Florida Power
CORPORATION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 000001-EI

FINAL TRUE-UP AMOUNT
January THROUGH DECEMBER 2000

DIRECT TESTIMONY
AND EXHIBITS OF

JOHN SCARDINO, JR.

For Filing May 3, 2000

FLORIDA POWER CORPORATION

DOCKET NO. 000001-EI

Fuel and Capacity Cost Recovery
Final True-up Amounts for
January through December 1999

DIRECT TESTIMONY OF
JOHN SCARDINO, JR.

Q. Please state your name and business address.

A. My name is John Scardino, Jr. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation (FPC) in the capacity of Vice President and Controller. In addition, I also hold the position of Vice President and Controller of Florida Progress Corporation, the holding company of Florida Power Corporation.

Q. Have your duties and responsibilities with FPC remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery and Capacity Cost Recovery final true-up amounts for the period of January through December 1999.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page fuel adjustment true-up variance analysis for the January through December 1999 period which examines the difference between the estimated true-up and the actual period-end true-up. This variance analysis is attached to my prepared testimony and designated Exhibit No. ___ (JS-1). Also attached to my prepared testimony and designated Exhibit No. ___ (JS-2) are the Capacity Cost Recovery Clause true-up calculations for the January through December 1999 period. My third exhibit will present the revenues and expenses associated with the purchase of the Tiger Bay facility approved in Docket No. 970096-EQ and the corresponding amortization. This presentation is also attached to my prepared testimony and designated Exhibit No. ___ (JS-3). Also, I will sponsor the applicable Schedules A1 through A9 (period to date) for December 1999, which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference and designated as Exhibit No. _____ (JS-4).

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

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. 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.

FUEL COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 1999 for fuel cost recovery?

A. The actual ending balance as of December 31, 1999 for true-up purposes is an under-recovery of $903,442.

Q. How does this amount compare to the estimated 1999 ending balance included in the Company's projections for calendar year 2000?

A. An estimated year-end under-recovery of $7,346,176 was included in the 2000 projections and is being collected from customers through FPC's currently effective fuel cost recovery factor. When this amount is compared to the actual year-end under-recovery balance of $903,442, the final net true-up attributable to the twelve-month period ended December 31, 1999 is an over-recovery of $6,442,734

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional under-recovery of$0.9 million as shown on your Exhibit No. ____ (JS-1)?

A. The factors contributing to the over-recovery are summarized on Sheet 1 of 3. The actual jurisdictional kWh sales were higher than the original estimate by 454,635,229 kWh. This increase in kWh sales, attributable to increased customer growth and economic growth, resulted in higher jurisdictional fuel revenues of $17.7 million. When revenues are adjusted for the estimated prior period true-up provision, the resulting current period net revenues are $15.4 million. The $17.2 million unfavorable variance in jurisdictional fuel and purchased power expense was primarily attributable to the increased use of higher cost peaking units to help meet demand.

When the differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an under-recovery of $1.8 million related to the January through December 1999 period. Other factors not directly related to the period include a$0.9 million recovery of interest. This results in the actual ending under-recovery balance of $0.9 million, as of December 31, 1999.

Q. Please explain the components shown on Exhibit No. ____ (JS-1), Sheet 2 of 3, which produced the $22.7 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 2 of 3 shows an analysis of the system variance for each energy source in terms of three interrelated components: (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH).

Q. What effect did these components have on the system fuel and net power variance for the true-up period?

A. As can be seen from Sheet 2 of 3, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost decrease of $9.0 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) reflected an unfavorable variance of $31.6 million. This variance was primarily the result of greater peaking unit operation than estimated.

A cost increase of $0.1 million resulted from the price variance (column D), which was caused by a number of sources detailed on lines 1 through 19 of Sheet 2 of 3, of Exhibit (JS-1).

Q. What were the major contributors to the $9.0 million cost decrease associated with the variance in MWH requirements?

A. The primary reason for the favorable variance in MWH requirements was that power sales were greater than estimated. Also, purchases from qualifying facilities decreased, which allowed the shortfall to be replaced by more economical FPC generation. The favorable variance from these two sources was offset by the higher costs associated with changes in the estimated generation mix.

Q. Does the period-ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Schedule A2, page 1 of 4, contained in my Exhibit No. _____ (JS-4), shows other jurisdictional adjustments to fuel expense in the footnote to line 6b. Noteworthy adjustments include the previously approved recovery of the costs associated with the following natural gas conversion projects: Intercession City P7 - P10, Debary P7 - P9, Bartow P2 and P4, and Suwannee P1 an P3.

Q. Did ratepayers benefit from the investment in these natural gas conversion projects?

A. Yes, for the true-up period the estimated system fuel savings related to the gas conversion projects was $13,504,015. The total system depreciation and return was $3,648,365, resulting in a net system benefit to ratepayers of $9,855,650. My Exhibit No. ___ (JS - 1), sheet 3 of 3, contains a schedule showing the development of these savings for each conversion project.

Q. Are any other noteworthy adjustments to fuel expense shown in the footnote to line 6b?

A. Yes. For the period, the Company has excluded $0.8 million of fuel costs associated with the testing of Hines Unit I that were capitalized to the unit's work order. The fair value of the remaining fuel burned at Hines Unit I is reflected in the A Schedules as part of recoverable fuel expense and offset by a corresponding amount of fuel revenue, in accordance with Commission Order No. PSC-94-1160-FOF-EI.

Q. Has the Company passed any sulfur dioxide emission allowance transactions through the current or prior true-up periods?

A. Yes. In prior true-up periods, the Company has passed through \$1,140,595 of proceeds from the mandated EPA Sulfur Dioxide Emission Allowance Auction as a credit to fuel expense. This amount represents the auction proceeds for the years 1993 through 1998. Additionally, the Company has incurred \$951,350 of expense for the purchase of 10,900 SO_2 allowances. Under the provisions of the Clean Air Act Amendments of 1990, a percentage of FPC's allowances are withheld each year to populate a pool of allowances which EPA offers for sale at auction. Although anyone can purchase, the real intent of the allowance pool was to ensure that allowances would be available for new units or new entrants to the energy market. Once these allowances are sold, proceeds are returned to the company that provided the allowances.

During the current true-up period, the Company received proceeds of \$309,689 from the EPA auction and has applied those proceeds as a credit to fuel expense. The Company also purchased 7,300 allowances during this period at a cost of \$1,359,350, which has applied as a debit to fuel expense.

Q. Were there any other unusual adjustments included in the current true-up period?

A. Yes. On July 1, 1997, the Commission approved an agreement between FPC and Tiger Bay Limited Partnership for the purchase of the Tiger Bay cogeneration facility and terminate the five related purchase power agreements (PPAs) as part of a stipulation between FPC and the other parties in Docket No. 980096-EQ. The purchase agreement was consummated on July 15, 1997, at which time the Tiger Bay facility became one of FPC's generating facilities.

Pursuant with the terms of the stipulation, FPC placed approximately $75 million of the purchase price into rate base, with the remaining amount set up as a regulatory asset for the retail jurisdiction, according to FPC's jurisdictional separation at that time. The stipulation allows FPC to continue collecting revenues from its ratepayer's as if the five terminated PPAs were still in effect. These revenues are then to be used to offset all fuel expenses relating to the Tiger Bay facility and interest applicable to the unamortized balance of the retail portion of the Tiger Bay regulatory asset, with any remaining revenues used to amortize the regulatory asset.

Following this methodology, a $37.2 million adjustment was made to remove the cost of fuel consumed by the Tiger Bay facility during the true-up period, since these costs were recovered from the PPA revenues. Exhibit No. ___ (JS-3) shows a year-end retail balance for the Tiger Bay regulatory asset of $287,817,871, computed in accordance with the approved stipulation. This balance reflects an additional reduction of $10.2 million in accelerated amortization.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 1999 for capacity cost recovery?

A. The actual ending balance as of December 31, 1999 for true-up purposes is an over-recovery of $28,834,883.

Q. How does this amount compare to the estimated 1999 ending balance included in the Company's projections for calendar year 2000?

A. When the estimated year-end over-recovery of $33,314,649 to be collected during 2000 is compared to the $28,834,883 actual over-recovery, the final net true-up attributable to the twelve-month period ended December 1999 is an under-recovery of $4,479,766.

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

A. Yes. The calculation of the final net true-up amount follows the procedures established by this Commission as set forth on Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. What factors contributed to the actual period-ending over-recovery of $28.8 million?

A. Exhibit No. _____ (JS-2), sheet 1 of 3, entitled "Capacity Cost Recovery Clause Summary of Actual True-Up Amount," compares actual results to the original forecast for the period. As can be seen from sheet 1, actual jurisdictional revenues were $6.6 million higher than forecasted revenues due to increased customer usage. Net capacity costs were $21.7 million lower, due to a reduction in purchases from qualifying facilities. The over-recovery also produced an additional interest credit of $0.5 million.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBITS TO THE TESTIMONY OF JOHN SCARDINO, JR.

