ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070290 -EI

In re: Petition of Progress Energy Florida, Inc. to increase base rates to recover the full revenue requirements of the Hines Unit 2 and Hines Unit 4 power plants pursuant to Commission Order No. PSC-05-0945-S-EI

DIRECT TESTIMONY OF JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 410 S. Wilmington Street Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director of Regulatory Planning.

Q. What are your duties and responsibilities?

A. I am responsible for regulatory planning, cost recovery and pricing functions for both Progress Energy Florida ("PEF" or the "Company") and Progress Energy Carolinas.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation and recoverability of the revenue requirements that PEF proposes to recover in base rates for its Hines Unit 2 and Hines Unit 4

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power plants as approved by the Commission in the Stipulation and Settlement Agreement that resolved PEF's petition to increase base rates in Docket No. 050078-EI.

Q. Do you have any exhibits to your testimony?

A. Yes. I am sponsoring exhibits JP-1, JP-2, JP-3, JP-4, JP-5, JP-6, JP-7, JP-8 and JP-9 attached to my testimony. Exhibit JP-1 contains the 2006 revenue requirements of Hines Unit 2, excluding the unit's non-fuel O&M expenses, which PEF proposes to transfer from the fuel cost recovery clause to base rates beginning with the commercial in-service date of Hines Unit 4. Exhibit JP-2 illustrates the impact to the fuel cost recovery factor due to the transfer of Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates in December 2007. Exhibit JP-3 contains the revenue requirements of the projected installed cost of Hines Unit 4 subject to the limitations of Rule 25-22.082(15) and the unit's non-fuel operating expenses that PEF proposes to recover in base rates beginning on the commercial in-service date of the unit. Exhibit JP-4 illustrates the impact to retail rates due to base rate recovery of Hines Unit 2 and Hines Unit 4 revenue requirements. Exhibit JP-5 is the test year 2006 MFR Schedule D-1a (Cost of Capital – 13 Month Average) using an 11.75% ROE and the capital structure filed in Docket No. 050078-EI to calculate Hines Unit 2 and Hines Unit 4 revenue requirements for base rate recovery. Exhibit JP-6 is page 128 of the January 3, 2003 Special Agenda Transcript in Docket No. 020398-EQ (Bid Rule). Exhibit JP-7 is the test year 2006 MFR C-44 (Revenue Expansion Factor) of the Net Operating Income Factor (1.6315%) used to derive Hines Unit 4 revenue requirements on Exhibit JP-4. Exhibit JP-8 is the Stipulation and Settlement Agreement and Order No. PSC-0945-S-EI that resolved the Company's petition to increase base rates in Docket No. 050078-EI. Exhibit JP-9 illustrates the impact of base rate recovery of Hines Unit 2 and Hines Unit 4 revenue requirements on interruptible and curtailable credits.

Q. What is the total Hines Unit 2 revenue requirements that PEF proposes to transfer from the fuel cost recovery clause to base rates?

A. As shown on Exhibit JP-1, PEF proposes to transfer $36.3 million of depreciation expense and return from the fuel cost recovery clause to base rates in accordance with the Stipulation and Settlement Agreement in Docket No. 050078-EI of PEF's base rate review proceeding.

Q. What ROE and capital structure was used to calculate the Hines Unit 2 revenue requirements for base rate recovery?

A. As shown on Exhibit JP-5 and as stated in the Stipulation and Settlement in Docket No. 050078-EI (Exhibit JP-8) , an 11.75% ROE and the capital structure set forth in the test year MFR Schedule D-1a was used to calculate the Hines Unit 2 revenue requirements.

Q. When will PEF transfer the Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates?

A. The revenue requirements will be transferred to base rates upon the commercial in-service date of Hines Unit 4.

Q. When is Hines Unit 4 expected to begin commercial operations?

A. PEF expects Hines Unit 4 to begin commercial operations on December 1, 2007.

Q. When will PEF change its base rates to account for recovery of Hines Unit 2 revenue requirements?

A. PEF's base rates will be revised beginning with the first billing cycle of December 2007.

Q. When will PEF adjust its fuel rates to account for the transfer of Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates?

A. PEF proposes to account for the transfer of Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates in its calculation of its 2008 fuel cost recovery factors which historically would be effective the first billing cycle of January 2008. The impact of any over/under recovery of fuel revenues due to continued recovery of Hines Unit 2 revenue requirements in December 2007 would be reflected in PEF's calculation of its prior period recovery true up, with interest, as part of its 2008 fuel cost recovery factors filing.

Q. What is the impact to the fuel cost recovery factor due to the transfer of Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates?

A. As shown on Exhibit JP-2, the 2007 levelized fuel cost recovery factor decreases 87 cents per kWh (adjusted for line losses) from 5.132 to 5.045.

Q. What are the total Hines Unit 4 revenue requirements that PEF proposes for base rate recovery?

A. As shown on Exhibit JP-3, PEF proposes to recover $52.4 million through base rates which includes the full revenue requirements of the installed cost of Hines Unit 4 subject to the limitations of Rule 25-22.082(15) and the unit's non-fuel operating expenses.

Q. What is the total current estimated Hines Unit 4 project costs included in the calculation of revenue requirements?

A. As shown on Exhibit JP-3, the total project costs included in revenue requirements for Hines Unit 4 are $327.1 million (System).

Q. Do the total current estimated Hines Unit 4 project costs exceed the need case estimates?

A. Yes. PEF expects the final total cost of the project, including associated transmission facilities to be approximately $327.1 million (System) or 14.33% more than the estimate in the need case of $286.1M. As stated in the Direct Testimony of Kevin Murray, PEF expects the final generating costs to be $267.0 million versus the $248.5 million estimate in the need case. As stated in the Direct Testimony of Gary Furman, PEF expects the final transmission costs to be $60.1 million versus the need estimate of $37.6 million.

Q. How did PEF select the Hines Unit 4 power plant as its next planned generation facility?

A. In 2003, through its rigorous integrated resource planning process, PEF identified the need for 500MW of power and identified Hines Unit 4 as its most cost-effective self-build option to meet that energy need. In accordance with Rule 25-22.082, F.A.C., PEF prepared a RFP, which it issued on October 7, 2003, to compare the cost-effectiveness of Hines Unit 4 against other generating alternatives. PEF issued the RFP in 2003 in order to be able to meet the December 2007 in-service date and to maintain its 20% reserve margin obligation if it chose the self-build option. PEF analyzed the bids from late 2003 and into 2004. The Company could not reasonably enter into contracts with vendors until it completed its bid evaluation. This meant that by the time it selected the self-build option and filed its Need case with the Commission in August 2004, the company was working off of the cost estimates against which it had compared all of the other bidders. It would have been impossible to go back and start the process over at that point in 2004 and meet PEF's commitment to provide 20% reserves.

Q. What was the estimated cost of the Hines Unit 4 generating plant and associated transmission facilities?

A. PEF estimated generation and transmission costs to be approximately $248.5 million and $37.6 million, respectively, including Allowance for Funds Used During Construction ("AFUDC").

Q. Should the Commission approve recovery of Hines Unit 4 project costs in excess of the need case estimates?

A. Yes. As stated in the Direct Testimonies of Kevin Murray and Gary Furman, costs in excess of Hines Unit 4 need estimates were prudently incurred and outside the control of the Company; therefore, the Commission should approve recovery of these costs. Per the amended Bid Rule (Rule 25-22.082(15)) which the Commission adopted in Order PSC-03-0653-FOF-EQ, if a public utility selects a self-build option, costs in addition to those identified in the need determination are recoverable if the utility "can demonstrate that such costs were prudently incurred and due to extraordinary circumstances." Commissioner Baez, who proposed the language during the Special Agenda Conference where the Commission adopted the rule, indicated that "extraordinary circumstances" was a concise way of saying "unforeseen and beyond [the utility's] control." See Docket No. 020398-EQ, Special Agenda

Transcript (Jan. 3, 2003), p. 128 attached as Exhibit JP-6.

Q. What ROE and capital structure was used to calculate the Hines Unit 4 revenue requirements for base rate recovery?

A. As shown on Exhibit JP-5 and as stated in the Stipulation and Settlement in Docket No. 050078-EI (Exhibit JP-8) , an 11.75% ROE and the capital structure set forth in the test year MFR Schedule D-1a was used to calculate the Hines Unit 4 revenue requirements.

Q. When will PEF adjust its base rates to account for recovery of Hines Unit 4 revenue requirements?

A. PEF's base rates will be adjusted the first billing cycle of December 2007.

Q. What is the impact to Retail rates due to base rate recovery of Hines Unit 2 and Hines Unit 4 revenue requirements?

A. As shown on Exhibit JP-4, Retail rates will increase 7.45%. This percentage increase will be uniformly applied to PEF's demand and energy base rate charges including it voltage credits, demand credits, power factor adjustment and premium distribution service rate. This increase will be partially offset by a decrease in the fuel cost recovery factor due to the transfer of Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates.

Q. What is the impact of base rate recovery of Hines Unit 2 and Hines Unit 4 revenue requirements on interruptible and curtailable credits?

A. As shown on Exhibit JP-9, interruptible and curtailable credits increased from $22.1 million to

$23.7 million.

Q. Does this conclude your testimony?

A. Yes.

Progress Eenrgy Florida
Hines Unit 2 - Revenue Requirements
Calculation of Retail Depreciation and Return

