44. NATURAL GAS	10.87	10.26	9.24	9.56	9.04	9.13
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)	**5.14**	**5.76**	**4.91**	**4.30**	**5.05**	**5.16**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	19,456	19,427	19,446	19,376	19,439	19,407
49. LIGHT OIL	10,605	10,612	10,597	10,627	10,712	10,737
50. COAL	10,601	10,601	10,612	10,610	10,635	10,676
51. NATURAL GAS	7,448	7,344	7,413	7,449	7,580	7,657
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,423**	**8,986**	**9,282**	**9,706**	**9,273**	**9,325**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	8.71	8.97	8.97	9.02	9.41	9.11
56. LIGHT OIL	13.97	13.81	13.80	13.81	13.65	13.62
57. COAL	2.79	2.80	2.82	2.84	2.84	2.84
58. NATURAL GAS	8.09	7.53	6.85	7.12	6.85	6.99
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)	**4.84**	**5.18**	**4.56**	**4.18**	**4.68**	**4.81**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2008 THROUGH DECEMBER 2008

SCHEDULE E3

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	924,630	961,762	769,708	276,392	127,202	180,118	5,251,131
2.	LIGHT OIL	861,659	868,416	644,726	624,844	598,561	481,286	7,432,269
3.	COAL	28,910,885	28,753,585	25,790,309	27,799,278	24,363,321	22,635,150	303,371,389
4.	NATURAL GAS	70,773,664	73,029,201	62,674,256	51,020,102	43,166,830	53,393,607	625,992,201
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**101,470,838**	**103,612,964**	**89,878,999**	**79,720,616**	**68,255,914**	**76,690,161**	**942,046,990**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	10,128	10,532	8,256	2,898	1,301	1,825	57,144
9.	LIGHT OIL	6,223	6,256	4,789	4,673	4,493	3,625	54,413
10.	COAL	1,012,538	1,014,392	914,846	989,863	865,243	801,626	10,739,070
11.	NATURAL GAS	971,339	992,493	880,543	753,782	616,606	739,342	8,735,870
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,000,228**	**2,023,673**	**1,808,434**	**1,751,216**	**1,487,643**	**1,546,418**	**19,586,497**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	15,738	16,379	12,805	4,470	2,014	2,825	88,556
16.	LIGHT OIL (BBL)	16,285	16,382	12,885	13,391	12,556	9,725	150,013
17.	COAL (TON)	458,208	457,328	409,254	440,715	384,330	358,854	4,807,344
18.	NATURAL GAS (MCF)	7,365,800	7,513,200	6,449,200	5,442,700	4,427,900	5,283,600	64,073,800
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	197,642	205,684	160,802	56,132	25,292	35,476	1,112,074
22	LIGHT OIL	68,608	69,341	51,178	49,505	47,547	38,408	584,158
23.	COAL	10,876,186	10,895,316	9,764,633	10,506,506	9,181,303	8,492,257	114,335,131
24.	NATURAL GAS	7,572,090	7,723,629	6,629,841	5,595,160	4,551,748	5,431,559	65,867,906
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**18,714,526**	**18,893,970**	**16,606,454**	**16,207,303**	**13,805,890**	**13,997,700**	**181,899,269**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.51	0.52	0.46	0.17	0.09	0.12	0.29
29.	LIGHT OIL	0.31	0.31	0.26	0.27	0.30	0.23	0.28
30.	COAL	50.62	50.13	50.59	56.52	58.16	51.84	54.83
31.	NATURAL GAS	48.56	49.04	48.69	43.04	41.45	47.81	44.60
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 ($/BBL)	58.75	58.72	60.11	61.83	63.16	63.76	59.30
36.	LIGHT OIL ($/BBL)	52.91	53.01	50.04	46.66	47.67	49.49	49.54
37.	COAL ($/TON)	63.10	62.87	63.02	63.08	63.39	63.08	63.11
38.	NATURAL GAS ($/MCF)	9.61	9.72	9.72	9.37	9.75	10.11	9.77
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	4.68	4.68	4.79	4.92	5.03	5.08	4.72
42.	LIGHT OIL	12.56	12.52	12.60	12.62	12.59	12.53	12.72
43.	COAL	2.66	2.64	2.64	2.65	2.65	2.67	2.65
44.	NATURAL GAS	9.35	9.46	9.45	9.12	9.48	9.83	9.50
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)**	**5.42**	**5.48**	**5.41**	**4.92**	**4.94**	**5.48**	**5.18**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	19,514	19,529	19,477	19,369	19,440	19,439	19,461
49.	LIGHT OIL	11,025	11,084	10,687	10,594	10,582	10,595	10,736
50.	COAL	10,742	10,741	10,674	10,614	10,611	10,594	10,647
51.	NATURAL GAS	7,796	7,782	7,529	7,423	7,382	7,346	7,540
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,356**	**9,336**	**9,183**	**9,255**	**9,280**	**9,052**	**9,287**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	9.13	9.13	9.32	9.54	9.78	9.87	9.19
56.	LIGHT OIL	13.85	13.88	13.46	13.37	13.32	13.28	13.66
57.	COAL	2.86	2.83	2.82	2.81	2.82	2.82	2.82
58.	NATURAL GAS	7.29	7.36	7.12	6.77	7.00	7.22	7.17
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)**	**5.07**	**5.12**	**4.97**	**4.55**	**4.59**	**4.96**	**4.81**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JANUARY 2008

(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	188,363	65.8	66.0	91.3	10,561	COAL	85,305	23,319,970	1,989,310.0	5,197,937	2.76	60.93
2. B.B.#2	395	202,571	68.9	69.1	91.3	10,633	COAL	89,152	24,160,198	2,153,930.0	5,432,348	2.68	60.93
3. B.B.#3	400	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. B.B.#4	442	260,936	79.3	80.0	87.9	10,603	COAL	118,645	23,319,904	2,766,790.0	7,229,461	2.77	60.93
5. B.B. STA.	**1,622**	**651,870**	**54.0**	**54.3**	**22.7**	**10,600**	**COAL**	**293,102**	**23,575,513**	**6,910,030.0**	**17,859,746**	**2.74**	**60.93**
6. PHILLIPS #1 (HVY OIL)	18	927	6.9	100.0	54.8	19,057	HVY OIL	1,437	12,293,667	17,666.0	80,742	8.71	56.19
7. PHILLIPS #2 (HVY OIL)	18	889	6.6	100.0	53.7	19,872	HVY OIL	1,377	12,829,339	17,666.0	77,371	8.70	56.19
8. SEB-PHILLIPS TOTAL	**36**	**1,816**	**6.8**	**100.0**	**27.1**	**19,456**	**HVY OIL**	**2,814**	**12,555,792**	**35,332.0**	**158,113**	**8.71**	**56.19**
9. POLK #1 GASIFIER	260	150,455	77.8	-	-	10,602	COAL	63,335	25,185,064	1,595,096.0	4,514,498	3.00	71.28
10. POLK #1 CT OIL	245	4,653	2.6	-	-	10,580	LGT OIL	8,494	5,795,738	49,229.0	655,145	14.08	77.13
11. POLK #1 TOTAL	**260**	**155,108**	**80.2**	**80.7**	**90.3**	**10,601**		**-**	**-**	**1,644,325.0**	**5,169,643**	**3.33**	**-**
12. POLK #2 CT GAS	175	1,384	1.1	-	-	12,048	GAS	16,200	1,029,321	16,675.0	180,959	13.08	11.17
13. POLK #2 CT OIL	184	73	0.1	-	-	11,301	LGT OIL	100	8,250,000	825.0	7,320	10.03	73.20
14. POLK #2 TOTAL	**184**	**1,457**	**1.1**	**100.0**	**72.0**	**12,011**		**-**	**-**	**17,500.0**	**188,279**	**12.92**	**-**
15. POLK #3 CT GAS	175	1,339	1.0	0.0	-	12,026	GAS	15,700	1,025,669	16,103.0	175,374	13.10	11.17
16. POLK #3 CT OIL	184	70	0.1	0.0	-	11,357	LGT OIL	100	7,950,000	795.0	7,320	10.46	73.20
17. POLK #3 TOTAL	**184**	**1,409**	**1.0**	**100.0**	**76.6**	**11,993**		**-**	**-**	**16,898.0**	**182,694**	**12.97**	**-**
18. POLK #4 CT GAS	**180**	**1781**	**1.3**	**100.0**	**66.0**	**12,618**	**GAS**	**21,900**	**1,026,119**	**22472.0**	**244,630**	**13.74**	**11.17**
19. POLK #5 CT GAS	**180**	**1479**	**1.1**	**100.0**	**74.7**	**12,114**	**GAS**	**17,400**	**1,029,713**	**17917.0**	**194,363**	**13.14**	**11.17**
20. CITY OF TAMPA GAS	**3**	**71**	**3.2**	**100.0**	**42.3**	**10,479**	GAS	**700**	1,062,857	**744.0**	**8,657**	**12.19**	**12.37**
21. BAYSIDE #1	793	187,324	31.8	92.6	69.3	7,363	GAS	1,341,800	1,027,962	1,379,320.0	14,988,309	8.00	11.17
22. BAYSIDE #2	1,048	297,081	38.1	91.9	77.5	7,404	GAS	2,139,700	1,028,004	2,199,620.0	23,901,091	8.05	11.17
23. BAYSIDE TOTAL	**1,841**	**484,405**	**35.4**	**92.2**	**37.2**	**7,388**	**GAS**	**3,481,500**	**1,027,988**	**3,578,940.0**	**38,889,400**	**8.03**	**11.17**
24. B.B.C.T.#1	13	0	0.0	100.0	0.0	0	LGT OIL	0	0	3.0	0	0.00	0.00
25. B.B.C.T.#2	80	2	0.0	66.0	0.0	14,500	LGT OIL	5	5,800,000	29.0	417	20.85	83.40
26. B.B.C.T.#3	45	1	0.0	66.0	0.0	13,000	LGT OIL	2	6,500,000	13.0	167	16.70	83.50
27. C.T. TOTAL (OIL)	**138**	**3**	**0.0**	**69.2**	**0.0**	**15,000**	**LGT OIL**	**7**	**6,428,571**	**45.0**	**584**	**19.47**	**83.43**
28. TOT COAL (BB,POLK)	**1,882**	**802,325**	**57.3**	**46.8**	**24.1**	**10,601**	**COAL**	**356,437**	**23,861,513**	**8,505,126.0**	**22,374,244**	**2.79**	**62.77**
29. SYSTEM	**4,628**	**1,299,399**	**37.7**	**78.9**	**10.2**	**9,423**	**-**	**-**	**-**	**12,244,203.0**	**62,896,109**	**4.84**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: FEBRUARY 2008

(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	176,799	66.0	66.0	91.7	10,560	COAL	80,062	23,319,927	1,867,040.0	4,939,022	2.79	61.69
2. B.B.#2	395	190,074	69.1	69.1	91.5	10,632	COAL	83,643	24,160,061	2,020,820.0	5,159,934	2.71	61.69
3. B.B.#3	400	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. B.B.#4	442	245,917	79.9	80.0	88.5	10,603	COAL	111,811	23,319,977	2,607,430.0	6,897,616	2.80	61.69
5. B.B. STA.	**1,622**	**612,790**	**54.3**	**54.3**	**22.8**	**10,600**	**COAL**	**275,516**	**23,575,001**	**6,495,290.0**	**16,996,572**	**2.77**	**61.69**
6. PHILLIPS #1 (HVY OIL)	18	740	5.9	100.0	50.8	19,532	HVY OIL	1,145	12,623,581	14,454.0	66,399	8.97	57.99
7. PHILLIPS #2 (HVY OIL)	18	748	6.0	100.0	50.7	19,324	HVY OIL	1,157	12,492,653	14,454.0	67,095	8.97	57.99
8. SEB-PHILLIPS TOTAL	**36**	**1,488**	**5.9**	**100.0**	**25.4**	**19,427**	**HVY OIL**	**2,302**	**12,557,776**	**28,908.0**	**133,494**	**8.97**	**57.99**
9. POLK #1 GASIFIER	260	47,515	26.3	-	-	10,614	COAL	19,999	25,216,711	504,309.0	1,471,465	3.10	73.58
10. POLK #1 CT OIL	245	1,470	0.9	-	-	10,575	LGT OIL	2,682	5,796,048	15,545.0	206,215	14.03	76.89
11. POLK #1 TOTAL	**260**	**48,985**	**27.1**	**27.8**	**90.6**	**10,613**		**-**	**-**	**519,854.0**	**1,677,680**	**3.42**	**-**
12. POLK #2 CT GAS	175	250	0.2	-	-	15,004	GAS	3,600	1,041,944	3,751.0	37,966	15.19	10.55
13. POLK #2 CT OIL	184	13	0.0	-	-	13,154	LGT OIL	0	0	171.0	0	0.00	0.00
14. POLK #2 TOTAL	**184**	**263**	**0.2**	**100.0**	**47.6**	**14,913**		**-**	**-**	**3,922.0**	**37,966**	**14.44**	**-**
15. POLK #3 CT GAS	175	182	0.1	0.0	-	15,648	GAS	2,800	1,017,143	2,848.0	29,529	16.22	10.55
16. POLK #3 CT OIL	184	10	0.0	0.0	-	12,400	LGT OIL	0	0	124.0	0	0.00	0.00
17. POLK #3 TOTAL	**184**	**192**	**0.1**	**100.0**	**52.2**	**15,479**		**-**	**-**	**2,972.0**	**29,529**	**15.38**	**-**
18. POLK #4 CT GAS	**180**	**438**	**0.3**	**100.0**	**48.7**	**14,249**	**GAS**	**6,100**	**1,023,115**	**6241.0**	**64,331**	**14.69**	**10.55**
19. POLK #5 CT GAS	**180**	**337**	**0.3**	**100.0**	**46.8**	**14,481**	**GAS**	**4,700**	**1,038,298**	**4880.0**	**49,567**	**14.71**	**10.55**
20. CITY OF TAMPA GAS	**3**	**50**	**2.4**	**100.0**	**35.5**	**10,400**	GAS	**500**	1,040,000	**520.0**	**5,865**	**11.73**	**11.73**
21. BAYSIDE #1	793	345,203	62.5	92.6	73.4	7,260	GAS	2,437,800	1,028,001	2,506,060.0	25,709,283	7.45	10.55
22. BAYSIDE #2	1,048	313,575	43.0	91.9	63.0	7,407	GAS	2,259,500	1,028,006	2,322,780.0	23,828,913	7.60	10.55
23. BAYSIDE TOTAL	**1,841**	**658,778**	**51.4**	**92.2**	**33.5**	**7,330**	**GAS**	**4,697,300**	**1,028,003**	**4,828,840.0**	**49,538,196**	**7.52**	**10.55**
24. B.B.C.T.#1	13	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25. B.B.C.T.#2	80	0	0.0	66.0	0.0	0	LGT OIL	0	0	2.0	0	0.00	0.00
26. B.B.C.T.#3	45	0	0.0	66.0	0.0	0	LGT OIL	0	0	1.0	0	0.00	0.00
27. C.T. TOTAL (OIL)	**138**	**0**	**0.0**	**69.2**	**0.0**	**0**	**LGT OIL**	**0**	**0**	**3.0**	**0**	**0.00**	**0.00**
28. TOT COAL (BB,POLK)	**1,882**	**660,305**	**50.4**	**46.8**	**21.2**	**10,601**	**COAL**	**295,515**	**23,686,104**	**6,999,599.0**	**18,468,037**	**2.80**	**62.49**
29. SYSTEM	**4,628**	**1,323,321**	**41.1**	**75.9**	**9.7**	**8,986**	**-**	**-**	**-**	**11,891,430.0**	**68,533,200**	**5.18**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MARCH 2008

(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	188,874	65.9	66.0	91.5	10,616	COAL	85,986	23,319,843	2,005,180.0	5,318,001	2.82	61.85
2. B.B.#2	395	203,124	69.1	69.1	91.5	10,609	COAL	89,192	24,160,239	2,154,900.0	5,516,284	2.72	61.85
3. B.B.#3	400	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. B.B.#4	442	262,575	79.8	80.0	88.4	10,618	COAL	119,557	23,319,923	2,788,060.0	7,394,277	2.82	61.85
5. B.B. STA.	**1,622**	**654,573**	**54.2**	**54.3**	**22.8**	**10,615**	**COAL**	**294,735**	**23,574,194**	**6,948,140.0**	**18,228,562**	**2.78**	**61.85**
6. PHILLIPS #1 (HVY OIL)	18	1,410	10.5	100.0	52.6	19,550	HVY OIL	2,183	12,627,119	27,565.0	126,411	8.97	57.91
7. PHILLIPS #2 (HVY OIL)	18	1,425	10.6	100.0	52.4	19,344	HVY OIL	2,207	12,489,805	27,565.0	127,801	8.97	57.91
8. SEB-PHILLIPS TOTAL	**36**	**2,835**	**10.6**	**100.0**	**26.3**	**19,446**	**HVY OIL**	**4,390**	**12,558,087**	**55,130.0**	**254,212**	**8.97**	**57.91**
9. POLK #1 GASIFIER	260	108,050	55.9	-	-	10,594	COAL	45,480	25,169,151	1,144,693.0	3,281,999	3.04	72.16
10. POLK #1 CT OIL	245	3,342	1.8	-	-	10,578	LGT OIL	6,099	5,796,196	35,351.0	464,528	13.90	76.16
11. POLK #1 TOTAL	**260**	**111,392**	**57.6**	**57.3**	**90.4**	**10,594**		**-**	**-**	**1,180,044.0**	**3,746,527**	**3.36**	**-**
12. POLK #2 CT GAS	175	353	0.3	-	-	14,252	GAS	4,800	1,048,125	5,031.0	45,580	12.91	9.50
13. POLK #2 CT OIL	184	19	0.0	-	-	12,526	LGT OIL	0	0	238.0	0	0.00	0.00
14. POLK #2 TOTAL	**184**	**372**	**0.3**	**100.0**	**50.5**	**14,164**		**-**	**-**	**5,269.0**	**45,580**	**12.25**	**-**
15. POLK #3 CT GAS	175	114	0.1	0.0	-	17,167	GAS	1,900	1,030,000	1,957.0	18,042	15.83	9.50
16. POLK #3 CT OIL	184	6	0.0	0.0	-	12,833	LGT OIL	0	0	77.0	0	0.00	0.00
17. POLK #3 TOTAL	**184**	**120**	**0.1**	**100.0**	**65.2**	**16,950**		**-**	**-**	**2,034.0**	**18,042**	**15.04**	**-**
18. POLK #4 CT GAS	**180**	**2484**	**1.9**	**100.0**	**65.7**	**12,252**	**GAS**	**29,600**	**1,028,142**	**30433.0**	**281,076**	**11.32**	**9.50**
19. POLK #5 CT GAS	**180**	**1167**	**0.9**	**100.0**	**54.0**	**13,021**	**GAS**	**14,800**	**1,026,757**	**15196.0**	**140,538**	**12.04**	**9.50**
20. CITY OF TAMPA GAS	**3**	**73**	**3.3**	**100.0**	**52.9**	**10,521**	GAS	**700**	1,097,143	**768.0**	**7,469**	**10.23**	**10.67**
21. BAYSIDE #1	793	308,091	52.2	71.7	82.5	7,307	GAS	2,189,900	1,027,983	2,251,180.0	20,794,852	6.75	9.50
22. BAYSIDE #2	1,048	247,786	31.8	41.5	88.9	7,454	GAS	1,796,700	1,027,974	1,846,960.0	17,061,104	6.89	9.50
23. BAYSIDE TOTAL	**1,841**	**555,877**	**40.6**	**54.5**	**41.0**	**7,372**	**GAS**	**3,986,600**	**1,027,979**	**4,098,140.0**	**37,855,956**	**6.81**	**9.50**
24. B.B.C.T.#1	13	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25. B.B.C.T.#2	80	2	0.0	66.0	0.0	13,000	LGT OIL	4	6,500,000	26.0	408	20.40	102.00
26. B.B.C.T.#3	45	0	0.0	66.0	0.0	0	LGT OIL	1	9,000,000	9.0	102	0.00	102.00
27. C.T. TOTAL (OIL)	**138**	**2**	**0.0**	**69.2**	**0.0**	**17,500**	**LGT OIL**	**5**	**7,000,000**	**35.0**	**510**	**25.50**	**102.00**
28. TOT COAL (BB,POLK)	**1,882**	**762,623**	**54.5**	**46.8**	**22.9**	**10,612**	**COAL**	**340,215**	**23,787,408**	**8,092,833.0**	**21,510,561**	**2.82**	**63.23**
29. SYSTEM	**4,628**	**1,328,895**	**38.6**	**62.6**	**9.9**	**9,282**	**-**	**-**	**-**	**12,335,189.0**	**60,578,472**	**4.56**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: APRIL 2008

(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	375	178,254	66.0	66.0	91.8	10,610	COAL	81,102	23,320,017	1,891,300.0	5,032,122	2.82	62.05
2. B.B.#2	385	192,295	69.4	69.1	91.8	10,605	COAL	84,410	24,160,052	2,039,350.0	5,237,373	2.72	62.05
3. B.B.#3	390	171,405	61.0	61.5	90.6	10,645	COAL	78,242	23,319,828	1,824,590.0	4,854,668	2.83	62.05
4. B.B.#4	432	248,207	79.8	80.0	88.4	10,606	COAL	112,890	23,319,957	2,632,590.0	7,004,466	2.82	62.05
5. B.B. STA.	**1,582**	**790,161**	**69.4**	**69.5**	**22.7**	**10,615**	**COAL**	**356,644**	**23,518,775**	**8,387,830.0**	**22,128,629**	**2.80**	**62.05**
6. PHILLIPS #1 (HVY OIL)	17	1,986	16.2	53.3	85.9	27,629	HVY OIL	3,064	17,908,616	54,872.0	179,168	9.02	58.48
7. PHILLIPS #2 (HVY OIL)	17	3,678	30.0	86.7	85.9	14,919	HVY OIL	5,675	9,669,075	54,872.0	331,846	9.02	58.48
8. SEB-PHILLIPS TOTAL	**34**	**5,664**	**23.1**	**70.0**	**42.9**	**19,376**	**HVY OIL**	**8,739**	**12,557,959**	**109,744.0**	**511,014**	**9.02**	**58.48**
9. POLK #1 GASIFIER	255	143,691	78.3	-	-	10,581	COAL	60,430	25,159,904	1,520,413.0	4,373,727	3.04	72.38
10. POLK #1 CT OIL	225	4,444	2.7	-	-	10,570	LGT OIL	8,104	5,796,027	46,971.0	609,751	13.72	75.24
11. POLK #1 TOTAL	**255**	**148,135**	**80.7**	**80.7**	**90.9**	**10,581**		**-**	**-**	**1,567,384.0**	**4,983,478**	**3.36**	**-**
12. POLK #2 CT GAS	150	607	0.6	-	-	12,560	GAS	7,400	1,030,270	7,624.0	72,709	11.98	9.83
13. POLK #2 CT OIL	160	32	0.0	-	-	11,719	LGT OIL	100	3,750,000	375.0	7,042	22.01	70.42
14. POLK #2 TOTAL	**160**	**639**	**0.6**	**100.0**	**79.9**	**12,518**		**-**	**-**	**7,999.0**	**79,751**	**12.48**	**-**
15. POLK #3 CT GAS	150	212	0.2	0.0	-	14,726	GAS	3,100	1,007,097	3,122.0	30,459	14.37	9.83
16. POLK #3 CT OIL	165	11	0.0	0.0	-	12,545	LGT OIL	0	0	138.0	0	0.00	0.00
17. POLK #3 TOTAL	**165**	**223**	**0.2**	**100.0**	**67.6**	**14,619**		**-**	**-**	**3,260.0**	**30,459**	**13.66**	**-**
18. POLK #4 CT GAS	**155**	**5134**	**4.6**	**100.0**	**87.2**	**12,065**	**GAS**	**60,300**	**1,027,214**	**61941.0**	**592,478**	**11.54**	**9.83**
19. POLK #5 CT GAS	**155**	**2607**	**2.3**	**100.0**	**84.1**	**12,114**	**GAS**	**30,700**	**1,028,730**	**31582.0**	**301,643**	**11.57**	**9.83**
20. CITY OF TAMPA GAS	**3**	**57**	**2.6**	**100.0**	**70.4**	**10,456**	GAS	**600**	993,333	**596.0**	**6,594**	**11.57**	**10.99**
21. BAYSIDE #1	702	391,490	77.5	92.6	92.8	7,345	GAS	2,797,100	1,027,975	2,875,350.0	27,482,906	7.02	9.83
22. BAYSIDE #2	930	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE TOTAL	**1,632**	**391,490**	**33.3**	**39.9**	**39.9**	**7,345**	**GAS**	**2,797,100**	**1,027,975**	**2,875,350.0**	**27,482,906**	**7.02**	**9.83**
24. B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT OIL	1	6,000,000	6.0	81	0.00	81.00
25. B.B.C.T.#2	60	9	0.0	66.0	0.0	21,222	LGT OIL	33	5,787,879	191.0	2,682	29.80	81.27
26. B.B.C.T.#3	45	5	0.0	66.0	0.0	30,000	LGT OIL	26	5,769,231	150.0	2,113	42.26	81.27
27. C.T. TOTAL (OIL)	**117**	**14**	**0.0**	**69.5**	**0.0**	**24,786**	**LGT OIL**	**60**	**5,783,333**	**347.0**	**4,876**	**34.83**	**81.27**
28. TOT COAL (BB,POLK)	**1,837**	**933,852**	**70.6**	**59.8**	**23.1**	**10,610**	**COAL**	**417,074**	**23,756,559**	**9,908,243.0**	**26,502,356**	**2.84**	**63.54**
29. SYSTEM	**4,258**	**1,344,124**	**43.8**	**63.4**	**9.7**	**9,706**	**-**	**-**	**-**	**13,046,033.0**	**56,121,828**	**4.18**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MAY 2008

(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	375	183,337	65.7	66.0	91.2	10,676	COAL	83,935	23,319,950	1,957,360.0	5,194,071	2.83	61.88
2. B.B.#2	385	197,881	69.1	69.1	91.5	10,631	COAL	87,072	24,160,235	2,103,680.0	5,388,195	2.72	61.88
3. B.B.#3	390	218,514	75.3	76.9	89.5	10,633	COAL	99,635	23,320,018	2,323,490.0	6,165,619	2.82	61.88
4. B.B.#4	432	254,761	79.3	80.0	87.8	10,635	COAL	116,189	23,319,850	2,709,510.0	7,190,015	2.82	61.88
5. B.B. STA.	**1,582**	**854,493**	**72.6**	**73.3**	**22.5**	**10,643**	**COAL**	**386,831**	**23,509,078**	**9,094,040.0**	**23,937,900**	**2.80**	**61.88**
6. PHILLIPS #1 (HVY OIL)	17	1,117	8.8	100.0	58.1	21,380	HVY OIL	1,729	13,812,030	23,881.0	105,063	9.41	60.77
7. PHILLIPS #2 (HVY OIL)	17	1,340	10.6	0.0	59.7	17,822	HVY OIL	2,074	11,514,465	23,881.0	126,027	9.41	60.77
8. SEB-PHILLIPS TOTAL	**34**	**2,457**	**9.7**	**50.0**	**29.5**	**19,439**	**HVY OIL**	**3,803**	**12,559,032**	**47,762.0**	**231,090**	**9.41**	**60.77**
9. POLK #1 GASIFIER	255	148,089	78.1	-	-	10,594	COAL	62,293	25,185,912	1,568,906.0	4,521,467	3.05	72.58
10. POLK #1 CT OIL	225	4,580	2.7	-	-	10,572	LGT OIL	8,354	5,795,906	48,419.0	621,458	13.57	74.39
11. POLK #1 TOTAL	**255**	**152,669**	**80.5**	**80.7**	**90.6**	**10,594**		**-**	**-**	**1,617,325.0**	**5,142,925**	**3.37**	**-**
12. POLK #2 CT GAS	150	5,521	4.9	-	-	12,957	GAS	69,600	1,027,802	71,535.0	646,438	11.71	9.29
13. POLK #2 CT OIL	160	291	0.2	-	-	12,124	LGT OIL	600	5,880,000	3,528.0	42,006	14.44	70.01
14. POLK #2 TOTAL	**160**	**5,812**	**4.9**	**100.0**	**64.9**	**12,915**		**-**	**-**	**75,063.0**	**688,444**	**11.85**	**-**
15. POLK #3 CT GAS	150	3,771	3.4	0.0	-	12,547	GAS	46,000	1,028,565	47,314.0	427,243	11.33	9.29
16. POLK #3 CT OIL	165	198	0.2	0.0	-	11,778	LGT OIL	400	5,830,000	2,332.0	28,004	14.14	70.01
17. POLK #3 TOTAL	**165**	**3,969**	**3.2**	**100.0**	**68.7**	**12,508**		**-**	**-**	**49,646.0**	**455,247**	**11.47**	**-**
18. POLK #4 CT GAS	**155**	**8778**	**7.6**	**100.0**	**69.1**	**12,886**	**GAS**	**110,000**	**1,028,282**	**113111.0**	**1,021,669**	**11.64**	**9.29**
19. POLK #5 CT GAS	**155**	**7262**	**6.3**	**100.0**	**67.9**	**12,878**	**GAS**	**91,000**	**1,027,714**	**93522.0**	**845,199**	**11.64**	**9.29**
20. CITY OF TAMPA GAS	**3**	**99**	**4.4**	**100.0**	**64.7**	**10,475**	GAS	**1,000**	1,037,000	**1,037.0**	**10,455**	**10.56**	**10.46**
21. BAYSIDE #1	702	342,772	65.6	92.6	91.3	7,416	GAS	2,472,900	1,028,004	2,542,150.0	22,968,048	6.70	9.29
22. BAYSIDE #2	930	457,465	66.1	86.0	89.6	7,410	GAS	3,297,500	1,028,009	3,389,860.0	30,626,850	6.69	9.29
23. BAYSIDE TOTAL	**1,632**	**800,237**	**65.9**	**88.8**	**45.2**	**7,413**	**GAS**	**5,770,400**	**1,028,007**	**5,932,010.0**	**53,594,898**	**6.70**	**9.29**
24. B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25. B.B.C.T.#2	60	1	0.0	66.0	0.0	20,000	LGT OIL	3	6,666,667	20.0	241	24.10	80.33
26. B.B.C.T.#3	45	0	0.0	66.0	0.0	0	LGT OIL	2	4,500,000	9.0	161	0.00	80.50
27. C.T. TOTAL (OIL)	**117**	**1**	**0.0**	**69.5**	**0.0**	**29,000**	**LGT OIL**	**5**	**5,800,000**	**29.0**	**402**	**40.20**	**80.40**
28. TOT COAL (BB,POLK)	**1,837**	**1,002,582**	**73.4**	**63.1**	**22.8**	**10,635**	**COAL**	**449,124**	**23,741,653**	**10,662,946.0**	**28,459,367**	**2.84**	**63.37**
29. SYSTEM	**4,258**	**1,835,777**	**57.9**	**83.4**	**11.0**	**9,273**	**-**	**-**	**-**	**17,023,545.0**	**85,928,229**	**4.68**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JUNE 2008

(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	375	178,902	66.3	66.0	92.1	10,699	COAL	82,076	23,319,850	1,914,000.0	5,070,405	2.83	61.78
2. B.B.#2	385	192,473	69.4	69.1	91.9	10,662	COAL	84,936	24,160,191	2,052,070.0	5,247,087	2.73	61.78
3. B.B.#3	390	214,818	76.5	76.9	90.9	10,676	COAL	98,349	23,320,013	2,293,500.0	6,075,701	2.83	61.78
4. B.B.#4	432	248,875	80.0	80.0	88.6	10,725	COAL	114,454	23,320,024	2,669,070.0	7,070,619	2.84	61.78
5. B.B. STA.	**1,582**	**835,068**	**73.3**	**73.3**	**22.8**	**10,692**	**COAL**	**379,815**	**23,507,866**	**8,928,640.0**	**23,463,812**	**2.81**	**61.78**
6. PHILLIPS #1 (HVY OIL)	17	3,993	32.6	100.0	88.6	19,305	HVY OIL	6,171	12,491,492	77,085.0	363,613	9.11	58.92
7. PHILLIPS #2 (HVY OIL)	17	3,951	32.3	100.0	89.0	19,510	HVY OIL	6,106	12,624,468	77,085.0	359,783	9.11	58.92
8. SEB-PHILLIPS TOTAL	**34**	**7,944**	**32.5**	**100.0**	**44.4**	**19,407**	**HVY OIL**	**12,277**	**12,557,628**	**154,170.0**	**723,396**	**9.11**	**58.92**
9. POLK #1 GASIFIER	255	143,807	78.3	-	-	10,580	COAL	60,475	25,159,868	1,521,543.0	4,340,484	3.02	71.77
10. POLK #1 CT OIL	225	4,448	2.7	-	-	10,568	LGT OIL	8,110	5,796,054	47,006.0	597,664	13.44	73.69
11. POLK #1 TOTAL	**255**	**148,255**	**80.7**	**80.7**	**91.0**	**10,580**		**-**	**-**	**1,568,549.0**	**4,938,148**	**3.33**	**-**
12. POLK #2 CT GAS	150	7,258	6.7	-	-	12,433	GAS	87,800	1,027,768	90,238.0	824,442	11.36	9.39
13. POLK #2 CT OIL	160	382	0.3	-	-	11,743	LGT OIL	800	5,607,500	4,486.0	56,101	14.69	70.13
14. POLK #2 TOTAL	**160**	**7,640**	**6.6**	**100.0**	**72.3**	**12,398**		**-**	**-**	**94,724.0**	**880,543**	**11.53**	**-**
15. POLK #3 CT GAS	150	5,425	5.0	0.0	-	12,579	GAS	66,400	1,027,726	68,241.0	623,496	11.49	9.39
16. POLK #3 CT OIL	165	286	0.2	0.0	-	11,822	LGT OIL	600	5,635,000	3,381.0	42,075	14.71	70.13
17. POLK #3 TOTAL	**165**	**5,711**	**4.8**	**100.0**	**67.9**	**12,541**		**-**	**-**	**71,622.0**	**665,571**	**11.65**	**-**
18. POLK #4 CT GAS	**155**	**17286**	**15.5**	**100.0**	**91.4**	**11,728**	**GAS**	**197,200**	**1,028,032**	**202728.0**	**1,851,708**	**10.71**	**9.39**
19. POLK #5 CT GAS	**155**	**13918**	**12.5**	**100.0**	**88.9**	**11,868**	**GAS**	**160,700**	**1,027,841**	**165174.0**	**1,508,973**	**10.84**	**9.39**
20. CITY OF TAMPA GAS	**3**	**149**	**6.9**	**100.0**	**92.0**	**10,456**	GAS	**1,500**	1,038,667	**1,558.0**	**15,852**	**10.64**	**10.57**
21. BAYSIDE #1	702	334,306	66.1	92.6	90.2	7,421	GAS	2,413,300	1,028,024	2,480,930.0	22,660,887	6.78	9.39
22. BAYSIDE #2	930	467,086	69.8	91.9	90.0	7,418	GAS	3,370,500	1,027,981	3,464,810.0	31,648,995	6.78	9.39
23. BAYSIDE TOTAL	**1,632**	**801,392**	**68.2**	**92.2**	**45.2**	**7,419**	**GAS**	**5,783,800**	**1,027,999**	**5,945,740.0**	**54,309,882**	**6.78**	**9.39**
24. B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT OIL	1	6,000,000	6.0	85	0.00	85.00
25. B.B.C.T.#2	60	4	0.0	66.0	0.0	18,500	LGT OIL	13	5,692,308	74.0	1,099	27.48	84.54
26. B.B.C.T.#3	45	2	0.0	66.0	0.0	20,500	LGT OIL	7	5,857,143	41.0	592	29.60	84.57
27. C.T. TOTAL (OIL)	**117**	**6**	**0.0**	**69.5**	**0.0**	**20,167**	**LGT OIL**	**21**	**5,761,905**	**121.0**	**1,776**	**29.60**	**84.57**
28. TOT COAL (BB,POLK)	**1,837**	**978,875**	**74.0**	**63.1**	**23.0**	**10,676**	**COAL**	**440,290**	**23,734,773**	**10,450,183.0**	**27,804,296**	**2.84**	**63.15**
29. SYSTEM	**4,258**	**1,837,369**	**59.9**	**85.1**	**10.3**	**9,325**	**-**	**-**	**-**	**17,133,026.0**	**88,359,661**	**4.81**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JULY 2008