Final True-Up Amount
January through December 2000

VARIANCE ANALYSIS (JS-1)

Florida Power Corporation
Docket No. 000001-EI
Witness: Scardino
Exhibit No. (JS-1)
Sheet 1 of 3

FLORIDA POWER CORPORATION
Fuel Adjustment Clause
Summary of Final True-Up Amount
January 1999 through December 1999

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
1	**KWH Sales:**	
2	Jurisdictional KWH Sales	454,635,229
3	Non-Jurisdictional KWH Sales	163,795,993
4	Total System KWH Sales Increased	
5	Schedule A2, pg 2 of 4, Line C1 through C3	618,431,222
6		
7	**System:**	
8	Fuel and Net Purchased Power Costs - Difference	
9	Schedule A2, page 3 of 4, Line D4	$ 22,677,769
10		
11	**Jurisdictional:**	
12	Fuel Revenues - Difference	
13	Schedule A2, page 3 of 4, Line D3	$ 17,736,735
14		
15	True Up Provision for the Period Over/(Under)	
16	Collection - Estimated	
17	Schedule A2, page 3 of 4, Line D7	(2,260,720)
18		
19	Net Fuel Revenues	15,476,015
20		
21		
22	Fuel and Net Purchased Power Costs - Difference	
23	Schedule A2, page 3 of 4, Line D6	17,241,429
24		
25	True Up Amount for the Period	(1,765,414)
26		
27	True Up for the Prior Period - Actual	
28	Schedule A2, page 3 of 4, Line D9+D10	3,577
29		
30	Interest Provision - Actual	
31	Schedule A2, page 3 of 4, Line D8	858,395
32		
33	Actual True Up ending balance for the period	
34	January 1999 through December 1999	(903,442)
35		
36	Estimated True Up ending balance for the period included in	
37	filing of Levelized Fuel Cost Factors January through December 2000,	
38	Docket No. 990001-EI.	(7,346,176)
39		
40	Final True Up for the period January 1999 through	
41	December 1999 (Line 34 - Line 36)	$ 6,442,734

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: JANUARY - DECEMBER 1999

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	$51,903,013	$3,028,983	$837,830	$55,769,826
2	Light Oil	19,455,543	7,404,301	(1,737,291)	25,122,553
3	Coal	(28,515,378)	5,021,324	(247,815)	(23,741,869)
4	Gas	13,500,544	16,282,249	(777,101)	29,005,692
5	Nuclear	1,125,941	(145,157)	(2,100,469)	(1,119,685)
6	Other Fuel	0	0	0	0
7	Total Generation	57,469,663	31,591,700	(4,024,846)	85,036,517
8	Firm Purchases	6,239,056	0	(5,695,914)	543,142
9	Economy Purchases	(8,156,824)	0	5,597,399	(2,559,425)
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(23,268,667)	0	(11,400,998)	(34,669,665)
12	Total Purchases	(25,186,435)	0	(11,499,513)	(36,685,948)
13	Economy Sales	18,821,423	0	(120,614)	18,700,809
14	Other Power Sales	(48,982,838)	0	26,400,880	(22,581,958)
15	Supplemental Sales	(11,121,139)	0	(10,950,550)	(22,071,689)
16	Total Sales	(41,282,554)	0	15,329,716	(25,952,838)
17	Nuclear Fuel Disposal Cost	0	0	344,088	344,088
18	Nuclear Decom & Decon	0	0	38,654	38,654
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	0	0	(102,704)	(102,704)
20	Total Fuel and Net Power	($8,999,326)	$31,591,700	$85,395	$22,677,769

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: JANUARY - DECEMBER 1999

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	$51,903,013	$3,028,983	$837,830	$55,769,826
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18	Nuclear Decom & Decon	0	0	38,654	38,654
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	0	0	(102,704)	(102,704)
20	Total Fuel and Net Power	($8,999,326)	$31,591,700	$85,395	$22,677,769

GAS CONVERSION PROJECTS
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY, 1999 THROUGH DECEMBER, 1999

Line		INTERCESSION CITY 7 & 9	INTERCESSION CITY 8 & 10	DEBARY 8	DEBARY 7 & 9	BARTOW 2 & 4	SUWANNEE 1 & 3	TOTAL
	PLANT INVESTMENT							
1	BEGINNING BALANCE	$ 2,340,875	$ 1,646,809	$ -	$ 3,352,257	$ 2,444,924	$ 3,460,560	$ 13,245,425
2	ADD INVESTMENT	-	-	1,230,945	-	-	-	1,230,945
3	LESS RETIREMENTS	-	-	168,408	-	-	-	168,408
4	ENDING BALANCE	2,340,875	1,646,809	1,062,537	3,352,257	2,444,924	3,460,560	14,307,962
5								
6	ACCUMULATED DEPRECIATION							
7	BEG. BALANCE ACCUM. DEPRECIATION	1,476,434	772,327	-	962,052	709,581	631,466	4,551,860
8	DEPRECIATION EXPENSE	468,180	329,364	92,087	670,452	488,976	692,112	2,741,171
9	LESS RETIREMENTS	-	-	-	-	-	-	-
10	END. BALANCE ACCUM. DEPRECIATION	1,944,614	1,101,691	92,087	1,632,504	1,198,557	1,323,578	7,293,031
11								
12								
13	ENDING NET INVESTMENT (LINE 4-10)	$ 396,261	$ 545,118	$ 970,450	$ 1,719,753	$ 1,246,367	$ 2,136,982	$ 7,014,931
14								
15	TOTAL RETURN REQUIREMENTS	73,028	82,235	53,467	238,075	172,720	287,669	$ 907,194
16								
17	TOTAL DEPRECIATION EXPENSE							
18	AND RETURN (LINE 8+ 15)	$ 541,208	$ 411,599	$ 145,554	$ 908,527	$ 661,696	$ 979,781	$ 3,648,365
19								
20								
21	ESTIMATED FUEL SAVINGS	1,853,073	1,661,560	1,121,668	1,969,569	2,067,503	4,830,642	13,504,015
22								
23	TOTAL DEPRECIATION & RETURN (1)	541,208	411,599	145,554	908,527	661,696	979,781	3,648,365
24								
24	NET BENEFIT (COST) TO RATEPAYER	$ 1,311,865	$ 1,249,961	$ 976,114	$ 1,061,042	$ 1,405,807	$ 3,850,861	$ 9,855,650
25								
25								
26								

27 **DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.**

28 **RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%). THIS IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 91-0890-EI.**

29 **RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%**

30 **(1) TOTAL AMOUNT DIFFERS FROM SCHEDULE A-2, PAGE 1 OF 4, LINE 6b BECAUSE A-2 EXCLUDES COST ASSIGNED TO SUPPLEMENTAL KWH SALES.**

EXHIBITS TO THE TESTIMONY OF JOHN SCARDINO, JR.

Final True-Up Amount
January through December 2000

CAPACITY COST RECOVERY (JS-2)

Florida Power Corporation
Docket No. 990001-EI
Witness: Scardino
Exhibit No. (JS-2)
Sheet 1 of 3

FLORIDA POWER CORPORATION
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 1999 through December 1999

Line No.	Description	Actual	Original Estimate	Variance
1				
2	**Jurisdictional:**			
3	Capacity Cost Recovery Revenues			
4	Sheet 2 of 3, Line 47	313,055,926.86	306,425,917.00	6,630,009.86
5				
6	Capacity cost Recovery Expenses			
7	Sheet 2 of 3, Line 43	284,694,487.62	306,425,917.00	(21,731,429.38)
8				
9	Plus/(Minus) Interest Provision			
10	Sheet 2 of 3, Line 49	473,443.48	(389,197.00)	862,640.48
11				
12	Sub Total Current Period Over/(Under) Recovery	28,834,882.72	(389,197.00)	29,224,079.72
13				
14	Prior Period True-up - April 1998 through			
15	December 1998 - Over/(Under) Recovery			
16	Sheet 2 of 3, Line 51 + Line 53	222,118.00	(4,856,714.00)	5,078,832.00
17				
18	Prior Period True-up (Refunded)/Collected			
19	Sheet 2 of 3, Line 52 - Line 53	(222,118.00)	4,856,714.00	(5,078,832.00)
20	April 1998 through December 1998			
21				
22				
23				
24				
25				
26	Actual True-up ending balance Over/(Under) recovery			
27	for the period January through December 1999			
28	Sheet 2 of 3, Column G, Line 54	28,834,882.72	(389,197.00)	29,224,079.72
29				
30	Estimated True-up ending balance for the			
31	period included in the filing of Levelized			
32	Fuel Cost Factors January through December 2000			
33	Docket No. 990001 - E1.	33,314,649.00		
34				
35				
36	Final Over/(Under) Recovery for the period January			
37	through December 1999 (Line 28 - Line 33)	(4,479,766.28)		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY 1999 THROUGH DECEMBER

Florida Power Corporation
Docket 980001-EI
Witness: Scardino
Exhibit No. (JS-2)
Sheet 2 of 3