Docket No. ________-E1
Witness: J. Portuondo
Exhibit JP-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	TOTAL
1 **Land**													
2 Beginning Balance	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196
3 Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
5 Ending Balance	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196
6 **Production Plant**													
7 Beginning Balance	239,413,368	239,536,196	239,674,458	239,825,068	239,985,701	240,154,353	240,329,607	240,508,868	240,691,334	240,876,364	241,063,521	241,252,379	239,413,368
8 Add Investment	122,828	138,262	150,610	160,633	168,652	175,254	179,261	182,466	185,030	187,157	186,858	186,506	2,025,517
9 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Ending Balance	239,536,196	239,674,458	239,825,068	239,985,701	240,154,353	240,329,607	240,508,868	240,691,334	240,876,364	241,063,521	241,252,379	241,438,885	241,438,885
11 Average Balance	239,474,782	239,605,327	239,749,763	239,905,385	240,070,027	240,241,980	240,419,238	240,600,101	240,783,849	240,969,943	241,157,950	241,345,632	240,360,081
12 Depreciation Rate (3.7% annual rate)	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	3.700000%
13 Depreciation Expense	738,380	738,782	739,228	739,707	740,215	740,745	741,292	741,850	742,416	742,990	743,570	744,148	8,893,323
14 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
15 Beginning Balance Depreciation	17,939,984	18,678,364	19,417,146	20,156,374	20,896,081	21,636,296	22,377,041	23,118,333	23,860,183	24,602,599	25,345,589	26,089,159	17,939,984
16 Ending Balance Depreciation	18,678,364	19,417,146	20,156,374	20,896,081	21,636,296	22,377,041	23,118,333	23,860,183	24,602,599	25,345,589	26,089,159	26,833,307	26,833,307
17 **Transmission Station Equip**													
18 Beginning Balance	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211
19 Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
21 Ending Balance	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211
22 Average Balance	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211	5,135,211
23 Depreciation Rate (2.2% annual rate)	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	2.200000%
24 Depreciation Expense	9,415	9,415	9,415	9,415	9,415	9,415	9,415	9,415	9,415	9,415	9,415	9,415	112,980
25 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
26 Beginning Balance Depreciation	223,716	233,131	242,546	251,961	261,376	270,791	280,206	289,621	299,036	308,451	317,866	327,281	223,716
27 Ending Balance Depreciation	233,131	242,546	251,961	261,376	270,791	280,206	289,621	299,036	308,451	317,866	327,281	336,696	336,696
28 **Total Depreciation**													
29 Total Depreciation Expense	747,795	748,197	748,643	749,122	749,630	750,160	750,707	751,265	751,831	752,405	752,985	753,563	9,006,303
30 Total End Balance Depreciation	18,911,495	19,659,692	20,408,335	21,157,457	21,907,087	22,657,247	23,407,954	24,159,219	24,911,050	25,663,455	26,416,440	27,170,003	27,170,003
31 **Return**													
32 Beginning Net Investment	240,926,537	227,966,108	227,356,173	226,758,140	226,169,651	225,588,673	225,013,767	224,442,321	223,873,522	223,306,721	222,741,473	222,177,346	240,926,537
33 Ending Net Investment	227,966,108	227,356,173	226,758,140	226,169,651	225,588,673	225,013,767	224,442,321	223,873,522	223,306,721	222,741,473	222,177,346	221,610,289	221,610,289
34 Average Investment	234,446,323	227,661,141	227,057,157	226,463,896	225,879,162	225,301,220	224,728,044	224,157,922	223,590,122	223,024,097	222,459,410	221,893,818	225,553,854
35 *Allowed Equity Return (1)*	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	.57083%	6.85000%
36 Equity Component After Tax	1,338,290	1,299,558	1,296,110	1,292,724	1,289,386	1,286,087	1,282,815	1,279,561	1,276,319	1,273,088	1,269,865	1,266,636	15,450,439
37 Conversion to Pre-tax (2)	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800
38 Equity Component Pre-Tax	2,178,736	2,115,680	2,110,067	2,104,555	2,099,120	2,093,750	2,088,423	2,083,125	2,077,847	2,072,587	2,067,340	2,062,083	25,153,313
39 Allowed Debt Return (1)	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	.17000%	2.04000%
40 Debt Component	398,559	387,024	385,997	384,989	383,995	383,012	382,038	381,068	380,103	379,141	378,181	377,219	4,601,326
41 Total Return Requirements	2,577,295	2,502,704	2,496,064	2,489,544	2,483,115	2,476,762	2,470,461	2,464,193	2,457,950	2,451,728	2,445,521	2,439,302	29,754,639
42 **Total Depreciation & Return**													
43 Total Depreciation & Return	3,325,090	3,250,901	3,244,707	3,238,666	3,232,745	3,226,922	3,221,168	3,215,458	3,209,781	3,204,133	3,198,506	3,192,865	38,760,942
44 Production Base Separation Factor	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%	93.753%
45 Retail Depreciation & Return	$3,117,372	$3,047,817	$3,042,010	$3,036,347	$3,030,795	$3,025,336	$3,019,942	$3,014,588	$3,009,266	$3,003,971	$2,998,695	$2,993,407	$36,339,546

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Witness: J. Portuondo
Exhibit JP-2

SCHEDULE E1 (Amended 10/06)

Progress Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January Through December 2007
Current Approved Rate - Revised to Exclude Hines Unit 2 Annual Depreciation & Return

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation		1,865,445,051	37,313,075	4.99944
2.	Spent Nuclear Fuel Disposal Cost		5,591,566	5,948,474 *	0.09400
3.	Coal Car Investment		2,781,762	0	0.00000
4.	Adjustment to Fuel Cost		3,323,608	0	0.00000
5.	TOTAL COST OF GENERATED POWER		1,877,141,986	37,313,075	5.03079
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		261,990,517	5,974,305	4.38529
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0	0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		56,994,410	662,478	8.60322
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)		159,230,743	4,560,548	3.49148
12.	TOTAL COST OF PURCHASED POWER		478,215,670	11,197,331	4.27080
13.	TOTAL AVAILABLE KWH			48,510,406	
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)	(19,584,223)	(354,120)	5.53039
15a.	Gain on Other Power Sales	(E6)	(2,176,024)	(354,120) *	0.61449
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)	(164,945,256)	(3,008,342)	5.48293
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(186,705,503)	(3,362,462)	5.55264
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		2,168,652,153	45,147,944	4.80344
21.	Net Unbilled		4,711,516	(98,086)	0.01116
22.	Company Use		6,916,946	(144,000)	0.01639
23.	T & D Losses		129,882,174	(2,703,944)	0.30776
24.	Adjusted System KWH Sales		2,168,652,153	42,201,914	5.13875
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(70,382,145)	(1,371,690)	5.13105
26.	Jurisdictional KWH Sales		2,098,270,008	40,830,224	5.13901
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.00382	2,106,285,399	40,830,224	5.15864
28.	Prior Period True-Up (Sch E1-A)		(46,480,257)	40,830,224	(0.11384)
29.	Total Jurisdictional Fuel Cost		2,059,805,142	40,830,224	5.04480
30.	Revenue Tax Factor				1.00072
31.	Fuel Cost Adjusted for Taxes		2,061,288,202	40,830,224	5.04844
32.	GPIF **		(1,547,048)	40,830,224	(0.00379)
33.	Fuel Factor Adjusted for taxes including GPIF		2,059,741,154	40,830,224	5.04465
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				5.045
35.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH) currently approved				5.132
				Difference	(0.087)

* For Informational Purposes Only
** Based on Jurisdictional Sales

Progress Energy Florida
Hines Unit 4 - Revenue Requirements
Year 2008

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Witness: J. Portuondo
Exhibit JP-3

(Dollars In Thousands)

Line No.		Generation System	Generation Separation Factor	Generation Retail Jurisdictional	Trasmission System	Trasmission Separation Factor	Trasmission Retail Jurisdictional	Total Retail Jurisdictional
1	Estimated In-Service Date 12/1/07							
2								
3	Annualized Rate Base							
4	Electric Plant in Service	$267,004	93.753%	$250,324	$60,071	70.597%	$42,408	$292,732
5	Accumulated Reserve for Depreciation	(5,153)	93.753%	(4,831)	(616)	70.597%	(435)	(5,266)
6	Fuel Inventory	1,100	89.884%	989	0		0	989
7	Working Capital - Income Taxes Payable	(3,988)		(3,727)	(591)		(442)	(4,169)
8	Total Annualized Rate Base	$258,963		$242,754	$58,864		$41,531	$284,286
9								
10	Annualized NOI							
11	O&M	$1,873	93.753%	$1,756	$0	70.597%	$0	$1,756
12	Depreciation Expense	10,306	93.753%	9,663	1,231	70.597%	869	10,532
13	Property Taxes	2,600	91.926%	2,390	600	91.926%	552	2,942
14	Payroll Taxes & Benefits	453	91.670%	415	0		0	415
15	Income Taxes -							
16	Direct Current & Deferred	(5,876)		(5,487)	(706)		(548)	(6,035)
17	Imputed Interest	(2,100)		(1,968)	(475)		(335)	(2,303)
18	Manufacturing Tax Benefit	(533)	91.251%	(486)	0		0	(486)
19	Total Annualized NOI	($6,724)		($6,283)	($650)		($538)	($6,821)
20								
21								
22	Calculation of Revenue Requirement							
23	Fully Adjusted Cost of Capital (MFR D-1)	8.89%		8.89%	8.89%		8.89%	8.89%
24	NOI Requirement (Line 8 * Line 23)	$23,022		$21,581	$5,233		$3,692	$25,273
25	NOI Deficiency (Line 24 less Line 19)	$29,746		$27,864	$5,883		$4,230	$32,094
26	Net Operating Income Multiplier (MFR C-44)	1.6315		1.6315	1.6313		1.6313	1.6313
27								
28	Revenue Requirement (Line 25 * Line 26)	**$48,530**	93.67%	**$45,460**	**$9,597**	71.90%	**$6,900**	**$52,354**
29								
30								
31								
32	Calculation of Taxes on Imputed Interest							
33	Weighted Cost of Debt Capital (MFR D-1):							
34	Long Term Debt Fixed Rate	1.88%		1.88%	1.88%		1.88%	
35	Long Term Debt Variable Rate	0.00%		0.00%	0.00%		0.00%	
36	Short Term Debt	0.02%		0.02%	0.02%		0.02%	
37	Customer Deposits	0.13%		0.13%	0.13%		0.13%	
38	JDIC	0.04%		0.04%	0.04%		0.04%	
39		2.07%		2.07%	2.07%		2.07%	
40								
41	Imputed Interest (Line 8 * Line 39)	$5,443		$5,102	$1,231		$869	
42	Income Taxes on Imputed Interest at 38.575%	($2,100)		($1,968)	($475)		($335)	

Progress Energy Florida
Proposed Base Rate Increase - Hines 2 and Hines 4

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Witness: J. Portuondo
Exhibit JP-4

DEVELOPMENT OF UNBILLED REVENUE @ PRESENT RATES AND SUMMARY OF TOTAL CLASS REVENUES

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
							Base Revenues $000's - Billed						7.45%		
Line		Rate Schedule	Billed MWH Sales	Total	Customer Charge	Energy and Demand Charge	Unbilled MWH Sales	Energy and Demand Chg $/MWH	Unbilled Revenue ($000)	Total Class Revenue ($000)	Billed and Unbilled Rev Energy and Demand		Increase @ 11.75% ROE	Total Class Revenue	Revenues from Demand & Energy Chgs
								(4) / (1)	(5) * (6)	(2) + (7)			88,694	(3) + (9) + (11)	
1	I. SALES	RS-1	20,435,616	$ 882,282	$ 133,258	$ 749,024	22,697	$ 36.65	$ 832	$ 883,114	$ 749,856	7.45%	55,828	938,942	805,684
2															
3		GS-1	1,353,988	63,877	14,760	49,117	1,503	36.28	55	63,932	49,171	7.45%	3,661	67,592	52,832
4															
5		GS-2	85,622	2,526	1,354	1,172	95	13.69	1	2,527	1,173	7.45%	87	2,615	1,261
6															
7		GSD	15,105,869	345,598	8,092	337,506	16,777	22.34	375	345,973	337,880	7.45%	25,156	371,128	363,036
8															
9		CS-1, CS-2, CS-3	356,624	6,712	17	6,695	396	18.77	7	6,720	6,702	7.45%	499	7,219	7,201
10															
11		IS-1, IS-2, IS-3	2,293,952	36,911	640	36,271	2,548	15.81	40	36,951	36,312	7.45%	2,703	39,655	39,015
12															
13		SS-1	14,661	618	18	600	17	40.92	1	618	601	7.45%	45	663	645
14															
15		SS-2	166,747	4,563	18	4,545	186	27.25	5	4,568	4,550	7.45%	339	4,907	4,888
16															
17		SS-3	1,842	226	1	225	2	122.32	0	226	226	7.45%	17	243	242
18															
19		LS-1	333,325	5,680	860	4,820	370	14.46	5	5,685	4,825	7.45%	359	6,044	5,184
20															
21		TOTAL	40,148,246	1,348,993	159,019	1,189,974	44,591		1,322	1,350,314	$ 1,191,296		$ 88,694	$ 1,439,008	$ 1,279,990
22													7.45%		
23															
24															
25	II. OTHER														
26		LS-1													
27		FIXTURE		24,669						$ 24,669	$ 24,669			$ 24,669	
28		MAINTENANCE		8,760						8,760	8,760			8,760	
29		POLES		18,260						18,260	18,260			18,260	
30		TOTAL OTHER REVENUE		$ 51,689					-	$ 51,689	$ 51,689		-	$ 51,689	
31															
32	III. TOTAL CLASS REVENUE			$ 1,400,682					$ 1,322	$ 1,402,004	$ 1,242,985		$ 88,694	$ 1,490,698	

Components of Increase -		
¶ 12a. Hines Unit 4	$	52,354
¶ 12b. Hines Unit 2	$	36,340
	$	88,694

Docket No. __________-E1
Witness: J. Portuondo
Exhibit JP-5

SCHEDULE D-1a

Cost of Capital - 13-Month Average

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: Provide the Company's 13-month average cost of capital for the test year, the prior year, and historical base year.