(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	375	184,661	66.2	66.0	91.9	10,788	COAL	85,425	23,319,754	1,992,090.0	5,272,480	2.86	61.72
2. B.B.#2	385	198,917	69.4	69.1	91.9	10,714	COAL	88,207	24,160,214	2,131,100.0	5,444,186	2.74	61.72
3. B.B.#3	390	222,927	76.8	76.9	91.3	10,768	COAL	102,933	23,319,927	2,400,390.0	6,353,084	2.85	61.72
4. B.B.#4	432	257,318	80.1	80.0	88.6	10,794	COAL	119,108	23,320,012	2,777,600.0	7,351,414	2.86	61.72
5. B.B. STA.	**1,582**	**863,823**	**73.4**	**73.3**	**22.8**	**10,767**	**COAL**	**395,673**	**23,507,240**	**9,301,180.0**	**24,421,164**	**2.83**	**61.72**
6. PHILLIPS #1 (HVY OIL)	17	5,082	40.2	100.0	96.7	19,445	HVY OIL	7,897	12,513,739	98,821.0	463,960	9.13	58.75
7. PHILLIPS #2 (HVY OIL)	17	5,046	39.9	100.0	97.0	19,584	HVY OIL	7,841	12,603,112	98,821.0	460,670	9.13	58.75
8. SEB-PHILLIPS TOTAL	**34**	**10,128**	**40.0**	**100.0**	**48.4**	**19,514**	**HVY OIL**	**15,738**	**12,558,267**	**197,642.0**	**924,630**	**9.13**	**58.75**
9. POLK #1 GASIFIER	255	148,715	78.4	-	-	10,591	COAL	62,535	25,185,992	1,575,006.0	4,489,721	3.02	71.80
10. POLK #1 CT OIL	225	4,599	2.7	-	-	10,569	LGT OIL	8,386	5,796,208	48,607.0	613,858	13.35	73.20
11. POLK #1 TOTAL	**255**	**153,314**	**80.8**	**80.7**	**91.0**	**10,590**		**-**	**-**	**1,623,613.0**	**5,103,579**	**3.33**	**-**
12. POLK #2 CT GAS	150	16,888	15.1	-	-	11,825	GAS	194,300	1,027,756	199,693.0	1,866,834	11.05	9.61
13. POLK #2 CT OIL	160	889	0.7	-	-	11,319	LGT OIL	1,700	5,919,412	10,063.0	120,199	13.52	70.71
14. POLK #2 TOTAL	**160**	**17,777**	**14.9**	**100.0**	**84.8**	**11,799**		**-**	**-**	**209,756.0**	**1,987,033**	**11.18**	**-**
15. POLK #3 CT GAS	150	11,229	10.1	0.0	-	12,228	GAS	133,600	1,027,792	137,313.0	1,283,629	11.43	9.61
16. POLK #3 CT OIL	165	591	0.5	0.0	-	11,516	LGT OIL	1,200	5,671,667	6,806.0	84,846	14.36	70.71
17. POLK #3 TOTAL	**165**	**11,820**	**9.6**	**100.0**	**74.6**	**12,193**		**-**	**-**	**144,119.0**	**1,368,475**	**11.58**	**-**
18. POLK #4 CT GAS	**155**	**32200**	**27.9**	**100.0**	**93.6**	**11,561**	**GAS**	**362,100**	**1,028,050**	**372257.0**	**3,479,057**	**10.80**	**9.61**
19. POLK #5 CT GAS	**155**	**27396**	**23.8**	**100.0**	**91.6**	**11,619**	**GAS**	**309,600**	**1,028,149**	**318315.0**	**2,974,637**	**10.86**	**9.61**
20. CITY OF TAMPA GAS	**3**	**251**	**11.2**	**100.0**	**108.7**	**10,446**	GAS	**2,600**	1,008,462	**2,622.0**	**28,038**	**11.17**	**10.78**
21. BAYSIDE #1	702	362,711	69.4	92.6	90.3	7,415	GAS	2,616,400	1,028,008	2,689,680.0	25,138,371	6.93	9.61
22. BAYSIDE #2	930	520,664	75.2	91.9	89.0	7,399	GAS	3,747,200	1,028,024	3,852,210.0	36,003,098	6.91	9.61
23. BAYSIDE TOTAL	**1,632**	**883,375**	**72.8**	**92.2**	**45.1**	**7,406**	**GAS**	**6,363,600**	**1,028,017**	**6,541,890.0**	**61,141,469**	**6.92**	**9.61**
24. B.B.C.T.#1	12	6	0.1	100.0	0.0	18,167	LGT OIL	19	5,736,842	109.0	1,502	25.03	79.05
25. B.B.C.T.#2	60	84	0.2	66.0	46.7	19,929	LGT OIL	289	5,792,388	1,674.0	22,840	27.19	79.03
26. B.B.C.T.#3	45	54	0.2	66.0	40.0	24,981	LGT OIL	233	5,789,700	1,349.0	18,414	34.10	79.03
27. C.T. TOTAL (OIL)	**117**	**144**	**0.2**	**69.5**	**20.5**	**21,750**	**LGT OIL**	**541**	**5,789,279**	**3,132.0**	**42,756**	**29.69**	**79.03**
28. TOT COAL (BB,POLK)	**1,837**	**1,012,538**	**74.1**	**63.1**	**23.0**	**10,742**	**COAL**	**458,208**	**23,736,351**	**10,876,186.0**	**28,910,885**	**2.86**	**63.10**
29. SYSTEM	**4,258**	**2,000,228**	**63.1**	**85.1**	**10.0**	**9,356**	**-**	**-**	**-**	**18,714,526.0**	**101,470,838**	**5.07**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: AUGUST 2008

	(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	375	184,826	66.2	66.0	92.0	10,787	COAL	85,498	23,319,961	1,993,810.0	5,259,942	2.85	61.52
2.	B.B.#2	385	198,962	69.5	69.1	92.0	10,713	COAL	88,226	24,160,225	2,131,560.0	5,427,772	2.73	61.52
3.	B.B.#3	390	223,822	77.1	76.9	91.7	10,766	COAL	103,328	23,319,913	2,409,600.0	6,356,866	2.84	61.52
4.	B.B.#4	432	257,822	80.2	80.0	88.8	10,794	COAL	119,337	23,320,010	2,782,940.0	7,341,759	2.85	61.52
5.	**B.B. STA.**	**1,582**	**865,432**	**73.5**	**73.3**	**22.8**	**10,767**	**COAL**	**396,389**	**23,506,984**	**9,317,910.0**	**24,386,339**	**2.82**	**61.52**
6.	PHILLIPS #1 (HVY OIL)	17	5,286	41.8	100.0	97.8	19,456	HVY OIL	8,220	12,511,192	102,842.0	482,672	9.13	58.72
7.	PHILLIPS #2 (HVY OIL)	17	5,246	41.5	100.0	98.3	19,604	HVY OIL	8,159	12,604,731	102,842.0	479,090	9.13	58.72
8.	**SEB-PHILLIPS TOTAL**	**34**	**10,532**	**41.6**	**100.0**	**49.0**	**19,529**	**HVY OIL**	**16,379**	**12,557,787**	**205,684.0**	**961,762**	**9.13**	**58.72**
9.	POLK #1 GASIFIER	255	148,960	78.5	-	-	10,589	COAL	60,939	25,885,000	1,577,406.0	4,367,246	2.93	71.67
10.	POLK #1 CT OIL	225	4,607	2.8	-	-	10,567	LGT OIL	8,399	5,796,166	48,682.0	612,488	13.29	72.92
11.	**POLK #1 TOTAL**	**255**	**153,567**	**80.9**	**80.7**	**91.1**	**10,589**		-	-	**1,626,088.0**	**4,979,734**	**3.24**	-
12.	POLK #2 CT GAS	150	16,905	15.1	-	-	11,865	GAS	195,100	1,028,114	200,585.0	1,896,313	11.22	9.72
13.	POLK #2 CT OIL	160	890	0.7	-	-	11,389	LGT OIL	1,700	5,962,353	10,136.0	121,480	13.65	71.46
14.	**POLK #2 TOTAL**	**160**	**17,795**	**14.9**	**100.0**	**81.8**	**11,842**		-	-	**210,721.0**	**2,017,793**	**11.34**	-
15.	POLK #3 CT GAS	150	11,199	10.0	0.0	-	12,318	GAS	134,200	1,027,973	137,954.0	1,304,384	11.65	9.72
16.	POLK #3 CT OIL	165	589	0.5	0.0	-	11,747	LGT OIL	1,200	5,765,833	6,919.0	85,751	14.56	71.46
17.	**POLK #3 TOTAL**	**165**	**11,788**	**9.6**	**100.0**	**70.7**	**12,290**		-	-	**144,873.0**	**1,390,135**	**11.79**	-
18.	**POLK #4 CT GAS**	**155**	**34109**	**29.6**	**100.0**	**93.2**	**11,529**	**GAS**	**382,500**	**1,028,105**	**393250.0**	**3,717,785**	**10.90**	**9.72**
19.	**POLK #5 CT GAS**	**155**	**24760**	**21.5**	**100.0**	**89.2**	**11,644**	**GAS**	**280,500**	**1,027,800**	**288298.0**	**2,726,376**	**11.01**	**9.72**
20.	**CITY OF TAMPA GAS**	**3**	**270**	**12.1**	**100.0**	**113.9**	**10,452**	GAS	**2,700**	1,045,185	**2,822.0**	**29,394**	**10.89**	**10.89**
21.	BAYSIDE #1	702	371,588	71.1	92.6	90.3	7,414	GAS	2,679,900	1,028,001	2,754,940.0	26,047,824	7.01	9.72
22.	BAYSIDE #2	930	533,662	77.1	91.9	89.1	7,394	GAS	3,838,300	1,028,002	3,945,780.0	37,307,125	6.99	9.72
23.	**BAYSIDE TOTAL**	**1,632**	**905,250**	**74.6**	**92.2**	**45.1**	**7,402**	**GAS**	**6,518,200**	**1,028,002**	**6,700,720.0**	**63,354,949**	**7.00**	**9.72**
24.	B.B.C.T.#1	12	11	0.1	100.0	91.7	20,727	LGT OIL	39	5,846,154	228.0	3,058	27.80	78.41
25.	B.B.C.T.#2	60	99	0.2	66.0	55.0	19,404	LGT OIL	331	5,803,625	1,921.0	25,956	26.22	78.42
26.	B.B.C.T.#3	45	60	0.2	66.0	44.4	24,250	LGT OIL	251	5,796,813	1,455.0	19,683	32.81	78.42
27.	**C.T. TOTAL (OIL)**	**117**	**170**	**0.2**	**69.5**	**20.8**	**21,200**	**LGT OIL**	**621**	**5,803,543**	**3,604.0**	**48,697**	**28.65**	**78.42**
28.	**TOT COAL (BB,POLK)**	**1,837**	**1,014,392**	**74.2**	**63.1**	**23.0**	**10,741**	**COAL**	**457,328**	**23,823,855**	**10,895,316.0**	**28,753,585**	**2.83**	**62.87**
29.	**SYSTEM**	**4,258**	**2,023,673**	**63.9**	**85.1**	**10.0**	**9,336**	-	-	-	**18,893,970.0**	**103,612,964**	**5.12**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: SEPTEMBER 2008

(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	375	113,600	42.1	41.8	92.1	10,699	COAL	52,116	23,320,094	1,215,350.0	3,212,255	2.83	61.64
2. B.B.#2	385	192,507	69.4	69.1	91.9	10,662	COAL	84,951	24,160,045	2,052,420.0	5,236,094	2.72	61.64
3. B.B.#3	390	215,719	76.8	76.9	91.3	10,674	COAL	98,743	23,320,033	2,302,690.0	6,086,187	2.82	61.64
4. B.B.#4	432	249,095	80.1	80.0	88.7	10,725	COAL	114,558	23,319,890	2,671,480.0	7,060,970	2.83	61.64
5. B.B. STA.	**1,582**	**770,921**	**67.7**	**67.5**	**22.9**	**10,691**	**COAL**	**350,368**	**23,523,667**	**8,241,940.0**	**21,595,506**	**2.80**	**61.64**
6. PHILLIPS #1 (HVY OIL)	17	4,149	33.9	100.0	93.5	19,378	HVY OIL	6,435	12,494,328	80,401.0	386,808	9.32	60.11
7. PHILLIPS #2 (HVY OIL)	17	4,107	33.6	100.0	93.6	19,577	HVY OIL	6,370	12,621,821	80,401.0	382,900	9.32	60.11
8. SEB-PHILLIPS TOTAL	**34**	**8,256**	**33.7**	**100.0**	**46.8**	**19,477**	**HVY OIL**	**12,805**	**12,557,751**	**160,802.0**	**769,708**	**9.32**	**60.11**
9. POLK #1 GASIFIER	255	143,925	78.4	-	-	10,580	COAL	58,886	25,858,319	1,522,693.0	4,194,803	2.91	71.24
10. POLK #1 CT OIL	225	4,451	2.7	-	-	10,569	LGT OIL	8,116	5,796,205	47,042.0	590,916	13.28	72.81
11. POLK #1 TOTAL	**255**	**148,376**	**80.8**	**80.7**	**91.1**	**10,579**		**-**	**-**	**1,569,735.0**	**4,785,719**	**3.23**	**-**
12. POLK #2 CT GAS	150	3,386	3.1	-	-	12,846	GAS	42,300	1,028,298	43,497.0	411,063	12.14	9.72
13. POLK #2 CT OIL	160	178	0.2	-	-	11,972	LGT OIL	400	5,327,500	2,131.0	28,908	16.24	72.27
14. POLK #2 TOTAL	**160**	**3,564**	**3.1**	**100.0**	**69.6**	**12,802**		**-**	**-**	**45,628.0**	**439,971**	**12.34**	**-**
15. POLK #3 CT GAS	150	2,840	2.6	0.0	-	12,746	GAS	35,200	1,028,381	36,199.0	342,067	12.04	9.72
16. POLK #3 CT OIL	165	149	0.1	0.0	-	11,906	LGT OIL	300	5,913,333	1,774.0	21,681	14.55	72.27
17. POLK #3 TOTAL	**165**	**2,989**	**2.5**	**100.0**	**67.1**	**12,704**		**-**	**-**	**37,973.0**	**363,748**	**12.17**	**-**
18. POLK #4 CT GAS	**155**	**9016**	**8.1**	**93.3**	**89.5**	**11,955**	**GAS**	**104,800**	**1,028,473**	**107784.0**	**1,018,425**	**11.30**	**9.72**
19. POLK #5 CT GAS	**155**	**6812**	**6.1**	**90.0**	**87.9**	**11,931**	**GAS**	**79,100**	**1,027,446**	**81271.0**	**768,678**	**11.28**	**9.72**
20. CITY OF TAMPA GAS	**3**	**191**	**8.8**	**100.0**	**92.3**	**10,471**	GAS	**1,900**	1,052,632	**2,000.0**	**20,684**	**10.83**	**10.89**
21. BAYSIDE #1	702	353,447	69.9	92.6	90.1	7,417	GAS	2,550,100	1,028,011	2,621,530.0	24,781,362	7.01	9.72
22. BAYSIDE #2	930	504,851	75.4	91.9	88.8	7,403	GAS	3,635,800	1,027,988	3,737,560.0	35,331,977	7.00	9.72
23. BAYSIDE TOTAL	**1,632**	**858,298**	**73.0**	**92.2**	**45.0**	**7,409**	**GAS**	**6,185,900**	**1,027,998**	**6,359,090.0**	**60,113,339**	**7.00**	**9.72**
24. B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT OIL	2	5,000,000	10.0	161	0.00	80.50
25. B.B.C.T.#2	60	9	0.0	41.8	0.0	21,111	LGT OIL	33	5,757,576	190.0	2,657	29.52	80.52
26. B.B.C.T.#3	45	2	0.0	41.8	0.0	15,500	LGT OIL	5	6,200,000	31.0	403	20.15	80.60
27. C.T. TOTAL (OIL)	**117**	**11**	**0.0**	**47.8**	**0.0**	**21,000**	**LGT OIL**	**40**	**5,775,000**	**231.0**	**3,221**	**29.28**	**80.53**
28. TOT COAL (BB,POLK)	**1,837**	**914,846**	**69.2**	**58.2**	**23.4**	**10,674**	**COAL**	**409,254**	**23,859,591**	**9,764,633.0**	**25,790,309**	**2.82**	**63.02**
29. SYSTEM	**4,258**	**1,808,434**	**59.0**	**81.8**	**10.6**	**9,183**	**-**	**-**	**-**	**16,606,454.0**	**89,878,999**	**4.97**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: OCTOBER 2008

(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	165,933	57.9	59.6	89.2	10,611	COAL	75,502	23,319,912	1,760,700.0	4,660,870	2.81	61.73
2. B.B.#2	395	198,612	67.6	69.1	89.5	10,606	COAL	87,185	24,160,234	2,106,410.0	5,382,082	2.71	61.73
3. B.B.#3	400	220,879	74.2	76.9	88.2	10,646	COAL	100,834	23,319,813	2,351,430.0	6,224,659	2.82	61.73
4. B.B.#4	442	256,009	77.9	80.0	86.2	10,608	COAL	116,455	23,319,995	2,715,730.0	7,188,970	2.81	61.73
5. B.B. STA.	**1,622**	**841,433**	**69.7**	**71.7**	**22.1**	**10,618**	**COAL**	**379,976**	**23,512,722**	**8,934,270.0**	**23,456,581**	**2.79**	**61.73**
6. PHILLIPS #1 (HVY OIL)	18	1,464	10.9	100.0	73.9	19,171	HVY OIL	2,258	12,429,584	28,066.0	139,618	9.54	61.83
7. PHILLIPS #2 (HVY OIL)	18	1,434	10.7	100.0	74.5	19,572	HVY OIL	2,212	12,688,065	28,066.0	136,774	9.54	61.83
8. SEB-PHILLIPS TOTAL	**36**	**2,898**	**10.8**	**100.0**	**37.1**	**19,369**	**HVY OIL**	**4,470**	**12,557,494**	**56,132.0**	**276,392**	**9.54**	**61.83**
9. POLK #1 GASIFIER	260	148,430	76.7	-	-	10,592	COAL	60,739	25,885,115	1,572,236.0	4,342,697	2.93	71.50
10. POLK #1 CT OIL	245	4,591	2.5	-	-	10,569	LGT OIL	8,372	5,795,748	48,522.0	609,852	13.28	72.84
11. POLK #1 TOTAL	**260**	**153,021**	**79.1**	**80.7**	**89.0**	**10,592**		**-**	**-**	**1,620,758.0**	**4,952,549**	**3.24**	**-**
12. POLK #2 CT GAS	175	850	0.7	-	-	12,588	GAS	10,400	1,028,846	10,700.0	97,490	11.47	9.37
13. POLK #2 CT OIL	184	45	0.0	-	-	11,933	LGT OIL	100	5,370,000	537.0	7,302	16.23	73.02
14. POLK #2 TOTAL	**184**	**895**	**0.7**	**93.5**	**54.0**	**12,555**		**-**	**-**	**11,237.0**	**104,792**	**11.71**	**-**
15. POLK #3 CT GAS	175	669	0.5	0.0	-	12,496	GAS	8,100	1,032,099	8,360.0	75,929	11.35	9.37
16. POLK #3 CT OIL	184	35	0.0	0.0	-	11,829	LGT OIL	100	4,140,000	414.0	7,302	20.86	73.02
17. POLK #3 TOTAL	**184**	**704**	**0.5**	**54.8**	**63.8**	**12,463**		**-**	**-**	**8,774.0**	**83,231**	**11.82**	**-**
18. POLK #4 CT GAS	**180**	**2687**	**2.0**	**100.0**	**74.6**	**12,095**	**GAS**	**31,600**	**1,028,418**	**32498.0**	**296,218**	**11.02**	**9.37**
19. POLK #5 CT GAS	**180**	**1074**	**0.8**	**100.0**	**54.2**	**13,143**	**GAS**	**13,700**	**1,030,365**	**14116.0**	**128,424**	**11.96**	**9.37**
20. CITY OF TAMPA GAS	**3**	**21**	**0.9**	**100.0**	**175.0**	**10,286**	GAS	**200**	1,080,000	**216.0**	**2,107**	**10.03**	**10.54**
21. BAYSIDE #1	793	345,127	58.5	92.6	78.8	7,358	GAS	2,470,200	1,028,022	2,539,420.0	23,155,655	6.71	9.37
22. BAYSIDE #2	1,048	403,354	51.7	91.9	73.0	7,412	GAS	2,908,500	1,027,970	2,989,850.0	27,264,279	6.76	9.37
23. BAYSIDE TOTAL	**1,841**	**748,481**	**54.6**	**92.2**	**37.7**	**7,387**	**GAS**	**5,378,700**	**1,027,994**	**5,529,270.0**	**50,419,934**	**6.74**	**9.37**
24. B.B.C.T.#1	13	0	0.0	77.4	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25. B.B.C.T.#2	80	1	0.0	59.6	0.0	19,000	LGT OIL	3	6,333,333	19.0	233	23.30	77.67
26. B.B.C.T.#3	45	1	0.0	59.6	0.0	13,000	LGT OIL	2	6,500,000	13.0	155	15.50	77.50
27. C.T. TOTAL (OIL)	**138**	**2**	**0.0**	**61.3**	**0.0**	**16,000**	**LGT OIL**	**5**	**6,400,000**	**32.0**	**388**	**19.40**	**77.60**
28. TOT COAL (BB,POLK)	**1,882**	**989,863**	**70.7**	**61.8**	**22.4**	**10,614**	**COAL**	**440,715**	**23,839,683**	**10,506,506.0**	**27,799,278**	**2.81**	**63.08**
29. SYSTEM	**4,628**	**1,751,216**	**50.9**	**82.7**	**10.3**	**9,255**	**-**	**-**	**-**	**16,207,303.0**	**79,720,616**	**4.55**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: NOVEMBER 2008

(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	182,005	65.7	66.0	91.3	10,599	COAL	82,720	23,319,995	1,929,030.0	5,126,767	2.82	61.98
2. B.B.#2	395	183,319	64.5	64.5	96.4	10,625	COAL	80,621	24,160,082	1,947,810.0	4,996,676	2.73	61.98
3. B.B.#3	400	219,726	76.3	76.9	90.6	10,606	COAL	99,928	23,319,890	2,330,310.0	6,193,273	2.82	61.98
4. B.B.#4	442	134,931	42.4	42.6	88.0	10,639	COAL	61,557	23,319,850	1,435,500.0	3,815,140	2.83	61.98
5. B.B. STA.	**1,622**	**719,981**	**61.7**	**62.0**	**22.4**	**10,615**	**COAL**	**324,826**	**23,528,443**	**7,642,650.0**	**20,131,856**	**2.80**	**61.98**
6. PHILLIPS #1 (HVY OIL)	18	647	5.0	100.0	59.9	19,546	HVY OIL	1,002	12,620,758	12,646.0	63,285	9.78	63.16
7. PHILLIPS #2 (HVY OIL)	18	654	5.0	100.0	59.6	19,336	HVY OIL	1,012	12,496,047	12,646.0	63,917	9.77	63.16
8. SEB-PHILLIPS TOTAL	**36**	**1,301**	**5.0**	**100.0**	**29.9**	**19,440**	**HVY OIL**	**2,014**	**12,558,093**	**25,292.0**	**127,202**	**9.78**	**63.16**
9. POLK #1 GASIFIER	260	145,262	77.6	-	-	10,592	COAL	59,504	25,857,976	1,538,653.0	4,231,465	2.91	71.11
10. POLK #1 CT OIL	245	4,493	2.5	-	-	10,580	LGT OIL	8,201	5,796,244	47,535.0	598,484	13.32	72.98
11. POLK #1 TOTAL	**260**	**149,755**	**80.0**	**80.7**	**90.1**	**10,592**		**-**	**-**	**1,586,188.0**	**4,829,949**	**3.23**	**-**
12. POLK #2 CT GAS	175	6	0.0	-	-	12,000	GAS	100	720,000	72.0	975	16.25	9.75
13. POLK #2 CT OIL	184	0	0.0	-	-	0	LGT OIL	0	0	4.0	0	0.00	0.00
14. POLK #2 TOTAL	**184**	**6**	**0.0**	**100.0**	**0.0**	**12,667**		**-**	**-**	**76.0**	**975**	**16.25**	**-**
15. POLK #3 CT GAS	175	2	0.0	0.0	-	12,000	GAS	0	0	24.0	0	0.00	0.00
16. POLK #3 CT OIL	184	0	0.0	0.0	-	0	LGT OIL	0	0	1.0	0	0.00	0.00
17. POLK #3 TOTAL	**184**	**2**	**0.0**	**100.0**	**0.0**	**12,500**		**-**	**-**	**25.0**	**0**	**0.00**	**-**
18. POLK #4 CT GAS	**180**	**168**	**0.1**	**100.0**	**46.7**	**15,321**	**GAS**	**2,500**	**1,029,600**	**2574.0**	**24,372**	**14.51**	**9.75**
19. POLK #5 CT GAS	**180**	**89**	**0.1**	**100.0**	**49.4**	**12,146**	**GAS**	**1,100**	**982,727**	**1081.0**	**10,724**	**12.05**	**9.75**
20. CITY OF TAMPA GAS	**3**	**6**	**0.3**	**100.0**	**200.0**	**11,167**	GAS	**100**	670,000	**67.0**	**1,093**	**18.22**	**10.93**
21. BAYSIDE #1	793	245,506	43.0	71.0	71.5	7,318	GAS	1,747,800	1,027,984	1,796,710.0	17,038,953	6.94	9.75
22. BAYSIDE #2	1,045	370,829	49.3	91.9	75.7	7,419	GAS	2,676,300	1,027,994	2,751,220.0	26,090,713	7.04	9.75
23. BAYSIDE TOTAL	**1,838**	**616,335**	**46.6**	**82.9**	**37.2**	**7,379**	**GAS**	**4,424,100**	**1,027,990**	**4,547,930.0**	**43,129,666**	**7.00**	**9.75**
24. B.B.C.T.#1	13	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25. B.B.C.T.#2	80	0	0.0	66.0	0.0	0	LGT OIL	1	5,000,000	5.0	77	0.00	77.00
26. B.B.C.T.#3	45	0	0.0	66.0	0.0	0	LGT OIL	0	0	2.0	0	0.00	0.00
27. C.T. TOTAL (OIL)	**138**	**0**	**0.0**	**69.2**	**0.0**	**0**	**LGT OIL**	**1**	**7,000,000**	**7.0**	**77**	**0.00**	**77.00**
28. TOT COAL (BB,POLK)	**1,882**	**865,243**	**63.9**	**53.4**	**23.2**	**10,611**	**COAL**	**384,330**	**23,889,114**	**9,181,303.0**	**24,363,321**	**2.82**	**63.39**
29. SYSTEM	**4,625**	**1,487,643**	**44.7**	**77.9**	**10.7**	**9,280**	-	**-**	**-**	**13,805,890.0**	**68,255,914**	**4.59**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: DECEMBER 2008

	(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	188,617	65.8	66.0	91.4	10,560	COAL	85,413	23,320,103	1,991,840.0	5,272,809	2.80	61.73
2.	B.B.#2	395	6,271	2.1	2.2	93.4	10,632	COAL	2,760	24,157,246	66,674.0	170,383	2.72	61.73
3.	B.B.#3	400	227,985	76.6	76.9	91.0	10,611	COAL	103,734	23,319,934	2,419,070.0	6,403,821	2.81	61.73
4.	B.B.#4	442	262,222	79.7	80.0	88.3	10,602	COAL	119,219	23,319,941	2,780,180.0	7,359,758	2.81	61.73
5.	**B.B. STA.**	**1,622**	**685,095**	**56.8**	**57.0**	**22.8**	**10,594**	**COAL**	**311,126**	**23,327,411**	**7,257,764.0**	**19,206,771**	**2.80**	**61.73**
6.	PHILLIPS #1 (HVY OIL)	18	907	6.8	100.0	52.5	19,557	HVY OIL	1,404	12,633,903	17,738.0	89,517	9.87	63.76
7.	PHILLIPS #2 (HVY OIL)	18	918	6.9	100.0	52.6	19,322	HVY OIL	1,421	12,482,759	17,738.0	90,601	9.87	63.76
8.	**SEB-PHILLIPS TOTAL**	**36**	**1,825**	**6.8**	**100.0**	**26.3**	**19,439**	**HVY OIL**	**2,825**	**12,557,876**	**35,476.0**	**180,118**	**9.87**	**63.76**
9.	POLK #1 GASIFIER	260	116,531	60.2	-	-	10,594	COAL	47,728	25,865,173	1,234,493.0	3,428,379	2.94	71.83
10.	POLK #1 CT OIL	245	3,604	2.0	-	-	10,579	LGT OIL	6,578	5,796,291	38,128.0	480,955	13.35	73.12
11.	**POLK #1 TOTAL**	**260**	**120,135**	**62.1**	**78.6**	**90.4**	**10,593**		**-**	**-**	**1,272,621.0**	**3,909,334**	**3.25**	**-**
12.	POLK #2 CT GAS	175	231	0.2	-	-	15,242	GAS	3,400	1,035,588	3,521.0	34,358	14.87	10.11
13.	POLK #2 CT OIL	184	12	0.0	-	-	13,250	LGT OIL	0	0	159.0	0	0.00	0.00
14.	**POLK #2 TOTAL**	**184**	**243**	**0.2**	**100.0**	**44.0**	**15,144**		**-**	**-**	**3,680.0**	**34,358**	**14.14**	**-**
15.	POLK #3 CT GAS	175	153	0.1	0.0	-	16,137	GAS	2,400	1,028,750	2,469.0	24,253	15.85	10.11
16.	POLK #3 CT OIL	184	8	0.0	0.0	-	13,000	LGT OIL	0	0	104.0	0	0.00	0.00
17.	**POLK #3 TOTAL**	**184**	**161**	**0.1**	**100.0**	**43.8**	**15,981**		**-**	**-**	**2,573.0**	**24,253**	**15.06**	**-**
18.	**POLK #4 CT GAS**	**180**	**740**	**0.6**	**100.0**	**45.7**	**13,943**	**GAS**	**10,000**	**1,031,800**	**10318.0**	**101,054**	**13.66**	**10.11**
19.	**POLK #5 CT GAS**	**180**	**520**	**0.4**	**100.0**	**48.1**	**14,219**	**GAS**	**7,200**	**1,026,944**	**7394.0**	**72,759**	**13.99**	**10.11**
20.	**CITY OF TAMPA GAS**	**3**	**58**	**2.6**	**100.0**	**39.5**	**10,466**	GAS	**600**	1,011,667	**607.0**	**6,779**	**11.69**	**11.30**
21.	BAYSIDE #1	793	430,022	72.9	92.6	84.2	7,263	GAS	3,038,300	1,028,012	3,123,410.0	30,703,237	7.14	10.11
22.	BAYSIDE #2	1,045	307,618	39.6	71.1	73.4	7,424	GAS	2,221,700	1,027,970	2,283,840.0	22,451,167	7.30	10.11
23.	**BAYSIDE TOTAL**	**1,838**	**737,640**	**53.9**	**80.4**	**38.4**	**7,330**	**GAS**	**5,260,000**	**1,027,994**	**5,407,250.0**	**53,154,404**	**7.21**	**10.11**
24.	B.B.C.T.#1	13	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
25.	B.B.C.T.#2	80	1	0.0	66.0	0.0	13,000	LGT OIL	2	6,500,000	13.0	221	22.10	110.50
26.	B.B.C.T.#3	45	0	0.0	66.0	0.0	0	LGT OIL	1	4,000,000	4.0	110	0.00	110.00
27.	**C.T. TOTAL (OIL)**	**138**	**1**	**0.0**	**69.2**	**0.0**	**17,000**	**LGT OIL**	**3**	**5,666,667**	**17.0**	**331**	**33.10**	**110.33**
28.	**TOT COAL (BB,POLK)**	**1,882**	**801,626**	**57.3**	**49.1**	**23.0**	**10,594**	**COAL**	**358,854**	**23,664,936**	**8,492,257.0**	**22,635,150**	**2.82**	**63.08**
29.	**SYSTEM**	**4,625**	**1,546,418**	**44.9**	**75.0**	**10.6**	**9,052**	**-**	**-**	**-**	**13,997,700.0**	**76,690,161**	**4.96**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY

SCHEDULE E5

ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH JUNE 2008

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	2,814	2,302	4,390	8,739	3,803	12,277
3. UNIT COST ($/BBL)	63.38	63.38	60.55	60.55	60.55	57.79
4. AMOUNT ($)	178,352	145,901	265,835	529,187	230,289	709,511
5. BURNED:						
6. UNITS (BBL)	2,814	2,302	4,390	8,739	3,803	12,277
7. UNIT COST ($/BBL)	56.19	57.99	57.91	58.48	60.77	58.92
8. AMOUNT ($)	158,113	133,494	254,212	511,014	231,090	723,396
9. ENDING INVENTORY:						
10. UNITS (BBL)	15,325	15,325	15,325	15,325	15,325	15,325
11. UNIT COST ($/BBL)	52.30	53.75	55.26	57.19	57.86	57.83
12. AMOUNT ($)	801,495	823,672	846,906	876,361	886,631	886,206
13. DAYS SUPPLY:	159	159	163	187	178	219
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	12,333	6,301	9,749	12,670	13,765	13,971
16. UNIT COST ($/BBL)	73.08	72.21	71.25	70.27	69.88	70.00
17. AMOUNT ($)	901,305	455,011	694,664	890,345	961,891	977,977
18. BURNED:						
19. UNITS (BBL)	12,333	6,301	9,749	12,670	13,765	13,971
20. UNIT COST ($/BBL)	54.36	32.73	47.70	49.07	50.26	49.93
21. AMOUNT ($)	670,369	206,215	465,038	621,669	691,870	697,616
22. ENDING INVENTORY:						
23. UNITS (BBL)	101,727	101,727	101,727	101,727	101,727	101,727
24. UNIT COST ($/BBL)	80.76	80.27	79.60	78.73	77.91	77.20
25. AMOUNT ($)	8,215,748	8,166,052	8,097,652	8,009,354	7,925,970	7,853,650
26. DAYS SUPPLY: NORMAL	252	247	252	255	257	261
27. DAYS SUPPLY: EMERGENCY	15	15	15	15	15	15
COAL						
28. PURCHASES:						
29. UNITS (TONS)	417,600	358,550	350,800	401,000	457,200	456,000
30. UNIT COST ($/TON)	61.06	61.25	62.28	62.34	62.52	62.24
31. AMOUNT ($)	25,497,593	21,962,549	21,848,196	24,999,825	28,582,080	28,379,325
32. BURNED:						
33. UNITS (TONS)	356,437	295,515	340,215	417,074	449,124	440,290
34. UNIT COST ($/TON)	62.77	62.49	63.23	63.54	63.37	63.15
35. AMOUNT ($)	22,374,244	18,468,037	21,510,561	26,502,356	28,459,367	27,804,296
36. ENDING INVENTORY:						
37. UNITS (TONS)	479,871	542,906	553,491	537,417	545,493	561,203
38. UNIT COST ($/TON)	61.00	61.21	61.38	61.29	61.49	61.61
39. AMOUNT ($)	29,270,483	33,229,156	33,973,307	32,935,938	33,542,367	34,575,256
40. DAYS SUPPLY:	41	41	39	38	41	44
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	3,553,400	4,715,000	4,038,400	2,899,200	6,088,000	6,297,400
43. UNIT COST ($/MCF)	11.17	10.55	9.50	9.83	9.29	9.39
44. AMOUNT ($)	39,693,381	49,725,454	38,348,662	28,486,788	56,545,902	59,134,352
45. BURNED:						
46. UNITS (MCF)	3,553,400	4,715,000	4,038,400	2,899,200	6,088,000	6,297,400
47. UNIT COST ($/MCF)	11.17	10.55	9.50	9.83	9.29	9.39
48. AMOUNT ($)	39,693,382	49,725,454	38,348,661	28,486,789	56,545,902	59,134,353
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
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.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY

SCHEDULE E5

ESTIMATED FOR THE PERIOD: JULY 2008 THROUGH DECEMBER 2008

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	15,738	16,379	12,805	4,470	2,014	2,825	88,556
3.	UNIT COST ($/BBL)	57.79	57.79	60.55	60.55	60.55	63.38	59.42
4.	AMOUNT ($)	909,529	946,574	775,403	270,679	121,957	179,049	5,262,266
5.	BURNED:							
6.	UNITS (BBL)	15,738	16,379	12,805	4,470	2,014	2,825	88,556
7.	UNIT COST ($/BBL)	58.75	58.72	60.11	61.83	63.16	63.76	59.30
8.	AMOUNT ($)	924,630	961,762	769,708	276,392	127,202	180,118	5,251,131
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	15,325	15,325	15,325	15,325	15,325	15,325	15,325
11.	UNIT COST ($/BBL)	57.81	57.80	59.05	59.39	59.53	60.13	60.13
12.	AMOUNT ($)	885,937	885,802	905,017	910,210	912,278	921,468	921,468
13.	DAYS SUPPLY:	174	139	113	94	79	68	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	16,285	16,382	12,885	13,391	12,556	9,725	150,013
16.	UNIT COST ($/BBL)	70.58	71.34	72.15	72.87	73.51	73.88	71.64
17.	AMOUNT ($)	1,149,468	1,168,639	929,642	975,868	923,023	718,523	10,746,356
18.	BURNED:							
19.	UNITS (BBL)	16,285	16,382	12,885	13,391	12,556	9,725	150,013
20.	UNIT COST ($/BBL)	52.91	53.01	50.04	46.66	47.67	49.49	49.54
21.	AMOUNT ($)	861,659	868,416	644,726	624,844	598,561	481,286	7,432,269
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	101,727	101,727	101,727	101,727	101,727	101,727	101,727
24.	UNIT COST ($/BBL)	76.58	76.11	75.83	75.61	75.50	75.45	75.45
25.	AMOUNT ($)	7,790,447	7,742,050	7,713,680	7,691,699	7,679,889	7,675,121	7,675,121
26.	DAYS SUPPLY: NORMAL	266	271	273	277	284	282	-
27.	DAYS SUPPLY: EMERGENCY	15	15	15	15	15	15	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	462,400	462,400	401,000	402,300	351,400	333,200	4,853,850
30.	UNIT COST ($/TON)	62.04	62.09	62.51	62.44	62.97	61.96	62.14
31.	AMOUNT ($)	28,688,187	28,708,769	25,066,516	25,119,113	22,129,047	20,645,437	301,626,637
32.	BURNED:							
33.	UNITS (TONS)	458,208	457,328	409,254	440,715	384,330	358,854	4,807,344
34.	UNIT COST ($/TON)	63.10	62.87	63.02	63.08	63.39	63.08	63.11
35.	AMOUNT ($)	28,910,885	28,753,585	25,790,309	27,799,278	24,363,321	22,635,150	303,371,389
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	565,395	570,467	562,213	523,798	490,868	465,214	465,214
38.	UNIT COST ($/TON)	61.70	61.90	62.27	62.68	63.24	63.21	63.21
39.	AMOUNT ($)	34,884,620	35,313,945	35,008,278	32,830,924	31,044,455	29,406,114	29,406,114
40.	DAYS SUPPLY:	45	44	43	40	37	35	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	7,365,800	7,513,200	6,449,200	5,442,700	4,427,900	5,283,600	64,073,800
43.	UNIT COST ($/MCF)	9.61	9.72	9.72	9.37	9.75	10.11	9.77
44.	AMOUNT ($)	70,773,662	73,029,199	62,674,256	51,020,102	43,166,828	53,393,608	625,992,194
45.	BURNED:							
46.	UNITS (MCF)	7,365,800	7,513,200	6,449,200	5,442,700	4,427,900	5,283,600	64,073,800
47.	UNIT COST ($/MCF)	9.61	9.72	9.72	9.37	9.75	10.11	9.77
48.	AMOUNT ($)	70,773,664	73,029,201	62,674,256	51,020,102	43,166,830	53,393,607	625,992,201
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	0	0	0	0	0	0	0
51.	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52.	AMOUNT ($)	0	0	0	0	0	0	0
53.	DAYS SUPPLY:	0	0	0	0	0	0	-
	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.