	Description	1999 JANUARY	1999 FEBRUARY	1999 MARCH	1999 APRIL	1999 MAY	1999 JUNE	1999 JULY	1999 AUGUST	1999 SEPTEMBER	1999 OCTOBER	1999 NOVEMBER	1999 DECEMBER	(g) 12 Months Cumulative
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
2	Auburndale Power Partners, L.P. (AUBRDLFC)	532,220	532,220	532,220	532,220	532,220	532,220	532,220	532,220	532,220	532,220	532,220	532,220	$6,386,640
3	Auburndale Power Partners, L.P. (AUBSET)	1,829,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	1,799,539	$21,624,465
4	Bay County (BAYCOUNT)	172,480	172,480	172,480	172,480	172,480	172,480	172,480	172,480	172,480	172,480	172,480	172,480	$2,069,760
5	Cargill Fertilizer, Inc. (CARGILLF)	372,900	372,900	372,900	372,900	372,900	372,900	372,900	372,900	372,900	372,900	372,900	372,900	$4,474,800
6	Central Power & Lime (FLACRUSH)	0	0	0	0	0	0	0	0	0	0	0	0	$0
7	Citrus World	0	0	0	0	0	0	0	0	0	0	0	0	$0
8	Lake Cogen Limited (LAKECOGL)	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	1,900,084	326,910	326,910	$19,654,663
9	Lake County (LAKCOUNT)	326,910	326,910	326,910	326,910	326,910	326,910	326,910	326,910	326,910	326,910	1,900,084	1,900,084	$7,069,268
10	Metro-Dade County (METRDADE)	637,965	647,541	655,720	696,497	688,815	710,938	698,750	698,750	690,241	690,897	663,913	684,260	$8,164,286
11	Orange Cogen (ORANGEAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
12	Orange Cogen (ORANGECO)	1,623,050	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	1,626,195	$19,511,199
13	Orlando Cogen Limited (ORLACOGL)	1,391,905	1,339,359	1,340,497	1,344,446	1,357,937	1,375,135	1,369,776	1,369,052	1,371,067	1,365,983	1,365,990	1,368,877	$16,360,023
14	Orlando Cogen Limited (ORLACOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
15	Pasco Cogen Limited (PASCOGL)	2,757,296	2,838,849	2,838,849	2,838,849	2,838,849	2,838,849	2,838,849	2,838,849	2,838,849	2,788,730	2,827,087	2,834,405	$33,918,306
16	Pasco County Resource Recovery (PASCOUNT)	589,490	589,490	589,490	589,490	589,490	589,490	589,490	589,490	589,490	589,490	589,490	589,490	$7,073,880
17	PCS Phosphate (OCSWFCRK)	0	0	0	0	0	0	0	0	0	0	0	0	$0
18	PCS Phosphate (OCSWHSPRS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
19	Pinellas County Resource Recovery (PINCOUNT)	970,429	1,173,193	893,846	1,271,785	1,403,243	1,403,243	1,403,243	1,403,243	1,403,243	1,403,243	1,403,243	1,403,243	$15,535,195
20	Polk Power Partners, L. P. (MULBERY)	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	2,065,402	$24,784,828
21	Polk Power Partners, L. P. (ROYSTER)	746,390	746,390	746,390	746,390	746,390	746,390	746,390	746,390	746,390	746,390	746,390	746,390	$8,956,682
22	St. Joe Forest Products (ST JOEFOR)	0	0	0	0	0	0	0	0	0	0	0	0	$0
23	Tiger Bay Limited Partnnership (ECOPEAT)	999,000	999,000	999,000	999,000	999,000	999,000	999,000	999,000	999,000	999,000	999,000	999,000	$11,988,000
24	Tiger Bay Limited Partnnership (GENPEAT)	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	3,520,000	$42,240,000
25	Tiger Bay Limited Partnnership (TIMBER2)	123,000	123,000	123,000	123,000	123,000	123,000	123,000	123,000	123,000	123,000	123,000	123,000	$1,476,000
26	Timber Energy Resources, Inc. (TIMBER)	342,485	342,485	325,125	325,125	342,740	342,740	342,740	342,740	342,740	342,740	342,740	342,740	$4,077,141
27	U.S. Agri-Chemicals (AGRICHEM)	35,848	35,848	35,848	35,848	35,848	35,848	35,848	35,848	35,848	35,848	35,848	35,848	$430,175
28	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	$9,611,350
29	Tiger Bay (EcoPeat lease credit)	(66,667)	(66,667)	(66,667)	(709,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	($1,443,001)
30	UPS Purchase (409 total mw)	4,410,441	4,233,735	4,259,965	3,877,759	3,900,379	4,160,986	2,181,709	3,874,909	4,054,958	3,913,202	3,953,563	3,465,518	$46,287,124
31	Other Power Sales	(309,924)	(873,871)	(815,382)	807,545	(399,353)	(3,046,958)	(6,656,729)	(1,324,538)	106,944	(312,970)	(439,214)	(382,363)	(13,646,812)
32	Subtotal - Base Level Capacity Charges	25,771,189	25,245,028	25,042,358	26,062,744	25,676,348	23,328,671	17,722,075	24,746,742	26,351,779	25,735,562	25,661,059	25,260,417	296,603,971
33	Base Production Jurisdictional Responsibility	96.110%	96.110%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.456%
34	Base Level Jurisdictional Capacity Charges	24,768,689	24,262,996	24,176,643	25,161,755	24,788,716	22,522,199	17,109,423	23,891,247	25,440,798	24,845,884	24,773,956	24,387,165	286,129,471
	Intermediate Production Level Capacity Charges:													
35	TECO Power Purchase (60 mw)	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	$6,786,804
36	Schedule H Capacity Sales	(2,662)	(2,404)	(2,662)	(2,576)	(2,385)	0	(2,385)	(4,692)	(2,308)	(2,385)	(2,317)	(2,385)	($29,161)
37	FPL / Morgan Stanley Capital Group							53,289					199,106	252,395
38	Subtotal - Intermediate Level Capacity Charges	562,905	563,163	562,905	562,991	563,182	565,567	616,471	560,875	563,259	563,182	563,250	762,288	7,010,038
39	Intermediate Production Jurisdict. Responsibility	73.773%	73.773%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	70.500%
40	Intermediate Level Jurisdict. Capacity Charges	415,272	415,462	392,243	392,303	392,437	394,098	429,570	390,829	392,490	392,436	392,484	531,178	4,930,802
41	Sebring Base Rate Credits	(356,323)	(273,476)	(321,391)	(319,764)	(316,979)	(339,077)	(373,108)	(421,342)	(398,237)	(345,106)	(288,136)	(295,814)	(4,048,753)
42	Adjustments-Premium/Liquidating Damages								(2,027,403)	(482,715)	193,086	0		(2,317,032)
43	Jurisdictional Capacity Charges	24,827,638	24,404,982	24,247,495	25,234,294	24,864,174	22,577,220	17,165,885	21,833,331	24,952,336	25,086,300	24,878,304	24,622,528	284,694,488
44	Capacity Cost Recovery Revenues (net of tax)	24,431,758	20,875,222	21,484,013	22,856,709	24,403,091	27,386,256	30,049,391	34,626,187	32,769,253	27,997,522	23,713,237	22,241,168	312,833,808
45	Capacity Cost Revenues Adjustment (Net of Tax)													0
46	Prior Period True-Up Provision	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	4,674,106	222,118
47	Current Period Capacity Cost Recovery Revenues (net of tax) (sum of lines 43 through 45)	24,027,032	20,470,495	21,079,286	22,451,983	23,998,365	26,981,530	29,644,665	34,221,461	32,364,527	27,592,796	23,308,511	26,915,275	313,055,927
48	True-Up Provision - Over/(Under) Recovery (line 46 - line 42)	(800,606)	(3,934,487)	(3,168,209)	(2,782,311)	(865,809)	4,404,310	12,478,780	12,388,130	7,412,191	2,506,496	(1,569,793)	2,292,747	28,361,439
49	Interest Provision for the Month	98	(7,812)	(20,627)	(30,967)	(36,720)	(28,898)	7,681	63,504	110,903	134,852	142,458	138,973	473,443.48
50	Current Cycle Balance (line 47 + line 48) Cumulative	(800,508)	(4,742,807)	(7,931,642)	(10,744,920)	(11,647,449)	(7,272,038)	5,214,423	17,666,057	25,189,151	27,830,499	26,403,164	28,834,883	
51	True-Up & Interest Provision (beginning)	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	
52	Prior Period True-Up Collected/(Refunded) Cumulati	404,726	809,452	1,214,179	1,618,905	2,023,631	2,428,357	2,833,083	3,237,809	3,642,536	4,047,262	4,451,988	(222,118)	
53	Other:	0	0	0	0	0	0	0	0	0	0	0	0	
54	End of Period Net True-Up (lines 47 through 52) Over / (Under)	($173,664)	($3,711,237)	($6,495,345)	($8,903,897)	($9,401,700)	($4,621,563)	$8,269,624	$21,125,984	$29,053,805	$32,099,879	$31,077,270	$28,834,883	$0

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY 1999 THROUGH DECEMBER 1999

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(j)	(j)
		1	2	3	4	5	6	7	8	9	10	11	12
		1999	1999	1999	1999	1999	1999	1999	1999	1999	1999	1999	1999
	Description	**JANUARY**	**FEBRUARY**	**MARCH**	**APRIL**	**MAY**	**JUNE**	**JULY**	**AUGUST**	**SEPTEMBER**	**OCTOBER**	**NOVEMBER**	**DECEMBER**
	Interest Provision:												
1.	Beginning True-Up	$222,118	($173,664)	($3,711,237)	($6,495,345)	($8,903,897)	($9,401,700)	($4,621,563)	$8,269,624	$21,125,984	$29,053,805	$32,099,879	$31,077,270
2.	Ending True-Up	($173,762)	($3,703,424)	($6,474,719)	($8,872,930)	($9,364,980)	($4,592,664)	$8,261,943	$21,062,480	$28,942,902	$31,965,027	$30,934,812	$28,695,910
3.	Total True-Up (line 1 + line 2)	$48,356	($3,877,088)	($10,185,956)	($15,368,276)	($18,268,877)	($13,994,364)	$3,640,380	$29,332,104	$50,068,886	$61,018,831	$63,034,691	$59,773,180
4.	Average True-Up (50% of line 3)	$24,178	($1,938,544)	($5,092,978)	($7,684,138)	($9,134,439)	($6,997,182)	$1,820,190	$14,666,052	$25,034,443	$30,509,416	$31,517,346	$29,886,590
5.	Interest Rate - First Day of Reporting Month	4.900%	4.810%	4.850%	4.880%	4.800%	4.850%	5.050%	5.080%	5.320%	5.300%	5.300%	5.550%
6.	Interest Rate - First Day of Subsequent Month	4.810%	4.850%	4.880%	4.800%	4.850%	5.050%	5.080%	5.320%	5.300%	5.300%	5.550%	5.600%
7.	Total Interest (line 5 + line 6)	9.710%	9.660%	9.730%	9.680%	9.650%	9.900%	10.130%	10.400%	10.620%	10.600%	10.850%	11.150%
8.	Average Interest Rate (50% of line 7)	4.855%	4.830%	4.865%	4.840%	4.825%	4.950%	5.065%	5.200%	5.310%	5.300%	5.425%	5.575%
9.	Monthly Average Interest Rate (line 8 / 12)	0.4046%	0.403%	0.405%	0.403%	0.402%	0.413%	0.422%	0.433%	0.443%	0.442%	0.452%	0.465%
10.	Interest Provision (line 4 x line 9)	98	(7,812)	(20,627)	(30,967)	(36,720)	(28,898)	7,681	63,504	110,903	134,852	142,458	138,973
11.	Cumulative Interest for the Period Ending	98	(7,715)	(28,341)	(59,308)	(96,029)	(124,927)	(117,246)	(53,742)	57,161	192,013	334,471	473,443

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SHEET: CCR

EXHIBITS TO THE TESTIMONY OF
JOHN SCARDINO, JR.