Type of data shown:
X Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Year Ended 12/31/2004
Witness: Portuondo

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Class of Capital	Co Total Per Books	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
1										
2	Common Equity	$2,715,814	$874,683	($8,126)	$3,582,371	74.93%	$2,684,417	57.83%	11.75%	6.80%
3	Preferred Stock	33,497		(100)	33,397	74.99%	25,044	0.54%	4.51%	0.02%
4	Long Term Debt - Fixed	2,131,302	(97,379)	(6,377)	2,027,546	75.00%	1,520,653	32.76%	5.73%	1.88%
5	Short Term Debt *	72,288	(38,652)	(216)	33,420	75.25%	25,148	0.54%	4.04%	0.02%
6	Customer Deposits									
7	Active	136,401		(408)	135,993	74.99%	101,979	2.20%	5.92%	0.13%
8	Inactive	0			0		0	0.00%		
9	Investment Tax Credit									
10	Post '70 Total	26,572	1,587	(80)	28,079		0			
11	Equity **			0		74.98%	13,485	0.29%	11.68%	0.03%
12	Debt **			0		74.98%	7,568	0.16%	5.73%	0.01%
13	Deferred Income Taxes	407,236	6,596	(1,218)	412,614	74.99%	309,400	6.67%		
14	FAS 109 DIT - Net	(56,547)	(5,098)	169	(61,476)	74.97%	(46,088)	-0.99%		
15										
16	Total	$5,466,563	$741,737	($16,356)	$6,191,944	74.96%	$4,641,606	100.00%		8.89%
17										
18										
19										
20										
21										
22										
23										
24										

Supporting Schedules:

Recap Schedules:

I think if we delete the word "prudently," although that's our current practice, the plain meaning of the rule would be that all costs that come under the extraordinary circumstances would be recovered. I think we accomplished the same thing, and you all need to correct me if I'm wrong, if we leave prudently incurred due to extraordinary circumstances.

COMMISSIONER BAEZ: I don't have a problem with that modification. I think, if anything, it just clarifies.

CHAIRMAN JABER: And then to convolute it just a little bit more, you see a distinction between extraordinary circumstances and unforeseen and beyond its control?

COMMISSIONER BAEZ: I just thought it was -- I don't see necessarily a distinction, I think it's just a little bit more concise.

CHAIRMAN JABER: Okay. I could support that. I just didn't -- I don't think deleting "prudently" necessarily implies what we do normally will apply here.

COMMISSIONER BAEZ: So then your modification would be for it to read "prudently incurred and due to extraordinary circumstances"?

COMMISSIONER PALECKI: I would second the motion --

CHAIRMAN JABER: Yes.

COMMISSIONER PALECKI: -- as modified.

CHAIRMAN JABER: Well, hang on. Commissioner Bradley -- actually, I think there was a motion and a second,

Docket No. __________-E1
Witness: J. Portuondo
Exhibit JP-7

SCHEDULE C-44

Revenue Expansion Factor REVISED 8-1-05

FLORIDA PUBLIC SERVICE COMMISSION

Explanation: Provide the calculation of the revenue expansion factor for the test year

Type of data shown:

Company: PROGRESS ENERGY FLORIDA

XX Projected Test Year Ended 12/31/2006
___ Prior Year Ended 12/31/2005
Witness: Portuondo

Docket No. 050078-EI

Line No.	Description	(A) Percent
1		
2	Revenue Requirement	100.0000%
3	Less:	
4	Gross Receipts Tax Rate	0.0000%
5		
6	Regulatory Assessment Rate	0.0720%
7		
8	Uncollectible Accounts	0.1444%
9		
10	**Net Before Income Taxes**	99.7836%
11		
12	State Income Tax Rate	5.5000%
13		
14	State Income Tax	5.4881%
15		
16	**Net Before Federal Income Tax**	94.2955%
17		
18	Federal Income Tax Rate	35.0000%
19		
20	Federal Income Tax	33.0034%
21		
22	Revenue Expansion Factor	61.2921%
23		
24	Net Operating Income Multiplier	1.6315%
25		
26		

27 **Note: Gross receipts taxes are not included in Base rates in this filing.**

Supporting Schedules:

Recap Schedules:

Docket No. ________-EI
Witness: Javier Portuondo
Exhibit No. __ (JP-8)

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Progress Energy Florida, Inc.	DOCKET NO. 050078-EI ORDER NO. PSC-05-0945-S-EI ISSUED: September 28, 2005

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
RUDOLPH "RUDY" BRADLEY
LISA POLAK EDGAR

ORDER APPROVING STIPULATION AND SETTLEMENT

BY THE COMMISSION:

BACKGROUND

On April 29, 2005, Progress Energy Florida, Inc. (PEF) filed a petition for approval of a permanent increase in rates and charges sufficient to generate additional total annual revenues of $205,556,000 beginning January 1, 2006. In support of its petition, PEF filed new rate schedules, testimony, Minimum Filing Requirements (MFRs), a Nuclear Decommissioning Study, Fossil Dismantlement Study, and Depreciation Study. By Order No. PSC-05-0694-PCO-EI, issued June 24, 2005, we suspended PEF's proposed new rate schedules to allow our staff and intervenors sufficient time to adequately and thoroughly examine the basis for the proposed new rates.

As part of this proceeding, we conducted service hearings at the following locations in PEF's service territory: Ocala, St. Petersburg, Clearwater, and Tallahassee. A formal administrative hearing was scheduled for September 7 – 16, 2005. The Office of Public Counsel (OPC), AARP, the Florida Industrial Power Users Group (FIPUG), White Springs Agricultural Chemicals, Inc. (WS), the Florida Retail Federation (FRF), Commercial Group (CG), Buddy L. Hansen and the Sugarmill Woods Civic Association, Inc. (SMW), and the Florida Attorney General (AG) were granted intervenor status.

On September 1, the parties filed a joint motion for approval of a Stipulation and Settlement Agreement (Stipulation)[1], between all parties to resolve all matters in this proceeding. Our staff reviewed the Stipulation and Settlement thoroughly, and provided its analysis to us at the start of our technical hearing on September 7, after which time this Commission rendered its vote on the matter.

[1] The Stipulation and Settlement is attached hereto as Attachment A and is incorporated herein by reference.

DOCUMENT NUMBER-DATE
09207 SEP 28 05

configuration or structure to address independent transmission system governance or operation. The parties to the Stipulation may participate in any proceeding relating to the recovery of costs contemplated in this provision for the purpose of challenging the reasonableness and prudency of such costs. (Paragraph 9)

- PEF will continue collecting its storm reserve deficiency as provided in Order No. PSC-05-0748-FOF-EI; however, PEF reserves the right to petition the Commission for approval to either: (a) securitize (1) any or all of its storm reserve deficiency as set forth in Order PSC-05-0748-FOF-EI, or (2) an amount necessary to replenish PEF's reserves for non-catastrophic storms, or both; or (b) increase its base rates or to impose a separate charge to collect and accrue reserves for non-catastrophic storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. Those Parties who have filed notices of appeal of Order No. PSC-05-0748-FOF-EI will withdraw their appeals. In the event PEF collects any remaining storm deficiency or collects and accrues for future non-catastrophic storm events pursuant to Section 366.8260, Florida Statutes, the parties agree to negotiate in good faith for an optional tariff rider whereby a class of demand-metered customers may pay its pro rata share of any remaining uncollected 2004 storm cost deficiency as established in Commission Order PSC-05-0748-FOF-EI through a charge over a period of no more than two years. (Paragraph 10)

- PEF will continue to suspend accruals to its reserve for nuclear decommissioning and fossil dismantlement, and shall apply the depreciation rates consistent with those in PEF's Depreciation Study, as modified by Exhibit 2, attached to the Stipulation. (Paragraph 11)

- Beginning on the commercial in-service date of Hines Unit 4, PEF will further increase its base rates to recover the full revenue requirements of the installed cost of Hines Unit 4 and the unit's non-fuel operating expenses. PEF will recover annually through the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause) the 2006 full revenue requirements of the installed cost of Hines Unit 2, excluding the unit's non-fuel Operations and Maintenance (O&M) expenses. Upon the commercial in-service date of Hines Unit 4, PEF will transfer the recovery of Hines Unit 2's 2006 full revenue requirements, excluding the unit's non-fuel O&M expenses, from the fuel cost recovery clause to base rates by decreasing PEF's fuel charges and increasing its base rates accordingly. (Paragraph 12)

- PEF will be authorized to accelerate the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, and Interest on Income Tax Deficiency over the term of the Stipulation. PEF's adjusted equity ratio will be capped at 57.83%. (Paragraph 13)

- PEF will continue to operate without an authorized return on equity (ROE) range for the purpose of addressing earnings levels, and the Stipulation's sharing mechanism will be the mechanism to address earnings levels. However, for purposes other than reporting or assessing earnings (such as cost recovery clauses or AFUDC), PEF will use 11.75% as its ROE, and the annual AFUDC rate will be 8.848%. (Paragraph 14)

- PEF will continue to collect its post-September 11, 2001, incremental security costs through the Capacity Cost Recovery Clause, and PEF's carrying costs of fuel inventory in transit and fuel procurement O&M costs will be collected through the fuel recovery clause. (Paragraph 16)

- New capital costs for expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, consistent with PEF's current cost of service methodology. (Paragraph 18)

- PEF will continue to focus on its customer service and reliability consistent with Commission standards and good utility practice. (Paragraph 19)

Most of the terms of the Stipulation and Settlement appear to be self-explanatory. Still, we believe that several provisions merit comment or clarification so that as full an understanding of the parties' intent can be reflected in this Order before the Stipulation is implemented.. Based on the parties' discussions with our staff and discussions during our September 7 vote to approve the Stipulation, we understand that the parties agree with the clarifications discussed below.

<u>Paragraphs 2 and 15</u>

Under Paragraphs 2 and 15, Exhibit 1 to the Stipulation sets forth a number of changes to PEF's cost of service and rate design matters. Notably, the Stipulation provides for increases to the lighting services schedule, both for the fixture and maintenance charges for most of the fixture types as well as an increase in the charge for many of the poles. The other notable charge is the addition of a late payment charge, which provides that late payments shall be assessed either $5 or 1.5%, whichever is greater. In all, the changes listed on Exhibit 1 will generate an additional $15 million in revenue per year, which will be subject to the revenue sharing, but which will not adjust the sharing threshold as addressed in Paragraph 6 of the Stipulation.

<u>Paragraphs 5 and 6</u>

Paragraph 5 describes and defines the revenue sharing plan agreed to by the parties. Subpart (c) of this paragraph states that the revenue sharing plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues based on PEF's current structure and regulatory framework. Further, subpart (c) indicates that incremental revenues attributable to a business combination or acquisition involving PEF, its parent, or its affiliates will be excluded in determining retail base rate revenues for purposes of the revenue sharing plan. The parties clarified that in the event that a portion of PEF's system is sold or municipalized, appropriate adjustments would be made to account for the associated revenue reduction before application of PEF's annual average growth rate upon which the revenue sharing thresholds and revenue cap are calculated. Also, in the event new customers or part of a system is added to PEF, those revenues and customers would be excluded from revenue sharing. We note that the rolling ten-year average growth rate in retail kWh sales rate embodied in this provision is based on PEF-specific information as opposed to statewide information, and that the growth rate has been adjusted to account for the sale of PEF's Winter Park system.

