State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 27, 2007

TO: Office of Commission Clerk (Cole)

FROM: Division of Economic Regulation (Slemkewicz, Bulecza-Banks, Draper, Kyle, Lester, Maurey, Sickel, Springer)
Office of the General Counsel (Brown)

RE: Docket No. 070290-EI – Petition to increase base rates to recover full revenue requirements of Hines Unit 2 and Unit 4 power plants pursuant to Order PSC-05-0945-S-EI, by Progress Energy Florida, Inc.

AGENDA: 10/09/07 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Argenziano

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\ECR\WP\070290.RCM.DOC
Attachments not available on line

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COMMISSION CLERK

Case Background

On April 30, 2007, Progress Energy Florida, Inc. (PEF or Company) filed a petition to increase its base rates to recover the $52.4 million revenue requirements associated with Hines Unit 4 and to transfer the recovery of the $36.3 million revenue requirements for Hines Unit 2 from the fuel clause to base rates. The increase in base rates would become effective with the commercial in-service date of Hines Unit 4. PEF anticipates that Hines Unit 4 will begin commercial operations on December 1, 2007. Base rates would be increased by 7.45%.

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In its petition, PEF has requested the following:

• Base rate increase of $36.3 million for the Hines Unit 2 revenue requirements currently recovered through the fuel clause.

• True-up procedure for the Hines Unit 2 revenue requirement currently being recovered through the fuel clause.

• Base rate increase of $52.4 million for the Hines Unit 4 and related transmission facilities revenue requirement.

• Recovery of the costs in excess of the need determination for the Hines Unit 4 ($18.5 million) and the related transmission facilities ($22.1 million).

• Base rate increase effective date coinciding with the first billing cycle after the commercial in-service date of Hines Unit 4 (12/01/07 anticipated date).

PEF has filed its petition pursuant to Paragraph 12. of the rate case Stipulation and Settlement Agreement (Stipulation) approved by Order No. PSC-05-0945-S-EI.[1] Paragraph 12. of the Stipulation states the following:

> 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-El,[2] 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-la filed by PEF in Docket No. 050078-El. 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-El, and set forth in Exhibit I, 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

[1]Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.
[2]Order No. PSC-04-1168-FOF-El, issued November 23, 2004, in Docket No. 040817-EI, In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc.

> 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-la filed by PEF in Docket No. 050078-El. 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-E1, and as included 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.

The recovery of the Hines Unit 2 investment through the fuel clause was previously authorized in Order No. PSC-02-0655-AS-EI.[3] Paragraph 9. of the stipulation approved in that order states the following:

> 9. Beginning with the in-service date of Hines Unit 2 through December 31, 2005, FPC will be allowed to recover through the fuel cost recovery clause a return on average investment and straight-line depreciation expense (but no other non-fuel expense) for Hines Unit 2, to the extent such costs do not exceed the unit's cumulative fuel savings over the recovery period. All costs associated with Hines Unit 2, including those described in this section, are subject to Commission review for prudence and reasonableness as a condition for recovery through the fuel cost recovery clause. The investment for Hines Unit 2 upon which a return is recovered under this section will be excluded from rate base for surveillance reporting purposes during the recovery period.

This recommendation addresses the issues raised in PEF's petition concerning the base rate increase associated with the revenue requirements for Hines Unit 2, Hines Unit 4, and the related transmission facilities. The Commission has jurisdiction over this matter pursuant to Sections 366.05 and 366.06, Florida Statutes.

[3]Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light, and in Docket No. 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Discussion of Issues

Issue 1: What is the appropriate jurisdictional revenue requirement to be included in base rates for Hines Unit 2?

Recommendation: The appropriate jurisdictional base rate revenue requirement for Hines Unit 2 is $36,339,546. (Slemkewicz, Springer)

Staff Analysis: Per Paragraph 9. of the stipulation approved in Order No. PSC-02-0655-AS-EI,[4] PEF was authorized to recover the Hines Unit 2 return on average investment and straight-line depreciation expense through the fuel cost recovery factor until December 31, 2005. The amount of the recovery was limited to the unit's cumulative fuel savings over the recovery period. Subsequently, Order No. PSC-05-0945-S-EI[5] approved Paragraph 12.b. of another stipulation that extended the fuel clause recovery of the investment and depreciation until the commercial in-service date of Hines Unit 4. PEF currently anticipates that Hines Unit 4 will begin commercial operations on December 1, 2007. At that time, PEF's base rates would be increased to recover the Hines Unit 2 2006 full revenue requirements, excluding the unit's non-fuel O&M expenses already being recovered in base rates. PEF would then cease making any further charges to the fuel clause for the recovery of the Hines Unit 2 investment and depreciation.

In Exhibit JP-1 (Attachment A) of PEF's filing, the Company provided a calculation of the 2006 revenue requirements for Hines Unit 2. Based on the methodology approved in Paragraph 12.b., the 2006 revenue requirements were calculated to be $38,760,942 on a system basis. After applying a production base separation factor[6] of 93.753 percent to the system amount, the jurisdictional portion of the 2006 Hines Unit 2 revenue requirements is $36,339,546. Staff has reviewed this calculation and it appears to be consistent with the applicable provisions of the stipulations.