Final True-Up Amount
January through December 2000

TIGER BAY REVENUES AND EXPENSES (JS-3)

Florida Power Corporation
Docket No. 990001-EI
Witness: Scardino
Exhibit No. (JS-3)
Sheet 1 of 1

TIGER BAY EXPENSE AND REVENUE TRACKING

Line #	Capacity Clause Revenues	A Jan-99	B Feb-99	C Mar-99	D Apr-99	E May-99	F Jun-99	G Jul-99	H Aug-99	I Sep-99	J Oct-99	K Nov-99	L Dec-99
1	Retail Capacity Revenues	$ 4,397,353	$ 4,397,353	$ 4,417,164	$ 3,796,393	$ 4,417,164	$ 4,417,164	$ 4,417,164	$ 4,417,164	$ 4,417,164	$ 4,417,164	$ 4,417,164	$ 4,417,164
3	Retail Related Interest on Reg. Asset	2,013,783	1,779,739	1,884,728	1,877,795	1,828,000	1,815,016	1,767,907	1,779,307	1,771,133	1,762,900	1,748,720	1,737,902
5	Funds Available for Amortization	$ 2,383,569	$ 2,617,614	$ 2,532,436	$ 1,918,598	$ 2,589,164	$ 2,602,148	$ 2,649,257	$ 2,637,857	$ 2,646,031	$ 2,654,264	$ 2,668,444	$ 2,679,262
8	***Fuel Adjustment Clause Revenues***												
10	Retail Energy Revenues	$ (68,493)	$ 272,143	$ 1,096,449	$ 822,162	$ 518,365	$ 1,663,831	$ 2,356,802	$ 2,359,896	$ 2,244,916	$ 1,966,523	$ 2,859,004	$ 2,384,149
12	Retail Fuel Expenses	2,030,455	2,045,185	2,539,104	1,722,135	3,395,126	3,295,957	3,478,769	3,292,852	3,522,338	3,329,843	4,123,975	3,368,284
14	Funds Available for Amortization	$ (2,098,949)	$ (1,773,043)	$ (1,442,655)	$ (899,973)	$ (2,876,761)	$ (1,632,126)	$ (1,121,967)	$ (932,956)	$ (1,277,422)	$ (1,363,320)	$ (1,264,972)	$ (984,135)
16	Underrecovery	-	-	-	-	287,596	(287,596)	-	-	-	-	-	-
21	***Tiger Bay Regulatory Asset - R***												
23	Beginning Balance	$ 320,998,634	$ 320,714,013	$ 319,869,442	$318,779,661	$ 317,761,036	$ 307,490,640	$ 306,808,214	$305,280,924	$ 303,576,024	$ 302,207,415	$ 300,916,470	$299,512,998
25	Amortization (Line 5+ Line 14 + Line 16)	(284,621)	(844,571)	(1,089,781)	(1,018,625)	-	(682,426)	(1,527,289)	(1,704,901)	(1,368,609)	(1,290,944)	(1,403,472)	(1,695,127)
27	Additional Amortization	-	-	-	-	(10,270,396)	-	-	-	-	-	-	-
29	Ending Balance	$ 320,714,013	$ 319,869,442	$ 318,779,661	$317,761,036	$ 307,490,640	$ 306,808,214	$ 305,280,924	$303,576,024	$ 302,207,415	$ 300,916,470	$ 299,512,998	$297,817,871

EXHIBITS TO THE TESTIMONY OF
JOHN SCARDINO, JR.

Final True-Up Amount
January through December 2000

SCHEDULES A1 through A9 (JS-4)
(Period-to-Date)

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
DECEMBER 1999

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	43,412,586	36,144,006	7,268,580	20.1	2,383,025	2,277,326	105,699	4.6	1.8217	1.5871	0.2346	14.8
2 SPENT NUCLEAR FUEL DISPOSAL COST	549,950	498,794	51,156	10.3	549,950	533,470	16,480	3.1	0.1000	0.0935	0.0065	7.0
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	6,461	0	6,461	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(3,209,923)	306,000	(3,515,923)	(1,149.0)	(128,799)	0	(128,799)	0.0	2.4922	0.0000	2.4922	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	40,759,074	36,948,800	3,810,274	10.3	2,254,226	2,277,326	(23,100)	(1.0)	1.8081	1.6225	0.1856	11.4
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	3,452,005	3,180,370	271,635	8.5	238,238	172,283	65,955	38.3	1.4490	1.8460	(0.3970)	(21.5)
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	350,985	968,300	(617,315)	(63.8)	7,297	30,000	(22,703)	(75.7)	4.8100	3.2277	1.5823	49.0
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	685,608	101,430	584,178	575.9	18,114	3,000	15,114	503.8	3.7850	3.3810	0.4040	12.0
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)	11,079,217	13,796,819	(2,717,602)	(19.7)	637,405	648,727	(11,322)	(1.8)	1.7382	2.1268	(0.3886)	(18.3)
12 TOTAL COST OF PURCHASED POWER	15,567,815	18,046,919	(2,479,104)	(13.7)	901,054	854,010	47,044	5.5	1.7277	2.1132	(0.3855)	(18.2)
13 TOTAL AVAILABLE MWH					3,155,280	3,131,336	23,944	0.8				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	(238,177)	(2,026,200)	1,788,023	(88.3)	(16,576)	(110,000)	93,424	(84.9)	1.4369	1.8420	(0.4051)	(22.0)
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	(76,989)	(116,160)	39,171	(33.7)	(16,576)	(110,000)	93,424	(84.9)	0.4645	0.1056	0.3589	339.9
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(2,109,625)	(592,700)	(1,516,925)	255.9	(115,446)	(24,025)	(91,421)	380.5	1.8274	2.4670	(0.6396)	(25.9)
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	0	(350,000)	0	0.0	(115,446)	(24,025)	(91,421)	380.5	0.0000	1.4568	(1.4568)	(100.0)
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 SUPPLEMENTAL SALES	(4,120,593)	(1,951,907)	(2,168,686)	111.1	(137,844)	(90,998)	(46,846)	51.5	2.9893	2.1450	0.8443	39.4
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(6,545,385)	(5,036,967)	(1,508,418)	30.0	(269,866)	(225,023)	(44,843)	19.9	2.4254	2.2384	0.1870	8.4
19 NET INADVERTENT AND WHEELED INTERCHANGE					6,053	0	6,053					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	49,781,505	49,958,752	(177,247)	(0.4)	2,891,467	2,906,313	(14,846)	(0.5)	1.7217	1.7190	0.0027	0.2
21 NET UNBILLED	1,714,524	3,161,708	(1,447,184)	(45.8)	(99,585)	(183,930)	84,345	(45.9)	0.0662	0.1240	(0.0578)	(46.6)
22 COMPANY USE	189,539	260,424	(70,885)	(27.2)	(11,009)	(15,150)	4,141	(27.3)	0.0073	0.0102	(0.0029)	(28.4)
23 T & D LOSSES	3,313,594	2,706,386	607,208	22.4	(192,464)	(157,442)	(35,022)	22.2	0.1280	0.1061	0.0219	20.6
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	49,781,505	49,958,752	(177,247)	(0.4)	2,588,409	2,549,791	38,618	1.5	1.9232	1.9593	(0.0361)	(1.8)
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(2,414,403)	(1,373,665)	(1,040,738)	75.8	(125,419)	(70,109)	(55,310)	78.9	1.9251	1.9593	(0.0342)	(1.8)
26 JURISDICTIONAL KWH SALES	47,367,102	48,585,087	(1,217,985)	(2.5)	2,462,990	2,479,682	(16,692)	(0.7)	1.9232	1.9593	(0.0361)	(1.8)
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.0011	47,419,205	48,638,531	(1,219,326)	(2.5)	2,462,990	2,479,682	(16,692)	(0.7)	1.9253	1.9615	(0.0362)	(1.9)
28 PRIOR PERIOD TRUE-UP	(16,336,721)	(1,236,487)	(15,100,234)	1,221.2	2,462,990	2,479,682	(16,692)	(0.7)	(0.6633)	(0.0499)	(0.6134)	1,229.3
28a MARKET PRICE TRUE-UP	0	(21,990)	21,990	(100.0)	2,462,990	2,479,682	(16,692)	(0.7)	0.0000	(0.0009)	0.0009	(100.0)
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	2,462,990	2,479,682	(16,692)	(0.7)	0.0000	0.0000	0.0000	0.0
29 TOTAL JURISDICTIONAL FUEL COST	31,082,484	47,380,054	(16,297,570)	(34.4)	2,462,990	2,479,682	(16,692)	(0.7)	1.2620	1.9107	(0.6487)	(34.0)
30 REVENUE TAX FACTOR									1.00083	1.00083	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									1.2630	1.9123	(0.6493)	(34.0)
32 GPIF	(36,413)	(36,382)			2,462,990	2,479,682			(0.0015)	(0.0015)	0.0000	0.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									1.262	1.911	(0.649)	(34.0)

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28-Apr-00

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TWELVE MONTH PERIOD ENDING - DECEMBER, 1999

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	596,411,148	474,154,715	122,256,433	25.8	32,140,257	28,784,780	3,355,477	11.7	1.8557	1.6472	0.2085	12.7
2 SPENT NUCLEAR FUEL DISPOSAL COST	5,438,652	5,094,564	344,088	6.8	5,220,894	5,448,733	(227,839)	(4.2)	0.1042	0.0935	0.0107	11.4
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	1,584,654	1,546,000	38,654	2.5	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(33,972,617)	3,350,000	(37,322,617)	(1,114.1)	(1,193,356)	0	(1,193,356)	0.0	2.8468	0.0000	2.8468	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	569,461,837	484,145,279	85,316,558	17.6	30,946,901	28,784,780	2,162,121	7.5	1.8401	1.6819	0.1582	9.4
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	43,258,801	42,715,660	543,141	1.3	2,567,159	2,239,993	327,166	14.6	1.6851	1.9070	(0.2219)	(11.6)
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	2,368,131	24,214,110	(21,845,979)	(90.2)	56,325	740,000	(683,675)	(92.4)	4.2044	3.2722	0.9322	28.5
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	20,704,914	1,418,360	19,286,554	1,359.8	476,541	41,580	434,961	1,046.1	4.3448	3.4112	0.9336	27.4
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)	127,504,083	162,173,748	(34,669,665)	(21.4)	6,446,758	7,526,711	(1,079,953)	(14.4)	1.9778	2.1546	(0.1768)	(8.2)
12 TOTAL COST OF PURCHASED POWER	193,835,929	230,521,878	(36,685,949)	(15.9)	9,546,782	10,548,284	(1,001,502)	(9.5)	2.0304	2.1854	(0.1550)	(7.1)
13 TOTAL AVAILABLE MWH					40,493,684	39,333,064	1,160,620	3.0				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	(816,845)	(17,487,400)	16,670,555	(95.3)	(50,267)	(1,060,000)	1,009,733	(95.3)	1.6250	1.6498	(0.0248)	(1.5)
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	(240,707)	(2,270,960)	2,030,253	(89.4)	(50,267)	(1,060,000)	1,009,733	(95.3)	0.4789	0.2142	0.2647	123.6
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(33,610,519)	(6,978,560)	(26,631,959)	381.6	(1,539,264)	(282,875)	(1,256,389)	444.2	2.1835	2.4670	(0.2835)	(11.5)
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	0	(4,050,000)	4,050,000	(100.0)	(1,223,618)	(282,875)	(940,743)	332.6	0.0000	1.4317	(1.4317)	(100.0)
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 SUPPLEMENTAL SALES	(55,299,670)	(33,227,981)	(22,071,689)	66.4	(2,067,558)	(1,549,090)	(518,468)	33.5	2.6746	2.1450	0.5296	24.7
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(89,967,740)	(64,014,901)	(25,952,839)	40.5	(3,657,089)	(2,891,965)	(765,124)	26.5	2.4601	2.2135	0.2466	11.1
19 NET INADVERTENT AND WHEELED INTERCHANGE					33,861	0	33,861					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	673,330,025	650,652,256	22,677,769	3.5	36,870,456	36,441,099	429,357	1.2	1.8262	1.7855	0.0407	2.3
21 NET UNBILLED	4,598,664	846,395	3,752,269	443.3	(251,816)	(144,369)	(107,447)	74.4	0.0133	0.0025	0.0108	432.0
22 COMPANY USE	2,299,618	3,241,059	(941,441)	(29.1)	(125,924)	(181,800)	55,876	(30.7)	0.0066	0.0095	(0.0029)	(30.5)
23 T & D LOSSES	33,542,501	36,978,407	(3,435,906)	(9.3)	(1,836,738)	(2,069,098)	232,360	(11.2)	0.0968	0.1086	(0.0118)	(10.9)
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	673,330,025	650,652,256	22,677,769	3.5	34,655,979	34,045,832	610,147	1.8	1.9429	1.9111	0.0318	1.7
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(23,089,302)	(19,631,822)	(3,457,480)	17.6	(1,191,228)	(1,027,430)	(163,798)	15.9	1.9383	1.9108	0.0275	1.4
26 JURISDICTIONAL KWH SALES	650,240,724	631,020,434	19,220,290	3.1	33,464,751	33,018,402	446,349	1.4	1.9431	1.9111	0.0320	1.7
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.0011	650,955,988	631,714,559	19,241,429	3.1	33,464,751	33,018,402	446,349	1.4	1.9452	1.9132	0.0320	1.7
28 PRIOR PERIOD TRUE-UP	(29,938,109)	(14,837,877)	(15,100,232)	101.8	33,464,751	33,018,402	446,349	1.4	(0.0895)	(0.0449)	(0.0446)	99.3
28a MARKET PRICE TRUE-UP	0	(263,847)	263,847	(100.0)	33,464,751	33,018,402	446,349	1.4	0.0000	(0.0008)	0.0008	(100.0)
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	8,346,289	8,346,290	(1)	0.0	33,464,751	33,018,402	446,349	1.4	0.0249	0.0253	(0.0004)	(1.6)
29 TOTAL JURISDICTIONAL FUEL COST	629,364,168	624,959,125	4,405,043	0.7	33,464,751	33,018,402	446,349	1.4	1.8806	1.8928	(0.0122)	(0.6)
30 REVENUE TAX FACTOR									1.00083	1.00083	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									1.8822	1.8944	(0.0122)	(0.6)
32 GPIF	(436,954)	(436,639)			33,464,751	33,018,402			(0.0013)	(0.0013)	0.0000	100.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									1.881	1.893	(0.012)	(0.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 1999