Paragraph 10

Paragraph 10 of the Stipulation addresses storm cost recovery, in the context of the recovery mechanism approved by Order No. PSC-05-0748-FOF-EI, issued July 14, in Docket No. 041272-EI, and with regard to securitization of storm costs pursuant to Section 366.8260, Florida Statutes. The Stipulation makes a distinction between "catastrophic" and "non-catastrophic" storms; however, we note that neither the Order nor the statute draws this distinction. The parties clarified that the intent of this section was to preserve PEF's option of seeking securitization or to seek a surcharge recovery, in the event of any storm that would cause depletion of PEF's storm reserve. PEF acknowledges that recovery for storm costs under either mechanism must necessarily be subject to the provisions of the applicable rules and statutes; nor does the Stipulation seek to change PEF's current practice or change the Commission's current policy concerning what constitutes an appropriate charge to PEF's storm reserve.

If PEF elects to seek recovery of storm-related costs pursuant to Section 366.08260, Florida Statutes, the total cost subject to recovery would be allocated to customer classes pursuant to that Statute. Subsection 10(c) of the Stipulation, however, provides that PEF may request approval of a tariff to allow a class of demand-metered customers to pay their pro rata share of costs prior to securitization over a period not to exceed two years. This contemplates that demand-metered customers would "opt-out" of the securitization costs, while the balance of funds would be sought through a securitized bond issuance and the total costs, including the cost of securitization, would be allocated to all other classes of customers. The language of the Stipulation appears to limit this shortened recovery period to only those costs that were identified in Order No. PSC-05-0748-FOF-EI. However, based on our staff's discussions with the parties, it has been clarified that the alternative recovery schedule would apply to the total storm related dollars allocated to that class, which would otherwise be sought in a securitization request. The parties further clarified that the intent of this Subsection is that it apply to the entire class of demand-metered customers. PEF noted however that in the event it moves forward with a petition for securitization or for an additional storm-related surcharge, it would be willing to work with individual customers and look for reasonable alternatives. We note that this Commission retains its authority to review any tariff which may be filed in conjunction with Subsection 10(c), to ensure it comports with all rule, statutory, and public interest requirements.

Paragraph 12

Paragraph 12 addresses base rate and clause recovery for costs associated with PEF's Hines 2 and Hines 4 units. With respect to Hines Unit 4, the parties clarified that the calculation of the costs that would be included in base rates would be based on the first 12 months of revenue requirements and would include half a year of depreciation. Further, with regard to the calculation of these costs, an overall (rather than incremental) cost of capital will be used, which would include components such as deferred taxes. We also note that this Commission retains its ability to review the installed costs of Hines Unit 4 for reasonableness and prudency in a future filing.

Paragraphs 16 and 17

Paragraph 16 provides that PEF will continue to collect its post-September 11, 2001, incremental security costs through the Capacity Cost Recovery Clause, and PEF's carrying costs of fuel inventory in transit and fuel procurement O&M costs will be collected through the fuel recovery clause. Paragraph 17 provides that Commission approval of the Stipulation constitutes approval of PEF's MFRs (for regulatory reporting purposes and for establishing baseline costs in PEF's next base rate proceeding, not for the purposes of passing upon the accuracy of the MFRs). The parties clarified that $3.28 million of incremental security costs that is reflected in the MFRs for recovery through base rates will actually be recovered through the Capacity Cost Recovery Clause on a going-forward basis. The parties further clarified that the fuel procurement O&M costs to be recovered through the Fuel Clause as referenced in Paragraph 16 are only those fuel procurement O&M costs associated with coal procurement, and not other types of fuel.

Paragraph 19

PEF's last rate case, Docket No. 000824-EI, was resolved by the approval of a joint stipulation in Order No. PSC-02-0655-AS-EI, issued May 14, 2002. That stipulation provided that in the event PEF did not achieve a 20 percent improvement in System Average Interruption Duration Index (SAIDI) during 2004 and 2005, the utility would refund $3 million for both years in equal amounts to the ten percent of PEF's customers served by PEF's worst performing distribution feeder lines. At the September 7 hearing, we clarified that the parties were not contesting PEF's performance for 2004. However, consistent with Order No. PSC-02-0655-AS-EI, the performance requirement still exists for 2005, and will continue in effect through 2005 with the same refund provisions should PEF fail to achieve the SAIDI performance target for 2005.

FINDINGS

Upon review and consideration, we find that the Stipulation provides a reasonable resolution of the issues in this proceeding with respect to PEF's rates and charges and its depreciation rates and capital recovery schedules. The Stipulation and Settlement appears to provide PEF's customers with a degree of stability and predictability with respect to their electricity rates while allowing PEF to maintain the financial strength to make investments necessary to provide customers with safe and reliable power. In addition, we recognize that the Stipulation reflects the agreement of a broad range of interests: PEF, OPC, the Attorney General, and residential, commercial, and industrial customers of PEF.

In conclusion, we find that the Stipulation establishes rates that are fair, just, and reasonable, and that approval of the Stipulation is in the public interest. Therefore, we approve the Stipulation. As with any settlement we approve, nothing in our approval of this Stipulation diminishes this Commission's ongoing authority and obligation to ensure fair, just, and reasonable rates. Nonetheless, this Commission has a long history of encouraging settlements, giving great weight and deference to settlements, and enforcing them in the spirit in which they were reached by the parties.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Stipulation and Settlement Agreement and exhibits, filed September 1, 2005, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that PEF shall file, for administrative approval, revised tariff sheets to reflect the terms of the Stipulation. It is further

ORDERED that Docket No. 050078-EI shall be closed.

By ORDER of the Florida Public Service Commission this 28th day of September, 2005.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

JSB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase of
Progress Energy Florida, Inc.

Docket No. 050078-EI

STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, pursuant to its April 29, 2005 filing, Progress Energy Florida, Inc. ("PEF" or the "Company"), has petitioned the Florida Public Service Commission (the "Commission") for an increase in base rates and other related relief;

WHEREAS, the Company, the Office of Public Counsel ("OPC"), the Attorney General of the State of Florida ("AG"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the AARP, Sugarmill Woods Civic Association, Inc. ("Sugarmill"), Buddy L. Hansen ("Hansen"), White Springs Agricultural Chemicals, Inc. ("White Springs") and the Commercial Group ("CG") (unless the context clearly requires otherwise, the term Party or Parties means a signatory to this Agreement), have entered into this Stipulation and Settlement Agreement (the "Agreement") for the purpose of reaching an informal resolution of all outstanding issues in Docket No. 050078-EI pending before the Commission and as more fully set forth below;

WHEREAS, PEF and the Parties to this Agreement recognize that this is a period of unprecedented world energy prices and that this Agreement will mitigate the impact of high energy prices;

WHEREAS, PEF has provided minimum filing requirements ("MFRs") as required by the Commission, which have been thoroughly reviewed by the Commission Staff and the Parties to this proceeding;

WHEREAS, PEF has filed comprehensive testimony in support of and detailing its MFRs;

WHEREAS, the Company has filed comprehensive Depreciation, Fossil Dismantlement and Nuclear Decommissioning Funding Studies in this docket in accordance with Commission rules;

WHEREAS, the Parties and the Commission Staff have conducted extensive discovery on the Company's MFRs, testimony and Depreciation, Fossil Dismantlement and Nuclear Decommissioning Funding Studies;

WHEREAS, the discovery conducted has included the production of and opportunity to inspect tens of thousands of pages of documents and information regarding PEF's costs and operations;

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability in PEF's base rates and charges, and to provide incentives to PEF to continue to promote efficiency through the terms of this Agreement;

WHEREAS, PEF is currently operating under a stipulation and settlement agreement agreed to by the OPC and other parties, and approved by the Commission in Order No. PSC-02-0655-AS-EI in 2002;

WHEREAS, that agreement provided for a cumulative reduction of $500 million in PEF's revenues and included a revenue sharing plan that has resulted in refunds to customers in excess of $50 million;

WHEREAS, the Company must make substantial investments in the construction of new electric generation and other infrastructure for the foreseeable future in order to continue to provide safe and reliable power to meet the growing needs of customers in the state of Florida; and

WHEREAS, continuing the preservation of the benefits of the 2002 $125 million annual base rate reduction, the revenue sharing plan under this Agreement, and the other provisions in this Agreement, including those addressing the recovery of costs associated with the Company's electric generating power plants will further be beneficial to retail customers;

NOW, THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby agree and stipulate as follows:

1. Upon approval and final order of the Commission, this Agreement will become effective with the first billing cycle in January of 2006 (the "Implementation Date"), and continue through the last billing cycle in December of 2009; provided, however, that PEF may, at its sole option, extend the term of this Agreement through the last billing cycle of June 2010 upon written notice to the Parties to this Agreement and to the Commission on or before March 1, 2009.

2. PEF will continue its existing base rates in effect for the term of this Agreement, without any change in such base rates except as otherwise provided for in this Agreement. All other cost of service and rate design changes will be determined in

ATTACHMENT A

accordance with Section 15 of this Agreement. PEF will begin applying the base rate charges required by this Agreement on the Implementation Date.

3. The billing demand credits for Interruptible and Curtailable customers currently receiving service under PEF's IS-1, IST-1, CS-1 and CST-1 rate schedules, as modified herein, shall remain in effect for the term of this Agreement, and thereafter until these rate schedules are reviewed in a general rate case; provided, however, that these rate schedules shall continue to be closed to new customers, as defined in the stipulation approved by the Commission in Docket No. 950645-EI.

4. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. OPC, AG, FIPUG, FRF, AARP, Sugarmill, Hansen, White Springs, and CG will neither seek nor support any reduction in PEF's base rates and charges, including interim rate decreases, that would take effect prior to the first billing cycle for January 2010 (or prior to the first billing cycle for July 2010, if PEF elects to extend this Agreement pursuant to Section 1), unless such reduction is requested by PEF. PEF may not petition for an increase in base rates and charges that would take effect prior to the first billing cycle for January 2010 (or that would take effect prior to the first billing cycle for July 2010, if PEF elects to extend this Agreement pursuant to Section 1), except as otherwise provided for in Sections 7 and 10 of this Agreement. During the term of this Agreement, except as otherwise provided for in this Agreement, or except for unforeseen extraordinary costs imposed by government agencies relating to safety or matters of national security, PEF will not petition for any new surcharges, on an interim or permanent basis, to recover costs that are of a type

that traditionally and historically would be, or are presently, recovered through base rates.

5. During the term of this Agreement, revenues that are above the levels stated in this Agreement will be shared between PEF and its retail electric utility customers as set forth in Section 6 below – it being expressly understood and agreed that the mechanism for revenue sharing herein established is not intended to be a vehicle for a "rate case" type inquiry concerning expenses, investment, and financial results of operations.