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

SCHEDULE E6

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-08	SEMINOLE	JURISD.	SCH. -D	1,059.0	0.0	1,059.0	6.648	7.309	70,400.00	77,400.00	7,000.00
	VARIOUS	JURISD.	MKT. BASE	5,408.0	0.0	5,408.0	4.852	7.291	262,400.00	394,300.00	112,300.00
	TOTAL			**6,467.0**	**0.0**	**6,467.0**	**5.146**	**7.294**	**332,800.00**	**471,700.00**	**119,300.00**
Feb-08	SEMINOLE	JURISD.	SCH. -D	991.0	0.0	991.0	6.932	7.366	68,700.00	73,000.00	4,300.00
	VARIOUS	JURISD.	MKT. BASE	9,865.0	0.0	9,865.0	7.025	8.454	693,000.00	834,000.00	105,300.00
	TOTAL			**10,856.0**	**0.0**	**10,856.0**	**7.016**	**8.355**	**761,700.00**	**907,000.00**	**109,600.00**
Mar-08	SEMINOLE	JURISD.	SCH. -D	1,060.0	0.0	1,060.0	6.236	6.858	66,100.00	72,700.00	6,600.00
	VARIOUS	JURISD.	MKT. BASE	450.0	0.0	450.0	2.822	5.000	12,700.00	22,500.00	8,200.00
	TOTAL			**1,510.0**	**0.0**	**1,510.0**	**5.219**	**6.305**	**78,800.00**	**95,200.00**	**14,800.00**
Apr-08	SEMINOLE	JURISD.	SCH. -D	1,021.0	0.0	1,021.0	4.956	5.455	50,600.00	55,700.00	5,100.00
	VARIOUS	JURISD.	MKT. BASE	8,806.0	0.0	8,806.0	2.685	5.304	236,400.00	467,100.00	198,800.00
	TOTAL			**9,827.0**	**0.0**	**9,827.0**	**2.921**	**5.320**	**287,000.00**	**522,800.00**	**203,900.00**
May-08	SEMINOLE	JURISD.	SCH. -D	1,021.0	0.0	1,021.0	4.114	4.525	42,000.00	46,200.00	4,200.00
	VARIOUS	JURISD.	MKT. BASE	15,703.0	0.0	15,703.0	3.381	5.659	530,900.00	888,600.00	300,900.00
	TOTAL			**16,724.0**	**0.0**	**16,724.0**	**3.426**	**5.590**	**572,900.00**	**934,800.00**	**305,100.00**
Jun-08	SEMINOLE	JURISD.	SCH. -D	834.0	0.0	834.0	4.724	5.192	39,400.00	43,300.00	3,900.00
	VARIOUS	JURISD.	MKT. BASE	12,695.0	0.0	12,695.0	4.129	6.300	524,200.00	799,800.00	229,600.00
	TOTAL			**13,529.0**	**0.0**	**13,529.0**	**4.166**	**6.232**	**563,600.00**	**843,100.00**	**233,500.00**
Jul-08	SEMINOLE	JURISD.	SCH. -D	844.0	0.0	844.0	5.190	5.711	43,800.00	48,200.00	4,400.00
	VARIOUS	JURISD.	MKT. BASE	10,458.0	0.0	10,458.0	4.527	6.744	473,400.00	705,300.00	194,000.00
	TOTAL			**11,302.0**	**0.0**	**11,302.0**	**4.576**	**6.667**	**517,200.00**	**753,500.00**	**198,400.00**
Aug-08	SEMINOLE	JURISD.	SCH. -D	844.0	0.0	844.0	5.723	6.291	48,300.00	53,100.00	4,800.00
	VARIOUS	JURISD.	MKT. BASE	10,970.0	0.0	10,970.0	5.491	7.614	602,400.00	835,300.00	193,200.00
	TOTAL			**11,814.0**	**0.0**	**11,814.0**	**5.508**	**7.520**	**650,700.00**	**888,400.00**	**198,000.00**
Sep-08	SEMINOLE	JURISD.	SCH. -D	814.0	0.0	814.0	5.197	5.725	42,300.00	46,600.00	4,300.00
	VARIOUS	JURISD.	MKT. BASE	22,016.0	0.0	22,016.0	5.622	7.229	1,237,700.00	1,591,600.00	274,200.00
	TOTAL			**22,830.0**	**0.0**	**22,830.0**	**5.607**	**7.176**	**1,280,000.00**	**1,638,200.00**	**278,500.00**
Oct-08	SEMINOLE	JURISD.	SCH. -D	824.0	0.0	824.0	4.466	4.915	36,800.00	40,500.00	3,700.00
	VARIOUS	JURISD.	MKT. BASE	10,767.0	0.0	10,767.0	3.669	5.853	395,000.00	630,200.00	196,200.00
	TOTAL			**11,591.0**	**0.0**	**11,591.0**	**3.725**	**5.786**	**431,800.00**	**670,700.00**	**199,900.00**
Nov-08	SEMINOLE	JURISD.	SCH. -D	716.0	0.0	716.0	4.316	4.749	30,900.00	34,000.00	3,100.00
	VARIOUS	JURISD.	MKT. BASE	11,460.0	0.0	11,460.0	3.241	5.761	371,400.00	660,200.00	247,300.00
	TOTAL			**12,176.0**	**0.0**	**12,176.0**	**3.304**	**5.701**	**402,300.00**	**694,200.00**	**250,400.00**
Dec-08	SEMINOLE	JURISD.	SCH. -D	785.0	0.0	785.0	5.949	6.548	46,700.00	51,400.00	4,700.00
	VARIOUS	JURISD.	MKT. BASE	5,558.0	0.0	5,558.0	5.723	7.366	318,100.00	409,400.00	71,200.00
	TOTAL			**6,343.0**	**0.0**	**6,343.0**	**5.751**	**7.265**	**364,800.00**	**460,800.00**	**75,900.00**
Jan-08	SEMINOLE	JURISD.	SCH. -D	10,813.0	0.0	10,813.0	5.419	5.938	586,000.00	642,100.00	56,100.00
THRU	VARIOUS	JURISD.	MKT. BASE	124,156.0	0.0	124,156.0	4.557	6.635	5,657,600.00	8,238,300.00	2,131,200.00
Dec-08	TOTAL			**134,969.0**	**0.0**	**134,969.0**	**4.626**	**6.580**	**6,243,600.00**	**8,880,400.00**	**2,187,300.00**

SCHEDULE E7

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH JUNE 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-08									
	HPP	IPP	12,017.0	0.0	0.0	12,017.0	12.893	12.893	1,549,300.00
	CALPINE	SCH. D	1,334.0	0.0	0.0	1,334.0	13.463	13.463	179,600.00
	OTHER	SCH. D	3,913.0	0.0	0.0	3,913.0	14.682	14.682	574,500.00
	TOTAL		**17,264.0**	**0.0**	**0.0**	**17,264.0**	**13.342**	**13.342**	**2,303,400.00**
Feb-08									
	HPP	IPP	8,621.0	0.0	0.0	8,621.0	13.519	13.519	1,165,500.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	OTHER	SCH. D	2,594.0	0.0	0.0	2,594.0	14.013	14.013	363,500.00
	TOTAL		**11,215.0**	**0.0**	**0.0**	**11,215.0**	**13.634**	**13.634**	**1,529,000.00**
Mar-08									
	HPP	IPP	33,324.0	0.0	0.0	33,324.0	8.693	8.693	2,896,800.00
	CALPINE	SCH. D	190.0	0.0	0.0	190.0	12.895	12.895	24,500.00
	OTHER	SCH. D	2,472.0	0.0	0.0	2,472.0	12.367	12.367	305,700.00
	TOTAL		**35,986.0**	**0.0**	**0.0**	**35,986.0**	**8.967**	**8.967**	**3,227,000.00**
Apr-08									
	HPP	IPP	47,233.0	0.0	0.0	47,233.0	8.517	8.517	4,022,900.00
	CALPINE	SCH. D	82.0	0.0	0.0	82.0	11.341	11.341	9,300.00
	OTHER	SCH. D	970.0	0.0	0.0	970.0	11.804	11.804	114,500.00
	TOTAL		**48,285.0**	**0.0**	**0.0**	**48,285.0**	**8.588**	**8.588**	**4,146,700.00**
May-08									
	HPP	IPP	47,608.0	0.0	0.0	47,608.0	8.154	8.154	3,881,900.00
	CALPINE	SCH. D	4,246.0	0.0	0.0	4,246.0	11.493	11.493	488,000.00
	OTHER	SCH. D	8,168.0	0.0	0.0	8,168.0	12.725	12.725	1,039,400.00
	TOTAL		**60,022.0**	**0.0**	**0.0**	**60,022.0**	**9.012**	**9.012**	**5,409,300.00**
Jun-08									
	HPP	IPP	60,214.0	0.0	0.0	60,214.0	8.172	8.172	4,920,900.00
	CALPINE	SCH. D	3,932.0	0.0	0.0	3,932.0	11.694	11.694	459,800.00
	OTHER	SCH. D	8,324.0	0.0	0.0	8,324.0	12.268	12.268	1,021,200.00
	TOTAL		**72,470.0**	**0.0**	**0.0**	**72,470.0**	**8.834**	**8.834**	**6,401,900.00**

SCHEDULE E7

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2008 THROUGH DECEMBER 2 008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jul-08									
	HPP	IPP	68,870.0	0.0	0.0	68,870.0	8.343	8.343	5,745,700.00
	CALPINE	SCH. D	7,617.0	0.0	0.0	7,617.0	12.091	12.091	921,000.00
	OTHER	SCH. D	22,212.0	0.0	0.0	22,212.0	11.449	11.449	2,543,100.00
	TOTAL		**98,699.0**	**0.0**	**0.0**	**98,699.0**	**9.331**	**9.331**	**9,209,800.00**
Aug-08									
	HPP	IPP	71,055.0	0.0	0.0	71,055.0	8.455	8.455	6,007,400.00
	CALPINE	SCH. D	8,525.0	0.0	0.0	8,525.0	12.231	12.231	1,042,700.00
	OTHER	SCH. D	27,279.0	0.0	0.0	27,279.0	11.423	11.423	3,116,100.00
	TOTAL		**106,859.0**	**0.0**	**0.0**	**106,859.0**	**9.514**	**9.514**	**10,166,200.00**
Sep-08									
	HPP	IPP	59,825.0	0.0	0.0	59,825.0	8.487	8.487	5,077,400.00
	CALPINE	SCH. D	2,177.0	0.0	0.0	2,177.0	12.435	12.435	270,700.00
	OTHER	SCH. D	3,973.0	0.0	0.0	3,973.0	12.935	12.935	513,900.00
	TOTAL		**65,975.0**	**0.0**	**0.0**	**65,975.0**	**8.885**	**8.885**	**5,862,000.00**
Oct-08									
	HPP	IPP	22,971.0	0.0	0.0	22,971.0	8.595	8.595	1,974,400.00
	CALPINE	SCH. D	164.0	0.0	0.0	164.0	13.476	13.476	22,100.00
	OTHER	SCH. D	1,294.0	0.0	0.0	1,294.0	12.419	12.419	160,700.00
	TOTAL		**24,429.0**	**0.0**	**0.0**	**24,429.0**	**8.830**	**8.830**	**2,157,200.00**
Nov-08									
	HPP	IPP	17,921.0	0.0	0.0	17,921.0	9.214	9.214	1,651,200.00
	CALPINE	SCH. D	1.0	0.0	0.0	1.0	10.000	10.000	100.00
	OTHER	SCH. D	402.0	0.0	0.0	402.0	14.204	14.204	57,100.00
	TOTAL		**18,324.0**	**0.0**	**0.0**	**18,324.0**	**9.323**	**9.323**	**1,708,400.00**
Dec-08									
	HPP	IPP	13,904.0	0.0	0.0	13,904.0	11.374	11.374	1,581,500.00
	CALPINE	SCH. D	374.0	0.0	0.0	374.0	12.620	12.620	47,200.00
	OTHER	SCH. D	1,092.0	0.0	0.0	1,092.0	13.370	13.370	146,000.00
	TOTAL		**15,370.0**	**0.0**	**0.0**	**15,370.0**	**11.547**	**11.547**	**1,774,700.00**
Jan-08	HPP	IPP	463,563.0	0.0	0.0	463,563.0	8.731	8.731	40,474,900.00
THRU	CALPINE	SCH. D	28,642.0	0.0	0.0	28,642.0	12.098	12.098	3,465,000.00
Dec-08	OTHER	SCH. D	82,693.0	0.0	0.0	82,693.0	12.039	12.039	9,955,700.00
	TOTAL		**574,898.0**	**0.0**	**0.0**	**574,898.0**	**9.375**	**9.375**	**53,895,600.00**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH JUNE 2008

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUST-MENT
Jan-08	VARIOUS	CO-GEN.	54,828.0	0.0	0.0	54,828.0	4.310	4.310	2,363,000.00
Feb-08	VARIOUS	CO-GEN.	49,688.0	0.0	0.0	49,688.0	4.272	4.272	2,122,700.00
Mar-08	VARIOUS	CO-GEN.	54,828.0	0.0	0.0	54,828.0	3.986	3.986	2,185,400.00
Apr-08	VARIOUS	CO-GEN.	54,946.0	0.0	0.0	54,946.0	4.354	4.354	2,392,100.00
May-08	VARIOUS	CO-GEN.	56,799.0	0.0	0.0	56,799.0	4.119	4.119	2,339,700.00
Jun-08	VARIOUS	CO-GEN.	54,946.0	0.0	0.0	54,946.0	4.400	4.400	2,417,700.00
Jul-08	VARIOUS	CO-GEN.	56,799.0	0.0	0.0	56,799.0	4.573	4.573	2,597,600.00
Aug-08	VARIOUS	CO-GEN.	56,799.0	0.0	0.0	56,799.0	4.954	4.954	2,813,900.00
Sep-08	VARIOUS	CO-GEN.	54,946.0	0.0	0.0	54,946.0	5.453	5.453	2,996,400.00
Oct-08	VARIOUS	CO-GEN.	56,799.0	0.0	0.0	56,799.0	4.172	4.172	2,369,900.00
Nov-08	VARIOUS	CO-GEN.	53,038.0	0.0	0.0	53,038.0	4.066	4.066	2,156,500.00
Dec-08	VARIOUS	CO-GEN.	54,828.0	0.0	0.0	54,828.0	4.289	4.289	2,351,600.00
TOTAL			**659,244.0**	**0.0**	**0.0**	**659,244.0**	**4.415**	**4.415**	**29,106,500.00**

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH JUNE 2008

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-08	VARIOUS	SCH. - J / MB	307,426.0	38.0	307,388.0	7.359	22,624,500.00	7.359	22,624,500.00	0.00
Feb-08	VARIOUS	SCH. - J / MB	106,487.0	1.0	106,486.0	7.542	8,030,900.00	7.542	8,030,900.00	0.00
Mar-08	VARIOUS	SCH. - J / MB	191,028.0	36.0	190,992.0	6.829	13,044,400.00	6.829	13,044,400.00	0.00
Apr-08	VARIOUS	SCH. - J / MB	202,885.0	428.0	202,457.0	7.903	16,033,000.00	7.903	16,033,000.00	0.00
May-08	VARIOUS	SCH. - J / MB	51,791.0	66.0	51,725.0	8.193	4,243,400.00	8.193	4,243,400.00	0.00
Jun-08	VARIOUS	SCH. - J / MB	112,508.0	298.0	112,210.0	8.004	9,005,100.00	8.004	9,005,100.00	0.00
Jul-08	VARIOUS	SCH. - J / MB	60,295.0	686.0	59,609.0	9.091	5,481,500.00	9.091	5,481,500.00	0.00
Aug-08	VARIOUS	SCH. - J / MB	55,524.0	792.0	54,732.0	9.362	5,198,300.00	9.362	5,198,300.00	0.00
Sep-08	VARIOUS	SCH. - J / MB	109,985.0	334.0	109,651.0	9.509	10,458,100.00	9.509	10,458,100.00	0.00
Oct-08	VARIOUS	SCH. - J / MB	53,896.0	24.0	53,872.0	8.270	4,457,400.00	8.270	4,457,400.00	0.00
Nov-08	VARIOUS	SCH. - J / MB	39,700.0	8.0	39,692.0	7.667	3,043,700.00	7.667	3,043,700.00	0.00
Dec-08	VARIOUS	SCH. - J / MB	72,748.0	3.0	72,745.0	7.462	5,428,600.00	7.462	5,428,600.00	0.00
TOTAL			**1,364,273.0**	**2,714.0**	**1,361,559.0**	**7.847**	**107,048,900.00**	**7.847**	**107,048,900.00**	**0.00**

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

SCHEDULE E10

	Current Jan 07 - Dec 07	Projected Jan 08 - Dec 08	Difference $	Difference %
Base Rate Revenue	$51.92	$51.92	0.00	0%
Fuel Recovery Revenue	59.22	52.41	-6.81	-11%
Conservation Revenue	0.73	0.98	0.25	34%
Capacity Revenue	3.25	5.17	1.92	59%
Environmental Revenue	(3.44)	1.04	4.48	-130%
Florida Gross Receipts Tax Revenue	2.86	2.86	0.00	0%
TOTAL REVENUE	**$114.54**	**$114.38**	**($0.16)**	**0%**

CAPACITY COSTS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2008 THROUGH DECEMBER 2008

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
HILLSBOROUGH COUNTY	1/10/1985	3/1/2010	QF
HARDEE POWER PARTNERS	1/1/1993	12/31/2012	LT
SEMINOLE ELECTRIC	6/1/1992	**	LT
CALPINE	5/1/2006	4/30/2011	LT
OTHER NON-FIRM	12/1/2007	3/31/2008	ST

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	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	19.0	19.0	19.0	19.0
HILLSBOROUGH COUNTY	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
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	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0
SEMINOLE ELECTRIC	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
CALPINE	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
OTHER NON-FIRM	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0

CAPACITY YEAR 2008	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
MCKAY BAY REFUSE	317,800	297,300	317,800	307,600	317,800	307,600	317,800	317,800	307,600	317,800	307,600	317,800	3,752,300
HILLSBOROUGH COUNTY	1,046,900	979,300	1,046,900	1,013,100	1,046,900	1,013,100	1,046,900	1,046,900	1,013,100	1,046,900	1,013,100	1,046,900	12,360,000
ORANGE COGEN LP	853,800	798,700	853,800	826,300	853,800	826,300	853,800	853,800	826,300	853,800	826,300	853,800	10,080,500
TOTAL COGENERATION	2,218,500	2,075,300	2,218,500	2,147,000	2,218,500	2,147,000	2,218,500	2,218,500	2,147,000	2,218,500	2,147,000	2,218,500	26,192,800
HARDEE POWER PARTNERS	[redacted]												
CALPINE - D													
OTHER NON-FIRM													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	3,691,700	3,685,300	3,654,300	2,884,900	2,865,100	2,879,400	2,887,100	2,891,300	2,870,100	2,880,400	2,920,700	2,941,900	37,052,200
TOTAL CAPACITY	$5,910,200	$5,760,600	$5,872,800	$5,031,900	$5,083,600	$5,026,400	$5,105,600	$5,109,800	$5,017,100	$5,098,900	$5,067,700	$5,160,400	$63,245,000

47

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY

SCHEDULE H1

PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2005	ACTUAL 2006	ACT/EST 2007	EST 2008	DIFFERENCE (%) 2006-2005	2007-2006	2008-2007
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	5,541,213	2,899,288	4,587,135	5,251,131	-47.7%	58.2%	14.5%
2 LIGHT OIL [1]	8,087,271	6,750,918	7,226,065	7,432,269	-16.5%	7.0%	2.9%
3 COAL	233,255,198	292,472,009	286,540,040	303,371,389	25.4%	-2.0%	5.9%
4 NATURAL GAS	528,761,324	513,398,597	581,718,254	625,992,201	-2.9%	13.3%	7.6%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**775,645,006**	**815,520,812**	**880,071,494**	**942,046,990**	**5.1%**	**7.9%**	**7.0%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	70,843	28,562	51,259	57,144	-59.7%	79.5%	11.5%
9 LIGHT OIL [1]	64,426	44,642	48,111	54,413	-30.7%	7.8%	13.1%
10 COAL	9,660,298	10,968,579	10,556,022	10,739,070	13.5%	-3.8%	1.7%
11 NATURAL GAS	7,566,524	7,135,589	8,292,713	8,735,870	-5.7%	16.2%	5.3%
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)	**17,362,091**	**18,177,372**	**18,948,105**	**19,586,497**	**4.7%**	**4.2%**	**3.4%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	110,256	46,507	80,240	88,556	-57.8%	72.5%	10.4%
16 LIGHT OIL (BBL) [1]	119,896	80,031	106,820	150,013	-33.2%	33.5%	40.4%
17 COAL (TON)	4,433,133	5,019,962	4,763,140	4,807,344	13.2%	-5.1%	0.9%
18 NATURAL GAS (MCF)	54,391,128	51,742,329	60,317,523	64,073,800	-4.9%	16.6%	6.2%
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]	691,701	291,767	503,693	1,112,074	-57.8%	72.6%	120.8%
22 LIGHT OIL [1]	674,718	453,076	501,033	584,158	-32.8%	10.6%	16.6%
23 COAL	104,591,939	118,342,601	113,154,572	114,335,131	13.1%	-4.4%	1.0%
24 NATURAL GAS	56,454,350	53,483,131	62,130,961	65,867,906	-5.3%	16.2%	6.0%
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)	**162,412,708**	**172,570,575**	**176,290,259**	**181,899,269**	**6.3%**	**2.2%**	**3.2%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.41	0.16	0.27	0.29	-	-	-
29 LIGHT OIL [1]	0.37	0.25	0.25	0.28	-	-	-
30 COAL	55.64	60.33	55.71	54.83	-	-	-
31 NATURAL GAS	43.58	39.26	43.77	44.60	-	-	-
32 NUCLEAR	0.00	0.00	0.00	0.00	-	-	-
33 OTHER	0.00	0.00	0.00	0.00	-	-	-
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**-**	**-**	**-**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	50.26	62.34	57.17	59.30	24.0%	-8.3%	3.7%
36 LIGHT OIL ($/BBL) [1]	67.45	84.35	67.65	49.54	25.1%	-19.8%	-26.8%
37 COAL ($/TON)	52.62	58.26	60.16	63.11	10.7%	3.3%	4.9%
38 NATURAL GAS ($/MCF)	9.72	9.92	9.64	9.77	2.1%	-2.8%	1.3%
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]	8.01	9.94	9.11	4.72	24.1%	-8.4%	-48.2%
42 LIGHT OIL [1]	11.99	14.90	14.42	12.72	24.3%	-3.2%	-11.8%
43 COAL	2.23	2.47	2.53	2.65	10.8%	2.4%	4.7%
44 NATURAL GAS	9.37	9.60	9.36	9.50	2.5%	-2.5%	1.5%
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)	**4.78**	**4.73**	**4.99**	**5.18**	**-1.0%**	**5.5%**	**3.8%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	9,764	10,215	9,826	19,461	4.6%	-3.8%	98.1%
49 LIGHT OIL [1]	10,473	10,149	10,414	10,736	-3.1%	2.6%	3.1%
50 COAL	10,827	10,789	10,719	10,647	-0.4%	-0.6%	-0.7%
51 NATURAL GAS	7,461	7,495	7,492	7,540	0.5%	0.0%	0.6%
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	9,494	9,304	9,287	1.5%	-2.0%	-0.2%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	7.82	10.15	8.95	9.19	29.8%	-11.8%	2.7%
56 LIGHT OIL [1]	12.55	15.12	15.02	13.66	20.5%	-0.7%	-9.1%
57 COAL	2.41	2.67	2.71	2.82	10.8%	1.5%	4.1%
58 NATURAL GAS	6.99	7.19	7.01	7.17	2.9%	-2.5%	2.3%
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)	4.47	4.49	4.64	4.81	0.4%	3.3%	3.7%

[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. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2008 - DECEMBER 2008

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 39
COMPANY Tampa Electric Co
WITNESS Carlos Aldazabal (CA-3)
DATE 11-06-07

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2008 THROUGH DECEMBER 2008
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MWH)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MWH)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)
RS	56.60%	9,337,419	1,883	1.06585	1.04883	9,793,346	2,007	46.06%	56.28%
GS, TS	59.28%	1,104,962	213	1.06585	1.04883	1,158,915	227	5.45%	6.37%
GSD, EV-X	71.68%	5,673,157	903	1.06518	1.04822	5,946,713	962	27.97%	26.98%
GSLD, SBF	84.31%	2,580,295	349	1.05143	1.03725	2,676,401	367	12.59%	10.29%
IS-1&3, SBI-1&3	NA	1,434,558	NA	NA	1.01750	1,459,666	NA	6.86%	NA
SL/OL	770.77%	216,846	3	1.06585	1.04883	227,434	3	1.07%	0.08%
TOTAL		20,347,237	3,351			21,262,475	3,566	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 2004 calendar data.
(2) Projected MWH sales for the period Jan. 2008 thru Dec. 2008.
(3) Calculated: Col (2) / (8760*Col (1)).
(4) Based on 2004 demand losses.
(5) Based on 2004 energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Col (6) / total for Col (6).
(9) Col (7) / total for Col (7).

NOTE: Interruptible rates not included in demand allocation of capacity payments.

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2008 THROUGH DECEMBER 2008
PROJECTED

		Estimated												
		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	3,700,100	3,700,100	3,660,100	2,917,600	2,917,600	2,917,600	2,917,600	2,917,600	2,917,600	2,917,600	2,957,600	2,957,600	37,398,700
2	CAPACITY PAYMENTS TO COGENERATORS	2,218,500	2,075,300	2,218,500	2,147,000	2,218,500	2,147,000	2,218,500	2,218,500	2,147,000	2,218,500	2,147,000	2,218,500	26,192,800
3	SECURITY COSTS	95,487	134,036	261,103	171,981	229,945	349,427	356,446	90,726	89,637	108,760	81,230	98,088	2,066,866
4	(UNIT POWER CAPACITY REVENUES)	(8,400)	(14,800)	(5,800)	(32,700)	(52,500)	(38,200)	(30,500)	(26,300)	(47,500)	(37,200)	(36,900)	(15,700)	(346,500)
5	TOTAL CAPACITY DOLLARS	$6,005,687	$5,894,636	$6,133,903	$5,203,881	$5,313,545	$5,375,827	$5,462,046	$5,200,526	$5,106,737	$5,207,660	$5,148,930	$5,258,488	$65,311,866
6	SEPARATION FACTOR	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
7	JURISDICTIONAL CAPACITY DOLLARS	$5,805,543	$5,698,193	$5,929,486	$5,030,458	$5,136,467	$5,196,674	$5,280,019	$5,027,215	$4,936,551	$5,034,111	$4,977,338	$5,083,245	$63,135,300
8	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2007 - DEC. 2007													23,796,584
9	TOTAL													$86,931,884
10	REVENUE TAX FACTOR													1.00072
11	TOTAL RECOVERABLE CAPACITY DOLLARS													$86,994,475

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2008 THROUGH DECEMBER 2008
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 ($)	(6) PROJECTED SALES AT METER (MWH)	(7) CAPACITY RECOVERY FACTOR ($/MWH)
RS	46.06%	56.28%	3,081,357	45,195,429	48,276,786	9,337,419	5.17
GS, TS	5.45%	6.37%	364,598	5,115,403	5,480,001	1,104,962	4.96
GSD, EV-X	27.97%	26.98%	1,871,158	21,666,181	23,537,339	5,673,157	4.15
GSLD, SBF	12.59%	10.29%	842,255	8,263,343	9,105,598	2,580,295	3.53
IS-1&3, SBI-1&3	6.86%	NA	458,925	0	458,925	1,434,558	0.32
SL/OL	1.07%	0.08%	71,582	64,244	135,826	216,846	0.63
TOTAL	100.00%	100.00%	6,689,875	80,304,600	86,994,475	20,347,237	4.28
			7.69%	92.31%			

NOTE: Using the 12 CP and 1/13th allocation method requires 1/13th or 7.69% of capacity costs to be allocated on the basis of energy, and 12/13th or 92.31% to be allocated on the basis of demand.

2008 Incremental Security O&M Expense

Calculation of 2008 Incremental Security O&M Expense:

Based on Security Expenses at Locations Where Post-9/11 Guards Patrol and Expenses to Comply with Post-9/11 NERC Cyber Security Standards

		2008 Projection
Adjusted Baseline Amount Developed in 2007	$	2,232,959
Multiplied by 2007 Growth Factor		1.0269
2008 Baseline Security O&M Expense Adjusted for Energy Sales Growth		2,293,026
Total Security O&M Expense at Locations Where Post-9/11 Guards Patrol	$	3,619,945
Incremental NERC Cyber-Security Expense		1,281,849
Less Baseline Adjusted for Energy Sales Growth		(2,293,026)
		2,608,768
Base Rate Items that Were Removed		
O&M Savings Associated with Critical Intervention Incremental Expense and Operational Changes		(470,334)
Savings Due to Reduction in Capital Spending		(71,568)
Recoverable Incremental Security O&M Expense [1]	$	2,066,866
Retail Jurisdictional Separation Factor		0.9666743
2008 Recoverable Retail Incremental Security O&M Expense	**$**	**1,997,986**

[1] All incremental security O&M expense is for guard services and NERC cyber security standards.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 40
COMPANY Tampa Electric Co.
WITNESS Carlos Aldazabal (CA-3)
DATE 11-06-07

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

TRUE-UP

JANUARY 2006 THROUGH DECEMBER 2006

TESTIMONY AND EXHIBIT

OF

DAVID R. KNAPP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 41
COMPANY Tampa Electric Co.
WITNESS David R. Knapp (DRK-1)
DATE 11-06-07

DOCKET NO. 070001-EI
GPIF 2006 TRUE-UP
EXHIBIT DRK-1

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

GENERATING PERFORMANCE INCENTIVE FACTOR

INDEX

DOCUMENT NO.	TITLE	BATES PAGE NO.
1	GPIF Schedules	11
2	Actual Unit Performance Data	40

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 070001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2006 - DECEMBER 2006
TRUE-UP

SCHEDULE	PAGE
GPIF REWARD / PENALTY TABLE - ACTUAL	2
GPIF CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS	3
CALCULATIONS OF SYSTEM GPIF POINTS - ACTUAL	4
GPIF TARGET AND RANGE SUMMARY	5
UNIT PERFORMANCE DATA - ACTUAL	6
ADJUSTMENTS TO PERFORMANCE	7 - 11
ADJUSTMENTS TO HEAT RATE	12 - 16
PLANNED OUTAGE SCHEDULE - ACTUAL	17
CRITICAL PATH METHOD DIAGRAMS	18 - 21
GENERATING PERFORMANCE INCENTIVE POINTS TABLES	22 - 26
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE	27
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION	28

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2006 - DECEMBER 2006

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	47,304.8	5,501.4
+9	42,574.3	4,951.3
+8	37,843.8	4,401.1
+7	33,113.4	3,851.0
+6	28,382.9	3,300.8
+5	23,652.4	2,750.7
+4	18,921.9	2,200.6
+3	14,191.4	1,650.4
+2	9,461.0	1,100.3
+1	4,730.5	550.1
0	0.0	0.0
-1	(7,868.1)	(550.1)
-2	(15,736.3)	(1,100.3)
-3	(23,604.4)	(1,650.4)
-4	(31,472.6)	(2,200.6)
-5	(39,340.7)	(2,750.7)
-6	(47,208.9)	(3,300.8)
-7	(55,077.0)	(3,851.0)
-8	(62,945.2)	(4,401.1)
-9	(70,813.3)	(4,951.3)
-10	(78,681.5)	(5,501.4)

GPI POINTS 2.617 ← | → REWARD DOLLARS $1,439,819

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2006 - DECEMBER 2006

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,397,064,560
Line 2	Month of January	2006	$	1,365,249,995
Line 3	Month of February	2006	$	1,372,165,914
Line 4	Month of March	2006	$	1,379,626,548
Line 5	Month of April	2006	$	1,372,714,617
Line 6	Month of May	2006	$	1,386,926,221
Line 7	Month of June	2006	$	1,402,697,771
Line 8	Month of July	2006	$	1,393,886,891
Line 9	Month of August	2006	$	1,415,659,121
Line 10	Month of September	2006	$	1,430,971,591
Line 11	Month of October	2006	$	1,386,239,722
Line 12	Month of November	2006	$	1,443,027,575
Line 13	Month of December	2006	$	1,444,641,084
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,399,297,816
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,699,251
Line 18	Jurisdictional Sales			19,020,146 MWH
Line 19	Total Sales			19,704,144 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			96.53%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,501,411**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2006 - DECEMBER 2006

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	57.4%	EAF	12.33%	-6.268	-0.773
BIG BEND 2	79.7%	EAF	11.47%	6.116	0.702
BIG BEND 3	60.8%	EAF	19.05%	6.285	1.197
BIG BEND 4	76.7%	EAF	13.62%	10.000	1.362
POLK 1	85.6%	EAF	10.20%	10.000	1.020
BIG BEND 1	11,058	ANOHR	5.49%	-3.237	-0.178
BIG BEND 2	10,451	ANOHR	5.89%	0.000	0.000
BIG BEND 3	11,130	ANOHR	6.45%	-2.046	-0.132
BIG BEND 4	11,103	ANOHR	8.49%	-6.841	-0.581
POLK 1	10,442	ANOHR	7.00%	0.000	0.000
			100.00%		2.617

GPIF REWARD	**$ 1,439,819**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	12.33%	63.6	68.6	53.7	5,832.8	(12,556.3)	57.4%	(3,655.7)
BIG BEND 2	11.47%	77.3	81.2	69.3	5,426.4	(11,122.1)	79.7%	3,318.9
BIG BEND 3	19.05%	56.2	63.5	41.6	9,010.8	(16,752.4)	60.8%	10,529.4
BIG BEND 4	13.62%	71.9	76.6	62.4	6,443.0	(12,663.9)	76.7%	12,663.9
POLK 1	10.20%	60.3	67.6	45.8	4,825.5	(9,820.5)	85.6%	9,820.5
GPIF SYSTEM	**66.67%**				**31,538.5**	**(62,915.2)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	5.49%	10,841	75.9	10,327	11,355	2,597.3	(2,597.3)	11,058	(840.9)
BIG BEND 2	5.89%	10,510	84.2	10,074	10,947	2,786.9	(2,786.9)	10,451	0.0
BIG BEND 3	6.45%	10,923	69.1	10,205	11,641	3,053.2	(3,053.2)	11,130	(624.8)
BIG BEND 4	8.49%	10,672	81.6	10,077	11,267	4,018.3	(4,018.3)	11,103	(2,749.0)
POLK 1	7.00%	10,497	88.9	9,330	11,664	3,310.5	(3,310.5)	10,442	0.0
GPIF SYSTEM	**33.33%**					**15,766.3**	**(15,766.3)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2006 - DECEMBER 2006

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	55.2	2.2	57.4
BIG BEND 2	82.8	-3.1	79.7
BIG BEND 3	61.9	-1.1	60.8
BIG BEND 4	74.7	2.0	76.7
POLK 1	78.8	6.8	85.6

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	11,069	-11	11,058
BIG BEND 2	10,395	56	10,451
BIG BEND 3	10,817	313	11,130
BIG BEND 4	11,149	-46	11,103
POLK 1	10,473	-31	10,442

(1) Documentation of adjustments to Actual EAF on pages 7 - 11

(2) Documentation of adjustments to Actual ANOHR on pages 12 - 16

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 1
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 12.33%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	63.6	55.2	57.4
POH	1,344.0	1,621.4	1,344.0
FOH + EFOH	1,452.3	1,811.2	1,881.6
MOH + EMOH	389.7	489.5	508.5
POF	15.3	18.5	15.3
EFOF	16.6	20.7	21.5
EMOF	4.4	5.6	5.8

-6.268 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1344}{8760 - 1621.4} \times (1811.2 + 489.5) = 2390.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 15.3 - \frac{2390.1}{8760.0} \times 100 = 57.4$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 11.47%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	77.3	82.8	79.7
POH	336.0	0.0	336.0
FOH + EFOH	1,286.2	1,242.4	1,194.7
MOH + EMOH	368.6	263.5	253.4
POF	3.8	0.0	3.8
EFOF	14.7	14.2	13.6
EMOF	4.2	3.0	2.9
	6.116	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 336}{8760 - 0} \times (1242.4 + 263.5) = 1448.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{1448.1}{8760.0} \times 100 = 79.7$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 3
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 19.05%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	56.2	61.9	60.8
POH	840.0	695.7	840.0
FOH + EFOH	2,558.8	2,205.4	2,165.9
MOH + EMOH	438.3	436.2	428.4
POF	9.6	7.9	9.6
EFOF	29.2	25.2	24.7
EMOF	5.0	5.0	4.9
	6.285	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 840}{8760 - 695.7} \times (2205.4 + 436.2) = 2594.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 9.6 - \frac{2594.3}{8760.0} \times 100 = 60.8$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 13.62%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	71.9	74.7	76.7
POH	504.0	728.3	504.0
FOH + EFOH	1,930.8	1,271.8	1,307.3
MOH + EMOH	29.2	217.6	223.7
POF	5.8	8.3	5.8
EFOF	22.0	14.5	14.9
EMOF	0.3	2.5	2.6
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 504}{8760 - 728.3} \times (1271.8 + 217.6) = 1531.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.8 - \frac{1531.0}{8760.0} \times 100 = 76.7$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 10.20%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	60.3	78.8	85.6
POH	384.1	1,054.6	384.1
FOH + EFOH	2,984.6	597.5	649.5
MOH + EMOH	106.1	208.8	227.0
POF	4.4	12.0	4.4
EFOF	34.1	6.8	7.4
EMOF	1.2	2.4	2.6
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 384}{8760 - 1054.6} \times (597.5 + 208.8) = 876.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 4.4 - \frac{876.5}{8760.0} \times 100 = 85.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 5.49%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (BTU/KWH)	10,841	11,069
NET GENERATION (GWH)	2,007.8	1,860.9
OPERATING BTU (10^9)	21,766.1	20,599.1
NET OUTPUT FACTOR	75.9	75.4