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$43,412,586	$36,144,006	$7,268,580	20.1	$596,411,148	$474,154,715	$122,256,433	25.8
1a.	NUCLEAR FUEL DISPOSAL COST	$549,950	498,794	51,156	10.3	5,438,652	5,094,564	344,088	6.8
1b.	NUCLEAR DECOM & DECON	$6,461	0	6,461	100.0	1,584,654	1,546,000	38,654	100.0
2 .	FUEL COST OF POWER SOLD	($2,347,802)	(2,618,900)	271,098	(10.4)	(34,427,364)	(24,465,960)	(9,961,404)	40.7
2a.	GAIN ON POWER SALES	($76,989)	(466,160)	389,171	(83.5)	(240,707)	(6,320,960)	6,080,253	(96.2)
3 .	FUEL COST OF PURCHASED POWER	$3,452,005	3,180,370	271,635	8.5	43,258,801	42,715,660	543,141	1.3
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	$11,079,217	13,796,819	(2,717,602)	(19.7)	127,504,083	162,173,748	(34,669,665)	(21.4)
3b.	DEMAND & NON FUEL COST OF PURCH POWER	$0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	$1,036,593	1,069,730	(33,137)	(3.1)	23,073,045	25,632,470	(2,559,425)	(10.0)
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	57,112,021	51,604,659	5,507,362	10.7	762,602,312	680,530,237	82,072,075	12.1
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF SUPPLEMENTAL SALES	($4,120,593)	(1,951,907)	(2,168,686)	111.1	(55,299,670)	(33,227,981)	(22,071,689)	66.4
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	($3,209,923)	306,000	(3,515,923)	(1,149.0)	(33,972,617)	3,350,000	(37,322,617)	(1,114.1)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	$0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$49,781,505	$49,958,752	($177,247)	(0.4)	$673,330,025	$650,652,256	$22,677,769	3.5

FOOTNOTE: DETAIL OF LINE 6B ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	2,773	0	2,773	32,979	0	32,979
PIPELINE EXPENSES {Wholesale Portion}	3,237	0	3,237	37,563	0	37,563
UNIV.OF FL STEAM REVENUE ALLOCATION {Wholesale Portion}	4,850	0	4,850	40,860	0	40,860
ADD'L ADJUSTMENT FOR 518.13 CLEANUP	(6,461)	0	(6,461)	(63,042)	0	(63,042)
GAS CONVERSION PROJECTS. {DEPRECIATION & RETURN}	275,300	306,000	(30,700)	3,328,116	3,350,000	(21,884)
EMISSIONS	0	0	0	1,049,661	0	1,049,661
TANK BOTTOM ADJUSTMENT {Grossed up}	0	0	0	(388,034)	0	(388,034)
HINES STARTUP FUEL INEFFICIENT PORTION {System}	0	0	0	(790,806)	0	(790,806)
TIGER BAY NET GENERATION	(3,489,622)	0	(3,489,622)	(37,219,916)	0	(37,219,916)
SUBTOTAL LINE 6B SHOWN ABOVE	($3,209,923)	306,000	(3,515,923)	(33,972,619)	3,350,000	(37,322,619)

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 1999

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B .	SALES REVENUES (EXCLUDE REVENUE TAXES)								
1 .	JURISDICTIONAL SALES REVENUE								
1a.	BASE FUEL REVENUE	$0	$0	$0	0.0	$0	$0	$0	0.0
1b.	FUEL RECOVERY REVENUE	45,713,578	46,901,896	(1,188,318)	(2.5)	627,162,112	624,525,923	2,636,189	0.4
1c.	JURISDICTIONAL FUEL REVENUE	45,713,578	46,901,896	(1,188,318)	(2.5)	627,162,112	624,525,923	2,636,189	0.4
1d.	NON FUEL REVENUE	125,733,623	130,213,655	(4,480,032)	(3.4)	1,734,234,804	1,777,750,903	(43,516,099)	(2.5)
1e.	TOTAL JURISDICTIONAL SALES REVENUE	171,447,200	177,115,551	(5,668,351)	(3.2)	2,361,396,915	2,402,276,826	(40,879,911)	(1.7)
2 .	NON JURISDICTIONAL SALES REVENUE	15,951,160	9,771,313	6,179,847	63.2	228,178,693	164,655,724	63,522,969	38.6
3 .	TOTAL SALES REVENUE	$187,398,361	$186,886,864	$511,497	0.3	$2,589,575,608	$2,566,932,550	$22,643,058	0.9
C .	KWH SALES								
1 .	JURISDICTIONAL SALES	2,462,990,879	2,479,682,000	(16,691,121)	(0.7)	33,473,038,229	33,018,403,000	454,635,229	1.4
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	125,418,862	70,109,000	55,309,862	78.9	1,191,225,993	1,027,430,000	163,795,993	15.9
3 .	TOTAL SALES	2,588,409,741	2,549,791,000	38,618,741	1.5	34,664,264,222	34,045,833,000	618,431,222	1.8
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	95.15	97.25	(2.10)	(2.2)	96.56	96.98	(0.42)	(0.4)

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 1999

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D .	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE (LINE B1c)	45,713,578	$46,901,896	($1,188,318)	(2.5)	$627,162,112	$624,525,923	$2,636,189	0.4
2 .	ADJUSTMENTS: PRIOR PERIOD ADJ	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION + RECOVERABLE NUC REPL FUEL	16,336,721	1,236,487	15,100,234	1,221.2	21,591,821	6,491,586	15,100,235	232.6
2b.	INCENTIVE PROVISION	36,387	36,382	5	0.0	436,641	436,329	312	0.1
2c.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	62,086,685	48,174,765	13,911,920	28.9	649,190,573	631,453,838	17,736,735	2.8
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	49,781,505	49,958,752	(177,247)	(0.4)	673,330,025	650,652,256	22,677,769	3.5
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE C4)	95.15	97.25	(2.10)	(2.2)				
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE D4 • LINE D5 * .11% "LINE LOSSES")	47,419,205	48,638,530	(1,219,325)	(2.5)	650,955,987	633,714,558	17,241,429	2.7
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE D3 - D6)	14,667,480	(463,765)	15,131,245	0.0	(1,765,414)	(2,260,720)	495,306	0.0
8 .	INTEREST PROVISION FOR THE MONTH (LINE E10)	(319)				858,395			
9 .	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	766,118				21,595,398			
10.	TRUE UP COLLECTED (REFUNDED)	(16,336,721)				(21,591,821)	(6,491,586)	(15,100,235)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES D7 + D8 + D9 + D10)	(903,442)				(903,442)			
12.	OTHER:								
13.	END OF PERIOD TOTAL NET TRUE UP (LINES D11 + D12)	(903,442)				(903,442)			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 1999

		CURRENT MONTH				PERIOD TO DATE		
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE
E .	INTEREST PROVISION							
1 .	BEGINNING TRUE UP (LINE D9)	$766,118	N/A	--	--		NOT	
2 .	ENDING TRUE UP (LINES D7 + D9 + D10 +D12)	(903,123)	N/A	--	--			
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(137,005)	N/A	--	--			
4 .	AVERAGE TRUE UP (50% OF LINE E3)	(68,503)	N/A	--	--			
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	5.550	N/A	--	--			
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	5.600	N/A	--	--			
7 .	TOTAL (LINE E5 + LINE E6)	11.150	N/A	--	--		APPLICABLE	
8 .	AVERAGE INTEREST RATE (50% OF LINE E7)	5.575	N/A	--	--			
9 .	MONTHLY AVERAGE INTEREST RATE (LINE E8/12)	0.465	N/A	--	--			
10.	INTEREST PROVISION (LINE E4 * LINE E9)	($319)	N/A	--	--			

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FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