6. Revenue Sharing Incentive Plan – Commencing on the Implementation Date and through the last billing cycle in December of 2009 (or through the last billing cycle in June 2010, if PEF elects to extend this Agreement pursuant to Section 1), PEF will be under a Revenue Sharing Incentive Plan (the "Plan") as set forth below.

a. Revenue Cap -- Under the Plan, all retail base rate revenues above the retail base rate revenue cap, as set forth below, will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2006 will be $1,549 million. For each succeeding calendar year during the term of this Agreement, the succeeding calendar year retail base rate revenue sharing cap amounts shall be established by increasing the prior year's cap by the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue sharing cap.

b. Sharing Threshold – Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap will be divided into two shares on a 1/3, 2/3 basis. PEF's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The retail base rate revenue sharing threshold for 2006 will be $1,499 million in retail base rate revenues. For each succeeding calendar year during the term of this Agreement, the succeeding calendar year retail base rate revenue sharing threshold amounts shall be established by increasing the prior year's threshold by the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue sharing threshold.

c. Revenue Exclusions – The Plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues of PEF based on its current structure and regulatory framework. Incremental base rate revenues attributable to any business combination or acquisition involving PEF, its parent, or its affiliates, whether inside or outside the state of Florida, or revenues from any clause, surcharge or other recovery mechanism other than retail base rates, shall be excluded in determining retail base rate revenues for purposes of revenue sharing under this Agreement.

d. The retail base rate revenue cap and sharing threshold are subject to further modification in accordance with Sections 4, 10 and 12 of this Agreement. After any such modification, the revenue sharing cap and threshold will increase annually as set forth in this Section 6.

e. Calculation of sharing threshold and revenue cap for partial calendar years – In the event that this Agreement is terminated other than at the end of a calendar year, the sharing threshold and revenue cap for the partial calendar year shall be determined at the end of that calendar year by (i) dividing the retail kWh sales during the partial calendar year by the retail kWh for the full calendar year, and (ii) applying the resulting fraction to the sharing threshold and revenue cap for the full calendar year that would have been calculated as set forth in Sections 6(a) and 6(b) above.

f. Calculation of annual average growth rate – For purposes of Section 6, the average annual growth rate shall be calculated by summing the percentage change in retail kWh sales for each year in the relevant ten year period and dividing by 10.

7. If PEF's retail base rate earnings fall below a 10% return on equity as reported on a Commission adjusted or pro-forma basis on a PEF monthly earnings surveillance report during the term of the Agreement, PEF may petition the Commission to amend its base rates notwithstanding the provisions of Section 4, either as a general rate proceeding or as a limited proceeding under Section 366.076, F.S. The Parties to this Agreement are not precluded from participating in such a proceeding, and, in the event PEF petitions to initiate a limited proceeding under this Section, any Party may petition to initiate any proceeding otherwise permitted by Florida law. This Agreement shall terminate upon the effective date of any Final Order issued in such proceeding that changes PEF's base rates under this Section. This Section shall not be construed to bar or limit PEF from any recovery of costs otherwise contemplated by this Agreement.

8. All revenue sharing refunds will be paid with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C., to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period at the rate of one-twelfth per month. All refunds with interest will be in the form of a credit on the customers' bills beginning with

the first day of the first billing cycle of the third month after the end of the applicable refund period. Refunds to former customers will be completed as expeditiously as reasonably possible.

9. PEF will be permitted clause recovery of prudently incurred incremental costs associated with the establishment of a Regional Transmission Organization or any other costs arising from an order of the Commission or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. Any Party to this Agreement may participate in any proceeding relating to the recovery of costs contemplated in this Section for the purpose of challenging the reasonableness and prudence of such costs, but not for the purpose of challenging PEF's right to clause recovery of such costs.

10. a. Storm Cost Recovery. PEF will continue collecting its storm reserve deficiency in the amount and through the mechanism established in Commission Order PSC-05-0748-FOF-EI, except as otherwise may be provided in Section 10.b. Those Parties who have filed notices of appeal or notices of joinder in appeals of Commission Order No. PSC-05-0748-FOF-EI shall, upon this Agreement becoming fully effective as provided for herein, withdraw their notices of appeal or notices of joinder in appeals. Nothing in this Agreement shall preclude PEF from petitioning the Commission to seek recovery of costs associated with any catastrophic storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The Parties expressly agree that any proceeding to recover costs associated with any catastrophic storm shall not be a vehicle for a "rate case" type inquiry

concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

b. PEF reserves the right to petition the Commission for approval to either: (a) securitize (1) any or all of its storm reserve deficiency as set forth in Commission Order PSC-05-0748-FOF-EI, or (2) an amount necessary to replenish PEF's reserves for non-catastrophic storms, pursuant to Section 366.8260, F.S. (2005), or both; or (b) increase its base rates or to impose a separate charge to collect and accrue reserves for non-catastrophic storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The Parties reserve the right to participate in any such proceeding under Section 10.b before the Commission and to challenge the reserve amount requested by PEF. The Parties expressly agree that any proceeding under Section 10.b shall be limited to the issue of the appropriateness of securitization or the appropriate amount of the Company's non-catastrophic storm reserve accrual without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings, and shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company. In the event the Commission grants a base rate increase under this Section, such amounts shall be added to the revenue sharing threshold and cap set forth in Section 6 of this Agreement.

c. In the event PEF collects any remaining storm deficiency or collects and accrues for future non-catastrophic storm events pursuant to Section 366.8260, F.S. (2005), the Parties agree to negotiate in good faith for an optional tariff rider whereby a class of demand-metered customers may pay its pro rata share of any remaining uncollected 2004 storm cost deficiency as established in Commission Order PSC-05-0748-FOF-EI through a charge over a period of no more than 2 years. If the Parties are able to agree upon such a tariff, PEF agrees to file the tariff for Commission approval and the Parties agree to support the tariff in proceedings before the Commission. If, however, the Commission does not approve the tariff or only approves it with modifications or conditions that are unacceptable to PEF in its reasonable judgment, then PEF shall not be required to put the tariff into effect. Within thirty days of any such denial or modification, the Parties agree to negotiate in good faith a revised tariff and if an agreement is reached to reapply for Commission approval. Revenues collected pursuant to Section 366.8260, F.S. (2005), pursuant to a tariff rider for demand-metered customers or otherwise under this Section 10.c will not be considered in the determination of revenue sharing in Section 6 of this Agreement. In the event PEF does not collect any remaining storm deficiency or does not collect and accrue reserves for future non-catastrophic storm events pursuant to Section 366.8260, F.S. (2005), then PEF shall continue to collect any remaining storm reserve deficiency through the mechanism established in Commission Order PSC-05-0748-FOF-EI and will collect and accrue reserves for future non-catastrophic storms as may be determined by the Commission irrespective of previous or current base rate earnings under Section 10.b(b).

11. Nuclear Decommissioning, Fossil Dismantlement and Depreciation Studies.

a. Beginning with the Implementation Date through the last billing cycle in December of 2009 (or through the last billing cycle in June 2010, if PEF elects to extend this Agreement pursuant to Section 1), PEF:

(1) will suspend accruals to its reserve for nuclear decommissioning, based on its filed Nuclear Decommissioning Study;

(2) will continue to suspend accruals to fossil dismantlement and will withdraw the Fossil Dismantlement Study PEF filed in this docket; and

(3) shall apply the depreciation rates consistent with those set forth in the Depreciation Study that PEF filed in this docket as modified by Exhibit 2 to this Agreement.

b. Approval of this Agreement by the Commission shall constitute approval of the Company's Nuclear Decommissioning and Depreciation Studies. PEF shall file with the Commission updated Nuclear Decommissioning, Fossil Dismantlement and Depreciation Studies on or before July 31, 2009 (or on or before December 31, 2009, if PEF elects to extend this Agreement pursuant to Section 1).

12. a. Beginning on the commercial in-service date of Hines Unit 4, for which the Commission has previously granted a need determination in Order PSC-04-1168-FOF-EI, PEF will further increase its base rates to recover the full revenue requirements of (a) the installed cost of Hines Unit 4 subject to the limitations of Rule 25-22.082(15), F.A.C., and (b) the unit's non-fuel operating expenses. The revenue requirements of the unit will be calculated using an 11.75% ROE and the capital structure as set forth in the test year 2006 MFR Schedule D-1a filed by PEF in Docket No. 050078-EI. Such base rate increase shall be established by the application of a uniform percentage

increase to the demand and energy charges of the Company's base rates including delivery voltage credits, demand credits, power factor adjustment and premium distribution service, and using billing determinants as filed by PEF in Docket No. 050078-EI, and set forth in Exhibit 1, Attachment C to this Agreement. Beginning on the commercial in-service date of Hines Unit 4, such amounts shall be added to the revenue sharing threshold and cap set forth in Section 6 of this Agreement.

b. Effective on the Implementation Date of this Agreement and until the commercial in-service date of Hines Unit 4 (the "Fuel Clause Recovery Period"), PEF will recover annually through the fuel cost recovery clause the 2006 full revenue requirements of the installed cost of Hines Unit 2, excluding the unit's non-fuel O&M expenses. During the Fuel Clause Recovery Period, the installed cost of Hines Unit 2 and corresponding depreciation accounts will be excluded from rate base for surveillance reporting purposes. Upon the commercial in-service date of Hines Unit 4, PEF will transfer the recovery of Hines Unit 2's 2006 full revenue requirements, excluding the unit's non-fuel O&M expenses, from the fuel cost recovery clause to base rates by decreasing PEF's fuel charges and increasing its base rates accordingly. The calculation of Hines Unit 2's revenue requirements for base rate recovery purposes will be calculated using an 11.75% ROE and the capital structure as set forth in the test year 2006 MFR Schedule D-1a filed by PEF in Docket No. 050078-EI. Such base rate increase shall be established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates including voltage credits, demand credits, power factor adjustment and premium distribution service, and using billing determinants as filed by PEF in Docket No. 050078-EI, and as included in Exhibit

F.S. (2005). Docket No. 050078-EI will be closed effective on the date the Commission Order approving this Agreement is final.

18. New capital costs for environmental expenditures recovered through the Environmental cost Recovery Clause will be allocated, for the purpose of clause recovery, consistent with PEF's current base cost of service methodology.

19. Service Quality. During the term of this agreement, PEF will continue to focus on its customer service and reliability consistent with Commission standards and good utility practice. PEF maintains that it has fulfilled its commitment, as part of the 2002 settlement agreement, to achieve a SAIDI of 80 by 2004, while at the same time improving the majority of the reliability performance indicators monitored by the Commission. During the term of this Agreement, PEF intends to continue the same performance focus with the goal of maintaining or improving the quality of service for its customers. Current plans in this area, as contemplated in the Company's rate filing in Docket No. 050078-EI and which are subject to revision by the Company at its discretion, include the implementation of the Mobile Meter Reading project designed to improve the amount, accuracy and timeliness of information for customers, and the assessment and subsequent implementation of targeted initiatives intended to improve overall system performance for customers.

20. This Agreement dated as of August 31, 2005 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signatures below.

Progress Energy Florida, Inc.

By____________________

Alex Glenn, Esquire
Post Office Box 14042
St. Petersburg, Florida 33733

Office of Public Counsel

By____________________

Harold McLean, Esquire
111 W. Madison St., Room 812
Tallahassee, Florida 32399

Attorney General, State of Florida

By:____________________
Charlie Crist, Attorney General
Christopher M. Kise, Esquire
Jack Shreve, Esquire
The Capitol-PL01
Tallahassee, Florida 32399-1050

ATTACHMENT A

AARP

By____________________

Michael B. Twomey, Esquire
8903 Crawfordville Road
Tallahassee, Florida 32305

Sugarmill Woods Civic Association, Inc.