-3.237 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-20.61) + 12405.19 = ANOHR

75.4 * (-20.61) + 12405.19 = 10,852

11,069 - 10,852 = 217

10,841 + 217 = 11,058 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 5.89%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (BTU/KWH)	10,510	10,395
NET GENERATION (GWH)	2,582.9	2,727.6
OPERATING BTU (10^9)	27,146.5	28,353.8
NET OUTPUT FACTOR	84.2	87.2

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-18.22) + 12043.31 = ANOHR

87.2 * (-18.22) + 12043.31 = 10,455

10,395 - 10,455 = (60)

10,510 + (60) = 10,451 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 6.45%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (BTU/KWH)	10,923	10,817
NET GENERATION (GWH)	1,601.7	2,155.2
OPERATING BTU (10^9)	17,496.5	23,313.0
NET OUTPUT FACTOR	69.1	74.2

-2.046 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-60.84) + 15124.77 = ANOHR

74.2 * (-60.84) + 15124.77 = 10,611

10,817 - 10,611 = 206

10,923 + 206 = 11,130 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 8.49%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (BTU/KWH)	10,672	11,149
NET GENERATION (GWH)	2,605.1	2,677.2
OPERATING BTU (10^9)	27,802.0	29,847.2
NET OUTPUT FACTOR	81.6	78.8

-6.841 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-16.29) + 12001.29 = ANOHR

78.8 * (-16.29) + 12001.29 = 10,718

11,149 - 10,718 = 431

10,672 + 431 = 11,103 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2006 - DECEMBER 2006

WEIGHTING FACTOR = 7.00%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (BTU/KWH)	10,497	10,473
NET GENERATION (GWH)	1,162.3	1,588.8
OPERATING BTU (10^9)	12,201.2	16,640.3
NET OUTPUT FACTOR	88.9	86.7

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-14.06) + 11747.01 = ANOHR

86.7 * (-14.06) + 11747.01 = 10,528

10,473 - 10,528 = (55)

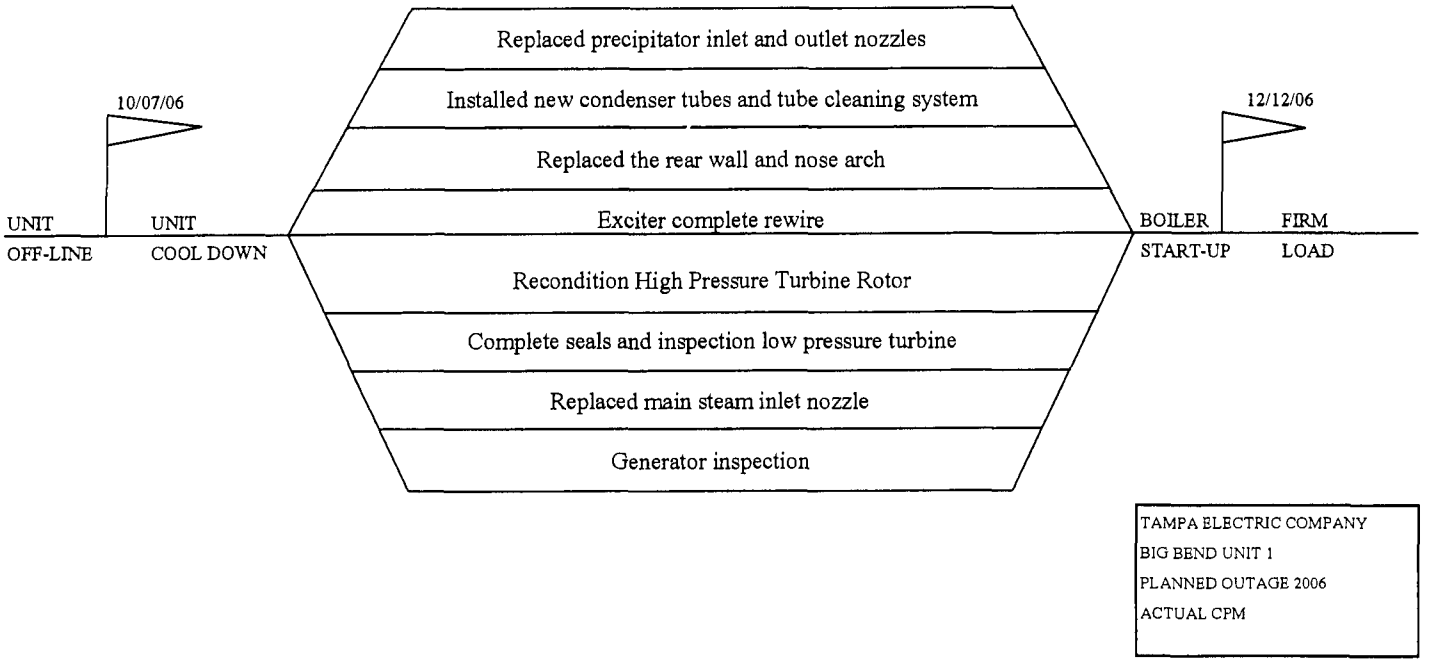
10,497 + (55) = 10,442 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

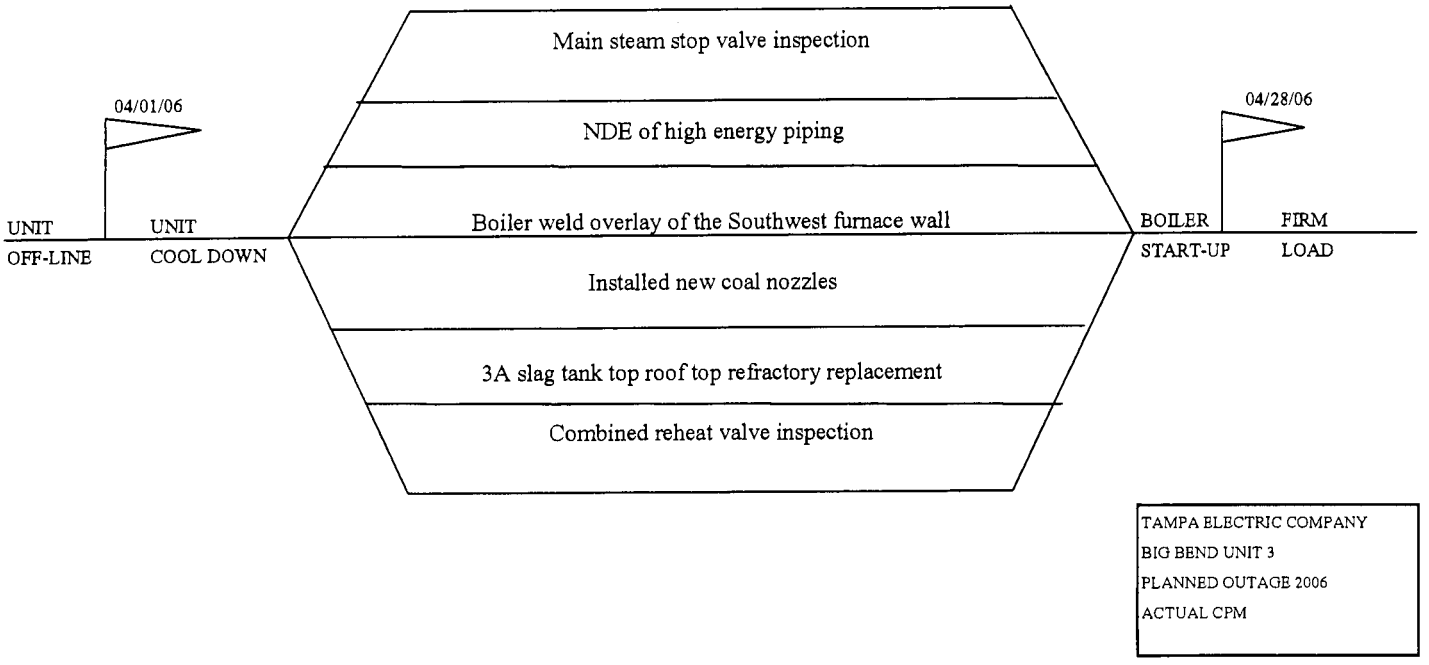
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2006 - DECEMBER 2006

PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
BIG BEND 1	Oct 07 - Dec 12	CP - High Pressure rotor at first and then converted to the exciter at the end of the outage. Other jobs worked include the following: High pressure turbine replaced the 2 control stage blades, main steam inlet nozzle, blade replacement in the reaction stage, complete seals and inspection, intermediate pressure turbine complete seals and inspection, low pressure turbine complete seals and inspection, generator inspection, exciter complete rewire, turbine valve remove and inspection. Work in the boiler includes the following: Replaced rear wall and nose arch, both north and south burner fronts, both north and south windboxes, UT inspection of the boiler and NDE of high energy piping, BOP - 6th point heater, new condenser tubes and tube cleaning system, new coal feeders, precipitator inlet and outlet nozzle replacement.
BIG BEND 3	Apr 01 - Apr 28	CP - Boiler weld overlay of the southwest furnace wall. Other jobs worked during this outage include: new coal nozzles, NDE of high energy piping, 3A slag tank top roof top refractory, main steam stop valve and combined reheat valve inspection.
BIG BEND 4	Feb 11 - Mar 14	CP - Weld overlay of the furnace walls (5,000 Sq Ft). Other jobs worked during this outage include: 4C mill roller replacement, 4D Southwest burner rebuild, UT inspection of the furnace side tubes, economizer restub (100) high energy piping replacement, 4B circulating water pump and motor remove and inspection.
POLK 1	Apr 13 May 26	Gasifier refractory replacement. Radiant syngas cooler tube additions and repairs to steam dump valves, waterwall and sootblower box. Gasifier fuel booster pump. Repaired superheater tube in heat recovery steam generator. Replaced compressor discharge casing. Steam turbine inspection.

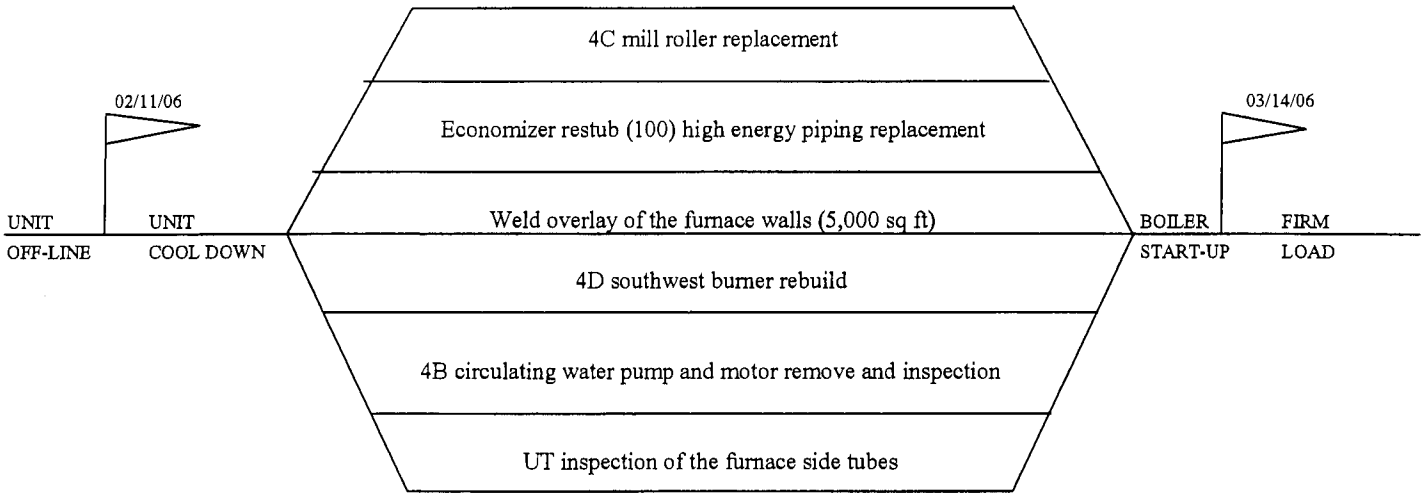
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006



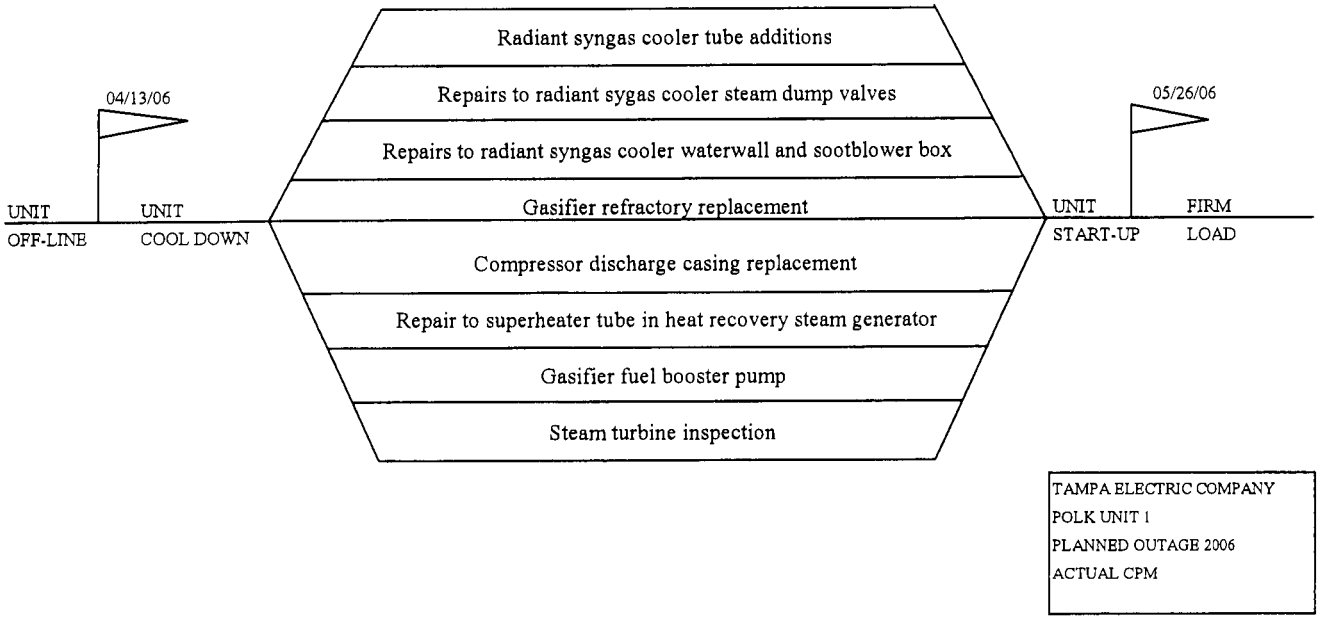
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2006 - DECEMBER 2006



TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2006 - DECEMBER 2006

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,832.8	68.6	+10	2,597.3	10,327
+9	5,249.5	68.1	+9	2,337.6	10,371
+8	4,666.2	67.6	+8	2,077.9	10,415
+7	4,083.0	67.1	+7	1,818.1	10,459
+6	3,499.7	66.6	+6	1,558.4	10,502
+5	2,916.4	66.1	+5	1,298.7	10,546
+4	2,333.1	65.6	+4	1,038.9	10,590
+3	1,749.8	65.1	+3	779.2	10,634
+2	1,166.6	64.6	+2	519.5	10,678
+1	583.3	64.1	+1	259.7	10,722
					10,766
0	0.0	63.6	0	0.0	10,841
					10,916
-1	(1,255.6)	62.6	-1	(259.7)	10,960
-2	(2,511.3)	61.6	-2	(519.5)	11,004
-3	(3,766.9)	60.6	-3	(779.2)	11,048
-4	(5,022.5)	59.7	-4	(1,038.9)	11,091
-5	(6,278.1)	58.7	-5	(1,298.7)	11,135
-6	(7,533.8)	57.7	-6	(1,558.4)	11,179
-7	(8,789.4)	56.7	-7	(1,818.1)	11,223
-8	(10,045.0)	55.7	-8	(2,077.9)	11,267
-9	(11,300.7)	54.7	-9	(2,337.6)	11,311
-10	(12,556.3)	53.7	-10	(2,597.3)	11,355

EAF POINTS **-6.268**

Adjusted EAF **57.4**

AHR POINTS **-3.237**

Adjusted ANOHR **11,058**

Weighting Factor = 12.33%

Weighting Factor = 5.49%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2006 - DECEMBER 2006

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	5,426.4	81.2	+10	2,786.9	10,074
+9	4,883.8	80.8	+9	2,508.2	10,110
+8	4,341.1	80.4	+8	2,229.5	10,146
+7	3,798.5	80.1	+7	1,950.9	10,182
+6 ← EAF POINTS 6.116	3,255.8	Adjusted EAF 79.7 → 79.7	+6	1,672.2	10,218
+5	2,713.2	79.3	+5	1,393.5	10,254
+4	2,170.6	78.9	+4	1,114.8	10,291
+3	1,627.9	78.5	+3	836.1	10,327
+2	1,085.3	78.1	+2	557.4	10,363
+1	542.6	77.7	+1	278.7	10,399
0	0.0	77.3	0 ← AHR POINTS 0.000	0.0	10,435 Adjusted ANOHR 10,451 → 10,510 10,585
-1	(1,112.2)	76.5	-1	(278.7)	10,621
-2	(2,224.4)	75.7	-2	(557.4)	10,658
-3	(3,336.6)	74.9	-3	(836.1)	10,694
-4	(4,448.8)	74.1	-4	(1,114.8)	10,730
-5	(5,561.0)	73.3	-5	(1,393.5)	10,766
-6	(6,673.3)	72.5	-6	(1,672.2)	10,802
-7	(7,785.5)	71.7	-7	(1,950.9)	10,838
-8	(8,897.7)	70.9	-8	(2,229.5)	10,874
-9	(10,009.9)	70.1	-9	(2,508.2)	10,911
-10	(11,122.1)	69.3	-10	(2,786.9)	10,947

Weighting Factor = 11.47%

Weighting Factor = 5.89%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2006 - DECEMBER 2006

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	9,010.8	63.5	+10	3,053.2	10,205
+9	8,109.7	62.8	+9	2,747.8	10,270
+8	7,208.6	62.1	+8	2,442.5	10,334
+7	6,307.6	61.3	+7	2,137.2	10,398
+6 ← EAF POINTS 6.285	5,406.5	Adjusted EAF 60.8 → 60.6	+6	1,831.9	10,463
+5	4,505.4	59.9	+5	1,526.6	10,527
+4	3,604.3	59.1	+4	1,221.3	10,591
+3	2,703.2	58.4	+3	915.9	10,656
+2	1,802.2	57.7	+2	610.6	10,720
+1	901.1	56.9	+1	305.3	10,784
					10,848
0	0.0	56.2	0	0.0	10,923
					10,998
-1	(1,675.2)	54.7	-1	(305.3)	11,063
-2	(3,350.5)	53.3	-2 ← AHR POINTS -2.046	(610.6)	Adjusted ANOHR 11,130 → 11,127
-3	(5,025.7)	51.8	-3	(915.9)	11,191
-4	(6,701.0)	50.3	-4	(1,221.3)	11,256
-5	(8,376.2)	48.9	-5	(1,526.6)	11,320
-6	(10,051.4)	47.4	-6	(1,831.9)	11,384
-7	(11,726.7)	45.9	-7	(2,137.2)	11,448
-8	(13,401.9)	44.5	-8	(2,442.5)	11,513
-9	(15,077.2)	43.0	-9	(2,747.8)	11,577
-10	(16,752.4)	41.6	-10	(3,053.2)	11,641

Weighting Factor = 19.05%

Weighting Factor = 6.45%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2006 - DECEMBER 2006

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 ← EAF POINTS 10.000	6,443.0	76.6 → Adjusted EAF 76.7	+10	4,018.3	10,077
+9	5,798.7	76.2	+9	3,616.5	10,129
+8	5,154.4	75.7	+8	3,214.7	10,181
+7	4,510.1	75.2	+7	2,812.8	10,233
+6	3,865.8	74.7	+6	2,411.0	10,285
+5	3,221.5	74.3	+5	2,009.2	10,337
+4	2,577.2	73.8	+4	1,607.3	10,389
+3	1,932.9	73.3	+3	1,205.5	10,441
+2	1,288.6	72.8	+2	803.7	10,493
+1	644.3	72.3	+1	401.8	10,545
					10,597
0	0.0	71.9	0	0.0	10,672
					10,747
-1	(1,266.4)	70.9	-1	(401.8)	10,799
-2	(2,532.8)	70.0	-2	(803.7)	10,851
-3	(3,799.2)	69.0	-3	(1,205.5)	10,903
-4	(5,065.6)	68.1	-4	(1,607.3)	10,955
-5	(6,331.9)	67.1	-5	(2,009.2)	11,007
-6	(7,598.3)	66.2	-6 ← AHR POINTS -6.841	(2,411.0) → Adjusted ANOHR 11,103	11,059
-7	(8,864.7)	65.2	-7	(2,812.8)	11,111
-8	(10,131.1)	64.3	-8	(3,214.7)	11,163
-9	(11,397.5)	63.3	-9	(3,616.5)	11,215
-10	(12,663.9)	62.4	-10	(4,018.3)	11,267

Weighting Factor = 13.62%

Weighting Factor = 8.49%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2006 - DECEMBER 2006

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,825.5	67.6	+10	3,310.5	9,330
+9	4,343.0	66.9	+9	2,979.5	9,439
+8	3,860.4	66.2	+8	2,648.4	9,549
+7	3,377.9	65.4	+7	2,317.4	9,658
+6	2,895.3	64.7	+6	1,986.3	9,767
+5	2,412.8	64.0	+5	1,655.3	9,876
+4	1,930.2	63.2	+4	1,324.2	9,985
+3	1,447.7	62.5	+3	993.2	10,095
+2	965.1	61.8	+2	662.1	10,204
+1	482.6	61.1	+1	331.1	10,313
					10,422
0	0.0	60.3	0	0.0	10,497
					10,572
-1	(982.1)	58.9	-1	(331.1)	10,681
-2	(1,964.1)	57.4	-2	(662.1)	10,791
-3	(2,946.2)	56.0	-3	(993.2)	10,900
-4	(3,928.2)	54.5	-4	(1,324.2)	11,009
-5	(4,910.3)	53.1	-5	(1,655.3)	11,118
-6	(5,892.3)	51.6	-6	(1,986.3)	11,227
-7	(6,874.4)	50.2	-7	(2,317.4)	11,336
-8	(7,856.4)	48.7	-8	(2,648.4)	11,446
-9	(8,838.5)	47.2	-9	(2,979.5)	11,555
-10	(9,820.5)	45.8	-10	(3,310.5)	11,664

EAF POINTS **10.000**

Adjusted EAF **85.6**

AHR POINTS **0.000**

Adjusted ANOHR **10,442**

Weighting Factor = 10.20%

Weighting Factor = 7.00%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 06 - DEC 06 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 06 - DEC 06 POF	EUOF	EUOR
BIG BEND 1	12.33%	18.5%	15.3	21.0	24.8	18.5	26.3	32.2
BIG BEND 2	11.47%	17.2%	3.8	18.9	19.6	0.0	17.2	17.2
BIG BEND 3	19.05%	28.6%	9.6	34.2	37.8	7.9	30.2	32.8
BIG BEND 4	13.62%	20.4%	5.8	22.4	23.7	8.3	17.0	18.5
POLK 1	10.20%	15.3%	4.4	35.3	36.9	12.0	9.2	10.5
GPIF SYSTEM	**66.67%**	**100.0%**	**8.1**	**26.9**	**29.3**	**9.2**	**21.3**	**23.7**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) 65.0 69.5

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
6.1	**25.8**	**27.4**	**68.1**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 06 - DEC 06	ADJUSTED ACTUAL HEAT RATE JAN 06 - DEC 06
BIG BEND 1	5.49%	16.5%	10,841	11,058
BIG BEND 2	5.89%	17.7%	10,510	10,451
BIG BEND 3	6.45%	19.4%	10,923	11,130
BIG BEND 4	8.49%	25.5%	10,672	11,103
POLK 1	7.00%	21.0%	10,497	10,442
GPIF SYSTEM	**33.33%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) 10,683 10,847

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2006 - DECEMBER 2006

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i(EAP_i) + e_i(AHRP_i) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	12.33%	*	(BB 1 EAP)	+	11.47%	*	(BB 2 EAP)	+	19.05%	*	(BB 3 EAP)
+	13.62%	*	(BB 4 EAP)	+							
+	10.20%	*	(PK 1 EAP)	+	5.49%	*	(BB 1 AHRP)	+	5.89%	*	(BB 2 AHRP)
+	6.45%	*	(BB 3 AHRP)	+	8.49%	*	(BB 4 AHRP)	+			
+				+	7.00%	*	(PK 1 AHRP)				

GPIP =	12.33%	*	-6.268	+	11.47%	*	6.116	+	19.05%	*	6.285
+	13.62%	*	10.000	+				+			
+	10.20%	*	10.000	+	5.49%	*	-3.237	+	5.89%	*	0.000
+	6.45%	*	-2.046	+	8.49%	*	-6.841	+			
+				+	7.00%	*	0.000				

GPIP =	-0.773	+	0.702	+	1.197
+	1.362	+	0.000	+	0.000
+	1.020	+	-0.178	+	0.000
+	-0.132	+	-0.581	+	0.000
+	0.000	+	0.000		

GPIP = 2.617 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = $1,439,819

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 070001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2006 - DECEMBER 2006

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.06A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

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 06	FEB 06	MAR 06	APR 06	MAY 06	JUN 06	JUL 06	AUG 06	SEP 06	OCT 06	NOV 06	DEC 06	2006
1. EAF (%)	73.4	51.1	75.3	85.6	64.2	71.3	64.0	47.7	78.4	15.5	0.0	36.6	55.2
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	699.2	452.6	637.7	719.0	577.4	648.9	611.1	474.1	720.0	146.3	0.0	317.5	6,003.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	44.8	219.4	106.3	0.0	166.7	71.1	132.9	269.9	0.0	598.7	720.0	426.5	2,756.1
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	598.7	720.0	302.7	1,621.4
7. FOH	16.8	123.0	106.3	0.0	166.7	71.1	7.8	269.9	0.0	0.0	0.0	123.8	885.3
8. MOH	28.0	96.4	0.0	0.0	0.0	0.0	125.1	0.0	0.0	0.0	0.0	0.0	249.5
9. PFOH	671.0	442.3	631.6	661.0	530.9	594.7	543.0	429.2	661.0	141.3	0.0	304.9	5,610.9
10. LR PF (MW)	82.6	96.4	48.1	45.2	57.5	68.0	68.2	85.1	72.2	80.8	0.0	61.0	67.8
11. PMOH	32.6	10.4	6.1	63.0	46.4	54.1	68.2	44.9	59.0	5.1	0.0	0.0	389.7
12. LR PM (MW)	231.0	211.1	248.5	203.2	227.8	282.7	272.3	278.6	276.1	272.4	0.0	0.0	253.1
13. NSC (MW)	411	411	411	411	411	411	411	411	411	411	411	411	411
14. OPR BTU(GBTU)	2,179.8	1,408.3	2,305.9	2,689.6	2,081.6	2,150.7	2,047.0	1,579.4	2,474.5	525.9	0.0	1,156.3	20,599.1
15. NET GEN (MWH)	203,426	128,337	213,552	241,557	185,664	196,328	181,812	137,553	219,697	46,321	0	106,667	1,860,915
16. ANOHR (BTU/KWH)	10,715	10,974	10,798	11,135	11,212	10,955	11,259	11,482	11,263	11,353	0	10,840	11,069
17. NOF (%)	70.8	69.0	81.5	81.7	78.2	73.6	72.4	70.6	74.2	77.0	0.0	81.7	75.4
18. NPC (MW)	411	411	411	411	411	411	411	411	411	411	411	411	411

DOCKET NO. 070001-EI
GPIF 2006 ACTUAL UNIT PERFORMANCE DATA
EXHIBIT DRK-1, DOC. 2, PAGE 1 OF 5

ORIGINAL SHEET NO. 8.401.06A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

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 06	FEB 06	MAR 06	APR 06	MAY 06	JUN 06	JUL 06	AUG 06	SEP 06	OCT 06	NOV 06	DEC 06	2006
1. EAF (%)	93.1	84.8	91.4	69.6	92.2	75.2	96.2	92.0	51.2	77.9	72.4	95.8	82.8
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	744.0	584.4	744.0	582.0	736.2	584.3	744.0	732.2	506.1	745.0	554.8	744.0	8,001.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	87.6	0.0	137.0	7.8	135.7	0.0	11.8	213.9	0.0	165.2	0.0	758.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	7.8	135.7	0.0	11.8	213.9	0.0	165.2	0.0	534.3
8. MOH	0.0	87.6	0.0	137.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.6
9. PFOH	352.3	577.8	548.3	575.7	730.6	296.6	160.4	620.0	506.1	736.1	549.8	421.2	6,074.8
10. LR PF (MW)	54.8	7.7	37.1	52.7	25.6	56.2	39.6	30.0	106.1	85.8	24.0	28.8	45.6
11. PMOH	391.3	6.6	18.9	6.3	5.6	0.0	20.5	0.0	0.0	7.8	0.0	0.0	457.1
12. LR PM (MW)	2.3	198.5	245.3	228.9	162.1	0.0	235.9	0.0	0.0	152.6	0.0	0.0	33.3
13. NSC (MW)	391	391	391	391	391	391	391	391	391	391	391	391	391
14. OPR BTU(GBTU)	2,574.1	2,220.4	2,597.9	1,943.6	2,703.5	2,169.1	2,838.4	2,775.7	1,514.6	2,327.5	2,024.6	2,664.3	28,353.8
15. NET GEN (MWH)	252,579	216,742	254,463	188,185	262,277	207,185	273,031	260,943	142,137	220,423	195,720	253,907	2,727,592
16. ANOHR (BTU/KWH)	10,191	10,245	10,209	10,328	10,308	10,470	10,396	10,637	10,656	10,559	10,344	10,493	10,395
17. NOF (%)	86.8	94.8	87.5	82.7	91.1	90.7	93.9	91.1	71.8	75.7	90.2	87.3	87.2
18. NPC (MW)	391	391	391	391	391	391	391	391	391	391	391	391	391

19. ANOHR EQUATION ANOHR = NOF(-12.783) + 11,130

ORIGINAL SHEET NO. 8.401.06A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

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 06	FEB 06	MAR 06	APR 06	MAY 06	JUN 06	JUL 06	AUG 06	SEP 06	OCT 06	NOV 06	DEC 06	2006
1. EAF (%)	78.7	77.2	79.6	1.2	63.7	65.6	63.0	51.3	76.9	49.4	81.4	56.4	61.9
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	716.3	672.0	741.4	23.3	603.9	562.5	580.5	503.8	693.9	517.0	670.5	624.4	6,909.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	27.7	0.0	2.6	695.7	140.1	157.5	163.5	240.2	26.1	228.0	49.5	119.6	1,850.5
6. POH	0.0	0.0	0.0	695.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	695.7
7. FOH	27.7	0.0	2.6	0.0	140.1	157.5	163.5	46.8	26.1	122.8	49.5	119.6	856.1
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	193.5	0.0	105.3	0.0	0.0	298.7
9. PFOH	663.9	608.5	695.0	22.0	588.5	548.5	571.3	487.8	666.6	513.4	648.3	624.4	6,638.1
10. LR PF (MW)	68.0	86.4	78.8	255.1	85.6	63.1	78.1	94.5	77.7	119.9	48.5	141.9	85.4
11. PMOH	52.4	63.5	44.0	1.3	15.4	14.0	9.3	16.0	27.3	0.0	22.2	0.0	265.3
12. LR PM (MW)	219.1	218.2	223.1	375.5	219.4	199.8	167.5	284.2	231.5	0.0	160.5	0.0	217.8
13. NSC (MW)	433	433	433	414	414	414	414	414	414	414	414	433	420
14. OPR BTU(GBTU)	2,412.5	2,326.0	2,519.5	36.5	1,972.2	1,988.5	2,064.2	1,669.3	2,388.7	1,617.2	2,391.8	1,926.5	23,313.0
15. NET GEN (MWH)	225,773	214,486	233,956	3,461	184,588	185,392	189,783	150,751	218,934	147,686	227,275	173,066	2,155,150
16. ANOHR BTU/KWH	10,686	10,844	10,769	10,550	10,685	10,726	10,877	11,073	10,911	10,950	10,524	11,132	10,817
17. NOF (%)	72.8	73.7	72.9	35.9	73.8	79.6	79.0	72.3	76.2	69.0	81.9	64.0	74.2
18. NPC (MW)	433	433	433	414	414	414	414	414	414	414	414	433	420
19. ANOHR EQUATION	ANOHR = NOF(-42.211) + 13,320												

DOCKET NO. 070001-EI
GPIF 2006 ACTUAL UNIT PERFORMANCE DATA
EXHIBIT DRK-1, DOC. 2, PAGE 3 OF 5

ORIGINAL SHEET NO. 8.401.06A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

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 06	FEB 06	MAR 06	APR 06	MAY 06	JUN 06	JUL 06	AUG 06	SEP 06	OCT 06	NOV 06	DEC 06	2006
1. EAF (%)	83.4	31.9	52.4	93.8	76.1	85.7	73.5	85.6	83.1	85.2	59.5	82.5	74.7
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	671.0	240.3	414.3	719.0	655.8	720.0	663.2	744.0	699.4	743.8	464.8	673.3	7,408.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	73.0	411.3	329.7	0.0	88.2	0.0	80.8	0.0	20.6	1.2	255.3	70.7	1,330.9
6. POH	0.0	411.3	317.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	728.3
7. FOH	72.5	0.0	12.8	0.0	88.2	0.0	80.8	0.0	20.6	1.2	255.3	70.7	602.1
8. MOH	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
9. PFOH	485.9	240.3	327.3	686.3	635.9	666.7	593.9	683.0	635.7	709.0	464.8	673.3	6,802.0
10. LR PF (MW)	39.6	89.0	32.7	24.7	55.1	47.1	54.2	43.9	42.5	55.4	35.6	40.7	45.2
11. PMOH	14.1	0.0	3.6	32.2	19.9	49.4	69.3	61.0	63.7	34.9	0.0	0.0	348.0
12. LR PM (MW)	289.9	0.0	196.8	110.8	302.0	315.2	304.1	309.2	300.8	302.3	0.0	0.0	286.1
13. NSC (MW)	462	462	462	457	457	457	457	457	457	457	457	462	459
14. OPR BTU(GBTU)	2,761.8	889.7	1,671.7	3,126.5	2,528.3	2,734.2	2,498.5	3,004.7	2,756.8	2,964.1	2,001.5	2,909.5	29,847.2
15. NET GEN (MWH)	251,103	72,670	151,694	287,968	228,884	247,663	215,560	266,512	243,347	270,241	180,613	260,905	2,677,159
16. ANOHR BTU/KWH	10,999	12,243	11,020	10,857	11,046	11,040	11,591	11,274	11,329	10,968	11,082	11,152	11,149
17. NOF (%)	81.0	65.4	79.3	87.6	76.4	75.3	71.1	78.4	76.1	79.5	85.0	83.9	78.8
18. NPC (MW)	462	462	462	457	457	457	457	457	457	457	457	462	459

19. ANOHR EQUATION ANOHR = NOF(-32.626) + 12,906

ORIGINAL SHEET NO. 8.401.06A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2006 - DECEMBER 2006

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 06	FEB 06	MAR 06	APR 06	MAY 06	JUN 06	JUL 06	AUG 06	SEP 06	OCT 06	NOV 06	DEC 06	2006
1. EAF (%)	91.2	93.8	94.9	38.6	10.8	95.9	90.2	95.9	87.6	69.5	94.2	83.8	78.8
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	667.8	637.8	744.0	290.3	84.8	709.9	692.6	744.0	667.2	576.8	666.6	659.3	7,141.0
4. RSH	21.5	32.6	0.0	5.3	0.0	0.0	32.3	0.0	0.0	0.0	53.3	0.0	145.0
5. UH	54.7	1.5	0.0	423.4	659.2	10.1	19.2	0.0	52.8	168.2	0.1	84.8	1,474.0
6. POH	0.0	0.0	0.0	423.4	612.0	0.0	19.2	0.0	0.0	0.0	0.0	0.0	1,054.6
7. FOH	0.0	1.5	0.0	0.0	47.3	10.1	0.0	0.0	1.7	168.2	0.1	1.4	230.2
8. MOH	54.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.1	0.0	0.0	83.4	189.2
9. PFOH	0.9	124.8	353.4	30.1	37.0	271.0	745.8	767.0	681.2	698.9	304.8	659.9	4,674.7
10. LR PF (MW)	63.9	83.3	28.0	77.2	30.8	18.0	18.4	10.1	13.6	21.5	34.6	14.2	20.2
11. PMOH	34.6	0.0	0.0	138.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.1
12. LR PM (MW)	80.0	0.0	0.0	16.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.0
13. NSC (MW) **	260	260	260	255	255	255	255	255	255	255	255	260	257
14. OPR BTU(GBTU)	1,617.2	1,560.8	1,566.6	655.8	192.0	1,765.8	1,612.9	1,794.5	1,530.3	1,237.1	1,482.5	1,624.8	16,640.3
15. NET GEN (MWH)	161,559	151,558	161,152	57,549	6,863	168,182	148,918	177,075	147,837	107,989	147,130	153,026	1,588,838
16. ANOHR BTU/KWH	10,010	10,298	9,721	11,396	27,982	10,499	10,831	10,134	10,351	11,456	10,076	10,618	10,473
17. NOF (%)	93.1	91.4	83.3	77.7	31.7	92.9	84.3	93.3	86.9	73.4	86.6	89.3	86.7
18. NPC (MW) **	260	260	260	255	255	255	255	255	255	255	255	260	257