Jan 99 Thru Dec 99
FINAL

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)					
1	HEAVY OIL	136,029,905	80,260,079	55,769,826	69.5%
2	LIGHT OIL	35,800,703	10,678,150	25,122,553	235.3%
3	COAL	253,061,882	276,803,751	-23,741,869	-8.6%
4	GAS	153,504,135	87,278,527	66,225,608	75.9%
5	NUCLEAR	18,014,523	19,134,208	-1,119,685	-5.9%
6					
7					
8	TOTAL ($)	596,411,148	474,154,715	122,256,433	25.8%
SYSTEM NET GENERATION (MWH)					
9	HEAVY OIL	6,299,200	3,825,311	2,473,889	64.7%
10	LIGHT OIL	700,971	248,390	452,581	182.2%
11	COAL	14,149,438	15,774,184	-1,624,746	-10.3%
12	GAS	5,221,193	3,488,163	1,733,030	49.7%
13	NUCLEAR	5,769,375	5,448,733	320,642	5.9%
14					
15					
16	TOTAL (MWH)	32,140,177	28,784,781	3,355,396	11.7%
UNITS OF FUEL BURNED					
17	HEAVY OIL (BBL)	9,886,884	5,945,744	3,941,140	66.3%
18	LIGHT OIL (BBL)	1,618,464	462,554	1,155,910	249.9%
19	COAL (TON)	5,389,190	5,928,099	-538,909	-9.1%
20	GAS (MCF)	46,388,707	28,991,438	17,397,269	60.0%
21	NUCLEAR (MMBTU)	59,161,373	56,277,079	2,884,294	5.1%
22					
23					

FLORIDA POWER CORPORATION

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

Jan 99 Thru Dec 99
FINAL

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
BTUS BURNED (MILLION BTU)					
24	HEAVY OIL	64,103,123	38,052,765	26,050,358	68.5%
25	LIGHT OIL	9,431,247	2,682,822	6,748,425	251.5%
26	COAL	136,357,695	149,009,220	-12,651,525	-8.5%
27	GAS	48,135,764	28,991,438	19,144,326	66.0%
28	NUCLEAR	59,161,373	56,277,079	2,884,294	5.1%
29					
30					
31	TOTAL (MILLION BTU)	317,189,202	275,013,324	42,175,878	15.3%
GENERATION MIX (% MWH)					
32	HEAVY OIL	19.6	13.29	6.3	47.5%
33	LIGHT OIL	2.2	0.86	1.3	152.7%
34	COAL	44.0	54.80	-10.8	-19.7%
35	GAS	16.2	12.12	4.1	34.1%
36	NUCLEAR	18.0	18.93	-1.0	-5.2%
37					
38					
39	TOTAL (% MWH)	100.0	100.0	0.0	0.0%

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
FUEL COST PER UNIT ($)					
40	HEAVY OIL ($/BBL)	13.76	13.50	0.26	1.9%
41	LIGHT OIL ($/BBL)	22.12	23.09	-0.97	-4.2%
42	COAL ($/TON)	46.96	46.69	0.26	0.6%
43	GAS ($/MCF)	3.31	3.01	0.30	9.9%
44	NUCLEAR ($/MBTU)	0.30	0.34	-0.04	-10.4%
45					
46					
FUEL COST PER MILLION BTU ($/MILLION BTU)					
47	HEAVY OIL	2.12	2.11	0.01	0.6%
48	LIGHT OIL	3.80	3.98	-0.18	-4.6%
49	COAL	1.86	1.86	0.00	-0.1%
50	GAS	3.19	3.01	0.18	5.9%
51	NUCLEAR	0.30	0.34	-0.04	-10.4%
52					
53					
54	SYSTEM ($/MBTU)	1.88	1.72	0.16	9.1%
BTU BURNED PER KWH (BTU/KWH)					
55	HEAVY OIL	10,176	9,948	229	2.3%
56	LIGHT OIL	13,455	10,801	2,654	24.57%
57	COAL	9,637	9,446	191	2.0%
58	GAS	9,219	8,311	908	10.9%
59	NUCLEAR	10,254	10,328	-74	-0.7%
60					
61					
62	SYSTEM (BTU/KWH)	9,869	9,554	315	3.3%

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
	GENERATED FUEL COST PER KWH (CENTS/KWH)				
63	HEAVY OIL	2.16	2.10	0.06	2.9%
64	LIGHT OIL	5.11	4.30	0.81	18.8%
65	COAL	1.79	1.75	0.03	1.9%
66	GAS	2.94	2.50	0.44	17.5%
67	NUCLEAR	0.31	0.35	-0.04	-11.1%
68					
69					
70	SYSTEM (CENTS/KWH)	1.86	1.65	0.21	12.7%

FLORIDA POWER CORPORATION

SYSTEM NET GENERATION AND FUEL COST

Schedule A-4

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Steam													
Anclote													
UNIT 1	517	1,917,464.00	42			10,088				19,343,400	43,454,803	2.266	
		1,726,474.11					#6	2,681,280	6.496	17,416,692	37,357,362	2.164	13.933
		180,082.86					GS	1,765,110	1.029	1,816,678	5,638,119	3.131	3.194
		10,907.03					#2	18,860	5.834	110,030	459,322	4.211	24.354
UNIT 2	522	2,324,768.00	51			9,955				23,143,702	51,699,457	2.224	
		2,087,111.23					#6	3,194,360	6.505	20,777,764	43,546,108	2.086	13.632
		230,759.24					GS	2,229,400	1.030	2,297,271	7,862,019	3.407	3.527
		6,897.53					#2	11,770	5.834	68,667	291,331	4.224	24.752
Bartow													
UNIT 1	116	582,039.00	57			10,303				5,996,663	12,559,968	2.158	
		581,572.48					#6	929,770	6.444	5,991,857	12,542,717	2.157	13.490
		466.52					#2	830	5.791	4,806	17,251	3.698	20.784
UNIT 2	117	531,551.00	52			10,555				5,610,476	11,935,966	2.245	
		531,551.00					#6	868,800	6.458	5,610,476	11,935,966	2.245	13.738
UNIT 3	210	1,310,304.00	71			10,043				13,159,676	29,574,851	2.257	
		1,101,149.67					#6	1,710,920	6.464	11,059,092	22,119,440	2.009	12.928
		209,154.33					GS	2,042,110	1.029	2,100,584	7,455,411	3.565	3.651
		0.00					#2	0	0.000	0	0	0.000	
Crystal River 1 & 2													
UNIT 1	372	1,819,158.00	56			9,883				17,978,018	29,664,044	1.631	
		4,337.15					#2	7,330	5.848	42,862	151,636	3.496	20.687
		1,814,820.85					CA	706,230	25.396	17,935,156	29,512,407	1.626	41.789
UNIT 2	468	3,112,100.00	76			9,747				30,332,888	50,086,360	1.609	
		3,765.08					#2	6,270	5.853	36,697	124,769	3.314	19.899
		3,108,334.92					CA	1,192,164	25.413	30,296,191	49,961,591	1.607	41.908

FLORIDA POWER CORPORATION

SYSTEM NET GENERATION AND FUEL COST

Schedule A-4

Jan 99 Thru Dec 99
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Crystal River 4 & 5													
UNIT 4	697	4,983,638.00	82			9,608				47,882,198	94,732,500	1.901	
		19,621.68					#2	32,380	5.822	188,523	680,755	3.469	21.024
		4,964,016.32					CA	1,904,946	25.037	47,693,675	94,051,745	1.895	49.372
UNIT 5	697	4,279,609.00	70			9,486				40,595,930	80,134,451	1.872	
		17,210.53					#2	28,020	5.826	163,257	598,312	3.476	21.353
		4,262,398.47					CA	1,616,092	25.019	40,432,673	79,536,139	1.866	49.215
Suwannee Plant													
UNIT 1	33	77,052.00	27			12,735				981,253	2,521,967	3.273	
		72,860.33					#6	142,760	6.500	927,873	2,351,241	3.227	16.470
		4,087.73					GS	50,050	1.040	52,057	162,826	3.983	3.253
		103.95					#2	260	5.091	1,324	7,900	7.600	30.385
UNIT 2	32	100,876.00	36			12,834				1,294,626	3,429,173	3.399	
		96,707.30					#6	190,560	6.513	1,241,126	3,259,013	3.370	17.102
		4,074.68					GS	49,770	1.051	52,294	161,434	3.962	3.244
		94.02					#2	240	5.028	1,207	8,727	9.282	36.362
UNIT 3	80	148,806.00	21			11,377				1,692,954	4,788,912	3.218	
		94,774.76					#6	168,480	6.400	1,078,245	2,918,060	3.079	17.320
		53,777.92					GS	589,560	1.038	611,827	1,855,938	3.451	3.148
		253.32					#2	560	5.146	2,882	14,914	5.887	26.632
TOTAL	3,861	21,187,365.00				9,818				208,011,785	414,582,451	1.957	
Nuclear													
Crystal River 3													
UNIT 3	751	5,769,374.59	88			10,255				59,164,109	18,030,516	0.313	
		0					NF	59,161,373	1.000	59,161,373	18,014,523	0.000	0.304
		0					#2	462	5.923	2,736	15,993	0.000	34.617
TOTAL	751	5,769,374.59				10,255				59,164,109	18,030,516	0.313	
Gas Turbine													
Avon Park Peaker	50	29,252.00	7			17,096				500,079	1,656,717	5.664	
		5,471.88					#2	16,070	5.821	93,545	376,207	6.875	23.411
		23,780.12					GS	391,580	1.038	406,535	1,280,509	5.385	3.270