By____________________

Michael B. Twomey
8903 Crawfordville Road
Tallahassee, Florida 32305

Buddy L. Hansen

By____________________

Michael B. Twomey
8903 Crawfordville Road
Tallahassee, Florida 32305

Florida Industrial Power Users Group

By____________________

John W. McWhirter, Jr., Esquire
McWhirter, Reeves
Post Office Box 3350
Tampa, Florida 33601

ATTACHMENT A

White Springs Agricultural Chemicals, Inc.

By________________________

James Bushee, Esquire
Sutherland Asbill & Brennan LLP
2282 Killearn Center Blvd
Tallahassee, Florida 32309-3576

Florida Retail Federation

By Robert Scheffel Wright

Robert Scheffel Wright, Esquire
Landers & Parsons, P.A.
310 West College Ave
Tallahassee, Florida 32302

The Commercial Group

By________________________

Alan Jenkins, Esquire
McKenna Long & Aldridge LLP
One Peachtree Center
303 Peachtree Street, N.E., Suite 5300
Atlanta, Georgia 30308

ATTACHMENT A

White Springs Agricultural Chemicals, Inc.

By

James Bushee, Esquire
Sutherland Asbill & Brennan LLP
1275 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Florida Retail Federation

By______________________

Robert Scheffel Wright, Esquire
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310 West College Ave
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303 Peachtree Street, N.E., Suite 5300
Atlanta, Georgia 30308

Exhibit No. 1
Page 1 of 2

Progress Energy

2005 Retail Rate Case
Docket No. 050078-EI
Cost of Service and Rate Design Matters

1. Progress Energy Florida, Inc. ("PEF" or the "Company") shall make the changes to its tariff schedules listed in this Exhibit. Except as otherwise provided below and in the August__, 2005 Stipulation and Settlement Agreement ("Agreement"), all other current PEF tariff schedules shall remain in effect:
    a. The Company's Temporary Service Charge shall be $227.
    b. Returned Check Charge shall be in accordance with Florida Statute 68.065.
    c. Late Payment Charge shall be the greater of $5 or 1.5% of past due amount except for those accounts of federal, state and local governments.
    d. The monthly seasonal customer charge for rate schedule RSS-1 shall be $4.20. See Attachment A to this Exhibit.
    e. The Transmission Delivery Voltage Credit shall be $1.01 per kW of Billing Demand for all demand rate tariffs. PEF will file revised tariff sheets reflecting the revisions to the Transmission Delivery Voltage Credit within 30 days of the issuance of a final order by the Commission approving the Agreement.
2. The charges for Lighting fixtures, maintenance, and poles, as well as the additions, deletions, and restrictions of certain fixtures and pole types as well as the modifications to the related standard form contracts shall be as those set forth in PEF's proposed rate schedule LS-1. See Attachment B to this Exhibit.
3. The regular rate for Residential service shall retain its current two-block, inverted rate design reflecting a 1000 KWH inversion breakpoint and a 1 cent rate block differential. The unit charges for this rate design shall be determined such that their application produces the same total annual revenues as that produced by the application of charges determined by a uniform increase to existing rate block charges.
4. The billing determinants as filed by the Company shall be the basis for determining the revised rates required to produce the total settlement revenues. These are detailed in the MFR E-13c provided as Attachment C to this Exhibit.
5. The 12 CP and 1/13th AD methodology will continue to be used for the allocation of PEF's production capacity costs to its retail customer classes during the term of the settlement.
6. The 12 CP methodology shall be used for the allocation of PEF's transmission capacity costs to its retail customer class during the term of the settlement.
7. In the form of housekeeping to tariff language, the proposed changes as filed and provided here as Attachment D to this Exhibit to the following tariffs:
    a. Special provision number 4 and 5 to rate schedules IS-1, IST-1, IS-2 and IST-2.
    b. Special provision number 6 to rate schedules CS-1, CST-1, CS-2, and CST-2.
    c. Special provision number 3, 4 and 13 to rate schedule SS-2.
    d. Special provision number 6 and 16 to rate schedule SS-3.
    e. The metering voltage adjustment and power factor clause of rate schedules CS-3 and CST-3.
    f. The elimination of the distinction of single phase and three phase secondary delivery in the customer charge of rate schedules RST-1 and GST-1.

Exhibit No. 1
Page 2 of 2

Progress Energy

2005 Retail Rate Case
Docket No. 050078-EI
Cost of Service and Rate Design Matters

8. The curtailable and interruptible credits of rate schedule SS-2 and SS-3 that correspond to the credits of rate schedules IS-1 and CS-1 shall be grandfathered to existing customers. Effective January 1, 2006 any new customers under these schedules shall be subject to the proposed credits provided for in the filing which correspond to the credits provided for in rate schedules IS-2 and CS-2. The tariff changes have been provided in Attachment E to this Exhibit. The following are the credits for accounts established on or after January 1 2006:
   a. SS-2 – the greater of
      i. $.308 per KW times the Specified Standby Capacity, or
      ii. The sum of the daily maximum 30 minute KW demand of actual standby use occurring during On-peak periods times $0.147 per KW times the appropriate monthly factor
   b. SS-3 – the greater of
      i. $0.231 per KW times the Specified Standby Capacity, or
      ii. The sum of the daily maximum 30 minute KW demand of actual standby use occurring during On-peak periods times $0.110 per KW times the appropriate monthly factor
9. The CISR-1 rate schedule shall be a permanent rate schedule as opposed to an experimental rate. The tariff changes have been provided in Attachment F to this Exhibit.
10. Subject to Commission approval, PEF may implement any new or revised tariff provision or rate schedule provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of the Agreement unless the application of such new or revised tariff or rate schedule is optional to PEF's customers.

Docket No. 050078-EI
Exhibit No. 1
Cost of Service and Rate Design Matters

ATTACHMENT C

MFR E-13c – Billing Determinants

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
___Historical Test Year Ended _/_/_
X Projected Test Year Ended 12/31/06
___Prior Year Ended _/_/_
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE RS-1

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:					
Standard					
Secondary Standard	16,270,818	Bills @ $	8.03	= $	130,654,669
Secondary Seasonal	617,913	Bills @ $	2.72	= $	1,680,723
Time-of-Use					
Single Phase	454	Bills @ $	14.84	= $	6,737
Three Phase	51	Bills @ $	20.28	= $	1,034
Customer CIAC Paid	120	Bills @ $	8.03	= $	964
TOTAL	16,889,356	Bills		$	132,344,127
Energy & Demand Charge:					
Standard					
Secondary	20,434,594				
0-1000 KWH	13,275,947	MWH @ $	33.15	= $	440,097,643
over 1000 KWH	7,158,647	MWH @ $	43.15	= $	308,895,618
Time-of-Use					
Secondary	1,022				
On-Peak	253	MWH @ $	104.31	= $	26,390
Off-Peak	769	MWH @ $	5.26	= $	4,046
TOTAL	20,435,616	MWH		$	749,023,698
Adjustments					
n/a				$	-
Total RS-1 Base Revenue				$	881,367,823

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
___Historical Test Year Ended _/_/_
X Projected Test Year Ended 12/31/06
___Prior Year Ended _/_/_
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GS-1

PRESENT REVENUE CALCULATIONS					PROPOSED REVENUE CALCULATIONS
Customer Charge:					
Standard					
Unmetered	7,814	Bills @ $	5.99 =	$ 46,806	
Secondary	1,375,812	Bills @ $	10.62 =	$ 14,611,123	
Primary	387	Bills @ $	134.31 =	$ 51,978	
Transmission		Bills @ $	662.48 =	$ -	
Time-of-Use					
Single Phase	919	Bills @ $	17.42 =	$ 16,009	
Three Phase	1,276	Bills @ $	22.87 =	$ 29,182	
Customer CIAC Paid	60	Bills @ $	10.62 =	$ 637	
Primary	26	Bills @ $	141.12 =	$ 3,669	
Transmission	12	Bills @ $	669.28 =	$ 8,031	
TOTAL	1,386,306	Bills		$ 14,767,435	
Energy & Demand Charge:					
Standard					
Secondary	1,327,178	MWH @ $	36.48 =	$ 48,415,453	
Primary	7,171	MWH @ $	36.48 =	$ 261,598	
Transmission		MWH @ $	36.48 =	$ -	
Time-of-Use					
Secondary					
On-Peak	2,844	MWH @ $	104.31 =	$ 296,658	
Off-Peak	12,429	MWH @ $	5.26 =	$ 65,377	
Primary					
On-Peak	537	MWH @ $	104.31 =	$ 56,014	
Off-Peak	1,608	MWH @ $	5.26 =	$ 8,458	
Transmission					
On-Peak	49	MWH @ $	104.31 =	$ 5,111	
Off-Peak	2,172	MWH @ $	5.26 =	$ 11,425	
TOTAL	1,353,988	MWH		$ 49,120,094	
Adjustments					
Distribution Primary Metering	1%	OF $	326,070 =	$ (3,261)	
Transmission Metering	2%	OF $	16,536 =	$ (331)	
TOTAL				$ (3,592)	
Total GS-1 Base Revenue				$ 63,883,937	

ORDER NO. PSC-05-0945-S-EI
DOCKET NO. 050078-EI
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ATTACHMENT A

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
___Historical Test Year Ended __/__/__
_X_Projected Test Year Ended 12/31/06
___Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GS-2

PRESENT REVENUE CALCULATIONS

Customer Charge:					
Standard					
Unmetered	17,254	Bills @ $	5.99	= $	103,351
Secondary	117,734	Bills @ $	10.62	= $	1,250,336
TOTAL	134,988	Bills		$	1,353,686
Energy & Demand Charge:					
Standard					
Secondary	85,622	MWH @ $	13.69	= $	1,172,165
Adjustments					
n/a				$	-
Total GS-2 Base Revenue				$	2,525,851

PROPOSED REVENUE CALCULATIONS

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended __/__/__
_X_ Projected Test Year Ended 12/31/06
___Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 - TOTAL GSD

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:					
Standard					
Secondary	519,415	Bills @ $	10.82	= $	5,516,187
Primary	1,998	Bills @ $	134.31	= $	268,351
Transmission	-	Bills @ $	662.48	= $	-
Time-of-Use					
Secondary	109,771	Bills @ $	17.42	= $	1,912,211
Customer CIAC Paid	192	Bills @ $	10.62	= $	2,039
Primary	2,702	Bills @ $	141.12	= $	381,306
Customer CIAC Paid	36	Bills @ $	134.31	= $	4,835
Transmission	11	Bills @ $	669.28	= $	7,362
TOTAL	634,126	Bills		$	8,092,291
Demand Charge:					
Standard					
Secondary					
Billed	17,990,264	kW @ $	3.45	= $	62,066,411
Primary					
Billed	731,836	kW @ $	3.18	= $	2,327,235
Transmission					
Billed	-	kW @ $	2.82	= $	-
Time-of-Use					
Secondary					
On-Peak	14,910,893	kW @ $	2.57	= $	38,320,995
Base	15,280,586	kW @ $	0.85	= $	12,988,498
Primary					
On-Peak	4,467,991	kW @ $	2.57	= $	11,482,737
Base	4,627,862	kW @ $	0.58	= $	2,684,160
Transmission					
On-Peak	449	kW @ $	2.57	= $	1,154
Base	465	kW @ $	0.22	= $	102
Sec/Pri					
On-Peak	30,201	kW @ $	2.57	= $	77,617
Base	30,701	kW @ $	0.85	= $	26,096
Premium Distrib. Charge	194,094	kW @ $	0.74	= $	143,630
TOTAL Billed/Base	38,601,713	KW	TOTAL	$	130,118,635

R:\2005 Rate Case\Rates\Settlement\E-13c revised sales forecast.xls / GSD work sheet