19. ANOHR EQUATION ANOHR = NOF(-8.7647) + 11,223

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI
IN RE: TAMPA ELECTRIC'S
FUEL & PURCHASED POWER COST RECOVERY
AND CAPACITY COST RECOVERY PROJECTIONS
JANUARY 2008 THROUGH DECEMBER 2008

TESTIMONY AND EXHIBIT
OF
DAVID R. KNAPP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 42
COMPANY Tampa Electric Co.
WITNESS David R. Knapp (DRK-2)
DATE 11-06-07

DOCUMENT NUMBER-DATE
07987 SEP-4 07
FPSC-COMMISSION CLERK

DOCKET NO. 070001-EI
GPIF 2008 PROJECTION FILING
EXHIBIT NO. DRK-2
DOCUMENT 1

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2008 - DECEMBER 2008

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

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2008 - DECEMBER 2008

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

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

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

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,535,090,000
Line 2	Month of January	2008	$	1,500,630,000
Line 3	Month of February	2008	$	1,515,323,669
Line 4	Month of March	2008	$	1,530,161,213
Line 5	Month of April	2008	$	1,550,072,829
Line 6	Month of May	2008	$	1,565,250,625
Line 7	Month of June	2008	$	1,580,577,037
Line 8	Month of July	2008	$	1,545,637,696
Line 9	Month of August	2008	$	1,560,772,066
Line 10	Month of September	2008	$	1,576,054,625
Line 11	Month of October	2008	$	1,596,009,239
Line 12	Month of November	2008	$	1,611,636,829
Line 13	Month of December	2008	$	1,627,417,440
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,561,125,636
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	6,358,366
Line 18	Jurisdictional Sales			20,347,237 MWH
Line 19	Total Sales			20,984,516 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			96.96%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**6,165,268**

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

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	11.14%	72.1	77.1	62.1	5,315.9	(10,291.1)
BIG BEND 2	4.02%	76.9	80.2	70.3	1,915.6	(4,438.6)
BIG BEND 3	12.00%	47.0	53.6	33.8	5,725.1	(11,662.2)
BIG BEND 4	13.40%	73.1	77.9	63.5	6,393.3	(11,814.9)
POLK 1	8.47%	77.2	80.6	70.5	4,039.9	(9,074.1)
BAYSIDE 1	3.18%	84.5	87.0	79.4	1,517.4	(3,451.6)
BAYSIDE 2	0.25%	83.6	84.6	81.6	121.0	(4,438.6)
GPIF SYSTEM	**52.46%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR TARGET Btu/kwh	ANOHR TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	3.53%	10,910	79.4	10,598	11,223	1,684.8	(1,684.8)
BIG BEND 2	3.84%	10,695	84.4	10,398	10,992	1,832.1	(1,832.1)
BIG BEND 3	5.59%	10,662	74.4	9,967	11,357	2,669.1	(2,669.1)
BIG BEND 4	8.74%	10,840	85.7	10,213	11,467	4,170.1	(4,170.1)
POLK 1	6.69%	10,607	87.2	9,784	11,429	3,190.7	(3,190.7)
BAYSIDE1	9.21%	7,320	83.9	7,190	7,449	4,392.0	(4,392.0)
BAYSIDE 2	9.94%	7,359	80.8	7,242	7,475	4,741.6	(4,741.6)
GPIF SYSTEM	**47.54%**						

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

EQUIVALENT AVAILABILITY (%)

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

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

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

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

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2008 - DECEMBER 2008
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	1,117,430.9	1,112,115.0	5,316	11.14%
EA_2 BIG BEND 2	1,117,430.9	1,115,515.3	1,916	4.02%
EA_3 BIG BEND 3	1,117,430.9	1,111,705.8	5,725	12.00%
EA_4 BIG BEND 4	1,117,430.9	1,111,037.6	6,393	13.40%
EA_7 POLK 1	1,117,430.9	1,113,391.0	4,040	8.47%
EA_8 BAYSIDE 1	1,117,430.9	1,115,913.5	1,517	3.18%
EA_9 BAYSIDE 2	1,117,430.9	1,117,309.9	121	0.25%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	1,117,430.9	1,115,746.1	1,685	3.53%
AHR_2 BIG BEND 2	1,117,430.9	1,115,598.8	1,832	3.84%
AHR_3 BIG BEND 3	1,117,430.9	1,114,761.8	2,669	5.59%
AHR_4 BIG BEND 4	1,117,430.9	1,113,260.8	4,170	8.74%
AHR_7 POLK 1	1,117,430.9	1,114,240.2	3,191	6.69%
AHR_8 BAYSIDE 1	1,117,430.9	1,113,038.9	4,392	9.21%
AHR_9 BAYSIDE 2	1,117,430.9	1,112,689.3	4,742	9.94%
TOTAL SAVINGS			47,708.7	100.00%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BIG BEND 1

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

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,915.6	80.2	+10	1,832.1	10,398
+9	1,724.0	79.9	+9	1,648.9	10,420
+8	1,532.5	79.6	+8	1,465.7	10,442
+7	1,340.9	79.2	+7	1,282.5	10,464
+6	1,149.4	78.9	+6	1,099.3	10,487
+5	957.8	78.6	+5	916.1	10,509
+4	766.2	78.2	+4	732.9	10,531
+3	574.7	77.9	+3	549.6	10,553
+2	383.1	77.6	+2	366.4	10,575
+1	191.6	77.3	+1	183.2	10,598
					10,620
0	0.0	76.9	0	0.0	10,695
					10,770
-1	(443.9)	76.3	-1	(183.2)	10,792
-2	(887.7)	75.6	-2	(366.4)	10,814
-3	(1,331.6)	74.9	-3	(549.6)	10,836
-4	(1,775.4)	74.3	-4	(732.9)	10,859
-5	(2,219.3)	73.6	-5	(916.1)	10,881
-6	(2,663.2)	73.0	-6	(1,099.3)	10,903
-7	(3,107.0)	72.3	-7	(1,282.5)	10,925
-8	(3,550.9)	71.6	-8	(1,465.7)	10,947
-9	(3,994.7)	71.0	-9	(1,648.9)	10,970
-10	(4,438.6)	70.3	-10	(1,832.1)	10,992
	Weighting Factor =	4.02%		Weighting Factor =	3.84%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,725.1	53.6	+10	2,669.1	9,967
+9	5,152.6	53.0	+9	2,402.2	10,029
+8	4,580.1	52.3	+8	2,135.3	10,091
+7	4,007.6	51.6	+7	1,868.4	10,153
+6	3,435.1	51.0	+6	1,601.5	10,215
+5	2,862.5	50.3	+5	1,334.6	10,277
+4	2,290.0	49.7	+4	1,067.7	10,339
+3	1,717.5	49.0	+3	800.7	10,401
+2	1,145.0	48.3	+2	533.8	10,463
+1	572.5	47.7	+1	266.9	10,525
					10,587
0	0.0	47.0	0	0.0	10,662
					10,737
-1	(1,166.2)	45.7	-1	(266.9)	10,799
-2	(2,332.4)	44.4	-2	(533.8)	10,861
-3	(3,498.7)	43.0	-3	(800.7)	10,923
-4	(4,664.9)	41.7	-4	(1,067.7)	10,985
-5	(5,831.1)	40.4	-5	(1,334.6)	11,047
-6	(6,997.3)	39.1	-6	(1,601.5)	11,109
-7	(8,163.5)	37.7	-7	(1,868.4)	11,171
-8	(9,329.8)	36.4	-8	(2,135.3)	11,233
-9	(10,496.0)	35.1	-9	(2,402.2)	11,295
-10	(11,662.2)	33.8	-10	(2,669.1)	11,357
	Weighting Factor =	12.00%		Weighting Factor =	5.59%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BIG BEND 4

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

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

POLK 1

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

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BAYSIDE 1

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

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2008 - DECEMBER 2008

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	121.0	84.6	+10	4,741.6	7,242
+9	108.9	84.5	+9	4,267.5	7,246
+8	96.8	84.4	+8	3,793.3	7,251
+7	84.7	84.3	+7	3,319.1	7,255
+6	72.6	84.2	+6	2,845.0	7,259
+5	60.5	84.1	+5	2,370.8	7,263
+4	48.4	84.0	+4	1,896.7	7,267
+3	36.3	83.9	+3	1,422.5	7,271
+2	24.2	83.8	+2	948.3	7,275
+1	12.1	83.7	+1	474.2	7,280
					7,284
0	0.0	83.6	0	0.0	7,359
					7,434
-1	(443.9)	83.4	-1	(474.2)	7,438
-2	(887.7)	83.2	-2	(948.3)	7,442
-3	(1,331.6)	83.0	-3	(1,422.5)	7,446
-4	(1,775.4)	82.8	-4	(1,896.7)	7,450
-5	(2,219.3)	82.6	-5	(2,370.8)	7,455
-6	(2,663.2)	82.4	-6	(2,845.0)	7,459
-7	(3,107.0)	82.2	-7	(3,319.1)	7,463
-8	(3,550.9)	82.0	-8	(3,793.3)	7,467
-9	(3,994.7)	81.8	-9	(4,267.5)	7,471
-10	(4,438.6)	81.6	-10	(4,741.6)	7,475
	Weighting Factor =	0.25%		Weighting Factor =	9.94%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	47.5	67.7	75.0	75.0	72.13
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.7	9.7	0.0	0.0	3.83
3. EUOF	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	15.8	22.6	25.0	25.0	24.04
4. EUOR	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	624	583	624	603	624	603	624	624	383	562	603	624	7,080
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	120	113	120	117	120	117	120	120	337	182	117	120	1704
9. POH	0	0	0	0	0	0	0	0	264	72	0	0	336
10. FOH & EFOH	158	148	158	153	158	153	158	158	97	143	153	158	1,795
11. MOH & EMOH	28	26	28	27	28	27	28	28	17	25	27	28	316
12. OPER BTU (GBTU)	2,053	1,922	2,043	1,980	2,046	1,980	2,046	2,046	1,257	1,845	1,989	2,047	23,251
13. NET GEN (MWH)	187,735	175,727	186,581	181,816	187,895	181,849	187,883	187,901	115,436	169,411	181,879	187,020	2,131,133
14. ANOHR (Btu/kwh)	10,937	10,936	10,947	10,889	10,889	10,889	10,889	10,889	10,889	10,889	10,935	10,943	10,910
15. NOF (%)	78.2	78.3	77.7	80.4	80.4	80.4	80.4	80.4	80.4	80.3	78.3	77.9	79.4
16. NPC (MW)	385	385	385	375	375	375	375	375	375	375	385	385	379
17. ANOHR EQUATION	ANOHR = NOF(	-22.19	) +	12,672.08									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	0.0	0.0	0.0	51.2	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	47.01
2. POF	100.0	100.0	100.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.50
3. EUOF	0.0	0.0	0.0	28.8	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	26.49
4. EUOR	0.0	0.0	0.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	0	0	0	463	597	578	597	597	578	597	578	597	5,182
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	744	696	744	257	147	142	147	147	142	147	142	147	3,602
9. POH	744	696	744	144	0	0	0	0	0	0	0	0	2,328
10. FOH & EFOH	0	0	0	163	211	204	211	211	204	211	204	211	1,832
11. MOH & EMOH	0	0	0	44	57	55	57	57	55	57	55	57	495
12. OPER BTU (GBTU)	0	0	0	1,450	1,873	1,812	1,853	1,842	1,808	1,870	1,822	1,854	16,208
13. NET GEN (MWH)	0	0	0	136,708	176,669	170,999	174,015	172,534	170,368	176,308	170,345	172,246	1,520,192
14. ANOHR (Btu/kwh)	13,900	13,900	13,900	10,605	10,599	10,599	10,649	10,677	10,611	10,606	10,694	10,762	10,662
15. NOF (%)	0.0	0.0	0.0	75.7	75.9	75.9	74.7	74.1	75.6	75.7	73.7	72.1	74.4
16. NPC (MW)	400	400	400	390	390	390	390	390	390	390	400	400	394
17. ANOHR EQUATION	ANOHR = NOF(	-43.50	) +	13,899.80									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	40.5	76.0	73.08
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.83
3. EUOF	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	12.8	24.0	23.09
4. EUOR	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	622	582	622	602	622	602	622	622	602	622	321	622	7,064
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	122	114	122	118	122	118	122	122	118	122	399	122	1,720
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. FOH & EFOH	139	130	139	134	139	134	139	139	134	139	72	139	1,573
11. MOH & EMOH	40	37	40	39	40	39	40	40	39	40	21	40	455
12. OPER BTU (GBTU)	2,557	2,380	2,497	2,440	2,525	2,443	2,501	2,484	2,439	2,522	1,323	2,506	28,623
13. NET GEN (MWH)	235,944	219,298	228,747	225,745	233,810	226,201	230,883	228,772	225,711	233,328	122,211	229,828	2,640,478
14. ANOHR (Btu/kwh)	10,837	10,854	10,915	10,807	10,801	10,802	10,834	10,857	10,808	10,807	10,828	10,903	10,840
15. NOF (%)	85.8	85.3	83.2	86.8	87.0	87.0	85.9	85.1	86.8	86.8	86.1	83.6	85.7
16. NPC (MW)	442	442	442	432	432	432	432	432	432	432	442	442	436
17. ANOHR EQUATION	ANOHR = NOF(		-29.85	) +		13,398.36							

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

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

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2008 - DECEMBER 2008

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE I	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	2008
1. EAF (%)	87.8	87.8	68.0	87.8	87.8	87.8	87.8	87.8	87.8	87.8	67.3	87.8	84.45
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	3.83
3. EUOF	12.2	12.2	9.4	12.2	12.2	12.2	12.2	12.2	12.2	12.2	9.3	12.2	11.72
4. EUOR	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.19
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	503	575	470	567	510	481	521	581	541	501	468	633	6,349
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	241	121	274	153	234	239	223	163	179	243	252	111	2,435
9. POH	0	0	168	0	0	0	0	0	0	0	168	0	336
10. FOH & EFOH	48	45	37	46	48	46	48	48	46	48	35	48	543
11. MOH & EMOH	43	40	33	42	43	42	43	43	42	43	32	43	487
12. OPER BTU (GBTU)	2,011	2,431	2,210	2,691	2,262	2,152	2,322	2,574	2,396	2,230	2,101	3,168	28,553
13. NET GEN (MWH)	272,716	330,382	301,450	369,266	309,400	294,471	317,694	352,000	327,692	305,103	287,546	433,246	3,900,966
14. ANOHR (Btu/kwh)	7,374	7,360	7,330	7,288	7,311	7,308	7,309	7,311	7,311	7,309	7,307	7,311	7,320
15. NOF (%)	68.3	72.5	81.0	92.8	86.4	87.3	86.9	86.3	86.2	86.8	87.6	86.3	83.9
16. NPC (MW)	793	793	793	702	702	702	702	702	702	702	702	793	732
17. ANOHR EQUATION	ANOHR = NOF(	-3.51	) +	7,614.23									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

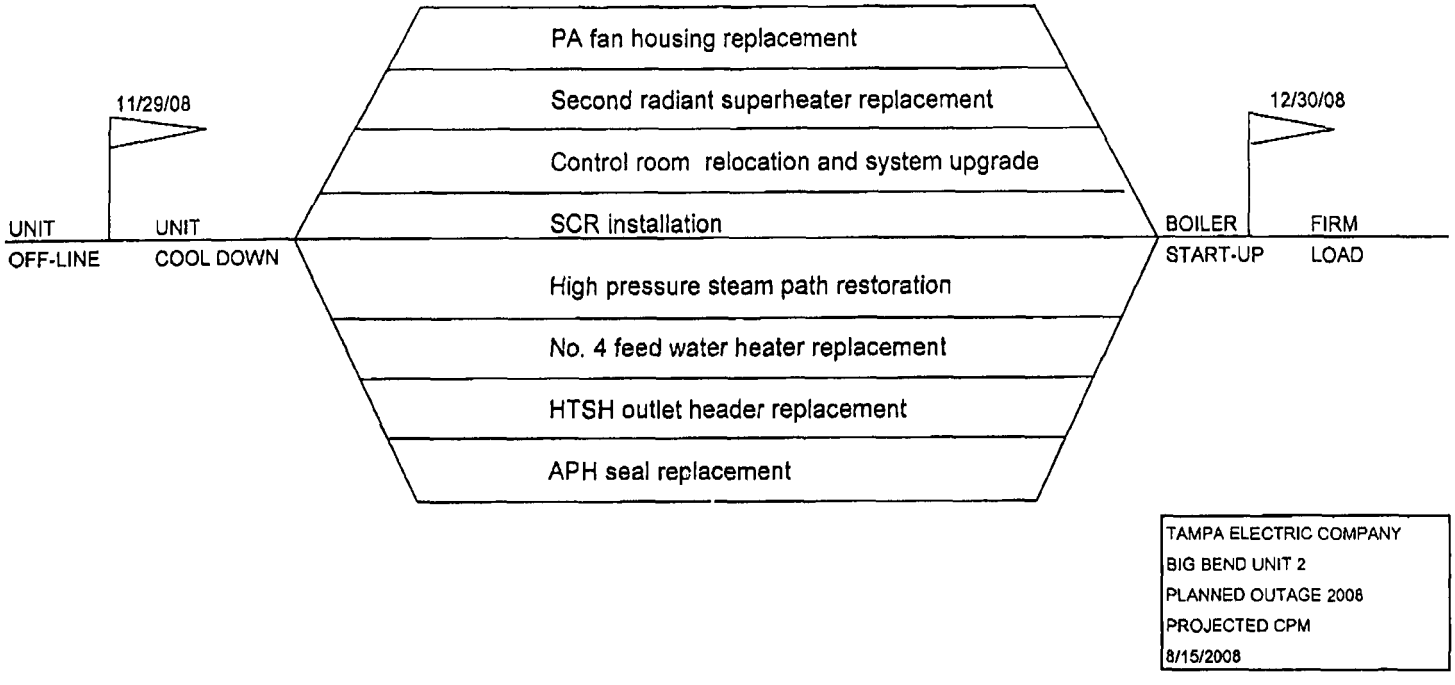
JANUARY 2008 - DECEMBER 2008

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

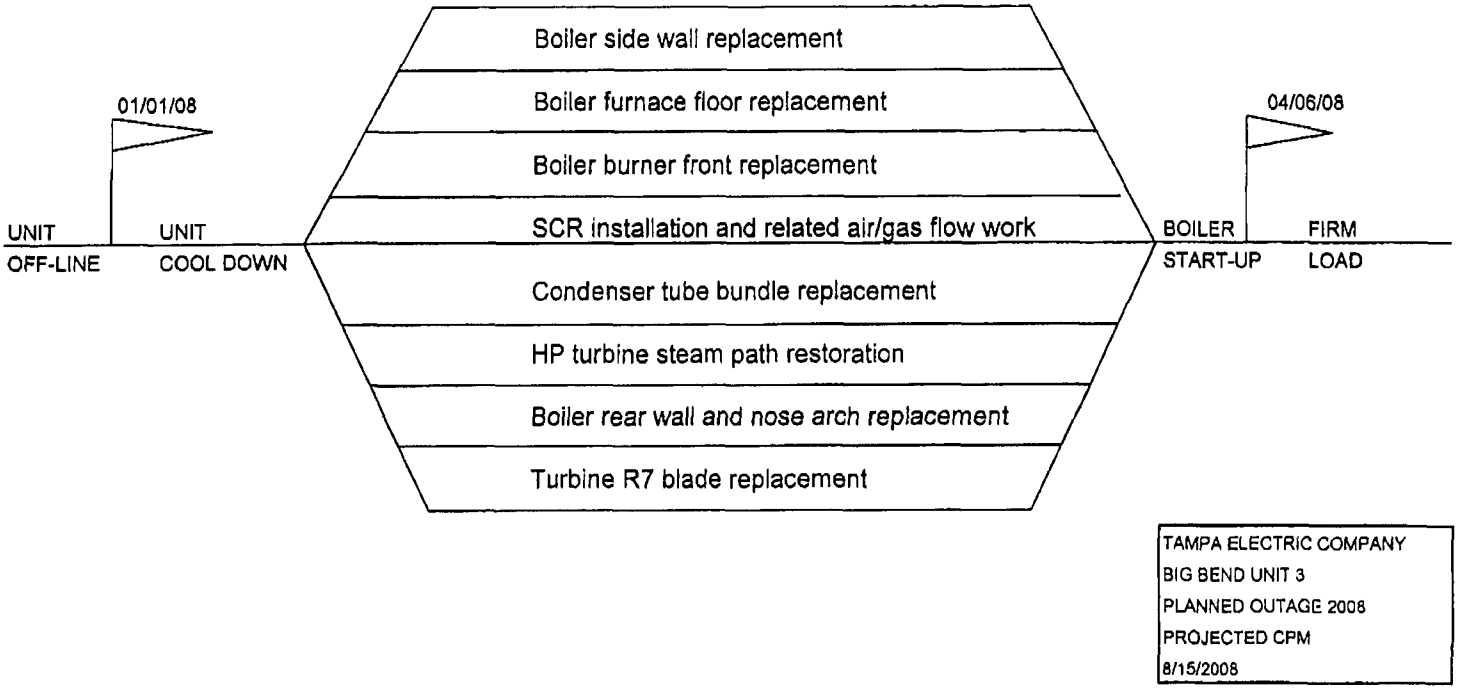
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2008 - DECEMBER 2008

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

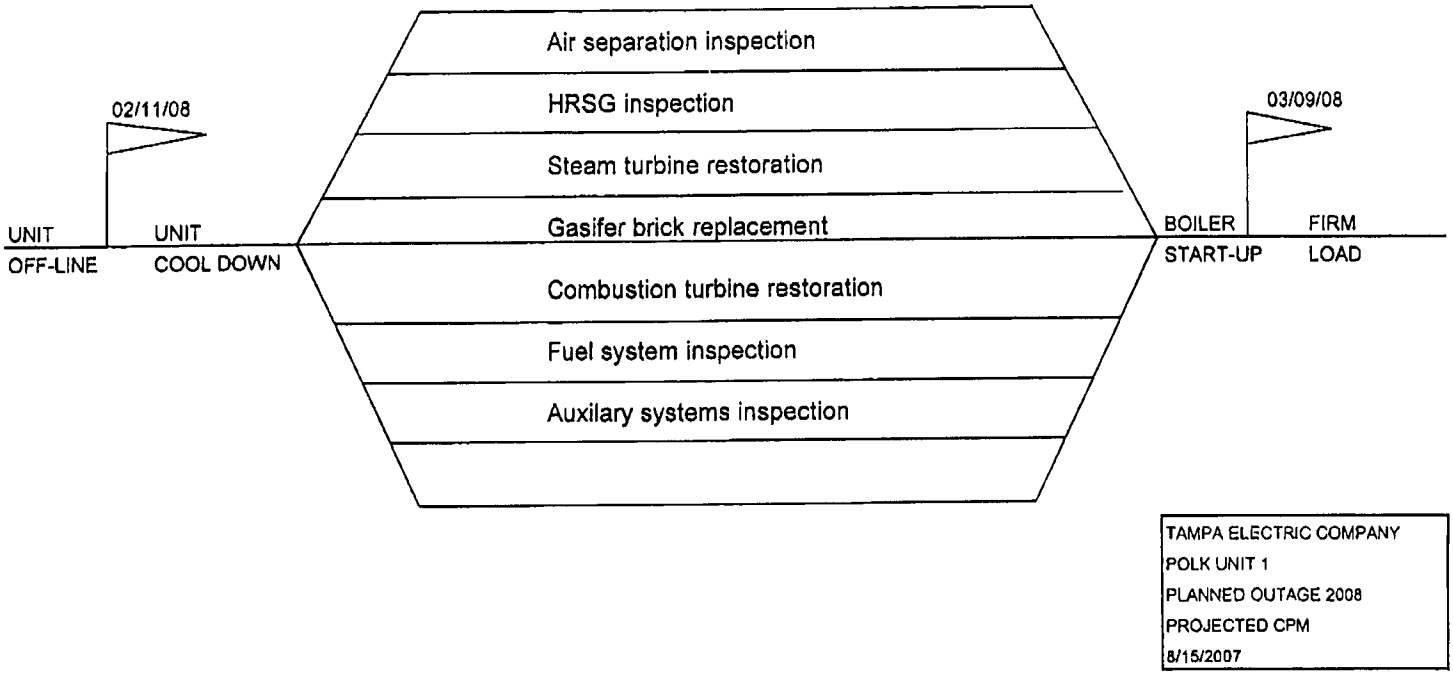
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008



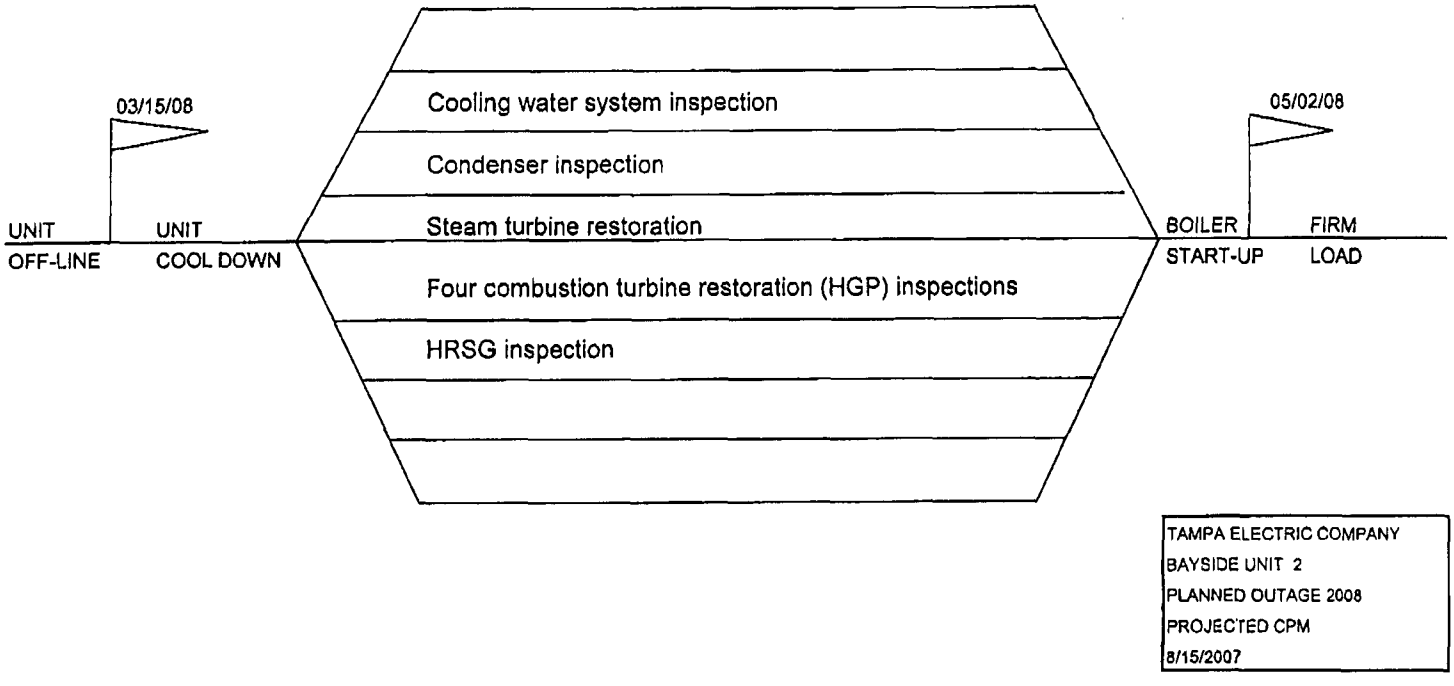
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008



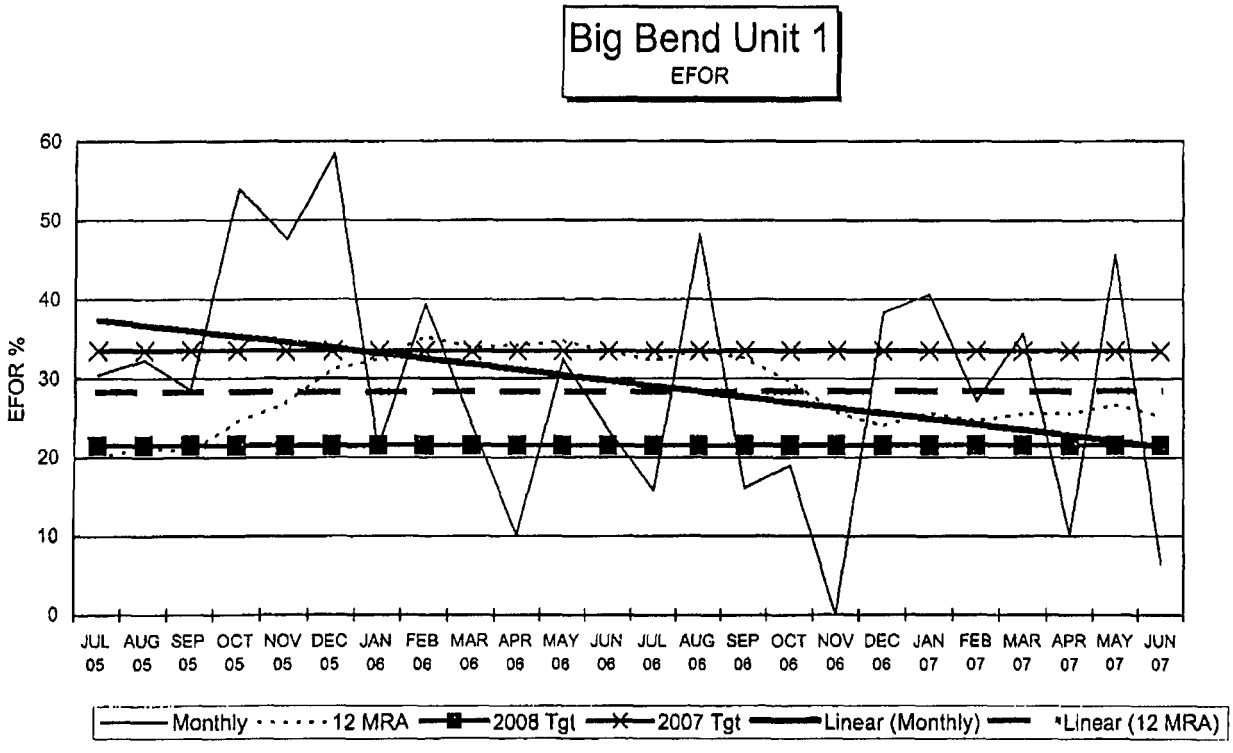
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008

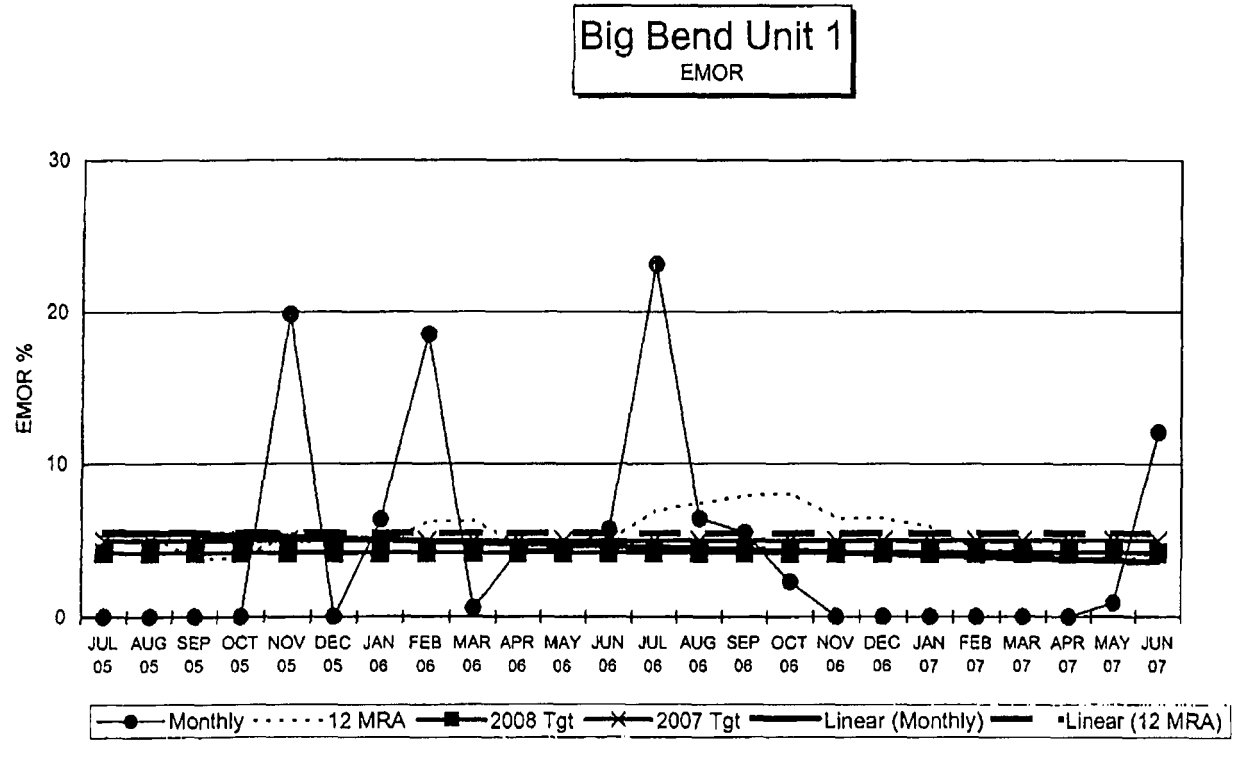


TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2008 - DECEMBER 2008

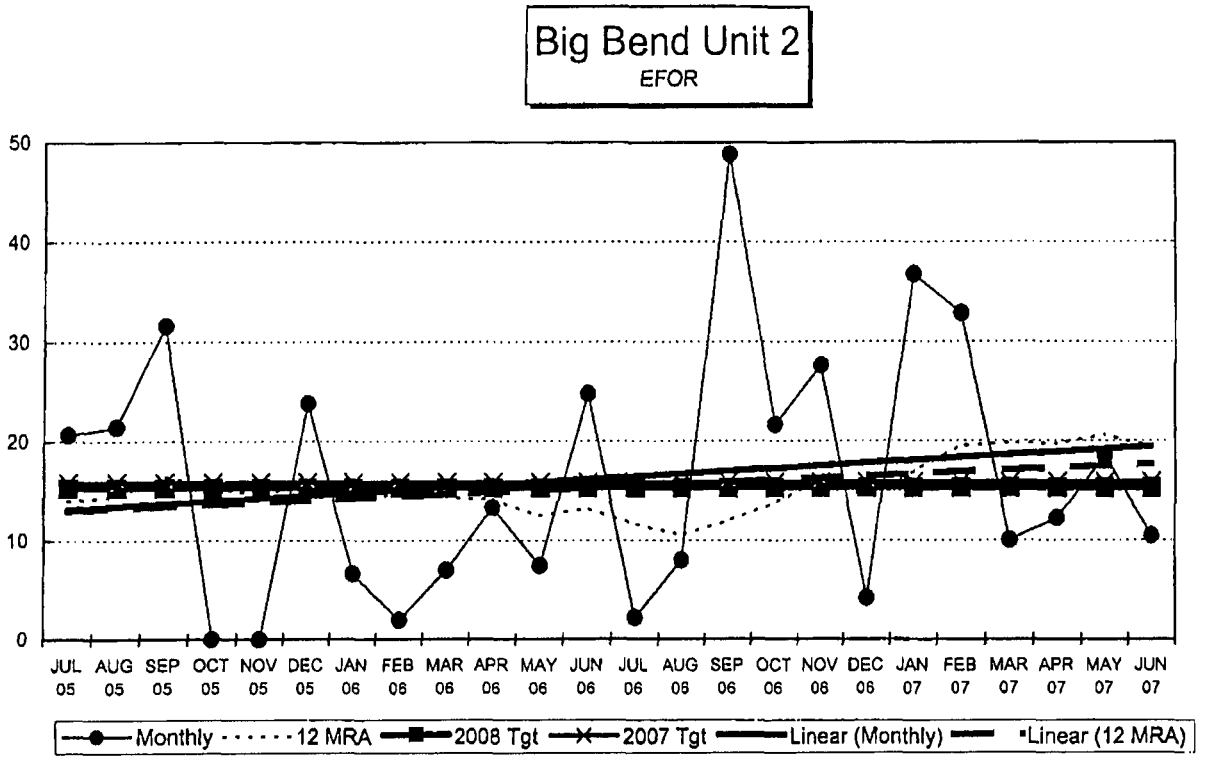


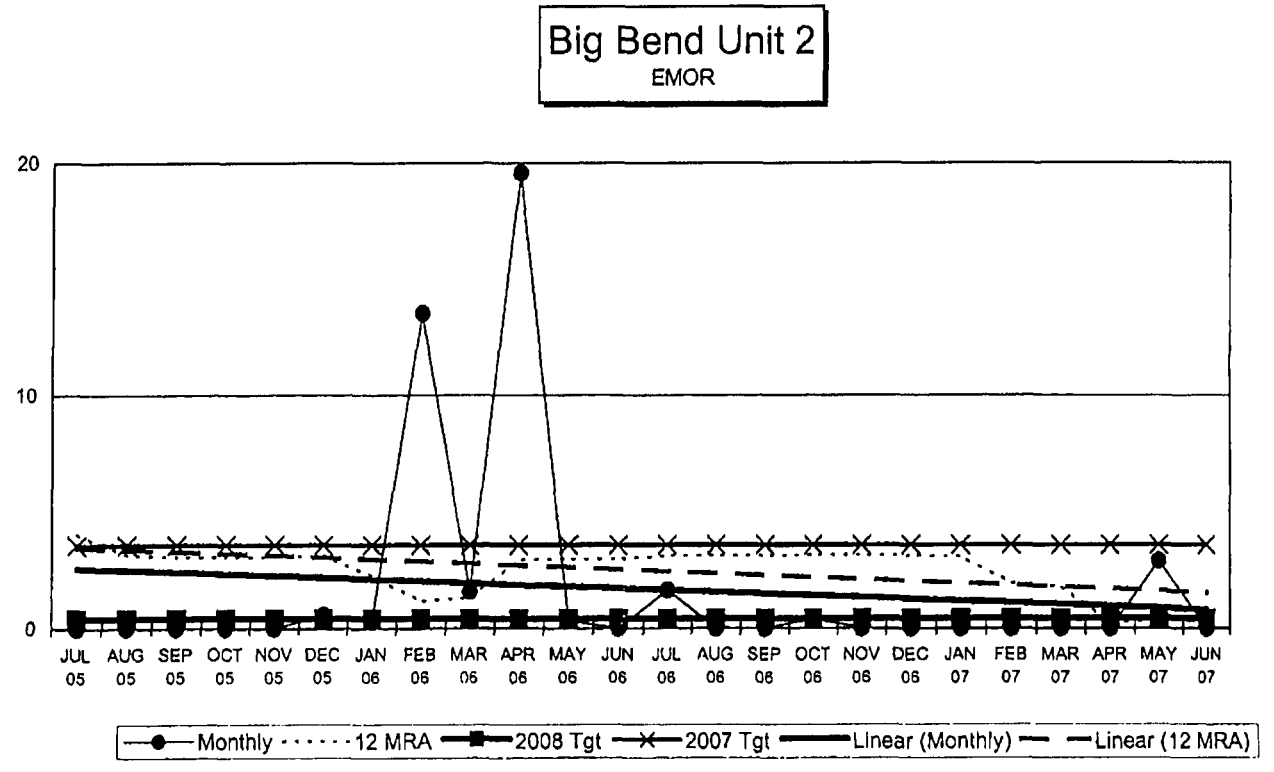
TAMPA ELECTRIC COMPANY
BAYSIDE UNIT 2
PLANNED OUTAGE 2008
PROJECTED CPM
8/15/2007