FLORIDA POWER CORPORATION

SYSTEM NET GENERATION AND FUEL COST

Schedule A-4

Jan 99 Thru Dec 99
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Bartow Peaker	176	139,585.00	9			15,187				2,119,880	6,758,555	4.842	
		30,797.09					#2	80,270	5.827	467,716	1,673,752	5.435	20.852
		108,787.91					GS	1,586,490	1.041	1,652,164	5,084,803	4.674	3.205
Bayboro Peaker	184	88,277.00	5			13,559				1,196,967	4,714,483	5.341	
		88,277.00					#2	205,530	5.824	1,196,967	4,714,483	5.341	22.938
Debary Peaker	614	509,964.00	9			13,068				6,664,252	22,988,717	4.508	
		230,383.47					#2	516,420	5.830	3,010,670	11,553,731	5.015	22.373
		279,580.53					GS	3,518,240	1.038	3,653,581	11,434,986	4.090	3.250
Higgins Peaker	110	73,938.00	8			16,618				1,228,723	3,822,994	5.171	
		326.50					#2	930	5.834	5,426	24,716	7.570	26.576
		73,611.50					GS	1,175,390	1.041	1,223,297	3,798,278	5.160	3.232
Hines Energy	400	2,050,770.00	59			7,310				14,991,530	43,432,447	2.118	
		25,365.32					#2	33,234	5.579	185,425	695,764	2.743	20.935
		2,025,404.68					GS	14,268,458	1.038	14,806,105	42,736,683	2.110	2.995
Intercession City Peaker	708	608,941.00	10			13,394				8,155,969	26,929,521	4.422	
		179,499.33					#2	411,690	5.840	2,404,159	8,933,359	4.977	21.699
		429,441.67					GS	5,529,230	1.040	5,751,810	17,996,162	4.191	3.255
Rio Pinar Peaker	15	4,818.00	4			17,417				83,917	321,743	6.678	
		4,818.00					#2	14,450	5.807	83,917	321,743	6.678	22.266
Suwannee Peaker	159	131,702.00	9			14,021				1,846,564	5,911,402	4.488	
		30,979.46					#2	74,080	5.863	434,356	1,817,413	5.867	24.533
		100,722.54					GS	1,359,110	1.039	1,412,208	4,093,989	4.065	3.012
Tiger Bay Cogen	218	1,193,356.00	62			7,752				9,250,991	37,197,215	3.117	
		1,193,356.00					GS	8,918,920	1.037	9,250,991	37,197,215	3.117	4.171
Turner Peaker	158	60,355.00	4			14,651				884,279	3,186,891	5.280	
		60,355.00					#2	151,138	5.851	884,279	3,186,891	5.280	21.086
Univ of Florida Cogen	42	292,479.00	79			10,565				3,090,157	6,877,499	2.351	
		3,955.77					#2	7,159	5.838	41,794	131,735	3.330	18.401
		288,523.23					GS	2,915,289	1.046	3,048,362	6,745,764	2.338	2.314
TOTAL	2,834	5,183,437.00				9,649				50,013,308	163,798,181	3.160	

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

Jan 99 Thru Dec 99
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
SYSTEM TOTAL	7,446	32,140,176.59				9,869				317,189,202	596,411,148	1.856	

NOTE: Includes the following steam transfers:

Plant	Unit	Fuel Type	Cost	Burn	BTUS
Crystal River 1 & 2	UNIT 2	Coal	$19,094.43	452.00	11,319,887,872

NOTE: Includes the following aerial survey adjustment:

Plant	Tons	Dollars	MMBTU
Crystal River 1 & 2	0	4,855.90	0.00
Crystal River 4 & 5	40,968	2,035,085.40	1,024,158.30

FLORIDA POWER CORPORATION

SYSTEM GENERATION FUEL COST

Schedule A-5

Jan 99 Thru Dec 99
FINAL

			Actual	Estimated	Difference	Difference (%)
HEAVY OIL	1	PURCHASES				
	2	Units (BBL)	10,338,501	5,945,744	4,392,757	73.9%
	3	Unit Cost ($/BBL)	14.64	13.77	0.87	6.3%
	4	Amount ($)	151,383,874	81,877,113	69,506,761	84.9%
	5	BURNED				
	6	Units (BBL)	9,886,884	5,945,744	3,941,140	66.3%
	7	Unit Cost ($/BBL)	13.76	13.50	0.26	1.9%
	8	Amount ($)	136,029,905	80,260,079	55,769,826	69.5%
	9	ADJUSTMENTS				
	10	Units (BBL)	-458			
	11	Amount ($)	-934,283			
	12	ENDING INVENTORY				
	13	Units (BBL)	1,053,263	800,000	253,263	31.7%
	14	Unit Cost ($/BBL)	19.94	14.46	5.48	37.9%
	15	Amount ($)	21,002,755	11,570,072	9,432,683	81.5%
	16					
	17	DAYS SUPPLY	0	0	0	0.0%
LIGHT OIL	18	PURCHASES				
	19	Units (BBL)	1,779,048	462,554	1,316,494	284.6%
	20	Unit Cost ($/BBL)	24.06	23.09	0.97	4.2%
	21	Amount ($)	42,797,050	10,679,821	32,117,229	300.7%
	22	BURNED				
	23	Units (BBL)	1,618,464	462,554	1,155,910	249.9%
	24	Unit Cost ($/BBL)	22.12	23.09	-0.97	-4.2%
	25	Amount ($)	35,800,703	10,678,150	25,122,553	235.3%
	26	ADJUSTMENTS				
	27	Units (BBL)	-93,994			
	28	Amount ($)	-1,911,686			
	29	ENDING INVENTORY				
	30	Units (BBL)	684,812	450,000	234,812	52.2%
	31	Unit Cost ($/BBL)	25.47	24.74	0.74	3.0%
	32	Amount ($)	17,443,306	11,131,358	6,311,948	56.7%
	33					
	34	DAYS SUPPLY	0	0	0	0.0%

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

			Actual	Estimated	Difference	Difference (%)
COAL	35	PURCHASES				
	36	Units (TON)	5,594,594	5,650,000	-55,406	-1.0%
	37	Unit Cost ($/TON)	46.76	46.89	-0.14	-0.3%
	38	Amount ($)	261,577,860	264,939,350	-3,361,490	-1.3%
	39	BURNED				
	40	Units (TON)	5,389,190	5,928,099	-538,909	-9.1%
	41	Unit Cost ($/TON)	46.96	46.69	0.26	0.6%
	42	Amount ($)	253,061,882	276,803,751	-23,741,869	-8.6%
	43	ADJUSTMENTS				
	44	Units (TON)	-41			
	45	Amount ($)	-9,842			
	46	ENDING INVENTORY				
	47	Units (TON)	826,487	225,329	601,158	266.8%
	48	Unit Cost ($/TON)	45.81	46.95	-1.14	-2.4%
	49	Amount ($)	37,864,716	10,579,971	27,284,745	257.9%
	50					
	51	DAYS SUPPLY	0	0	0	0.0%
OTHER	52					
	53					
	54					
	55					
	56					
	57					
	58					
	59					
	60					
	61					
	62					
	63					
	64					
	65					

FLORIDA POWER CORPORATION

SYSTEM GENERATION FUEL COST

Schedule A-5

Jan 99 Thru Dec 99
FINAL

			Actual	Estimated	Difference	Difference (%)
GAS	66	BURNED				
	67	Units (MCF)	46,388,707	28,991,438	17,397,269	60.0%
	68	Unit Cost ($/MCF)	3.31	3.01	0.30	9.9%
	69	Amount ($)	153,504,135	87,278,527	66,225,608	75.9%
NUCLEAR	70	BURNED				
	71	Units (MM BTU)	59,161,373	56,277,079	2,884,294	5.1%
	72	Unit Cost ($/MM BTU)	0.30	0.34	-0.04	-10.4%
	73	Amount ($)	18,014,523	19,134,208	-1,119,685	-5.9%

NOTE: Purchase dollars and units do not include plant to plant transfers. See schedule A-5, Attachment #1 for detail of adjustments.

FLORIDA POWER CORPORATION
SCHEDULE A6

POWER SOLD
FOR THE MONTH OF:
DEC 1999

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD (000)	(4) KWH WHEELED FROM OTHER SYSTEMS (000)	(5) KWH FROM OWN GENERATION (000)	(6a) FUEL COST C/KWH	(6b) TOTAL COST C/KWH	(7) FUEL ADJ. TOTAL $	(8) TOTAL COST $	(9) 80% GAIN ON ECONOMY ENERGY SALES	(10) NON FUEL AMOUNT FOR FUEL ADJ.
ESTIMATED		**110,000**	**0**	**110,000**	**1.842**	**1.974**	**2,026,200**	**2,171,400**	**116,160**	**0**
ACTUAL:										
Florida Power & Light Company	Schedule C	16,576		16,576	1.437	2.017	238,177	334,413	76,989	Not Applicable
SubTotal - Gain on Economy Energy Sales		16,576		16,576			238,177	334,413	76,989	
SEMINOLE	Load Following	3,086		3,086	3.812	3.812	117,634	117,634	Not Applicable	-
American Electric Power Co., Inc.	Market Rates	3,200		3,200	1.616	2.080	51,712	66,550	"	14,838
Aquila Energy Marketing Corp.	Schedule OS	824		824	1.701	2.292	14,016	18,884	"	4,868
City of New Smyma Beach, FL	Schedule I	-		-	-	-	6,979	6,979	"	-
City of Tallahassee, FL	Schedule OS	980		980	2.422	2.517	23,731	24,671	"	940
Coral Power, L. L. C.	Schedule OS	103		103	1.326	1.743	1,366	1,796	"	430
Dynegy, Inc	Market Rates	24,416		24,416	1.806	1.858	440,943	453,622	"	12,679
Dynegy, Inc	Schedule OS	800		800	1.888	1.832	15,104	14,657	"	(447)
El Paso Power Services Co.	Cost Rates	496		496	1.570	2.213	7,787	10,975	"	3,187
Enron Power Marketing, Inc.	Schedule OS	6,424		6,424	1.719	1.917	110,449	123,178	"	12,729
Entergy Power Marketing Corp.	Market Rates	800		800	1.578	2.122	12,624	16,972	"	4,348
Gainesville Regional Utilities	Schedule A	66		66	1.302	2.699	859	1,781	"	922
LG & E Energy Marketing, Inc.	Schedule OS	4,116		4,116	1.628	1.751	67,000	72,066	"	5,066
Oglethorpe Power Corporation	Market Rates	1,975		1,975	1.558	1.514	30,771	29,894	"	(876)
Oglethorpe Power Corporation	Schedule R	200		200	1.274	1.467	2,548	2,933	"	385
Orlando Utilities Commission	Schedule OS	100		100	7.026	5.682	7,026	5,682	"	(1,344)
Reedy Creek Improvement Dist.	Schedule OS	7,314		7,314	1.424	1.591	104,146	116,376	"	12,229
Reliant Energy Services, Inc.	Schedule OS	132		132	6.048	5.329	7,983	7,034	"	(950)
Sonat Power Marketing, Inc.	Schedule OS	800		800	1.658	1.638	13,262	13,108	"	(154)
Southeastern Power Admin.	Pump	7,696		7,696	1.451	1.351	111,706	103,988	"	(7,718)
Southern Co. Energy Mrktg., L. P.	Market Rates	1,600		1,600	1.632	2.119	26,111	33,911	"	7,800
Southern Company Services, Inc.	Market Rates	13,500		13,500	1.610	2.030	217,406	274,092	"	56,686
Tampa Electric Company	Cost Rates	24,025		24,025	1.862	2.763	447,297	663,875	"	216,578
Tampa Electric Company	Schedule J	6,588		6,588	2.418	2.711	159,287	178,582	"	19,295
The Energy Authority	Market Rates	833		833	1.355	1.181	11,287	9,836	"	(1,452)
The Energy Authority	Schedule OS	4,572		4,572	1.785	2.136	81,614	97,653	"	16,039
Williams Energy Service Co.	Market Rates	800		800	2.372	2.285	18,976	18,281	"	(695)
ADJUSTMENTS										
SubTotal - Gain on Other Power Sales		115,446		115,446			2,109,625	2,485,010		375,384
CURRENT MONTH TOTAL		132,022		132,022	1.617	1.941	2,347,802	2,819,423	76,989	375,384
DIFFERENCE		132,022		132,022	1.617	1.941	2,347,802	2,819,423	76,989	375,384
DIFFERENCE %		0.00%		0.00%	0.000	0.000	0.00%	0.00%	0.00%	0.00%
CUMULATIVE ACTUAL		1,589,531		1,589,531	1.969	2.767	34,427,362	48,385,322	240,707	13,639,830
CUMULATIVE ESTIMATED		1,060,000		1,060,000	1.5	1.742	17,487,400	20,316,000	2,270,960	-
CUMULATIVE DIFFERENCE		529,531		529,531	2.908	4.819	16,939,962	28,069,322	(2,030,253)	13,639,830
CUMULATIVE DIFFERENCE %		49.96%		49.96%	0.176	0.251	96.87%	138.16%	-89.40%	