Staff recommends that the appropriate jurisdictional base rate revenue requirement for Hines Unit 2 is $36,339,546, as calculated in Exhibit JP-1.

[4]Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light, and in Docket No. 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[5]Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.
[6]Cost of service factor for allocating base production facilities between the retail and wholesale jurisdictions.

Issue 2: Should the Commission approve PEF's proposal not to revise its 2007 fuel cost recovery factors after the Hines Unit 2 revenue requirements have been transferred to base rates?

Recommendation: Yes. The Commission should approve PEF's proposal not to revise its 2007 fuel cost recovery factors after the Hines Unit 2 revenue requirements have been transferred to base rates. Any fuel revenue over or under recovery due to the continued recovery of Hines Unit 2 revenue in the fuel clause for December 2007 will be reflected in the prior period true up as part of the calculation of 2008 fuel cost recovery factors. (Lester)

Staff Analysis: PEF proposes to transfer the 2006 revenue requirements associated with Hines Unit 2 from the fuel clause to base rates in December 2007. The total revenue requirement associated with Hines Unit 2 is $36.3 million and consists of depreciation expense and return on investment. The table below summarizes PEF's calculation of the levelized fuel factor for 2007 with and without the Hines Unit 2 revenue requirements. The detailed calculation is provided on Exhibit JP-2.

LEVELIZED FUEL FACTOR EFFECT	
	CENTS/KWH
Current 2007 Levelized Fuel Cost Recovery Factor	5.132
2007 Factor Without the Hines Unit 2 Revenue Requirements	5.045
Difference	0.087

PEF proposes that it not change fuel factors at the same time that base rates change. Instead, PEF proposes to recognize the effect of the removal of Hines Unit 2 revenue requirements from the fuel clause in its calculation of the 2008 fuel factors. Base rates will change with the first billing cycle after December 1, 2007, and fuel factors for 2008 will become effective for the first billing cycle of January 2008. PEF proposes that any fuel revenue over or under recovery due to the continued recovery of Hines Unit 2 revenue in the fuel clause for December 2007 will be reflected in the prior period true-up as part of the calculation of 2008 fuel cost recovery factors. PEF will apply interest to the true-up amounts.

Staff notes that PEF's proposed treatment of the effect on fuel factors can be verified in the upcoming fuel clause proceeding, at which the Commission will establish the 2008 factors. Further, staff will audit the actual true-up for 2007 in 2008. Staff believes PEF's proposed methodology is appropriate.

Issue 3: Should PEF be allowed to recover the costs in excess of the need determination for Hines Unit 4 and the related transmission facilities?

Recommendation: Yes. PEF should be allowed to recover the $41 million of costs in excess of the need determination for Hines Unit 4 and the related transmission facilities. (Sickel)

Staff Analysis: Pursuant to Paragraph 12.a. of the stipulation approved in Order No. PSC-05-0945-S-EI,[7] PEF was authorized to increase its base rates to recover the installed cost of Hines Unit 4 and the unit's non-fuel operating expenses beginning on the unit's commercial in-service date. The amount of the installed cost to be recovered was limited by Rule 25-22.082(15), Florida Administrative Cost, as follows:

> If the public utility selects a self-build option, costs in addition to those identified in the need determination proceeding shall not be recoverable unless the utility can demonstrate that such costs were prudently incurred and due to extraordinary circumstance.

PEF alleges that the final total cost for Hines Unit 4 will be about $41 million more than the estimated cost of $286.1 million that was authorized by Order No. PSC-04-1168-FOF-EI.[8] PEF currently estimates that costs for the generating plant have increased by $18.5 million and that transmission costs have increased by $22.5 million.

The reported increase in the cost for the Hines Unit 4 power plant is attributed to several developments. The first change was an increase of $13 million in the fixed price for the engineering and procurement contract. The need determination for Hines Unit 4 was filed in early August 2004, just prior to the hurricane events of that year. By the time the contract was signed on December 14, 2004, both material and labor costs reflected the impact of the storms on market-based prices. The reported increase appears reasonable, recognizing the impact of events of the time.

PEF was able to mitigate some of the increase in the contract cost by purchasing equipment on the secondary market and by cost-effective management of direct owner costs. The reported changes in costs and pricing appear reasonable, resulting from necessary work and prudent management practices. At present, PEF estimates that the actual increase in costs for the power plant amounts to $4.8 million.

The estimated AFUDC charges have increased by approximately $13.7 million since the need was granted. A part of that increase is due to expenditures incurred earlier than originally planned in order to secure purchase of major equipment items while they were available on the secondary market. Also, the AFUDC rate was increased in the Stipulation previously cited. The total increase of $18.5 million results from the power plant costs and additional AFUDC costs that PEF has explained.

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[7]Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[8]Order No. PSC-04-1168-FOF-EI, issued November 23, 2004, in Docket No. 040817-EI, In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc.