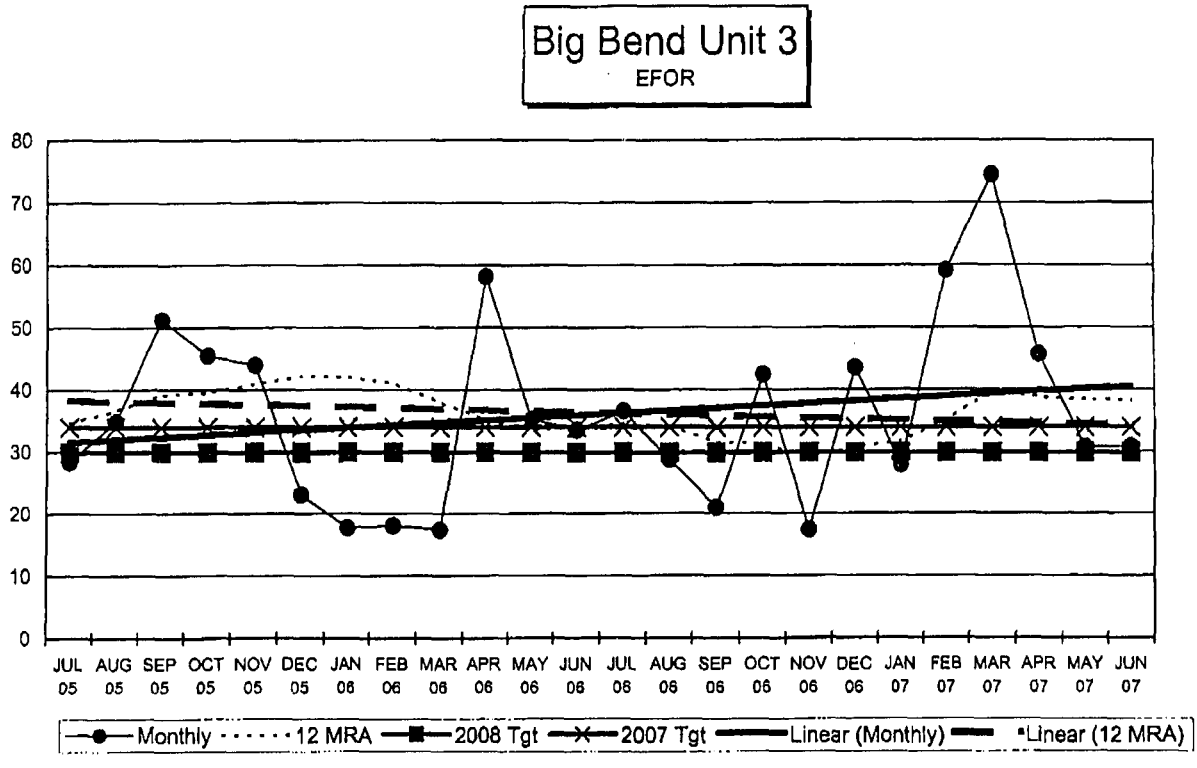


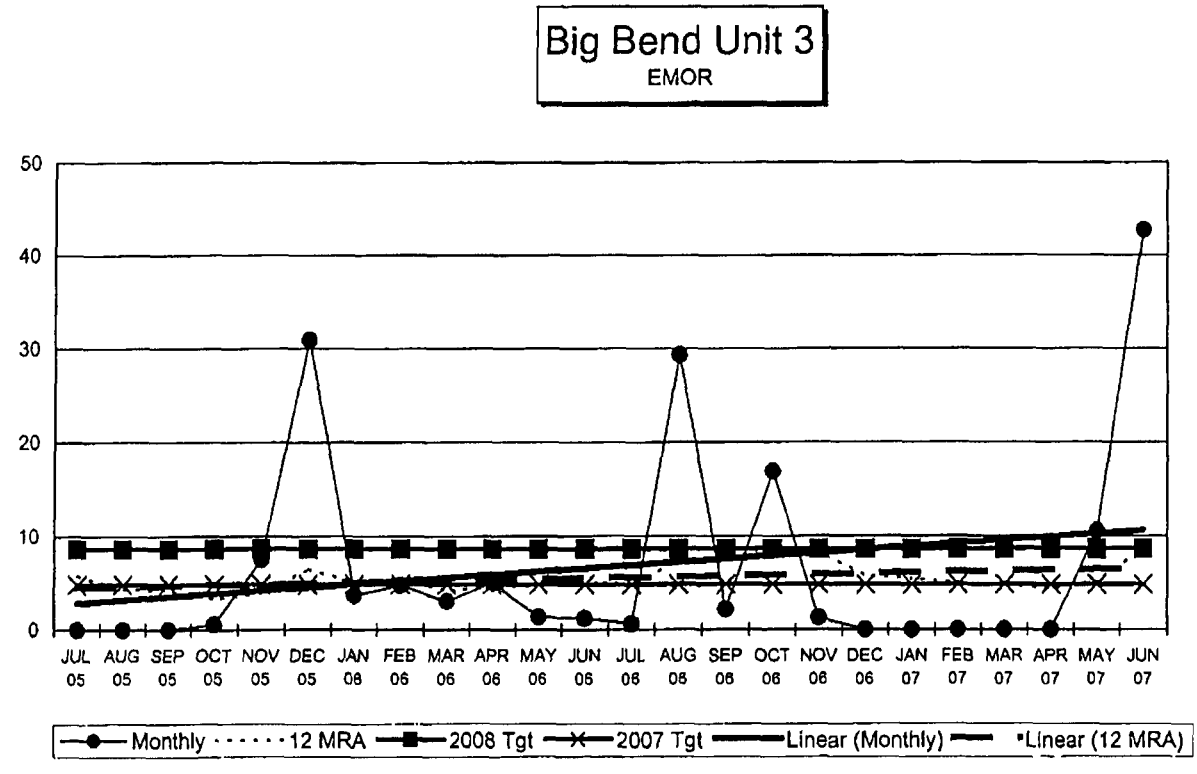
12 MRA = 12 Month Rolling Average



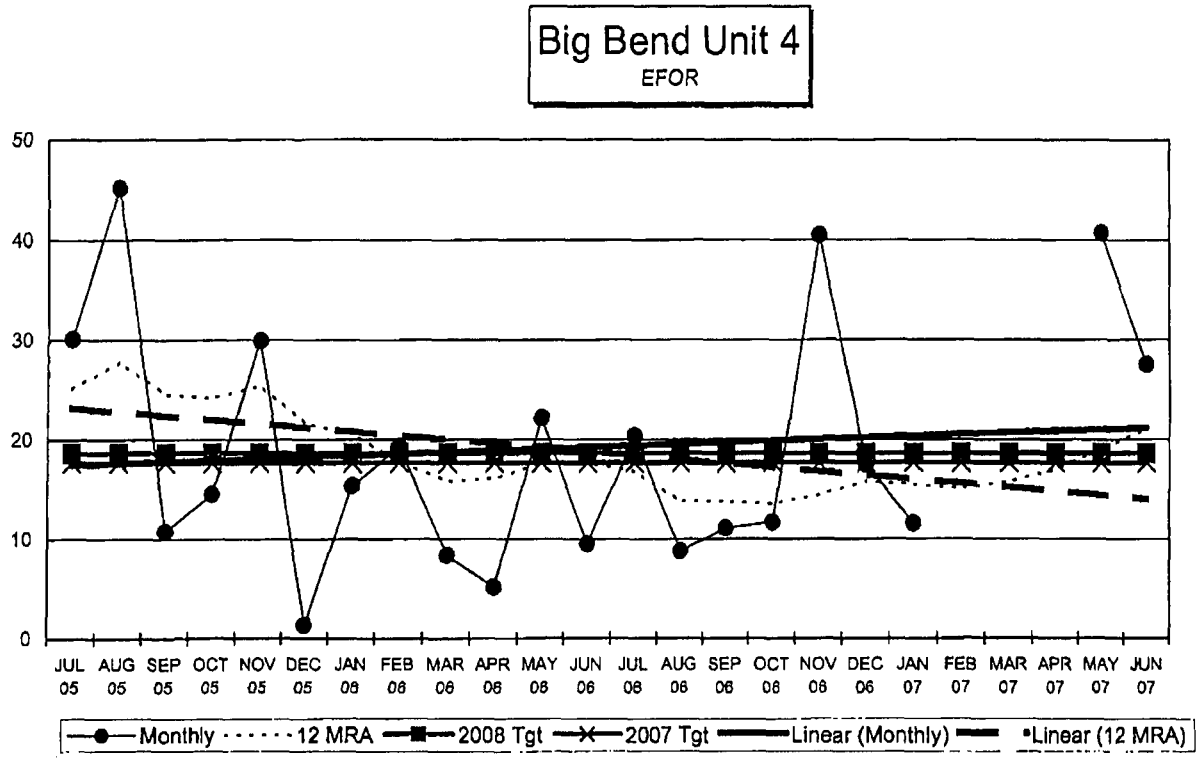


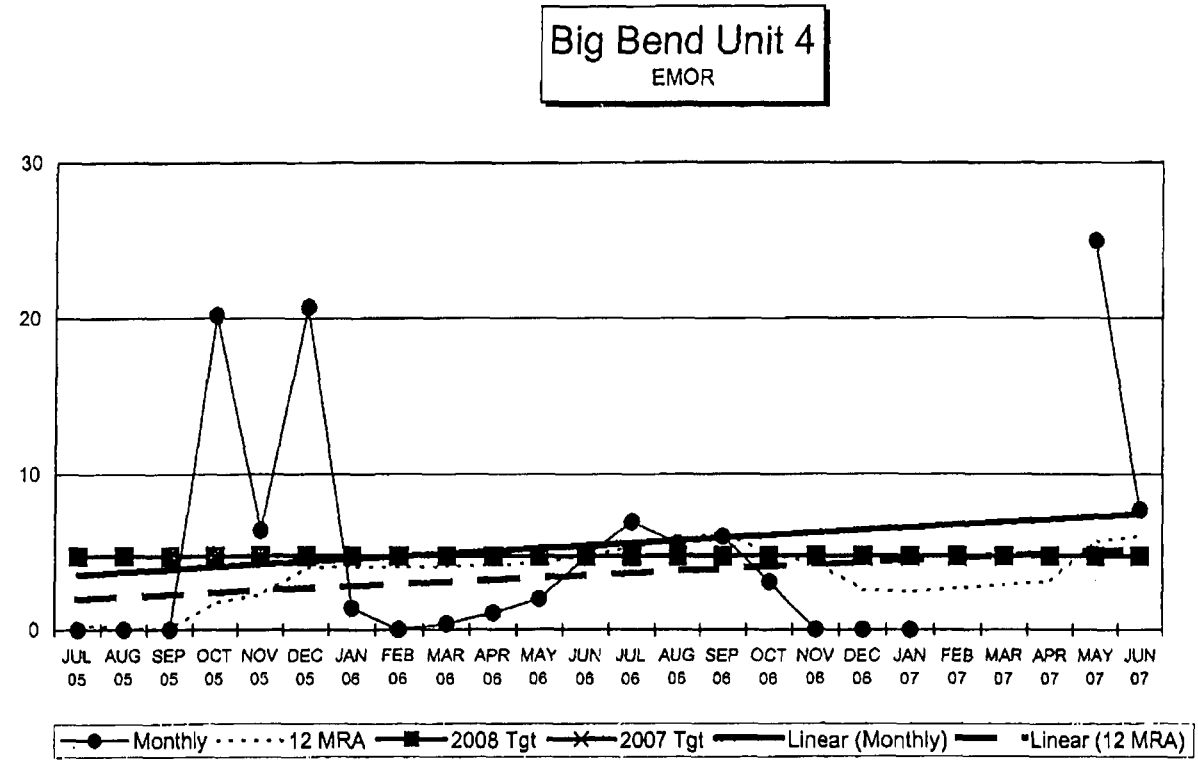
12 MRA = 12 Month Rolling Average





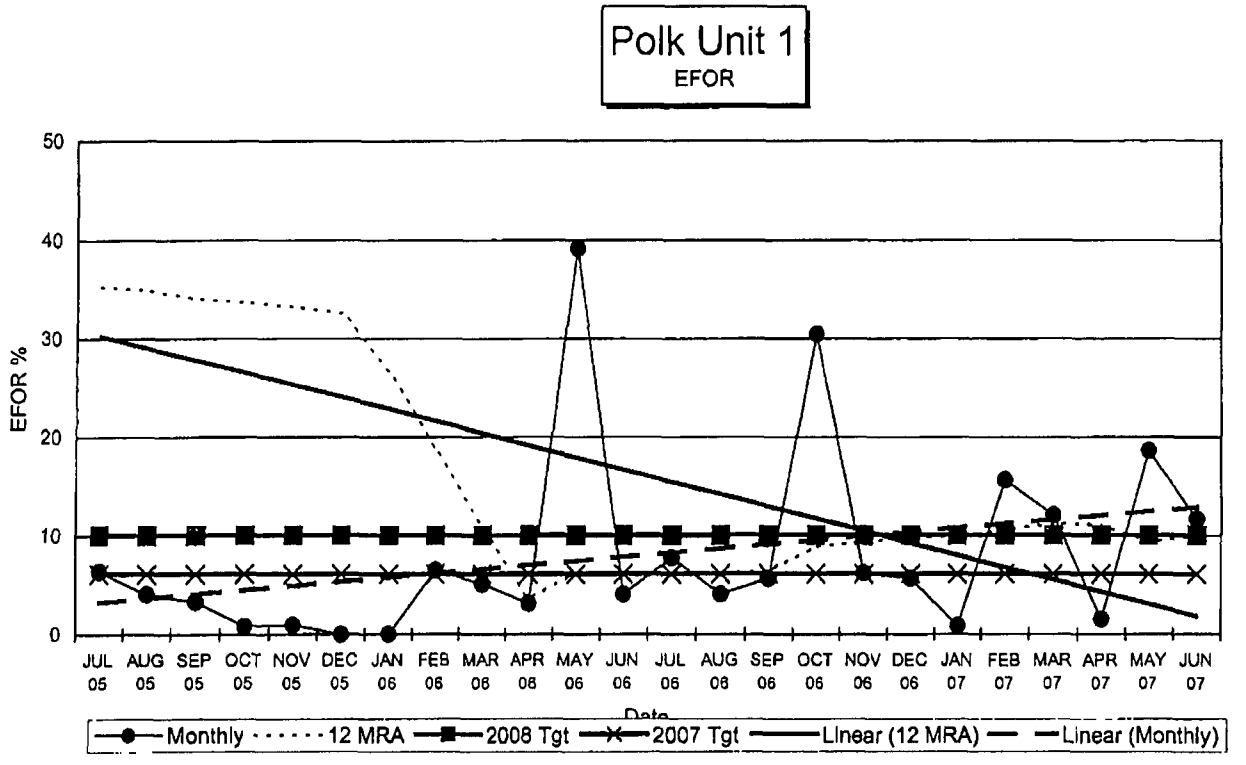
12 MRA ◘ 12 Month Rolling Average

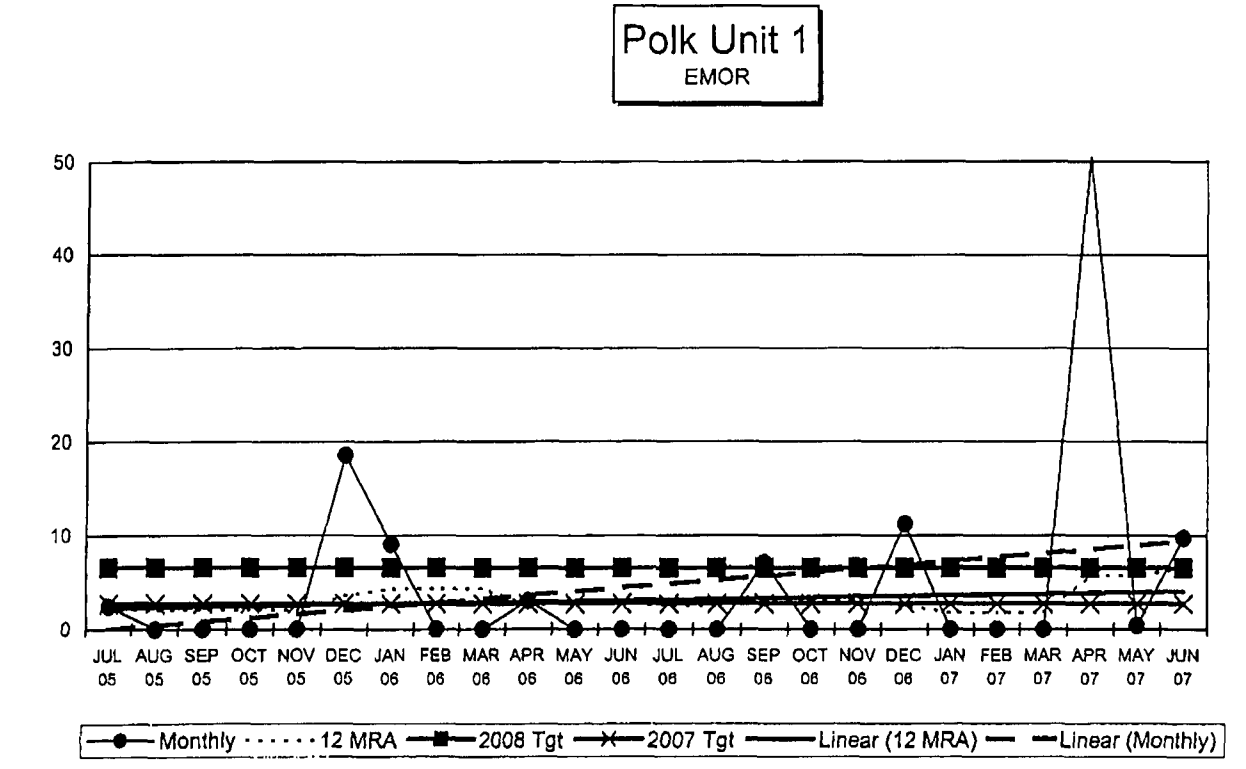




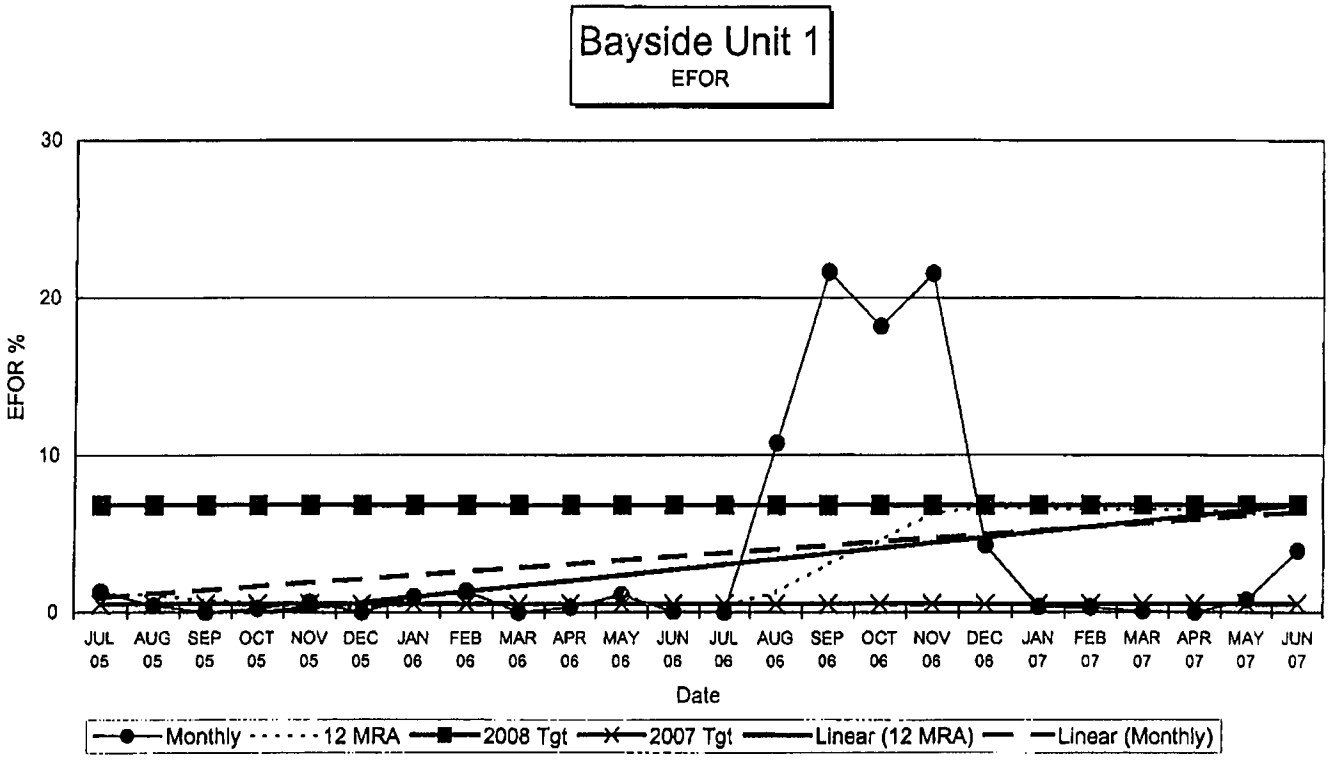
Note: Big Bend Unit 4 was offline for SCR installation from 2/1/2007 to 5/19/2007; therefore, data is not available for the months of February, March and April.