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ATTACHMENT A

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended __/__/__
_X_Projected Test Year Ended 12/31/06
___Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 - TOTAL GSD

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Energy Charge:						
Standard						
Secondary	5,251,343	MWH @ $	15.03	= $	78,927,685	
Primary	233,176	MWH @ $	15.03	= $	3,504,835	
Transmission	-	MWH @ $	15.03	= $	-	
Time-of-Use						
Secondary						
On-Peak	2,031,263	MWH @ $	33.16	= $	67,358,349	
Off-Peak	5,195,493	MWH @ $	5.26	= $	27,328,293	
Primary						
On-Peak	647,485	MWH @ $	33.16	= $	21,470,603	
Off-Peak	1,729,297	MWH @ $	5.26	= $	9,096,102	
Transmission						
On-Peak	35	MWH @ $	33.16	= $	1,161	
Off-Peak	132	MWH @ $	5.26	= $	694	
Sec/Pri						
On-Peak	4,758	MWH @ $	33.16	= $	157,775	
Base	12,897	MWH @ $	5.26	= $	67,838	
TOTAL	15,105,869	MWH			$ 207,911,135	
Adjustments						
Distribution Primary Metering	1% OF	$	50,920,894	= $	(509,209)	
Transmission Metering	2% OF	$	3,111	= $	(62)	
Power Factor				$	(14,891)	
TOTAL				$	(524,162)	
Total GSD-1 Base Revenue					$ 345,597,899	

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___ Historical Test Year Ended _/_/_
X Projected Test Year Ended 12/31/06
___ Prior Year Ended _/_/_
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 - EXCLUDING CUSTOMERS TRANSFERRED TO CS-1

PRESENT REVENUE CALCULATIONS							PROPOSED REVENUE CALCULATIONS
Customer Charge:							
Standard							
Secondary	494,405	Bills @ $	10.62	=	$	5,250,681	
Primary	1,998	Bills @ $	134.31	=	$	268,351	
Transmission	-	Bills @ $	662.48	=	$	-	
Time-of-Use							
Secondary	109,493	Bills @ $	17.42	=	$	1,907,368	
Customer CIAC Paid	192	Bills @ $	10.62	=	$	2,039	
Primary	2,702	Bills @ $	141.12	=	$	381,306	
Customer CIAC Paid	36	Bills @ $	134.31	=	$	4,835	
Transmission	11	Bills @ $	669.28	=	$	7,362	
TOTAL	608,837	Bills			$	7,821,842	
Demand Charge:							
Standard							
Secondary							
Billed	17,110,909	kW @ $	3.45	=	$	59,032,636	
Primary							
Billed	731,835	kW @ $	3.18	=	$	2,327,235	
Transmission							
Billed	-	kW @ $	2.82	=	$	-	
Time-of-Use							
Secondary							
On-Peak	14,890,682	kW @ $	2.57	=	$	38,269,053	
Base	15,259,809	kW @ $	0.85	=	$	12,970,838	
Primary							
On-Peak	4,467,991	kW @ $	2.57	=	$	11,482,737	
Base	4,627,862	kW @ $	0.58	=	$	2,684,160	
Transmission							
On-Peak	449	kW @ $	2.57	=	$	1,154	
Base	465	kW @ $	0.22	=	$	102	
Sec/Pri							
On-Peak	30,201	kW @ $	2.57	=	$	77,617	
Base	30,701	kW @ $	0.85	=	$	26,096	
Premium Distrib. Charge	194,094	kW @ $	0.74	=	$	143,630	
TOTAL Billed/Base	37,761,501	KW	TOTAL		$	127,016,258	

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SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS
Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended __/__/__
_X_ Projected Test Year Ended 12/31/06
___Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 -- EXCLUDING CUSTOMERS TRANSFERRED TO GS-1

PRESENT REVENUE CALCULATIONS							PROPOSED REVENUE CALCULATIONS
Energy Charge:							
Standard							
Secondary	5,103,226	MWH @	$	15.03	=	$ 76,701,487	
Primary	233,176	MWH @	$	15.03	=	$ 3,504,635	
Transmission	-	MWH @	$	15.03	=	$ -	
Time-of-Use							
Secondary							
On-Peak	2,030,235	MWH @	$	33.16	=	$ 67,322,593	
Off-Peak	5,193,057	MWH @	$	5.26	=	$ 27,315,480	
Primary							
On-Peak	647,485	MWH @	$	33.16	=	$ 21,470,603	
Off-Peak	1,729,297	MWH @	$	5.26	=	$ 9,096,102	
Transmission							
On-Peak	35	MWH @	$	33.16	=	$ 1,161	
Off-Peak	132	MWH @	$	5.26	=	$ 694	
Sec/Pri							
On-Peak	4,758	MWH @	$	33.16	=	$ 157,775	
Off-Peak	12,897	MWH @	$	5.26	=	$ 67,838	
TOTAL	14,954,298	MWH				$ 205,638,368	
Adjustments							
Distribution Primary Metering	1%	OF	$	50,920,894	=	$ (509,209)	
Transmission Metering	2%	OF	$	3,111	=	$ (62)	
Power Factor @ 20¢ per kVar						$ (14,891)	
TOTAL						$ (524,162)	
Total GSD-1 Base Revenue						$ 339,951,306	

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS
Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended _/_/_
X Projected Test Year Ended 12/31/06
___Prior Year Ended _/_/_
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 - CUSTOMERS TRANSFERRED TO GS-1

PRESENT REVENUE CALCULATIONS - GSD-1 TARIFF | PROPOSED REVENUE CALCULATIONS - GS-1 TARIFF

Customer Charge:						
Standard						
Secondary	25,010	Bills @ $	10.62	= $	265,606	
Primary	-	Bills @ $	134.31	= $	-	
Transmission	-	Bills @ $	662.48	= $	-	
Time-of-Use						
Secondary	278	Bills @ $	17.42	= $	4,843	
Customer CIAC Paid	-	Bills @ $	10.62	= $	-	
Primary	-	Bills @ $	141.12	= $	-	
Customer CIAC Paid	-	Bills @ $	134.31	= $	-	
Transmission	-	Bills @ $	669.28	= $	-	
TOTAL	25,288	Bills		$	270,449	
Demand Charge:						
Standard						
Secondary						
Billed	879,356	kW @ $	3.45	= $	3,033,776	
Primary						
Billed		kW @ $	3.18	= $	-	
Transmission						
Billed		kW @ $	2.82	= $	-	
Time-of-Use						
Secondary						
On-Peak	20,211	kW @ $	2.57	= $	51,942	
Base	20,777	kW @ $	0.85	= $	17,660	
Primary						
On-Peak		kW @ $	2.57	= $	-	
Base		kW @ $	0.58	= $	-	
Transmission						
On-Peak		kW @ $	2.57	= $	-	
Base		kW @ $	0.22	= $	-	
Sec/Pri						
On-Peak		kW @ $	2.57	= $	-	
Base		kW @ $	0.85	= $	-	
Premium Distrib. Charge		kW @ $	0.74	= $	-	
TOTAL Billed/Base	900,132	KW	TOTAL	$	3,103,377	

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___ Historical Test Year Ended __/__/__
X Projected Test Year Ended 12/31/06
___ Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE GSD-1 - CUSTOMERS TRANSFERRED TO GS-1

PRESENT REVENUE CALCULATIONS - GSD-1 TARIFF							PROPOSED REVENUE CALCULATIONS - GS-1 TARIFF
Energy Charge:							
Standard							
Secondary	148,117	MWH @ $	15.03	= $	2,226,190		
Primary	-	MWH @ $	15.03	= $	-		
Transmission	-	MWH @ $	15.03	= $	-		
Time-of-Use							
Secondary							
On-Peak	1,018	MWH @ $	33.16	= $	33,757		
Off-Peak	2,436	MWH @ $	5.26	= $	12,813		
Primary							
On-Peak	-	MWH @ $	33.16	= $	-		
Off-Peak	-	MWH @ $	5.26	= $	-		
Transmission							
On-Peak	-	MWH @ $	33.16	= $	-		
Off-Peak	-	MWH @ $	5.26	= $	-		
Sec/Pri							
On-Peak	-	MWH @ $	33.16	= $	-		
Base	-	MWH @ $	5.26	= $	-		
TOTAL	151,571	MWH		$	2,272,769		
Adjustments							
Distribution Primary Metering	1% OF	$	-	= $	-		
Transmission Metering	2% OF	$	-	= $	-		
Power Factor				$	-		
TOTAL				$	-		
Total GSD-1 Base Revenue				$	5,646,696		

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ATTACHMENT A

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended __/__/__
_X_Projected Test Year Ended 12/31/06
___Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE CS-1, CS-2, CS-3

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:					
Standard					
Secondary	7	Bills @ $	69.81	= $	487
Primary	-	Bills @ $	193.30	= $	-
Transmission	-	Bills @ $	721.46	= $	-
Time-of-Use					
Secondary	-	Bills @ $	69.81	= $	-
Primary	88	Bills @ $	193.30	= $	17,010
Transmission	-	Bills @ $	721.46	= $	-
TOTAL	95	Bills		$	17,497
Demand Charge:					
Standard					
Secondary					
Billed	1,600	kW @ $	5.56	= $	8,896
Primary					
Billed	-	kW @ $	5.29	= $	-
Transmission					
Billed	-	kW @ $	4.93	= $	-
Time-of-Use					
Secondary					
On-Peak	-	kW @ $	4.68	= $	-
Base	-	kW @ $	0.83	= $	-
Primary					
On-Peak	700,313	kW @ $	4.68	= $	3,277,465
Base	740,875	kW @ $	0.56	= $	414,890
Transmission					
On-Peak	-	kW @ $	4.68	= $	-
Base	-	kW @ $	0.20	= $	-
TOTAL Billed/Base	742,475	kW	TOTAL	$	3,701,251

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SCHEDULE E-13c Revised 8/6/05	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS Reflects Revised Sales Forecast and Winter Park Treated as Wholesale	
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: PROGRESS ENERGY FLORIDA, INC DOCKET NO.: 050078-EI	EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP	Type of Data Shown: ___Historical Test Year Ended _/_/_ _X_Projected Test Year Ended 12/31/06 ___Prior Year Ended _/_/_ Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE CS-1, CS-2, CS-3

PRESENT REVENUE CALCULATIONS

Energy Charge:							
Standard							
Secondary	646	MWH @	$	9.62	=	$	5,362
Primary		MWH @	$	9.62	=	$	-
Transmission	-	MWH @	$	9.62	=	$	-
Time-of-Use							
Secondary							
On-Peak	-	MWH @	$	18.28	=	$	-
Off-Peak	-	MWH @	$	5.26	=	$	-
Primary							
On-Peak	90,044	MWH @	$	18.28	=	$	1,846,004
Off-Peak	266,034	MWH @	$	5.26	=	$	1,399,339
Transmission							
On-Peak	-	MWH @	$	18.28	=	$	-
Off-Peak	-	MWH @	$	5.26	=	$	-
TOTAL	356,624	MWH				$	3,050,705
Adjustments							
Distribution Primary Metering	1%	OF	$	6,754,708	=	$	(67,547)
Transmission Metering	2%	OF	$	-	=	$	-
Power Factor @ 20¢ per kVar						$	10,344
TOTAL						$	(57,203)
Total CS-1, CS-2, CS-3 Base Revenue						$	6,712,260

PROPOSED REVENUE CALCULATIONS

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ATTACHMENT A

Reflects Revised Sales Forecast and Winter Park Treated as Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___Historical Test Year Ended _/_/_
_X_Projected Test Year Ended 12/31/06
___Prior Year Ended _/_/_
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE IS-1, IS-2