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FLORIDA POWER CORPORATION
SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE MONTH OF:
DEC 1999

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUPTIBLE (000)	(6) KWH FOR FIRM (000)	(7) ENERGY COST C/KWH	(8) TOTAL COST C/KWH	(9) TOTAL AMOUNT FOR FUEL ADJ $
ESTIMATED		648,727			648,727	2.127	2.127	13,796,819
ACTUAL								
AUBURNDALE (EL DORADO)	CO-GEN	84,245			84,245	2.456	2.456	2,069,136
ADJ		0			0			(119,438)
AUBURNDALE LFC POWER SYSTEMS	CO-GEN	8,432			8,432	1.593	1.593	134,316
ADJ		0			0			(31,108)
BAY COUNTY	CO-GEN	7,020			7,020	1.609	1.609	112,952
ADJ		0			0			(17,238)
CARGILL FERTILIZER	CO-GEN	15,175			15,175	1.490	1.490	226,108
ADJ		0			0			(27,888)
CENTRAL POWER & LIME (FLACRUSH)	CO-GEN	0			0	0.000	0.000	-
ADJ		0			0			-
CITRUS WORLD	CO-GEN	0			0	0.000	0.000	-
ADJ		0			0			-
LAKE ORDER COGEN LIMITED	CO-GEN	60,495			60,495	2.015	2.015	1,218,974
ADJ		0			0			(166,309)
LAKE COUNTY	CO-GEN	6,670			6,670	1.679	1.679	111,989
ADJ		0			0			(14,265)
METRO-DADE COUNTY	CO-GEN	23,201			23,201	1.632	1.632	378,640
ADJ		0			0			(104,724)
ORANGE COGEN	CO-GEN	32,853			32,853	1.671	1.671	548,978
ADJ		0			0			(124,439)
ORLANDO COGEN	CO-GEN	58,579			58,579	2.351	2.351	1,377,276
ADJ		0			0			(48,777)
PASCO COGEN LIMITED	CO-GEN	61,393			61,393	1.778	1.778	1,091,568
ADJ		0			0			159,020
PASCO COUNTY RESOURCE RECOVERY	CO-GEN	16,990			16,990	1.661	1.661	282,204
ADJ		0			0			(35,793)
PCS PHOSPHATE	CO-GEN	0			0	0.000	0.000	-
ADJ		(14)			(14)			(416)
PERPETUAL ENERGY	CO-GEN	(372)			(372)	(0.285)	(0.285)	1,061
ADJ		0			0			6,784
PINELLAS COUNTY	CO-GEN	34,659			34,659	1.609	1.609	557,663
ADJ		0			0			(106,052)
POLK POWER - MULBERRY ENERGY	CO-GEN	33,183			33,183	1.542	1.542	511,676
ADJ		0			0			(63,625)
POLK POWER- ROYSTER ENERGY	CO-GEN	12,904			12,904	1.557	1.557	200,921
ADJ		0			0			(11,822)
ST. JOE PAPER	CO-GEN	0			0	0.000	0.000	-
ADJ		0			0			-
TIMBER ENERGY RESOURCES	CO-GEN	7,954			7,954	1.664	1.664	132,355
ADJ		(22)			(22)			(32,574)
U.S. AGRI-CHEMICALS	CO-GEN	5,055			5,055	1.728	1.728	87,350
ADJ		0			0			(43,456)
WHEELABRATOR RIDGE ENERGY	CO-GEN	15,422			15,422	2.886	2.886	445,079
ADJ		0			0			18,079
SUBTOTAL EXCLUDING TIGER BAY STIPULATED PAYMENTS								
CURRENT MONTH TOTAL		483,822			483,822	1.803	1.803	8,724,204
DIFFERENCE		(164,905)			(164,905)	(0.324)	(0.324)	(5,072,615)
DIFFERENCE %		(25.4)			(25.4)	(15.2)	(15.2)	(36.8)
TIGER BAY STIPULATED PAYMENTS								
TIGER BAY - ECOPEAT	CO-GEN	28,319			28,319	1.630	1.630	461,712
TIGER BAY - GENERAL PEAT	CO-GEN	121,032			121,032	1.566	1.566	1,895,824
TIGER BAY - TIMBER 2	CO-GEN	4,232			4,232	1.651	1.651	69,861
TIGER BAY - STEAM SALES	CO-GEN				0	0.000	0.000	(72,384)
TOTAL QF ENERGY PAYMENTS INCLUDING TIGER BAY								
CURRENT MONTH TOTAL		637,405			637,405	1.738	1.738	11,079,216
DIFFERENCE		(11,322)			(11,322)	1.738	1.738	(2,717,603)
DIFFERENCE %		(1.7)			(1.7)	0.0	0.0	(19.7)
CUMULATIVE ACTUAL		6,446,757			6,446,757	1.978	1.978	127,504,084
CUMULATIVE ESTIMATED		7,526,711			7,526,711	2.155	2.155	162,173,748
CUMULATIVE DIFFERENCE		(1,079,954)			(1,079,954)	(0.177)	(0.177)	(34,669,664)
CUMULATIVE DIFFERENCE %		(14.3)			(14.3)	(8.2)	(8.2)	(21.4)

FLORIDA POWER CORPORATION
SCHEDULE A9

ECONOMY ENERGY PURCHASES INCLUDING LONG TERM PURCHASES FOR THE MONTH OF: DEC 1999

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) ENERGY COST C/KWH	(5) TOTAL AMOUNT FOR FUEL ADJ $	(6) COST IF GENERATED C/KWH	(7) COST IF GENERATED $	(8) FUEL SAVINGS $
ESTIMATED		**33,000**	**3.242**	**1,069,730**	**3.242**	**1,069,730**	**0**
ACTUAL							
Florida Power & Light Co.	Schedule C	7,202	4.816	346,814	5.352	385,460	38,646
Oglethorpe Power Corp.	Schedule C	95	4.391	4,171	5.880	5,586	1,415
Subtotal - Energy Purchases (Broker)		**7,297**	**4.810**	**350,985**	**5.359**	**391,047**	**40,062**
SEMINOLE	Load Following	2,977	2.964	88,253	2.964	88,253	-
City of Lakeland, FL	Schedule OS	50	2.591	1,295	2.798	1,399	104
City of Tallahassee, FL	Schedule OS	40	3.140	1,256	3.292	1,317	61
City of Tallahassee, FL	Transmission	-	0.000	3,350	0.000	-	(3,350)
Dynegy, Inc	Schedule S	800	4.091	32,724	5.873	46,988	14,264
Jacksonville Electric Authority	Transmission	-	0.000	6,000	0.000	-	(6,000)
LG & E Energy Marketing, Inc.	Schedule S	1,070	2.393	25,605	2.671	28,577	2,972
Morgan Stanley Cap. Grp., Inc.	Schedule J	800	5.169	41,353	6.657	53,256	11,903
Orlando Utilities Commission	Schedule OS	3,155	4.452	140,470	5.168	163,053	22,583
Reedy Creek Improvement Dist.	Schedule OS	920	4.958	45,616	5.923	54,493	8,877
Reliant Energy Services, Inc.	Schedule S	195	5.086	9,917	6.048	11,794	1,877
Seminole Electric Coop., Inc.	Transmission	-	0.000	1,146	0.000	-	(1,146)
Southern Company Srvcs., Inc.	Transmission	-	0.000	4,662	0.000	-	(4,662)
Tampa Electric Company	Market Rates	5,181	3.954	204,862	4.941	255,991	51,129
Tampa Electric Company	Schedule J	817	2.567	20,970	2.676	21,861	891
The Energy Authority	Schedule OS	1,740	3.013	52,431	3.767	65,546	13,116
ADJUSTMENTS							
City of Tallahassee, FL	Transmission	-	0.000	(39)	0.000	-	39
Seminole Electric Coop., Inc.	Transmission	-	0.000	29	0.000	-	(29)
Seminole Electric Coop., Inc.	RPR	369	1.547	5,710	1.547	5,710	-
Subtotal - Energy Purchases (Non-Broker)		**18,114**		**685,608**		**798,236**	**112,629**
CURRENT MONTH TOTAL		25,411	4.079	1,036,593	4.680	1,189,283	152,690
DIFFERENCE		(7,589)	(0.737)	(33,137)	(0.672)	119,553	152,690
DIFFERENCE %		(23.0)	(15.3)	(3.1)	(12.6)	11.2	0.0
CUMULATIVE ACTUAL		532,866	4.330	23,073,044	4.670	24,886,148	2,120,468
CUMULATIVE ESTIMATED		781,580	3.280	25,632,470	3.280	25,632,470	
CUMULATIVE DIFFERENCE		(248,714)	1.050	(2,559,426)	1.390	(746,322)	2,120,468
CUMULATIVE DIFFERENCE %		(31.8)	32.0	(10.0)	42.4	(2.9)	

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