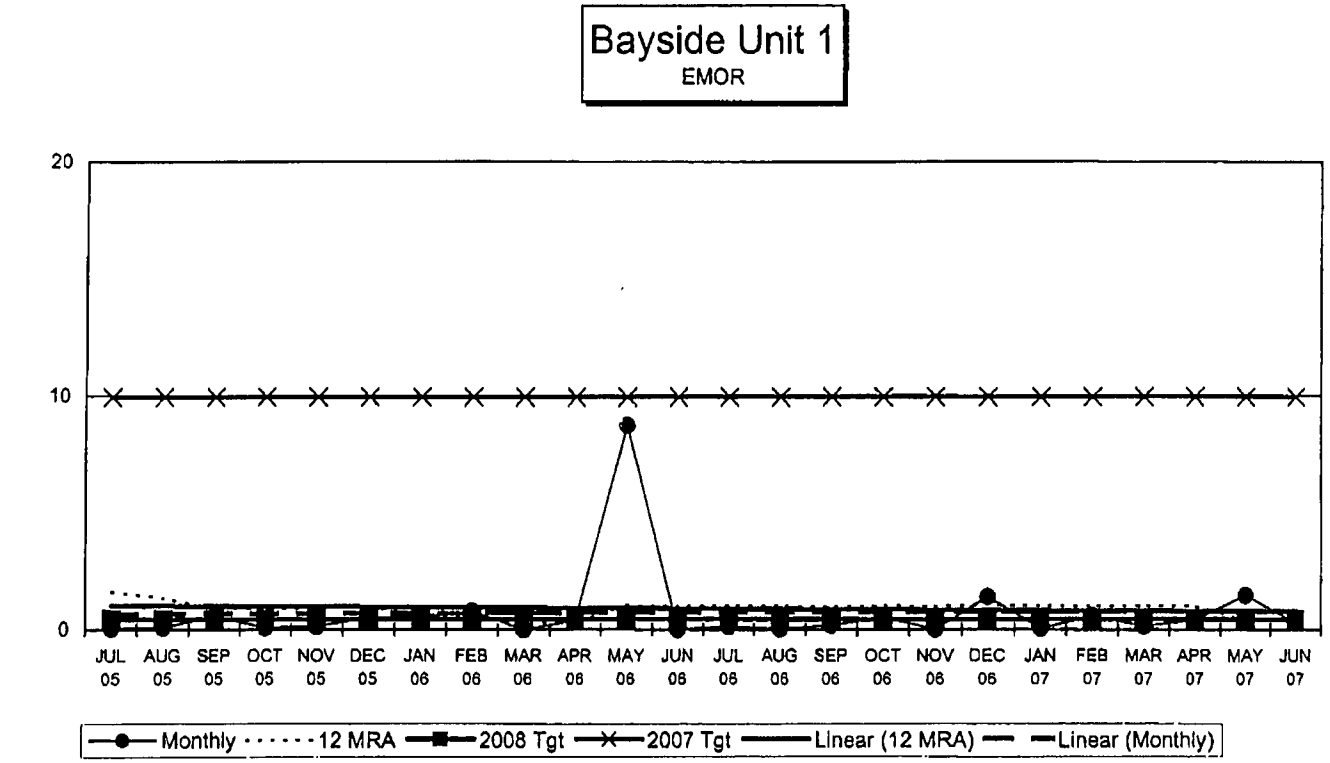
12 MRA = 12 Month Rolling Average



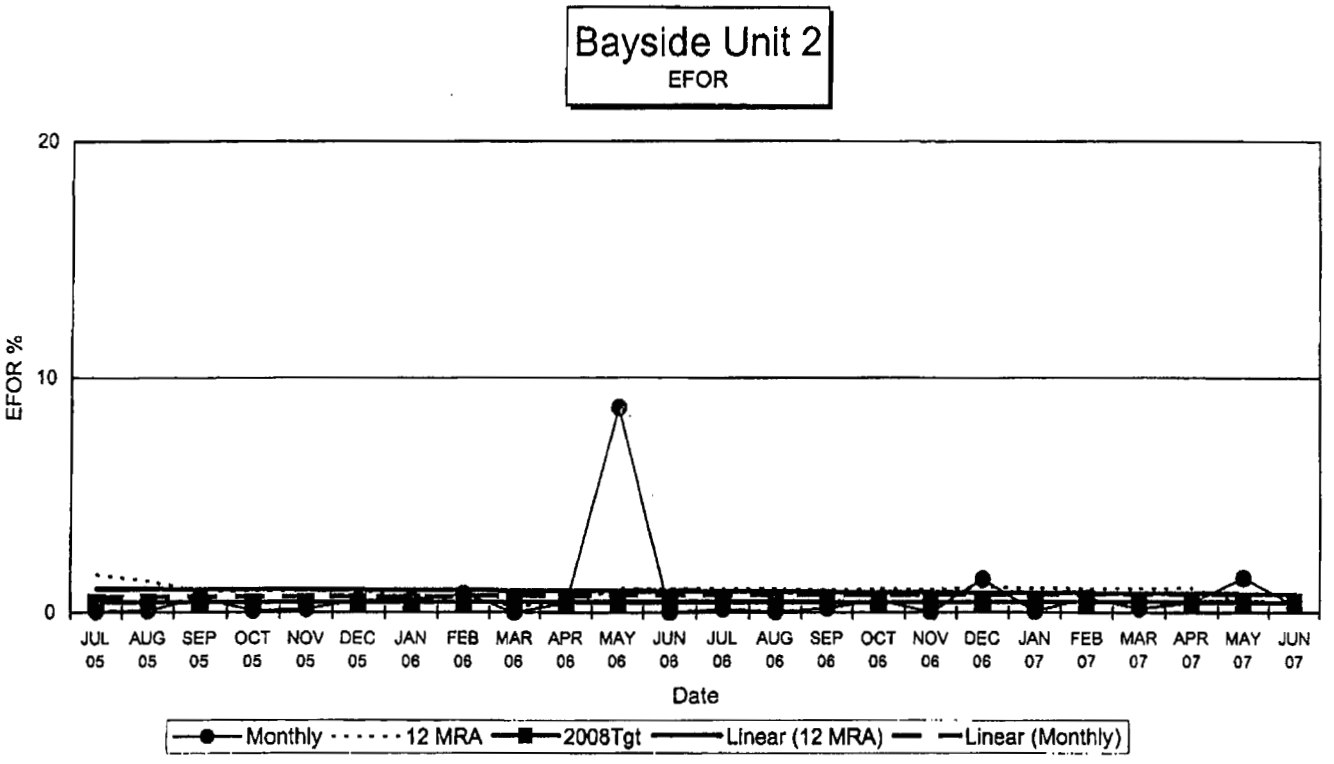


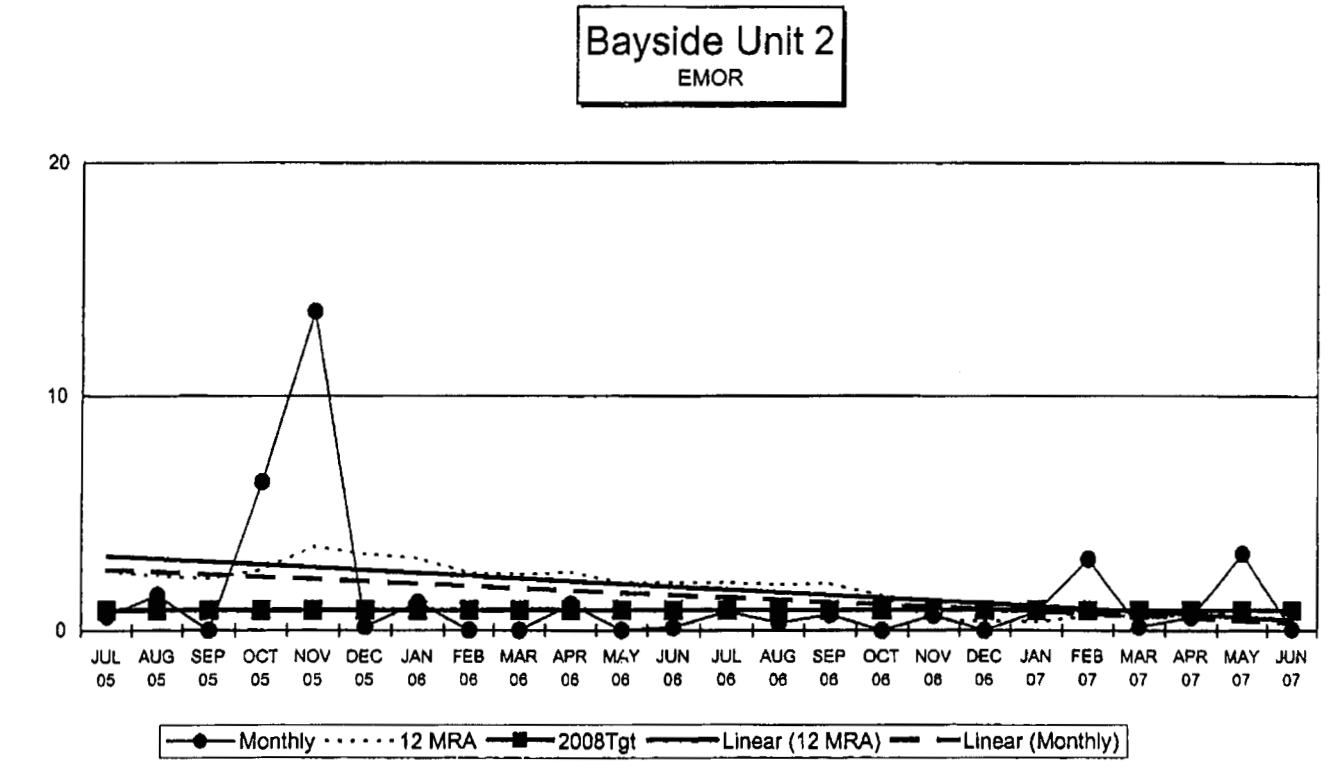
12 MRA = 12 Month Rolling Average





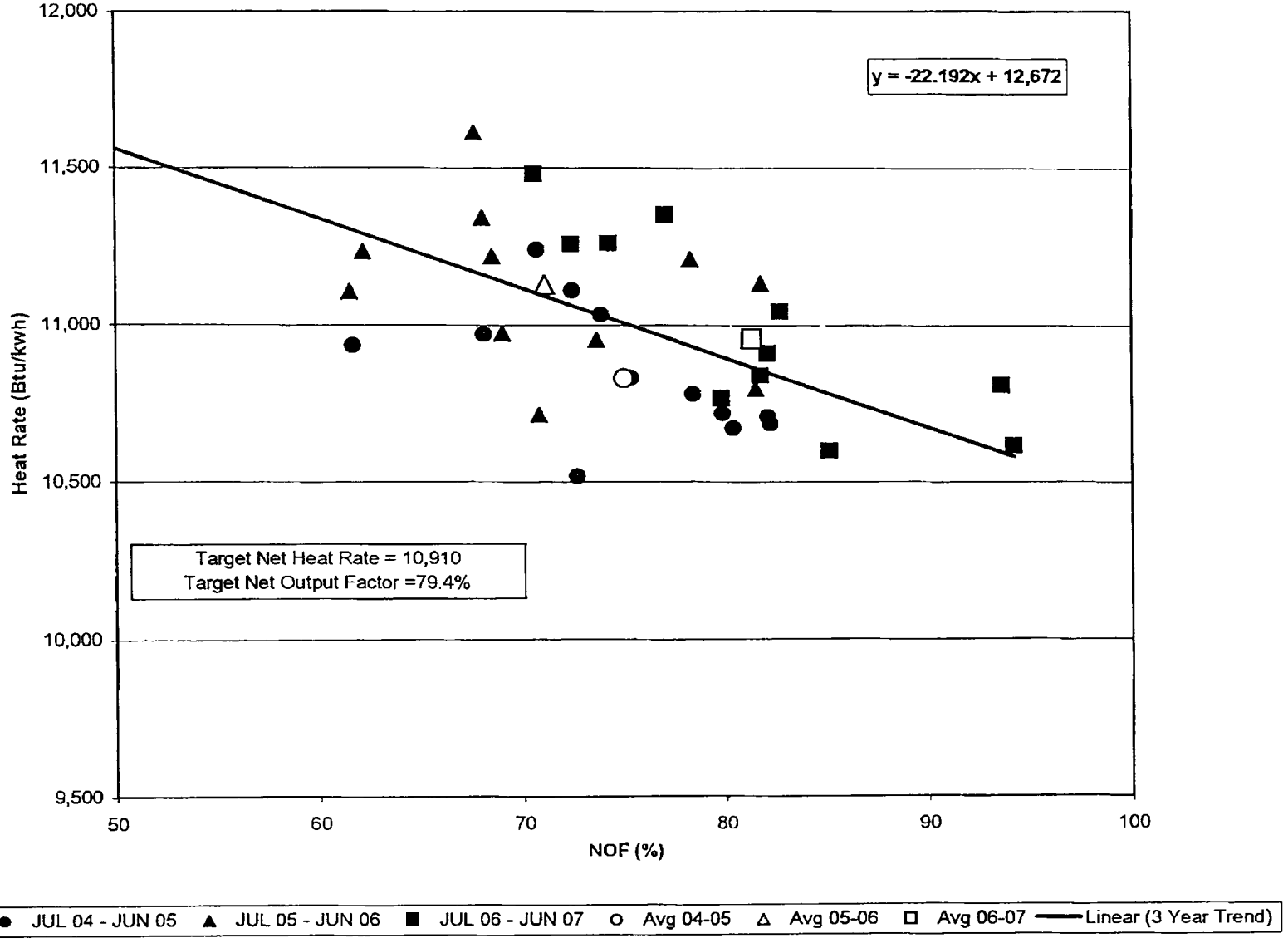
12 MRA = 12 Month Rolling Average



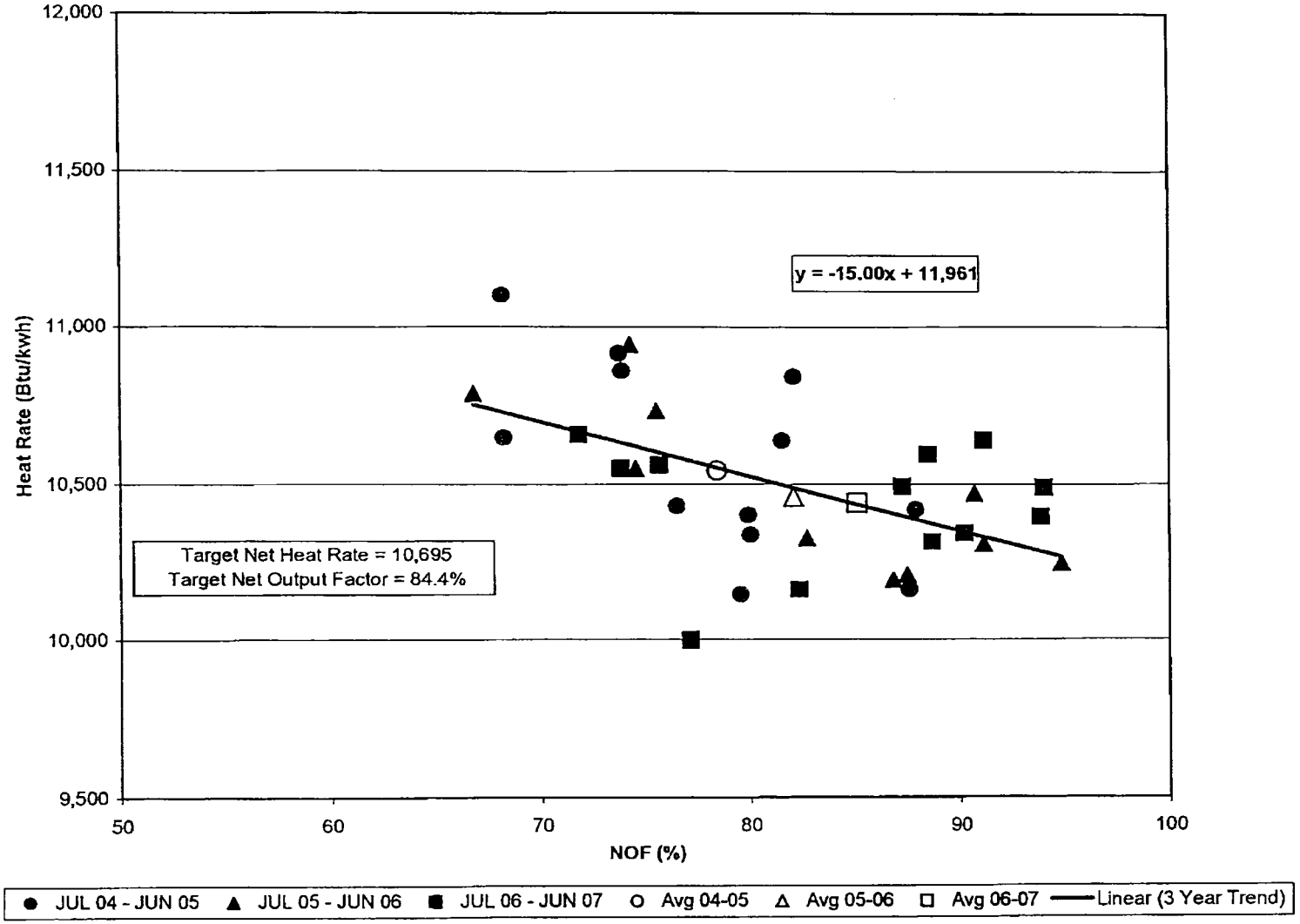


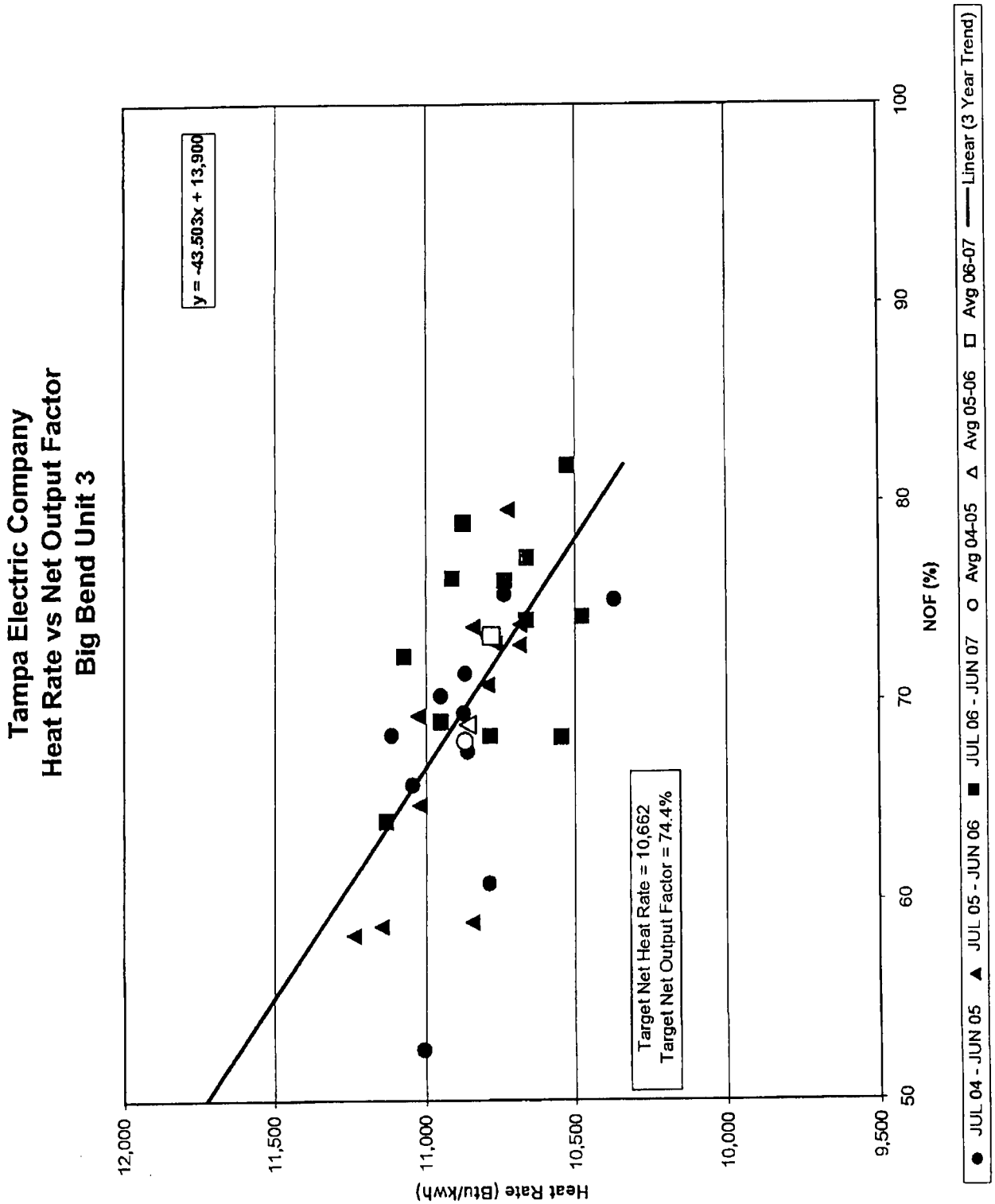
12 MRA = 12 Month Rolling Average

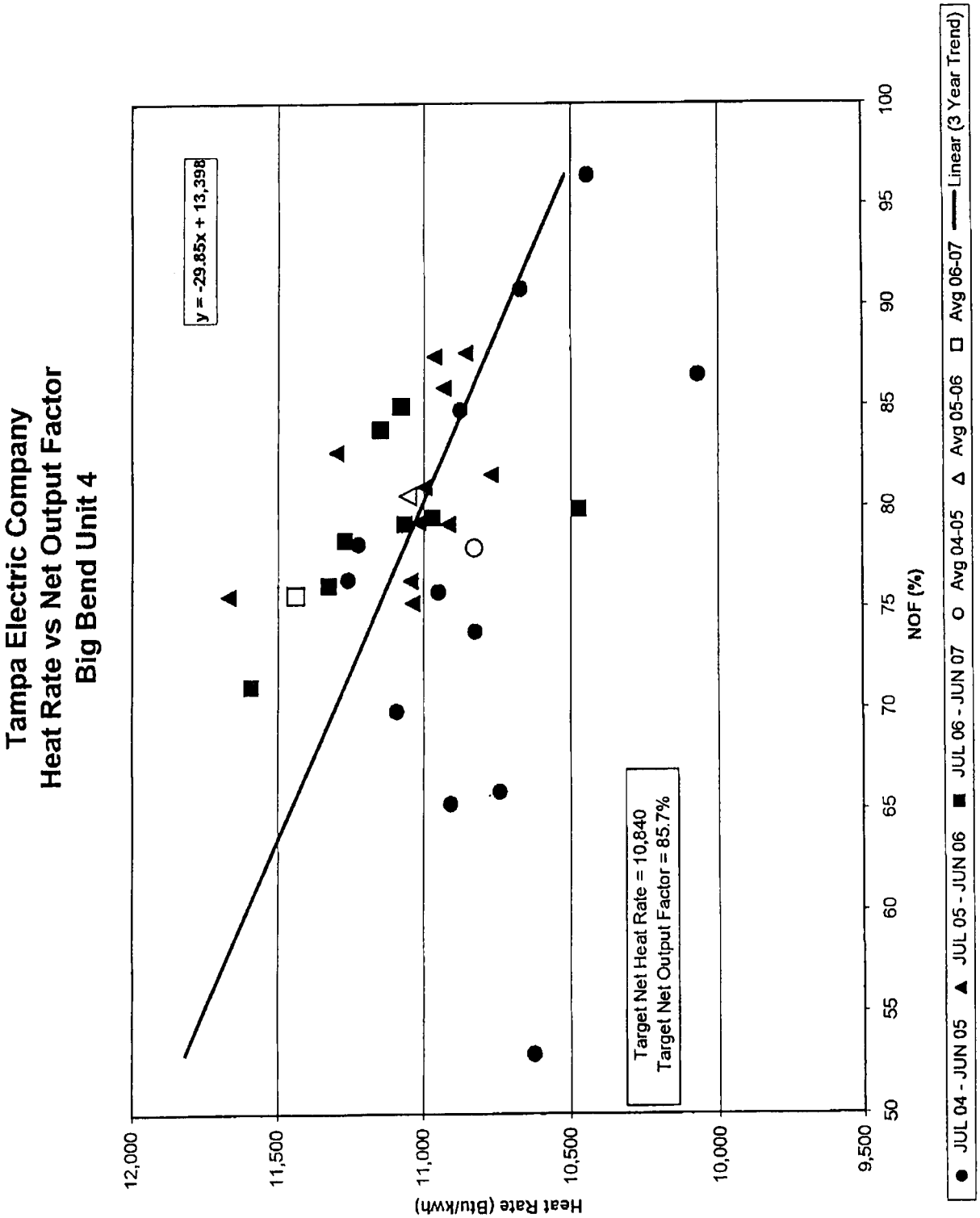
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1



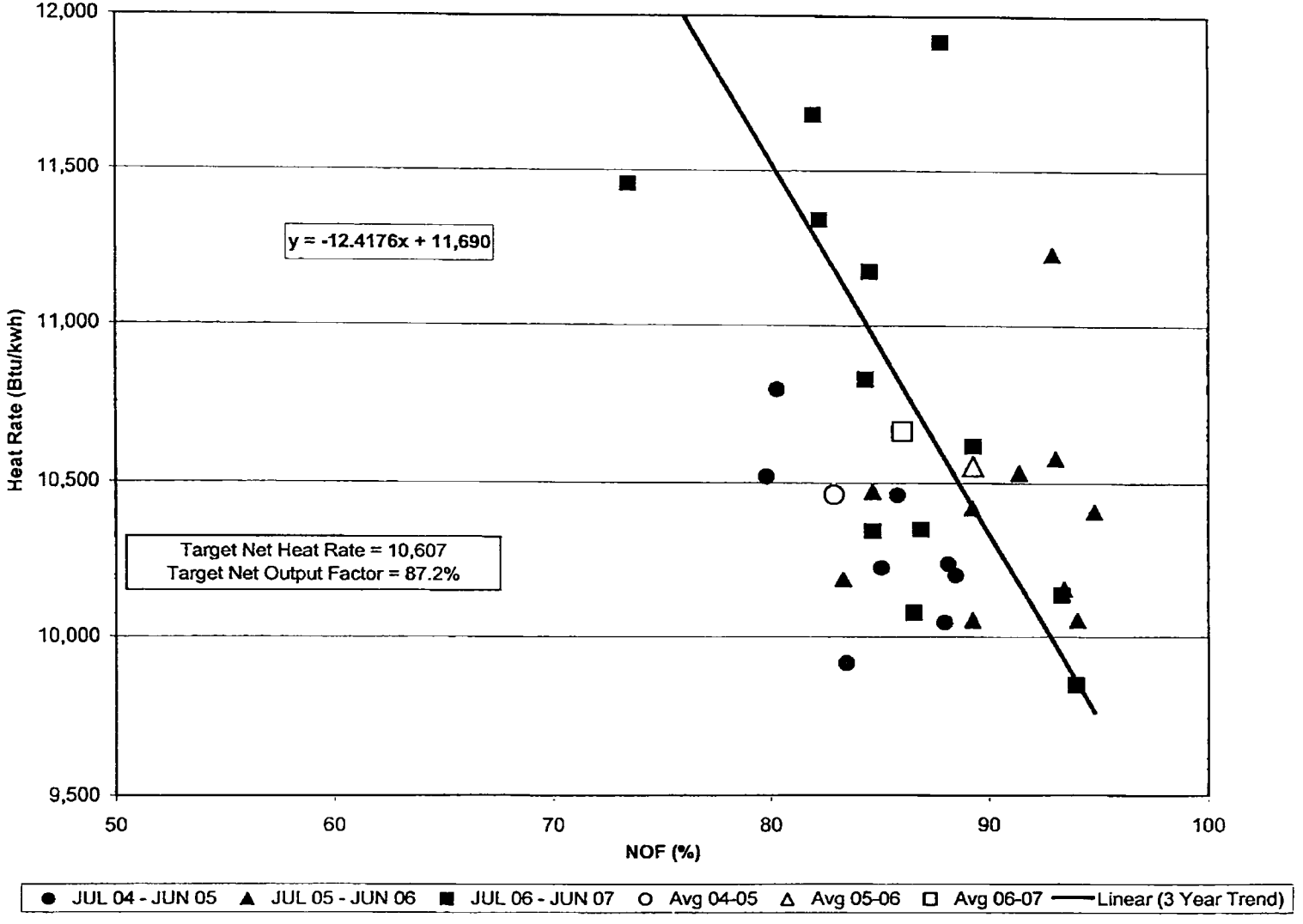
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2

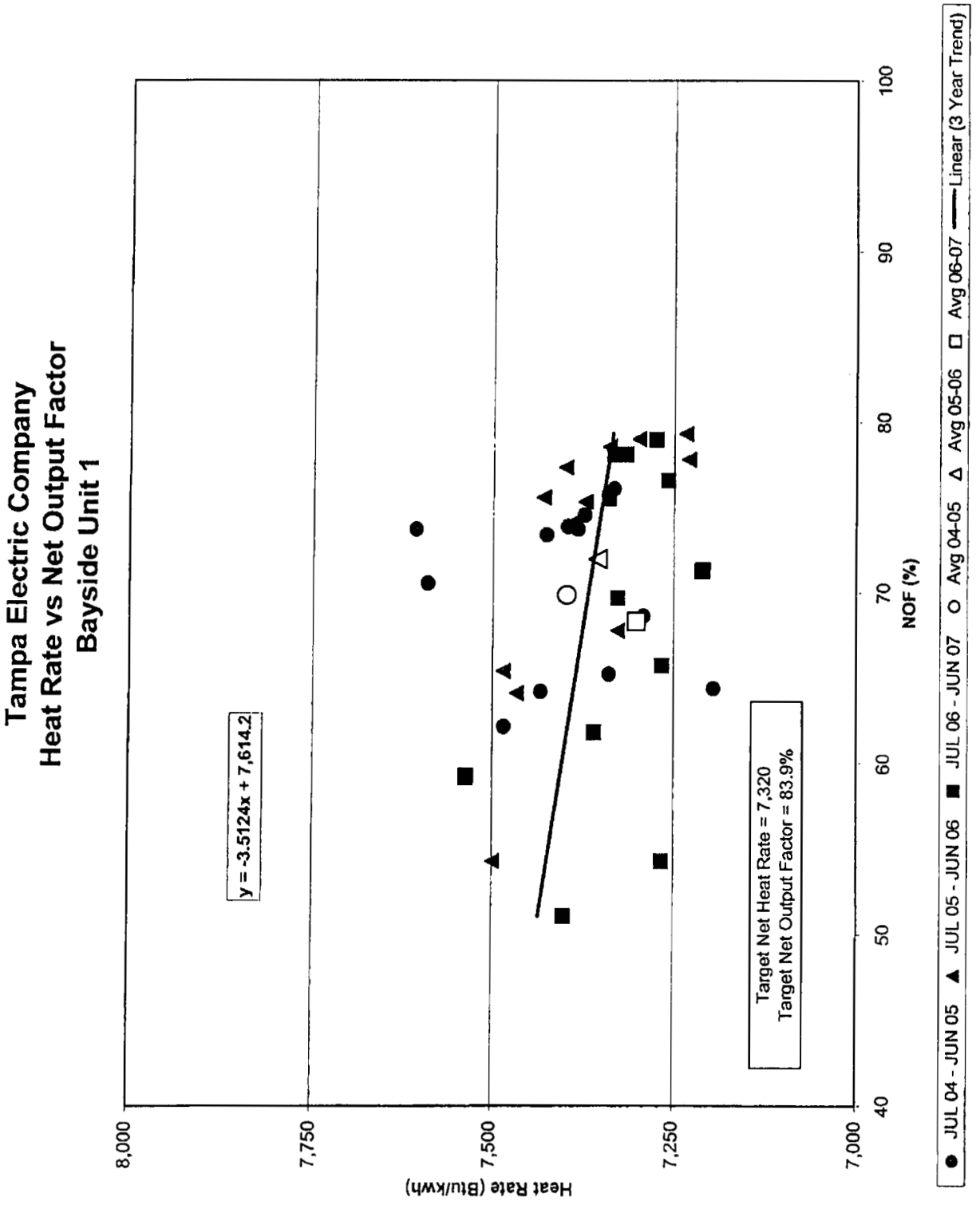



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
y = -43.503x + 13,900
Target Net Heat Rate = 10,662
Target Net Output Factor = 74.4%
Heat Rate (Btu/kwh)
NOF (%)
12,000
11,500
11,000
10,500
10,000
9,500
50
60
70
80
90
100
JUL 04 - JUN 05
JUL 05 - JUN 06
JUL 06 - JUN 07
Avg 04-05
Avg 05-06
Avg 06-07
Linear (3 Year Trend)

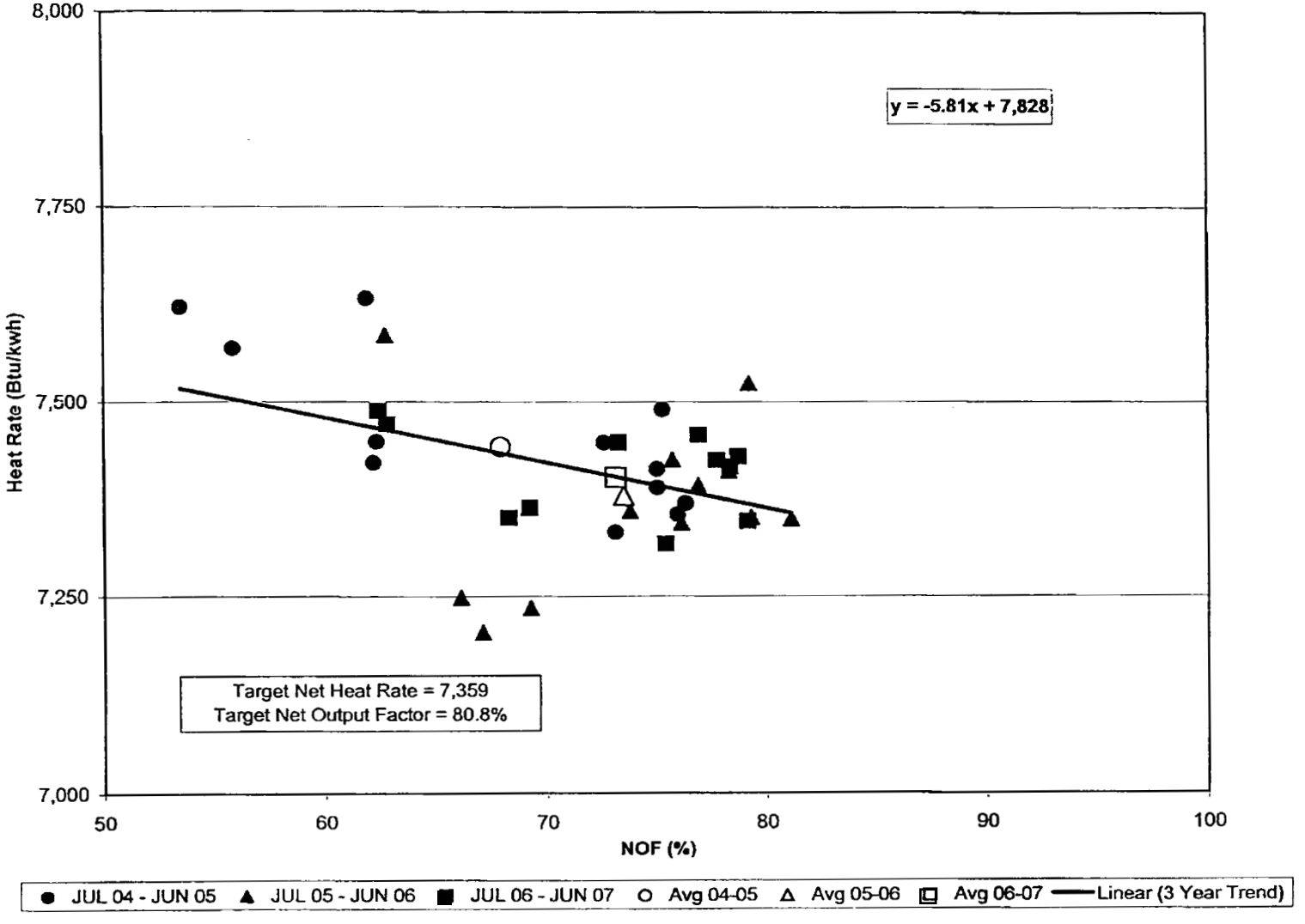

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4
y = -29.85x + 13,398
Target Net Heat Rate = 10,840
Target Net Output Factor = 85.7%
Heat Rate (Btu/kwh)
NOF (%)
12,000
11,500
11,000
10,500
10,000
9,500
50
55
60
65
70
75
80
85
90
95
100
JUL 04 - JUN 05
JUL 05 - JUN 06
JUL 06 - JUN 07
Avg 04-05
Avg 05-06
Avg 06-07
Linear (3 Year Trend)

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




Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
y = -3.5124x + 7,614.2
Target Net Heat Rate = 7,320
Target Net Output Factor = 83.9%
Heat Rate (Btu/kwh)
NOF (%)
8,000
7,750
7,500
7,250
7,000
40
50
60
70
80
90
100
JUL 04 - JUN 05
JUL 05 - JUN 06
JUL 06 - JUN 07
Avg 04-05
Avg 05-06
Avg 06-07
Linear (3 Year Trend)

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



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

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

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2008 - DECEMBER 2008

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

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

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

GENERATION BY COAL UNITS: 10,352,772 MWH
% GENERATION BY COAL UNITS 53.45%

GENERATION BY NATURAL GAS UNITS: 8,954,840 MWH
% GENERATION BY NATURAL GAS UNITS 46.23%

GENERATION BY OIL UNITS: 62,367 MWH
% GENERATION BY OIL UNITS: 0.32%

GENERATION BY GPIF UNITS: 18,977,830 MWH
% GENERATION BY GPIF UNITS: 97.98%

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

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2008 - DECEMBER 2008

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

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

1/ Original Sheet 8.401.07E, Page 14

2/ Original Sheet 8.401.07E, Page 15

3/ Original Sheet 8.401.07E, Page 16

4/ Original Sheet 8.401.07E, Page 17

5/ Original Sheet 8.401.07E, Page 18

6/ Original Sheet 8.401.07E, Page 19

7/ Original Sheet 8.401.07E, Page 20

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FINAL TRUE-UP

JANUARY 2006 THROUGH DECEMBER 2006

TESTIMONY AND EXHIBIT

OF

JOANN T. WEHLE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 43
COMPANY Tampa Electric Co.
WITNESS Joann T. Wehle (JTW-1)
DATE 11-06-07

Calculation of Incremental Hedging Expenses

		Actual Expenses				
	Baseline	2002	2003	2004	2005	2006
1. Payroll and Fringe Benefits	$159,723	$252,939	$256,362	$290,096	$242,663	$278,170
2. Travel Costs	2,500	0	210	0	0	0
3. Training	6,930	0	0	0	0	0
4. Consultants / Subscriptions to Market Publications	0	0	20,682	28,242	29,200	36,437
5. System License Fees	0	0	645	60,860	62,250	65,195
6. Total	$169,153	$252,939	$277,899	$379,198	$334,113	$379,802
Incremental Hedging Expenses (Annual Expenses - Baseline)	**$0**	**$83,786**	**$108,746**	**$210,045**	**$164,960**	**$210,649**

Note: The baseline is actual 2001 risk management expenses.

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2008 THROUGH DECEMBER 2008

TESTIMONY AND EXHIBIT

OF

JOANN T. WEHLE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 44
COMPANY Tampa Electric Co.
WITNESS Joann T. Wehle (JTW-2)
DATE 11-06-07

TAMPA ELECTRIC COMPANY
DOCKET NO. 070001-EI
FILED: 9/4/07

EXHIBIT TO THE TESTIMONY OF

JOANN T. WEHLE

2006 WATERBORNE TRANSPORTATION COST ADJUSTMENT

January - December 2006	(A) Contract $/Ton [1] [3]	(B) Adjusted $/Ton [2]	(C) Disallowance $/Ton	(D) Total Tons	(A*D) Contract Total	(B*D) Adjusted Total	(C*D) Disallowed Total
Inland River Docks							
Pet Coke Refinery (M.P. 140)					$ 827,493	$ 716,288	$ 111,205
Chester Dock					5,740,957	4,957,790	783,167
Overland/Camp					-	-	-
Hamilton					-	-	-
Empire Dock					-	-	-
Cora, Non-Zeigler					4,097,454	3,539,233	558,221
Yankeetown					-	-	-
Mount Vernon					4,004,554	3,458,478	546,076
Cook					1,026,926	887,827	139,099
Henderson River Port					-	-	-
Rigsby & Barnard (Arclar)					-	-	-
Patriot					277,443	239,733	37,711
Owensboro					-	-	-
New Hope					-	-	-
Dekoven					2,706,855	2,337,920	368,934
Jefferson					-	-	-
Powhatan					-	-	-
Caseyville					78,530	67,811	10,719
S. Indiana/Evansville					181,006	156,403	24,603
Pyramid					-	-	-
Ken Mine					-	-	-
GRT					-	-	-
Kentucky Lakes Dock					-	-	-
Transcontinental (TTI)					-	-	-
Sebree					2,785,687	2,406,274	379,413
Amon					932,662	805,529	127,134
Shawneetown					7,702,226	6,650,380	1,051,846
Total River					**$ 30,361,792**	**$ 26,223,666**	**$ 4,138,126**
Ocean							
Coal					37,008,248	25,831,571	11,176,676
Petcoke from Texas					-	-	-
Total Ocean					**$ 37,008,248**	**$ 25,831,571**	**$ 11,176,676**
						Total	**$ 15,314,802**

1 Contract rate per contract signed with TECO Transport.

2 Adjusted rate based on methodology set forth in Order No. PSC-04-0999-FOF-EI, which takes the weighted average rate for all upriver terminals minus $1 and divides it by the weighted average rate of all upriver terminals multiplied by the contract rate for that specific upriver terminal. Ocean rate based on the aforementioned Order.

3 Contract rate subject to quarterly escalation provisions in the contract. Therefore, ratio between total contract amount and adjustment will change moving forward.

DOCKET NO. 070001-EI
FAC 2008 PROJECTION FILING
EXHIBIT NO.___ (JTW-2), PAGE 1 OF 1
DOCUMENT NO. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT #45 Withdrawn
COMPANY _____
WITNESS _____
DATE _____

DOCKET NO. 070001-EI
NOVEMBER 6, 2007 HEARING
ADDITIONAL STIPULATIONS

All stipulations are for true-up purposes. The specific expenditures remain subject to any subsequent prudence review.

ISSUE 1: What are the appropriate fuel adjustment true-up amounts for the period January 2006 through December 2006?

POSITION

FPUC: Marianna: $74,131 (over recovery) which includes an adjustment of $130,592 for Audit Finding 1 of the 2006 FPUC Fuel Audit, Audit Control No. 07-022-4-2.
Fernandina Beach: $272,928 (over recovery) which includes an adjustment of $187,940, for Audit Finding 1 of the 2006 FPUC Fuel Audit, Audit Control No. 07-022-4-2.

ISSUE 2: What are the appropriate fuel adjustment true-up amounts for the period January 2007 through December 2007?

POSITION

FPUC: Marianna: $77,987 (under-recovery)
Fernandina Beach: $277,968 (under-recovery)

ISSUE 3: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2008 to December 2008?

POSITION

FPUC: Marianna: $3,856 (to be collected)
Fernandina Beach: $5,040 (to be collected)

ISSUE 5: What are the appropriate projected net fuel and purchased power cost recovery amounts to be included in the recovery factor for the period January 2008 through December 2008?

POSITION

FPUC: Marianna: $27,061,406
Fernandina Beach: $31,882,724

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 46
COMPANY FPSC Staff
WITNESS Additional Stipulations
DATE 11-06-07

ISSUE 6: What are the appropriate levelized fuel cost recovery factors for the period January 2008 through December 2008?

POSITION

FPUC: Marianna: 4.711¢/kwh
Fernandina: 4.591¢/kwh

ISSUE 8: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

POSITION

FPUC:

Marianna:

Rate Schedule	Adjustment
RS	$.07945
GS	$.07840
GSD	$.07483
GSLD	$.07151
OL, OL1	$.06097
SL1, SL2, and SL3	$.06146
Step Rate for RS	
RS with less than a 1,000 kWh/month	$.07610
RS with more than a 1,000 kWh/month	$.08610

Fernandina:

Rate Schedule	Adjustment
RS	$.06963
GS	$.06811
GSD	$.06481
GSLD	$.06533
OL	$.05005
SL	$.04961
Step Rate for RS	
RS with less than a 1,000 kWh/month	$.06628
RS with more than a 1,000 kWh/month	$.07628

ISSUE 13A: With respect to the outage extension at Turkey Point Unit 3 which was caused by a drilled hole in the pressurized piping, should customers or FPL be responsible for the additional fuel cost incurred as a result of the extension?

POSITION This issue should be deferred to the 2008 fuel proceeding. The money at issue will continue to be held by FPL, subject to refund pending the outcome of the hearing in 2008.

ISSUE 23: What are the appropriate capacity cost recovery true-up amounts for the period January 2006 through December 2006?

POSITIONS

PEF: $3,381,972 under-recovery.

FPL: $4,030,283 under- recovery. Pursuant to Order No. PSC-01-2516-FOF-EI, issued December 26, 2001 and as clarified in Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, a portion of the capacity costs include post 9/11 incremental security costs. Some of those incremental security costs are for guard service4s at FPL's nuclear power plants. FPL acknowledges that on October 30, 2007, it received a letter from the Nuclear Regulatory Commission notifying FPL of possible security violations at FPL's nuclear plant. The Public Service Commission's approval of the capacity costs will not preclude a subsequent Commission review of the prudence of costs related to guard services and to order a refund if some or all of those costs are deemed imprudent. As always, the Public Service Commission retains jurisdiction to review issues of prudence when those issues are brought to its attention and to require refund when expenditures are deemed by the Public Service Commission to be imprudent.

GULF: $458,084 over-recovery.

TECO: $2,666,246 under-recovery.

ISSUE 24: What are the appropriate capacity cost recovery true-up amounts for the period January 2007 through December 2007?

POSITIONS

PEF: $11,417,892 under-recovery, which includes an adjustment for Audit Finding No. 1 of the PEF Capacity Clause Audit, Audit Control No. 07-022-2-4.

FPL: $15,561,009 under-recovery. Pursuant to Order No. PSC-01-2516-FOF-EI, issued December 26, 2001 and as clarified in Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, a portion of the capacity

costs include post 9/11 incremental security costs. Some of those incremental security costs are for guard service4s at FPL's nuclear power plants. FPL acknowledges that on October 30, 2007, it received a letter from the Nuclear Regulatory Commission notifying FPL of possible security violations at FPL's nuclear plant. The Public Service Commission's approval of the capacity costs will not preclude a subsequent Commission review of the prudence of costs related to guard services and to order a refund if some or all of those costs are deemed imprudent. As always, the Public Service Commission retains jurisdiction to review issues of prudence when those issues are brought to its attention and to require refund when expenditures are deemed by the Public Service Commission to be imprudent.

GULF: $1,635,509 over-recovery.

TECO: $21,130,338 under-recovery.

ISSUE 25: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2008 through December 2008?

POSITIONS

PEF: $14,799,865 under-recovery.

FPL: $19,591,292 . Pursuant to Order No. PSC-01-2516-FOF-EI, issued December 26, 2001 and as clarified in Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, a portion of the capacity costs include post 9/11 incremental security costs. Some of those incremental security costs are for guard service4s at FPL's nuclear power plants. FPL acknowledges that on October 30, 2007, it received a letter from the Nuclear Regulatory Commission notifying FPL of possible security violations at FPL's nuclear plant. The Public Service Commission's approval of the capacity costs will not preclude a subsequent Commission review of the prudence of costs related to guard services and to order a refund if some or all of those costs are deemed imprudent. As always, the Public Service Commission retains jurisdiction to review issues of prudence when those issues are brought to its attention and to require refund when expenditures are deemed by the Public Service Commission to be imprudent.

GULF: $2,093,593 over-recovery.

TECO: $23,796,584 under-recovery.

ISSUE 26: What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2008 through December 2008?

POSITIONS

PEF: $422,682,129

FPL: $566,444,416 . Pursuant to Order No. PSC-01-2516-FOF-EI, issued December 26, 2001 and as clarified in Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, a portion of the capacity costs include post 9/11 incremental security costs. Some of those incremental security costs are for guard service4s at FPL's nuclear power plants. FPL acknowledges that on October 30, 2007, it received a letter from the Nuclear Regulatory Commission notifying FPL of possible security violations at FPL's nuclear plant. The Public Service Commission's approval of the capacity costs will not preclude a subsequent Commission review of the prudence of costs related to guard services and to order a refund if some or all of those costs are deemed imprudent. As always, the Public Service Commission retains jurisdiction to review issues of prudence when those issues are brought to its attention and to require refund when expenditures are deemed by the Public Service Commission to be imprudent.

GULF: $26,894,321

TECO: $86,994,475

ISSUE 28: What are the appropriate capacity cost recovery factors for the period January 2008 through December 2008?

POSITIONS

PEF:

Rate Class	CCR Factor
Residential	1.192 cents/kWh
General Service Non-Demand	1.009 cents/kWh
@ Primary Voltage	0.999 cents/kWh
@ Transmission Voltage	0.989 cents/kWh
General Service 100% Load Factor	0.691 cents/kWh
General Service Demand	0.852 cents/kWh
@ Primary Voltage	0.843 cents/kWh
@ Transmission Voltage	0.835 cents/kWh
Curtailable	0.620 cents/kWh
@ Primary Voltage	0.614 cents/kWh
@ Transmission Voltage	0.608 cents/kWh
Interruptible	0.728 cents/kWh
@ Primary Voltage	0.721 cents/kWh
@ Transmission Voltage	0.713 cents/kWh
Lighting	0.169 cents/kWh

FPL: The capacity cost recovery factors are as listed below. Pursuant to Order No. PSC-01-2516-FOF-EI, issued December 26, 2001 and as clarified in Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, a portion of the capacity costs include post 9/11 incremental security costs. Some of those incremental security costs are for guard service4s at FPL's nuclear power plants. FPL acknowledges that on October 30, 2007, it received a letter from the Nuclear Regulatory Commission notifying FPL of possible security violations at FPL's nuclear plant. The Public Service Commission's approval of the capacity costs will not preclude a subsequent Commission review of the prudence of costs related to guard services and to order a refund if some or all of those costs are deemed imprudent. As always, the Public Service Commission retains jurisdiction to review issues of prudence when those issues are brought to its attention and to require refund when expenditures are deemed by the Public Service Commission to be imprudent.

Rate Schedule	Capacity Recovery Factor ($/kw)	Capacity Recovery Factor ($/kwh)
RS1/RST1	-	0.00546
GS1/GST1	-	0.00534
GSD1/GSDT1/HLFT(21-499 kW)	1.63	-
OS2	-	0.00584
GSLD1/GSLDT1/CS1/CST1/HLFT(500-1,999 kW)	2.05	-
GSLD2/GSLDT2/CS2/CST2/HLFT(2,000+ kW)	1.98	-
GSLD3/GSLDT3/CS3/CST3	1.86	-
CILC D/CILC G	2.15	-
CILC T	2.06	-
MET	2.18	-
OL1/SL1/PL1	-	0.00194
SL2, GSCU1	-	0.00297

RATE CLASS	CAPACITY RECOVERY FACTOR (RESERVATION DEMAND CHARGE) ($/KW)	CAPACITY RECOVERY FACTOR (SUM OF DAILY DEMAND CHARGE) ($/KW)
ISST1D	.25	.12
ISST1T	.24	.12
SST1T	.24	.12
SST1D1/SST1D2/SST1D3	.25	.12

GULF: See table below:

	CAPACITY COST

RATE CLASS	RECOVERY FACTORS ¢/KWH
RS, RSVP	0.271
GS	0.248
GSD, GSDT, GSTOU	0.212
LP, LPT	0.183
PX, PXT, RTP, SBS	0.154
OS-I/II	0.063
OSIII	0.165

TECO: The appropriate factors are as follows:

Rate Schedule	Capacity Cost Recovery Factor (cents per kWh)
Average Factor	0.428
RS	0.517
GS and TS	0.496
GSD, EV-X	0.415
GSLD and SBF	0.353
IS-1, IS-3, SBI-1, SBI-3	0.032
SL-2, OL-1 and OL-3	0.063

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	)))	Docket No. 070001-EI Date Filed: June 29, 2007

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-10)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's FIRST Set of Interrogatories (Nos. 1-10) on the following pages.