PRESENT REVENUE CALCULATIONS						PROPOSED REVENUE CALCULATIONS
Customer Charge:						
Standard						
Secondary	375	Bills @ $	255.64	= $	95,865	
Primary	477	Bills @ $	379.34	= $	180,945	
Transmission	2	Bills @ $	907.50	= $	1,816	
Time-of-Use						
Secondary	204	Bills @ $	255.64	= $	52,151	
Primary	604	Bills @ $	379.34	= $	229,121	
Transmission	88	Bills @ $	907.50	= $	79,860	
TOTAL	1,750	Bills		$	639,757	
Demand Charge:						
Standard						
Secondary - Billed	169,702	kW @ $	4.70	= $	797,599	
Primary - Billed	794,136	kW @ $	4.43	= $	3,518,022	
Transmission - Billed	-	kW @ $	4.07	= $	-	
Billed Sec/Pri	6,853	kW @ $	4.70	= $	32,209	
Billed Transm/Pri	16,570	kW @ $	4.07	= $	67,440	
Time-of-Use						
Secondary						
On-Peak	159,013	kW @ $	4.11	= $	653,543	
Base	162,440	kW @ $	0.74	= $	120,206	
Primary						
On-Peak	2,747,340	kW @ $	4.11	= $	11,291,567	
Base	3,228,020	kW @ $	0.47	= $	1,517,169	
Transmission						
On-Peak	746,820	kW @ $	4.11	= $	3,069,430	
Base	795,253	kW @ $	0.11	= $	87,478	
Sec/Pri						
On-Peak	5,761	kW @ $	4.11	= $	23,678	
Base	5,901	kW @ $	0.74	= $	4,367	
Pri/Transm						
On-Peak	76,419	kW @ $	4.11	= $	314,082	
Base	78,228	kW @ $	0.47	= $	36,767	
Transm/Pri						
On-Peak	243,358	kW @ $	4.11	= $	1,000,201	
Base	273,709	kW @ $	0.11	= $	30,108	
TOTAL Billed/Base	5,630,812	kW	TOTAL	$	22,563,868	

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ATTACHMENT A

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___ Historical Test Year Ended __/__/__
_X_ Projected Test Year Ended 12/31/06
___ Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE IS-1, IS-2

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Energy Charge:							
Standard							
Secondary	51,206	MWH @	$	6.60	=	$	332,839
Primary	235,814	MWH @	$	6.60	=	$	1,531,491
Transmission	-	MWH @	$	6.60	=	$	-
Sec/Pri	1,941	MWH @	$	6.50	=	$	12,617
Transm/Pri	1,106	MWH @	$	6.50	=	$	7,189
Time-of-Use							
Secondary							
On-Peak	23,381	MWH @	$	9.22	=	$	215,573
Off-Peak	61,268	MWH @	$	5.26	=	$	322,270
Primary							
On-Peak	323,948	MWH @	$	9.22	=	$	2,986,782
Off-Peak	1,115,882	MWH @	$	5.26	=	$	5,869,539
Transmission							
On-Peak	89,671	MWH @	$	9.22	=	$	826,846
Off-Peak	284,984	MWH @	$	5.26	=	$	1,498,911
Sec/Pri							
On-Peak	905	MWH @	$	9.22	=	$	8,344
Off-Peak	2,683	MWH @	$	5.26	=	$	14,113
Pri/Transm							
On-Peak	9,469	MWH @	$	9.22	=	$	87,304
Off-Peak	30,169	MWH @	$	5.26	=	$	158,689
Transm/Pri							
On-Peak	14,456	MWH @	$	9.22	=	$	133,284
Off-Peak	47,391	MWH @	$	5.26	=	$	249,277
TOTAL	2,293,952	MWH					14,264,087
Adjustments							
Distribution Primary Metering	1% OF		$	28,229,957	=	$	(282,300)
Transmission Metering	2% OF		$	6,145,946	=	$	(122,919)
Power Factor @ 20¢ per kVar						$	(19,628)
TOTAL						$	(424,847)
Total IS-1, IS-2 Base Revenue						$	37,032,843

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ATTACHMENT A

Reflects Revised Sales Forecast and Winter Park Treatas Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposeas for the test year. If any customers are to be transferred from one schedule to another, show revenues sepaly for the transfer group. Correction factors are used for historic test years only. The total base revenue by clmust equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KWh FOR EACH RATCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Showd ral
___ Historical Test Yealndod __/__/__
X Projected Test Yeasa Inded 12/31/06
___ Prior Year Ended TE __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE LS-1

PRESENT REVENUE CALCULATIONS						PROPOSED REVENUE CALCULATIONS
Customer Charge:						
Standard						
Unmetored	777,415	Bills @ $	1.09	= $	847,382	
Secondary	3,965	Bills @ $	3.13	= $	12,410	
TOTAL	781,380	Bills		$	859,792	
Energy & Demand Charge:						
Standard						
Secondary	333,326	MWH @ $	14.46	= $	4,819,880	
Adjustments						
n/a				$	-	
Total LS-1 Base Revenue				$	5,679,672	

ATTACHMENT A

ATTACHMENT A

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATS

Reflects Revised Sales Forecast and Winter Park Treates Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed n for the test year. If any customers are to be transferred from one schedule to another, show revenues separator the transfer group. Correction factors are used for historic test years only. The total base revenue by classst equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATEHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown: sles
____Historical Test Yearly fied __/__/__
_X_ Projected Test Year3 mled 12/31/06
____Prior Year Ended __ .9C __/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE SS-1

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:							
Primary	12	Bills @	$	215.99	=	$	2,592
Transmission	12	Bills @	$	744.15	=	$	8,930
Pri/Transm (Customer Owned)	84	Bills @	$	74.42	=	$	6,251
Total	108	Bills				$	17,773
Demand Charge:							
Distribution Charge							
Primary	33,660	kW @	$	1.36	=	$	45,778
Transmission (bulk)	85,397	kW @	$	-	=	$	-
Generation & Transm							
(Greater of SB Cap/DD)							
Primary							
Specified SB Cap	47,796	kW @	$	0.758	=	$	36,229
Daily Demand	262,692	kW @	$	0.361	=	$	94,832
Transmission (bulk)							
Specified SB Cap	324,708	kW @	$	0.758	=	$	246,129
Daily Demand	260,505	kW @	$	0.361	=	$	94,042
Total Specified Demand	372,504			Total		$	517,010
Energy Charge:							
Standard							
Primary	7,683	MWH @	$	6.33	=	$	48,633
Transmission	6,978	MWH @	$	6.33	=	$	44,171
Total	14,661	MWH				$	92,804
Adjustments							
Distribution Primary Metering	1%	OF	$	225,472	=	$	(2,255)
Transmission Metering	2%	OF	$	384,342	=	$	(7,687)
Total						$	(9,942)
Total SS-1 Base Revenue						$	617,645

SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULANS

Reflects Revised Sales Forecast and Winter Park Treates Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposeds for the test year. If any customers are to be transferred from one schedule to another, show revenues seperr for the transfer group. Correction factors are used for historic test years only. The total base revenue by clenust equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown rate
___Historical Test Yealahded __/__/__
_X_Projected Test Yeass fnded 12/31/06
___Prior Year Ended TE S__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE SS-2

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:							
Primary	30	Bills @	$	402.02	=	$	12,061
Transmission	-	Bills @	$	930.19	=	$	-
Transmission (Customer Owned)	24	Bills @	$	260.46	=	$	6,251
Total	54	Bills					18,312
Demand Charge:							
Local Transm & Distri							
Primary	343,409	kW @	$	1.36	=	$	467,036
Transmission (bulk)	431,662	kW @	$	-	=	$	-
Generation & Transm							
(Greater of SB Cap/DD)							
Primary							
Specified SB Cap	339,240	kW @	$	0.758	=	$	257,144
Daily Demand	3,420,321	kW @	$	0.361	=	$	1,234,736
Transmission (bulk)							
Specified SB Cap	614,880	kW @	$	0.758	=	$	466,079
Daily Demand	3,148,201	kW @	$	0.361	=	$	1,136,501
Total Specified Demand	954,120			Total		$	3,561,496
Energy Charge:							
Standard							
Primary	5,048	MWH @	$	6.33	=	$	31,954
Transmission	161,699	MWH @	$	6.33	=	$	1,023,555
Total	166,747	MWH				$	1,055,609
Adjustments							
Distribution Primary Metering	1%	OF	$	1,990,870	=	$	(19,909)
Transmission Metering	2%	OF	$	2,626,135	=	$	(52,523)
Total						$	(72,432)
Total SS-2 Base Revenue						$	4,562,685

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SCHEDULE E-13c Revised 8/5/05

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS
Reflects Revised Sales Forecast and Winter Park Treates Wholesale

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 050078-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
___ Historical Test Year Ended __/__/__
_X_ Projected Test Year Ended 12/31/06
___ Prior Year Ended __/__/__
Witness: Slusser

2006 REVENUE CALCULATION FOR RATE SCHEDULE SS

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:							
Primary (Customer Owned)	12	Bills @	$	74.42	=	$	893
Transmission	-	Bills @			=	$	-
Total	12	Bills				$	893
Demand Charge:							
Local Transm & Distri							
Primary	39,309	kW @	$	1.36	=	$	53,460
Transmission (bulk)	-	kW @	$	-	=	$	-
Generation & Transm							
(Greater of SB Cap/DD)							
Primary							
Specified SB Cap	167,328	kW @	$	0.758	=	$	126,835
Daily Demand	98,722	kW @	$	0.361	=	$	35,639
Transmission (bulk)							
Specified SB Cap	-	kW @	$	0.758	=	$	-
Daily Demand	-	kW @	$	0.361	=	$	-
Total Specified Demand	167,328	kW		Total		$	216,934
Energy Charge:							
Standard							
Primary	1,842	MWH @	$	6.33	=	$	11,660
Transmission	-	MWH @	$	6.33	=	$	-
Total	1,842	MWH				$	11,660
Adjustments:							
Distribution Primary Metering	1%	OF	$	227,594	=	$	(2,276)
Transmission Metering	2%	OF	$	-	=	$	-
Total						$	(2,276)
Total SS-3 Base Revenue						$	226,211

Progress Energy Florida
Impact of H2 & H4 Revenue Requirements on IS and CS Credits
$000's

Docket No. __________-E1
Witness: J. Portuondo
Exhibit JP-9

Base Rate Increase	88,694
Current Base Rates - Total	1,402,004
Less Customer Charges, LS Fixt & Maint	210,708
Current Base Rates - Demand & Energy	1,191,296
% Increase - Demand & Energy Charges	7.45%

	IS-1	IS-2	CS-1	CS-2	Total
Current Credits	19,877	883	663	663	22,085
Percentage Increase	7.45%	7.45%	7.45%	7.45%	7.45%
Increase in Credits	1,480	66	49	49	1,644

Impact of Change in Credits on ECCR - 2007 Data

	RS	GS	GS2	GSD	CS	IS	LS	Total
Demand Allocator by Class	60.218%	3.353%	0.138%	30.943%	0.534%	4.681%	0.133%	100.000%
Increase in Credits Allocated by Class	990	55	2	509	9	77	2	1,644
Class MWH	20,912,280	1,375,687	82,483	15,080,444	363,849	2,689,417	326,064	40,830,224
Rate Impact - $ per MWH	$ 0.047	$ 0.040	$ 0.027	$ 0.034	$ 0.024	$ 0.029	$ 0.007	$ 0.040