Respectfully submitted the 29th day of June, 2007,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT Composite #47 (Non-Confidential portion)
COMPANY Gulf Power Co
WITNESS Responses to 1st Set of Interrogatories (1-10)
DATE 11/6/07

1. For each Request for Proposal for coal issued in 2006 by GULF, list the bids received.

ANSWER:

Gulf Power's response to this request is being provided pursuant to a Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.006(3)(a), Florida Administrative Code.

2. For each Request for Proposal for coal issued in 2006 by GULF, what action was taken? Include with your response, a summary of the evaluation process, and how the successful proposal was selected.

ANSWER:

Gulf Power's response to this request is being provided pursuant to a Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.006(3)(a), Florida Administrative Code.

3. For each Request for Proposal for coal issued in 2006 by GULF, identify all documents in Gulf's possession that summarize and evaluate the proposals.

ANSWER:

- Summary Letter dated August 31, 2006, from Tris Swindle to Rusty Ball
- Confirmation Letter Agreements with the successful bidders
- Bid Evaluation Spreadsheets
- Transportation Rate Evaluations

4. List the tonnage, delivered price, coal quality, and vendor information for all spot coal procured by GULF in 2006.

ANSWER:

Gulf Power's response to this request is being provided pursuant to a Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.006(3)(a), Florida Administrative Code.

5. For each Request for Proposal for natural gas issued in 2006 by GULF, list the bids received.

ANSWER:

Gulf Power's response to this request is being provided pursuant to a Notice of Intent to Request Confidential Classification pursuant to Rule 25-22.006(3)(a), Florida Administrative Code.

6. For each Request for Proposal for natural gas issued in 2006 by GULF, what action was taken? Include with your response, a summary of the evaluation process, and how the successful proposal was selected.

ANSWER:

Southern Company Services compiled and evaluated the bids received as a result of the corresponding RFP's referenced in Item No. 5, based on bid price and supply receipt point relating to existing Firm Transportation Contracts. Upon evaluation of the January 18, 2006 RFP, contracts for a cumulative supply of 55,000 MMBTU per day were executed with the successful bidders. Upon evaluation of the November 18, 2006 RFP, contracts for a cumulative supply of 40,000 MMBTU per day were executed with the successful bidders.

7. For each Request for Proposal for natural gas issued in 2006 by GULF, identify all documents in GULF's possession that summarize and evaluate the proposals.

ANSWER:

- Request for Bids for Natural Gas Supply - due February 16, 2006.
- Request for Bids for Natural Gas Supply - due November 21, 2006.
- Bid Distribution Lists
- Gas Supply Bid Evaluation Spreadsheets

8. For each Request for Proposal for heavy oil issued in 2006 by GULF, list the bids received.

ANSWER:

No RFP was issued for heavy oil by GULF in 2006.

9. For each Request for Proposal for heavy oil issued in 2006 by GULF, what action was taken? Include with your response, a summary of the evaluation process, and how the successful proposal was selected.

ANSWER:

No RFP was issued for heavy oil by GULF in 2006.

10. For each Request for Proposal for heavy oil issued in 2006 by GULF, identify all documents in GULF's possession that summarize and evaluate the proposals.

ANSWER:

No RFP was issued for heavy oil by GULF in 2006.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

Before me, the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager for Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 29th day of June, 2007.

Brame Nye Holsinger
Notary Public, State of Florida at Large

BRAME NYE HOLSINGER
MY COMMISSION # DD 401210
EXPIRES: April 10, 2009
Bonded Thru Notary Public Underwriters

Commission Number: DD 401210

Commission Expires: 4/10/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	Docket No. 070001-EI Date Filed: October 26, 2007

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 17 - 23)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Fourth Set of Interrogatories (Nos. 17 - 23) on the following pages.

Respectfully submitted the 25th day of October, 2007,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

17. Do you agree that $1.25 per MMBtu is a reasonable estimate of the average transportation and handling cost per MMBtu of natural gas from Henry Hub?

ANSWER:

No. Gulf Power's transportation agreements have a receipt point in Florida Gas Transmission's (FGT) Zone 3 production region, not Henry Hub. The FGT Zone 3 commodity price includes a basis differential cost component to compensate suppliers for transportation from the Henry Hub. The Henry Hub basis differential to FGT Zone 3 has been increasing in cost and volatility as gas demand in Florida has continued to grow, while supply and pipeline capacity have struggled to keep up. There were several months during the summer of 2007 when just the basis differential between Henry Hub and FGT Zone 3 exceeded $2 per MMBtu. As shown on page 2 in TABLE 1, the actual average cost of gas transportation, handling, and storage from FGT Zone 3 to Plant Smith for the period 2005 through September 2007 was $1.28 per MMBtu. Using Staff's average annual estimated gas transportation and handling rate of $1.25 added to a FGT Zone 3 market rate might be reasonable to determine an average annual estimated price delivered to Gulf's Plant Smith. However, it should not be used to estimate monthly prices for the following reasons:

- FGT transportation rates to deliver gas from FGT Zone 3 to generating plants change significantly depending on seasonal demand. Months with higher gas demand have higher firm and variable gas transportation rates.
- As natural gas commodity prices have increased, so have pipeline fuel retention charges. FGT's fuel retention charges in 2006 and 2007 are higher and more volatile than in previous years.
- Changes in natural gas prices affect the economic dispatch of gas units and the quantity of gas burn. The majority of Gulf's natural gas is transported using firm transportation agreements and stored using firm storage agreements. Using an average transportation and handling cost amount does not reflect the impact of allocating firm transportation and storage costs over variable monthly burn volumes.

Therefore, Gulf believes average monthly gas transportation and handling costs applied to each month is not a good representation of the market cost for each month.

Staff's Fourth Set of Interrogatories - Natural Gas Volatility (TABLE 1)

Gulf Gas Purchase data taken from Schedules A-5
Gulf Hedging Settlement Cost from Schedule A-1
Staff's Market Estimate taken from Staff's Table attached to the Fourth Set of Interrogatories

	Gulf Actual Purchases MMBtu	Gas Purchases Commodity	Gas Purchases Transportation and Storage	Gulf Actual Purchases Total Delivered	Gas Hedge Settlement	Gas Purchases Gulf Actual Commodity $/MMBtu	FGT Zone 3 Market Price Commodity $/MMBtu	Gas Purchases Gulf Actual Trans & Storage $/MMBtu	Gas Purchases Gulf Actual Delivered Cost $/MMBtu	Gas Purchases Gulf Hedged Delivered Cost $/MMBtu	Gas Purchases Gulf Market Estimate FGT Z3 + Act T&S $/MMBtu	Gas Purchases Staff Market Estimate Henry Hub + $1.25 $/MMBtu
Jan-05	1,270,144	$ 8,546,398	$ 763,185	$ 9,309,583	$ 252,980	$ 6.73	$ 6.52	$ 0.60	$ 7.33	$ 7.53	$ 7.12	$ 7.46
Feb-05	1,664,017	$ 10,578,067	$ 867,582	$ 11,445,649	$ 399,320	$ 6.36	$ 6.18	$ 0.52	$ 6.88	$ 7.12	$ 6.70	$ 7.54
Mar-05	1,871,087	$ 13,540,179	$ 791,997	$ 14,332,176	$ 128,230	$ 7.24	$ 6.92	$ 0.42	$ 7.66	$ 7.73	$ 7.35	$ 7.97
Apr-05	1,025,313	$ 7,810,287	$ 2,094,786	$ 9,905,073	$ (571,755)	$ 7.62	$ 7.29	$ 2.04	$ 9.66	$ 9.10	$ 9.33	$ 8.57
May-05	966,945	$ 6,105,657	$ 2,483,092	$ 8,588,749	$ (432,340)	$ 6.31	$ 6.47	$ 2.57	$ 8.88	$ 8.44	$ 9.04	$ 8.00
Jun-05	1,032,718	$ 10,296,552	$ 1,580,151	$ 11,876,703	$ (921,387)	$ 9.97	$ 7.09	$ 1.53	$ 11.50	$ 10.61	$ 8.62	$ 7.37
Jul-05	1,671,714	$ 13,415,664	$ 2,225,038	$ 15,640,702	$ (1,359,870)	$ 8.03	$ 7.93	$ 1.33	$ 9.36	$ 8.54	$ 9.26	$ 8.23
Aug-05	1,449,673	$ 14,958,795	$ 1,849,346	$ 16,808,141	$ (3,174,481)	$ 10.32	$ 10.14	$ 1.28	$ 11.59	$ 9.40	$ 11.42	$ 8.90
Sep-05	1,170,197	$ 18,399,519	$ 1,838,026	$ 20,237,545	$ (5,434,906)	$ 15.72	$ 14.69	$ 1.57	$ 17.29	$ 12.65	$ 16.26	$ 12.10
Oct-05	1,342,329	$ 18,750,831	$ 2,945,258	$ 21,696,089	$ (4,348,649)	$ 13.97	$ 14.12	$ 2.19	$ 16.16	$ 12.92	$ 16.31	$ 15.45
Nov-05	1,420,034	$ 14,985,719	$ 796,631	$ 15,782,350	$ (4,447,534)	$ 10.55	$ 10.16	$ 0.56	$ 11.11	$ 7.98	$ 10.72	$ 15.08
Dec-05	396,260	$ 5,461,297	$ 758,571	$ 6,219,868	$ (2,661,584)	$ 13.78	$ 13.59	$ 1.91	$ 15.70	$ 8.98	$ 15.50	$ 12.43
Jan-06	946,274	$ 8,220,137	$ 948,929	$ 9,169,066	$ 52,040	$ 8.69	$ 8.83	$ 1.00	$ 9.69	$ 9.74	$ 9.83	$ 12.27
Feb-06	807,685	$ 6,624,801	$ 636,915	$ 7,261,716	$ 894,967	$ 8.20	$ 7.86	$ 0.79	$ 8.99	$ 10.10	$ 8.65	$ 9.65
Mar-06	794,710	$ 5,781,916	$ 861,930	$ 6,643,846	$ 2,369,750	$ 7.28	$ 7.01	$ 1.08	$ 8.36	$ 11.34	$ 8.09	$ 8.36
Apr-06	914,578	$ 7,271,661	$ 1,723,727	$ 8,995,388	$ 976,400	$ 7.95	$ 7.33	$ 1.88	$ 9.84	$ 10.90	$ 9.21	$ 8.48
May-06	1,311,815	$ 8,671,010	$ 2,125,450	$ 10,796,460	$ 1,348,845	$ 6.61	$ 6.38	$ 1.62	$ 8.23	$ 9.26	$ 8.00	$ 8.45
Jun-06	1,369,363	$ 9,590,900	$ 2,072,984	$ 11,663,884	$ 1,879,290	$ 7.00	$ 6.76	$ 1.51	$ 8.52	$ 9.89	$ 8.27	$ 7.18
Jul-06	1,565,449	$ 10,917,412	$ 2,210,328	$ 13,127,740	$ 3,020,757	$ 6.97	$ 6.65	$ 1.41	$ 8.39	$ 10.32	$ 8.06	$ 7.36
Aug-06	1,981,477	$ 17,072,464	$ 2,222,574	$ 19,295,038	$ 1,960,976	$ 8.62	$ 8.21	$ 1.12	$ 9.74	$ 10.73	$ 9.33	$ 8.29
Sep-06	1,618,665	$ 8,513,988	$ 2,338,943	$ 10,852,931	$ 2,816,400	$ 5.26	$ 5.14	$ 1.44	$ 6.70	$ 8.44	$ 6.58	$ 8.06
Oct-06	1,777,923	$ 10,539,680	$ 2,424,162	$ 12,963,842	$ 1,515,633	$ 5.93	$ 5.62	$ 1.36	$ 7.29	$ 8.14	$ 6.98	$ 5.45
Nov-06	1,184,521	$ 9,067,311	$ 873,522	$ 9,940,833	$ 856,611	$ 7.65	$ 7.43	$ 0.74	$ 8.39	$ 9.12	$ 8.17	$ 8.40
Dec-06	1,171,369	$ 8,937,108	$ 705,568	$ 9,642,676	$ 1,022,893	$ 7.63	$ 7.64	$ 0.60	$ 8.23	$ 9.11	$ 8.24	$ 9.57
Jan-07	1,244,900	$ 8,820,827	$ 704,187	$ 9,525,014	$ 1,221,103	$ 6.94	$ 6.79	$ 0.57	$ 7.65	$ 8.63	$ 7.36	$ 7.09
Feb-07	1,651,421	$ 15,170,042	$ 702,620	$ 15,872,662	$ 887,712	$ 8.67	$ 8.70	$ 0.43	$ 9.61	$ 10.15	$ 9.12	$ 8.17
Mar-07	2,091,154	$ 15,352,523	$ 942,158	$ 16,294,681	$ 1,030,480	$ 7.20	$ 7.15	$ 0.45	$ 7.79	$ 8.28	$ 7.60	$ 8.80
Apr-07	1,347,980	$ 9,849,607	$ 2,313,740	$ 12,163,347	$ 103,000	$ 7.77	$ 7.75	$ 1.72	$ 9.02	$ 9.10	$ 9.47	$ 8.46
May-07	1,479,257	$ 7,518,272	$ 3,800,179	$ 11,318,451	$ 71,000	$ 7.73	$ 7.71	$ 2.57	$ 7.65	$ 7.70	$ 10.28	$ 8.45
Jun-07	1,303,804	$ 10,461,907	$ 1,722,717	$ 12,184,624	$ 336,800	$ 7.56	$ 7.50	$ 1.32	$ 9.35	$ 9.60	$ 8.82	$ 8.84
Jul-07	1,575,305	$ 11,123,887	$ 2,114,159	$ 13,238,046	$ 1,179,680	$ 6.79	$ 6.72	$ 1.34	$ 8.40	$ 9.15	$ 8.06	$ 8.18
Aug-07	1,693,778	$ 14,083,874	$ 2,015,153	$ 16,099,027	$ 1,299,000	$ 7.90	$ 7.90	$ 1.19	$ 9.50	$ 10.27	$ 9.09	
Sep-07	1,436,340	$ 9,743,236	$ 2,255,084	$ 11,998,320	$ 1,119,300	$ 6.61	$ 6.67	$ 1.57	$ 8.35	$ 9.13	$ 8.24	
TOTAL	44,548,199	356,181,527	54,708,693	410,890,220	$ 3,390,661							
Mean						$ 8.23	$ 7.96	$ 1.28	$ 9.48	$ 9.40	$ 9.25	$ 8.99
Variance									$ 6.17	$ 1.77	$ 5.78	$ 4.79
Standard Deviation									$ 2.48	$ 1.33	$ 2.40	$ 2.19

Staff's First Set of Interrogatories
Docket No. 070001-EI
GULF POWER COMPANY
October 26, 2007
Item No. 17
Page 2 of 2

18. If your response to Interrogatory No. 17 is no, please state the cost(s) Gulf believes is a reasonable estimate of the average transportation and handling cost per MMBtu of natural gas from Henry Hub and explain how you determined your number.

ANSWER:

The transportation rate from Henry Hub to FGT Zone 3, commonly referred to as basis differential, has been highly volatile depending on the changing daily demand for gas in Florida. The basis differential in 2007 has been as low as $0.25 per MMBtu and as high as $2.50 per MMBtu. Determining an average basis differential to use in this type of actual to market price comparative analysis would be highly speculative but it appears that $0.25 per MMBTU for the 2005 through 2006 period would be acceptable.

The average gas transportation, handling, and storage rate from FGT Zone 3 to Plant Smith, estimated to be $1.28 per MMBtu, needs to be added to the basis differential from Henry Hub to FGT Zone 3 to get a true gas transportation, handling, and storage rate from Henry Hub to Gulf's Plant Smith. That total rate of $1.53 per MMBtu would be added to the Henry Hub commodity price to deliver the gas to Gulf's Plant Smith.

However, since natural gas purchased by Gulf is delivered to the FGT Zone 3 production area, this should be the basis of Gulf's gas commodity market costs. The monthly transportation and handling cost of gas should be the sum of the transportation cost from the FGT Zone 3 production area to Gulf's Plant Smith, FGT applicable fuel retention costs, and gas storage and storage utilization costs for that month. Since the actual amount of these costs and delivered price will vary depending on the quantity of gas delivered to the generating plant, the commodity price of gas, and the amount of storage utilization; coming up with an historical average price per MMBtu to predict future transportation and handling costs in a specific month will not be effective. On page 2 of Interrogatory No. 17, TABLE 1 shows the actual natural gas transportation and handling cost per MMBtu from FGT Zone 3 to Plant Smith by month for January 2005 through September 2007. The table shows the amount of variability in gas transportation, handling, and storage costs from month to month and the difficulty in determining an average market value to use in this analysis. While the average annual transportation and handling rate is approximately $1.28 per MMBtu this rate should be applied to the FGT Zone 3 annual average market commodity price for comparison purposes.

19. From 2005 to 2006, the average market price of natural gas changed by $0.70 ($9.65 less 8.95) per MMBtu [Column (n)], and the average price paid by Gulf changed by -$1.55 ($8.20 less $9.75) per MMBtu [Column (m)]. Based on the previous year, do you agree that Gulf's 2006 natural gas prices were more variable than the market prices?

ANSWER:

No.

20. If your response to Interrogatory No. 19 is no, please provide a detailed explanation why you disagree with Staff's assertion that Gulf's 2006 natural gas prices were more variable than the market prices.

ANSWER:

Gulf does not believe that the market price of natural gas used in this evaluation is a comparable representation to Gulf's actual price of natural gas due to the use of NYMEX's Henry Hub Monthly Last Day index price as a proxy for market pricing instead of FGT Zone 3 weighted average daily pricing.

Since Gulf purchases natural gas under contracts that specifically tie the price of gas purchased daily to the FGT Zone 3 published market price, there is very little difference between the actual commodity price of daily gas purchases and the market commodity price of gas. The only variance that occurs between Gulf's actual monthly weighted average commodity price of natural gas including monthly hedge settlements and the monthly weighted average FGT Zone 3 market commodity price of gas is the amount of the monthly hedge settlement divided by the MMBtu of actual gas expensed during that month. TABLE 3 on page 3 of 3 shows the actual monthly hedge settlement amounts expressed in $ per MMBtu, which is the difference between actual gas cost and the average monthly market gas price. As shown in TABLE 2 on page 2 of 3, the net hedge settlement over the 2005 to 2006 period resulted in a credit of $0.13 per MMBtu to the customer, which is relatively small.

Staff's Fourth Set of Interrogatories - Natural Gas Volatility (TABLE 2)

Gulf Gas Purchase data taken from Schedules A-5
Gulf Hedging Settlement Cost from Schedule A-1
Staff's Market Estimate taken from Staff's Table attached to the Fourth Set of Interrogatories

	Gulf Actual Purchases MMBtu	Gas Purchases Commodity	Gas Purchases Transportation and Storage	Gulf Actual Purchases Total Delivered	Gas Hedge Settlement	Gas Purchases Gulf Actual Commodity $/MMBtu	FGT Zone 3 Market Price Commodity $/MMBtu	Gas Purchases Gulf Actual Trans & Storage $/MMBtu	Gas Purchases Gulf Actual Delivered Cost $/MMBtu	Gas Purchases Gulf Hedged Delivered Cost $/MMBtu	Gas Purchases Gulf Market Estimate FGT Z3 + Act T&S $/MMBtu	Gas Purchases Staff Market Estimate Henry Hub + $1.25 $/MMBtu
Jan-05	1,270,144	$ 8,546,398	$ 763,185	$ 9,309,583	$ **252,980**	$ 6.73	$ 6.52	$ 0.60	$ 7.33	$ 7.53	$ 7.12	$ 7.46
Feb-05	1,664,017	$ 10,578,067	$ 867,582	$ 11,445,649	$ **399,320**	$ 6.36	$ 6.18	$ 0.52	$ 6.88	$ 7.12	$ 6.70	$ 7.54
Mar-05	1,871,087	$ 13,540,179	$ 791,997	$ 14,332,176	$ **128,230**	$ 7.24	$ 6.92	$ 0.42	$ 7.66	$ 7.73	$ 7.35	$ 7.97
Apr-05	1,025,313	$ 7,810,287	$ 2,094,786	$ 9,905,073	$ **(571,755)**	$ 7.62	$ 7.29	$ 2.04	$ 9.66	$ 9.10	$ 9.33	$ 8.57
May-05	966,945	$ 6,105,657	$ 2,483,092	$ 8,588,749	$ **(432,340)**	$ 6.31	$ 6.47	$ 2.57	$ 8.88	$ 8.44	$ 9.04	$ 8.00
Jun-05	1,032,718	$ 10,296,552	$ 1,580,151	$ 11,876,703	$ **(921,387)**	$ 9.97	$ 7.09	$ 1.53	$ 11.50	$ 10.61	$ 8.62	$ 7.37
Jul-05	1,671,714	$ 13,415,664	$ 2,225,038	$ 15,640,702	$ **(1,359,870)**	$ 8.03	$ 7.93	$ 1.33	$ 9.36	$ 8.54	$ 9.26	$ 8.23
Aug-05	1,449,673	$ 14,958,795	$ 1,849,346	$ 16,808,141	$ **(3,174,481)**	$ 10.32	$ 10.14	$ 1.28	$ 11.59	$ 9.40	$ 11.42	$ 8.90
Sep-05	1,170,197	$ 18,399,519	$ 1,838,026	$ 20,237,545	$ **(5,434,906)**	$ 15.72	$ 14.69	$ 1.57	$ 17.29	$ 12.65	$ 16.26	$ 12.10
Oct-05	1,342,329	$ 18,750,831	$ 2,945,258	$ 21,696,089	$ **(4,348,649)**	$ 13.97	$ 14.12	$ 2.19	$ 16.16	$ 12.92	$ 16.31	$ 15.45
Nov-05	1,420,034	$ 14,985,719	$ 796,631	$ 15,782,350	$ **(4,447,534)**	$ 10.55	$ 10.16	$ 0.56	$ 11.11	$ 7.98	$ 10.72	$ 15.08
Dec-05	396,260	$ 5,461,297	$ 758,571	$ 6,219,868	$ **(2,661,584)**	$ 13.78	$ 13.59	$ 1.91	$ 15.70	$ 8.98	$ 15.50	$ 12.43
Jan-06	946,274	$ 8,220,137	$ 948,929	$ 9,169,066	$ **52,040**	$ 8.69	$ 8.83	$ 1.00	$ 9.69	$ 9.74	$ 9.83	$ 12.27
Feb-06	807,685	$ 6,624,801	$ 636,915	$ 7,261,716	$ **894,967**	$ 8.20	$ 7.86	$ 0.79	$ 8.99	$ 10.10	$ 8.65	$ 9.65
Mar-06	794,710	$ 5,781,916	$ 861,930	$ 6,643,846	$ **2,369,750**	$ 7.28	$ 7.01	$ 1.08	$ 8.36	$ 11.34	$ 8.09	$ 8.36
Apr-06	914,578	$ 7,271,661	$ 1,723,727	$ 8,995,388	$ **976,400**	$ 7.95	$ 7.33	$ 1.88	$ 9.84	$ 10.90	$ 9.21	$ 8.48
May-06	1,311,815	$ 8,671,010	$ 2,125,450	$ 10,796,460	$ **1,348,845**	$ 6.61	$ 6.38	$ 1.62	$ 8.23	$ 9.26	$ 8.00	$ 8.45
Jun-06	1,369,363	$ 9,590,900	$ 2,072,984	$ 11,663,884	$ **1,879,290**	$ 7.00	$ 6.76	$ 1.51	$ 8.52	$ 9.89	$ 8.27	$ 7.18
Jul-06	1,565,449	$ 10,917,412	$ 2,210,328	$ 13,127,740	$ **3,020,757**	$ 6.97	$ 6.65	$ 1.41	$ 8.39	$ 10.32	$ 8.06	$ 7.36
Aug-06	1,981,477	$ 17,072,464	$ 2,222,574	$ 19,295,038	$ **1,960,976**	$ 8.62	$ 8.21	$ 1.12	$ 9.74	$ 10.73	$ 9.33	$ 8.29
Sep-06	1,618,665	$ 8,513,988	$ 2,338,943	$ 10,852,931	$ **2,816,400**	$ 5.26	$ 5.14	$ 1.44	$ 6.70	$ 8.44	$ 6.58	$ 8.06
Oct-06	1,777,923	$ 10,539,680	$ 2,424,162	$ 12,963,842	$ **1,515,633**	$ 5.93	$ 5.62	$ 1.36	$ 7.29	$ 8.14	$ 6.98	$ 5.45
Nov-06	1,184,521	$ 9,067,311	$ 873,522	$ 9,940,833	$ **856,611**	$ 7.65	$ 7.43	$ 0.74	$ 8.39	$ 9.12	$ 8.17	$ 8.40
Dec-06	1,171,369	$ 8,937,108	$ 705,568	$ 9,642,676	$ **1,022,893**	$ 7.63	$ 7.64	$ 0.60	$ 8.23	$ 9.11	$ 8.24	$ 9.57
TOTAL	**30,724,260**	**$ 254,057,352**	**$ 38,138,696**	**$ 292,196,048**	$ **(3,857,414)**							
Mean ($/MMBtu)					$ (0.13)	$ 8.52	$ 8.16	$ 1.30	$ 9.81	$ 9.50	$ 9.46	$ 9.19
Variance									$ 7.86	$ 2.16	$ 7.48	$ 5.91
Standard Deviation									$ 2.80	$ 1.47	$ 2.73	$ 2.43

Staff's First Set of Interrogatories
Docket No. 070001-EI
GULF POWER COMPANY
October 26, 2007
Item No. 20
Page 2 of 3

Staff's Fourth Set of Interrogatories - Natural Gas Volatility (TABLE 3)

Gulf Hedging Settlement Cost from Schedule A-1

Gas Cost of Net Generation and Gas Generation BTU's burned from Schedule A-3

	Gas Burn for Generation MMBtu	Gulf Hedge Settlement Total $	Gulf Hedge Settlement $/MMBtu	Gas Cost for Generation Actual Cost	Gas Cost for Generation Hedged Cost	Gas Cost for Generation Actual Cost $/MMBtu	Gas Cost for Generation Hedged Cost $/MMBtu
Jan-05	1,336,992	$ 252,980	$ 0.19	$ 10,063,657	$ 10,316,637	$ 7.53	$ 7.72
Feb-05	1,409,337	$ 399,320	$ 0.28	$ 9,945,388	$ 10,344,708	$ 7.06	$ 7.34
Mar-05	1,904,145	$ 128,230	$ 0.07	$ 14,474,876	$ 14,603,106	$ 7.60	$ 7.67
Apr-05	1,011,455	$ (571,755)	$ (0.57)	$ 9,279,417	$ 8,707,662	$ 9.17	$ 8.61
May-05	840,709	$ (432,340)	$ (0.51)	$ 7,687,891	$ 7,255,551	$ 9.14	$ 8.63
Jun-05	1,360,925	$ (921,387)	$ (0.68)	$ 12,516,470	$ 11,595,083	$ 9.20	$ 8.52
Jul-05	1,595,817	$ (1,359,870)	$ (0.85)	$ 14,962,616	$ 13,602,746	$ 9.38	$ 8.52
Aug-05	1,680,653	$ (3,174,481)	$ (1.89)	$ 18,540,948	$ 15,366,467	$ 11.03	$ 9.14
Sep-05	1,276,908	$ (5,434,906)	$ (4.26)	$ 20,332,068	$ 14,897,162	$ 15.92	$ 11.67
Oct-05	979,861	$ (4,348,649)	$ (4.44)	$ 15,840,941	$ 11,492,292	$ 16.17	$ 11.73
Nov-05	1,396,391	$ (4,447,534)	$ (3.19)	$ 17,713,426	$ 13,265,892	$ 12.69	$ 9.50
Dec-05	419,130	$ (2,661,584)	$ (6.35)	$ 5,917,250	$ 3,255,666	$ 14.12	$ 7.77
Jan-06	551,999	$ 52,040	$ 0.09	$ 6,313,546	$ 6,365,586	$ 11.44	$ 11.53
Feb-06	1,011,459	$ 894,967	$ 0.88	$ 10,427,316	$ 11,322,283	$ 10.31	$ 11.19
Mar-06	874,555	$ 2,369,750	$ 2.71	$ 8,199,272	$ 10,569,022	$ 9.38	$ 12.09
Apr-06	872,221	$ 976,400	$ 1.12	$ 8,454,859	$ 9,431,259	$ 9.69	$ 10.81
May-06	1,303,649	$ 1,348,845	$ 1.03	$ 11,453,486	$ 12,802,331	$ 8.79	$ 9.82
Jun-06	1,308,645	$ 1,879,290	$ 1.44	$ 11,379,223	$ 13,258,513	$ 8.70	$ 10.13
Jul-06	1,653,598	$ 3,020,757	$ 1.83	$ 14,105,887	$ 17,126,644	$ 8.53	$ 10.36
Aug-06	1,981,186	$ 1,960,976	$ 0.99	$ 18,749,710	$ 20,710,686	$ 9.46	$ 10.45
Sep-06	1,604,815	$ 2,816,400	$ 1.75	$ 12,131,183	$ 14,947,583	$ 7.56	$ 9.31
Oct-06	1,815,274	$ 1,515,633	$ 0.83	$ 13,445,098	$ 14,960,731	$ 7.41	$ 8.24
Nov-06	1,243,602	$ 856,611	$ 0.69	$ 10,091,497	$ 10,948,108	$ 8.11	$ 8.80
Dec-06	1,065,009	$ 1,022,893	$ 0.96	$ 8,798,009	$ 9,820,902	$ 8.26	$ 9.22
Jan-07	1,454,861	$ 1,221,103	$ 0.84	$ 11,585,254	$ 12,806,357	$ 7.96	$ 8.80
Feb-07	1,776,967	$ 887,712	$ 0.50	$ 16,522,229	$ 17,409,941	$ 9.30	$ 9.80
Mar-07	2,007,565	$ 1,030,480	$ 0.51	$ 16,148,663	$ 17,179,143	$ 8.04	$ 8.56
Apr-07	1,346,327	$ 103,000	$ 0.08	$ 11,754,925	$ 11,857,925	$ 8.73	$ 8.81
May-07	836,910	$ 71,000	$ 0.08	$ 8,108,427	$ 8,179,427	$ 9.69	$ 9.77
Jun-07	1,366,522	$ 336,800	$ 0.25	$ 13,087,063	$ 14,266,743	$ 9.58	$ 10.44
Jul-07	1,602,414	$ 1,179,680	$ 0.74	$ 14,212,740	$ 15,511,740	$ 8.87	$ 9.68
Aug-07	1,824,517	$ 1,299,000	$ 0.71	$ 17,196,530	$ 18,495,530	$ 9.43	$ 10.14
Sep-07	1,328,900	$ 1,119,300	$ 0.84	$ 11,680,358	$ 12,799,658	$ 8.79	$ 9.63
TOTAL	44,043,318	$ 3,390,661	$ 0.08	$ 411,120,223	$ 415,473,084		

Mean	$	9.61	$	9.53
Variance	$	4.76	$	1.53
Standard Deviation	$	2.18	$	1.24

Staff's First Set of Interrogatories
Docket No. 070001-EI
GULF POWER COMPANY
October 26, 2007
Item No. 20
Page 3 of 3

21. To what extent does Gulf attribute the difference between the two annual differences ($0.70 and -$1.55)

ANSWER:

Gulf purchases natural gas daily under supply contracts at market prices indexed to the published FGT Zone 3 daily price and believes that its contracts for firm natural gas transportation, gas storage, and other variable gas handling charges are at market prices. Any difference between Gulf's actual delivered natural gas cost per MMBtu and a truly comparable market price of natural gas delivered to Gulf's generating plants on a daily basis is directly attributable to the gains and losses incurred in Gulf's financial gas hedging program. As shown by the calculation of the net monthly gas hedge settlement expressed in $/MMBtu on TABLE 2 in response to Interrogatory No. 20, the net difference over the period 2005 through 2006 is relatively small, approximately 13 cents per MMBtu, and was an average net credit to the customer's fuel cost. On TABLE 3 in response to Interrogatory No. 20, the total hedged natural gas burn expense for the period 2005 through 2006 was $286,996,620 and the net hedge settlement was ($3,857,414), which represents only 1.34% of the total gas expense for the period.

22. Do you agree that making the calculation in question (2) above is the appropriate way to determine whether Gulf's 2006 delivered prices were more volatile than market prices?

ANSWER:

No, this is not a reasonable test of price volatility.

Volatility is how much variance a set of data has around the mean value of the data in question. Standard deviation is the statistical measure of how tight the values in question are distributed around the mean and would be the more appropriate measure of volatility. In addition, using two data points as Staff has proposed is not a large enough sample to make a valid statistical determination of volatility. The greater the number of data points used, the more accurate the measure of volatility.

23. If your response to Interrogatory No. 22 is no, please provide a detailed explanation of what is the appropriate way to determine whether Gulf's 2006 delivered prices were more volatile than market prices.

ANSWER:

A more appropriate statistical test would use a larger sample, such as each month's average price over the two year period, and use a recognized statistical test to determine volatility such as standard deviation. As shown in Interrogatory No. 20 page 2, the standard deviation of Gulf's monthly actual delivered gas purchase price including hedging settlements for the period the period January 2005 through December 2006 is 1.47. The standard deviation of the estimated monthly delivered market price for the period determined by Staff (Henry Hub + $1.25 per MMBtu) is calculated to be 2.43, and the standard deviation of the FGT Zone 3 monthly delivered market price is calculated to be 2.73. This comparison shows that Gulf's actual monthly delivered gas purchase price including hedging settlements has a smaller standard deviation from the mean and is, therefore, less volatile than either Staff's estimated monthly market price or the FGT Zone 3 monthly market price for gas purchases including transportation, handling, and storage.

As shown on page 3 in response to Interrogatory No. 20, the standard deviation of Gulf's actual gas burn cost including hedge settlements is 1.24 for the period January 2005 through September 2007. The standard deviation of the market burn cost excluding hedge settlements is 2.18. This comparison shows that Gulf's monthly hedged burn expense has a smaller standard deviation around the mean and is, therefore, less volatile than the comparable gas burn cost if financial hedging of natural gas prices had not been utilized.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 070001-EI

Before me the undersigned authority, personally appeared Terry A. Davis, Assistant Secretary and Assistant Treasurer of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information and belief, based on the information provided by others in the course of business. She is personally known to me.

Terry A. Davis
Assistant Secretary and Assistant Treasurer

Sworn to and subscribed before me this
25th day of October, 2007.

BRAME NYE HOLSINGER
MY COMMISSION # DD 401210
EXPIRES: April 10, 2009
Bonded Thru Notary Public Underwriters

Brame Nye Holsinger
Notary Public, State of Florida at Large

Late Filed Exhibit No. 3
Docket No. 070001-EI
FPL's Cumulative Hedging Results

Year	Physical			Financial			Annual Total	Cumulative
	Natural Gas	Heavy Oil	Power	Natural Gas	Heavy Oil	Power		
2002	[redacted]						46,994,087	46,994,087
2003							15,701,704	62,695,791
2004							251,922,139	314,617,930
2005							625,001,025	939,618,955
2006							(468,638,337)	470,980,618
2007*							(675,038,705)	(204,058,087)
Total							**(204,058,087)**	

*Note: 2007 data contains realized values through September 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 43
COMPANY Florida Power & Light
WITNESS FPL Hedging
DATE 11-06-07

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 49
COMPANY Progress Energy FL
WITNESS PEF Hedging
DATE 11-06-07

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive factor.

Docket No. 070001-EI

Dated: November 7, 2007

RECEIVED-FPSC
07 NOV -7 PM 4:32
COMMISSION CLERK

NOTICE OF INTENT TO REQUEST CONFIDENTIAL CLASSIFICATION

Progress Energy Florida, Inc., ("PEF" or "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Notice of Intent to Request Confidential Classification of confidential information requested at the Fuel Hearing on November 6, 2007.

Specifically, the information requested, PEF's 2007 hedged percentages for natural gas and oil, contain sensitive business information, the disclosure of which could impair the efforts of the Company to negotiate hedges on favorable terms.

Attached as Exhibit A is a confidential, highlighted copy of the above referenced document.

CMP _____
COM _____
CTR _____
ECR 1
GCL 1
OPC _____
RCA _____
SCR _____
SGA _____
SEC _____
OTH 1 conf records

Pursuant to Rule 25-22.006(3)(a)(1), PEF will file its Request for Confidential Classification for such confidential information contained therein within twenty-one (21) days of filing this request.

This docketed notice of intent was filed with Confidential Document No. 10169-07 The document has been placed in confidential storage pending timely receipt of a request for confidentiality.

DOCUMENT NUMBER-DATE
10168 NOV-7 07
FPSC-COMMISSION CLERK

50

Hearing Exhibit 50
Gulf Power Company
Hedging Percentages for 2007
(Financial & Physical)

Gulf's coal purchases for 2007 are made through 17% spot contracts and 83% long-term contracts. Coal purchases are all made through fixed-price contracts with suppliers; therefore, coal is 100% physically hedged.

Gulf's gas purchases are all indexed at market prices through predominately long-term contracts. Approximately 41% of Gulf's forecasted natural gas burn for 2007 was financially hedged. Since all gas purchases are made at market prices, 0% of gas purchases are physically hedged.

Gulf's fuel mix of generation is made up of ~~86~~ 84% coal and 16% gas. Therefore, approximately 6.5% of Gulf's total fuel burn is financially hedged.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI EXHIBIT 50
COMPANY Gulf Power Co.
WITNESS Hedging Percentages for 2007
DATE 11-26-07

Docket No. 070001-EI
Tampa Electric Company
Late-Filed Exhibit 51
Witness: Joann T. Wehle

TAMPA ELECTRIC COMPANY
HEDGING BREAKDOWN FOR 2007

During 2007 Tampa Electric Company has hedged approximately [redacted] of all of its natural gas purchases and 0% of its oil purchases. 100% of its natural gas price hedges are financial.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070001-EI **EXHIBIT** 51
COMPANY Tampa Electric Co.
WITNESS TECO Hedging
DATE 11-06-07