Within the planning for Hines Unit 4, PEF performed transmission planning analyses consistent with utility industry practice and reliability requirements. Transmission system and facility modifications required for the addition of Hines Unit 4 included three projects:

(1) Expansion of the Hines Energy Center substation;
(2) A 230 kV interconnection between the new Hines Unit 4 generator and the West Lake Wales substation; and
(3) Replacement of 16 circuit breakers to accommodate increased fault current.

After approval was granted for Hines Unit 4, and during the construction of the 230 kV transmission interconnection between the Hines Unit 4 generator and the West Lake Wales substation, plans and costs changed because of environmental requirements, property valuation, material costs, and labor costs. These changes in circumstances, and their impacts on the Hines Unit 4 project, are briefly discussed below.

Environmental issues developed with regard to plans for the needed 230 kV transmission installation across the Peace River. The utility anticipated a route adjacent to an existing roadway and bridge, based on the concept that a transmission line would add little to the impact of the structures and usage already present at the site. After the authorization of need was granted by the Commission, the Florida Department of Environmental Protection became involved in the process of making detailed wetland and engineering evaluations. Revisions to planning were required in order to provide towers of sufficient height to span the Peace River areas, including the sag required for such a span. As a result, the transmission structures are 295 feet in height, rather than the 185 foot high structures that had been originally included in the planning. Increased costs associated with the river crossing are reported to be $1.3 million.

Based on previous projects, PEF estimated that eminent domain proceedings would be necessary in 5 – 10 percent of the easements needed. Between the time of the original estimate and the initial efforts to acquire rights of easement, developers moved into the area. Many owners demanded eminent domain proceedings, and property valuations were changed from agricultural to residential or commercial. Ultimately, 35 percent of the acquisitions required eminent domain proceedings and increased costs were about $4 million.

In addition, the transmission cost estimates made for the need determination were based on easement agreements that had been traditionally used. The orange trees that were typical in the area of the proposed route were not assessed to be a risk to the utility's operations. Following the "Northeast Blackout" of 2003, issues relating to tree management became a subject of increased regulatory focus by NERC.[9] To meet the increased reliability requirements imposed nationwide, PEF revised the easement agreements used by the utility. The owner of land crossed by an easement is required to give the utility full discretion regarding any question of tree removal. PEF reports that 32 parcels were affected by these changes in the agreement, resulting in $1 million in increased costs.

[9]NERC - North American Electric Reliability Corporation is certified by the Federal Energy Regulatory Commission as the national electric reliability organization.

The costs of transmission structures increased by about $3 million to provide seven more poles than originally estimated, and because the weight per pole had been underestimated. Increased material costs for steel and raw aluminum for the conductor resulted in $3.9 million in additional costs. An increase of about $9.5 million is attributed to labor costs included in electrical construction, foundation construction, road construction, and land clearing.

PEF alleges that the increase of $18.5 million for construction of Hines Unit 4 and $22.5 million for providing the required transmission facilities are the result of events commonly known now but unforeseen when costs were estimated for purposes of the need determination. Staff is in agreement that the developments described could not have been predicted by August 2004, when the need was filed, and that the resulting impacts could not have been forecasted. Staff recommends that the additional costs that have been described are necessary in the construction associated with the Hines Unit 4 project, and that they are in addition to reasonable estimates that could have been made when the determination of need was granted. Therefore, staff recommends that such costs may be included in the recovery provided for the investment made in the construction of Hines Unit 4.

Issue 4: What is the appropriate jurisdictional revenue requirement to be included in base rates for Hines Unit 4 and the related transmission facilities?

Recommendation: The appropriate jurisdictional base rate revenue requirement is $52,354,000 for Hines Unit 4 and the related transmission facilities. (Slemkewicz, Springer)

Staff Analysis: Pursuant to Paragraph 12.a. of the stipulation approved in Order No. PSC-05-0945-S-EI,[10] PEF was authorized to increase its base rates to recover the installed cost of Hines Unit 4 and the unit's non-fuel operating expenses beginning on the unit's commercial in-service date. The amount of the installed cost to be recovered was limited by Rule 25-22.082(15), Florida Administrative Cost, as discussed in Issue 3.

In Exhibit JP-3 (Attachment B) of PEF's filing, the Company provided a calculation of the revenue requirement for Hines Unit 4 and the related transmission facilities. Based on the methodology approved in Paragraph 12.a., the jurisdictional revenue requirement was calculated to be a total of $52,354,000 ($58,127,000 system). Based on PEF's calculation, the jurisdictional revenue requirement for the unit is $45,460,000 ($48,530,000 system) and $6,900,000 ($9,597,000 system) for the transmission facilities. Staff has reviewed this calculation and it appears to be consistent with the applicable provisions of the stipulation.

During its review of Exhibit JP-3, staff noted that PEF utilized an incorrect net operating income (NOI) multiplier in calculating the total revenue requirement and the transmission facilities revenue requirement. Per Exhibit JP-7, the appropriate NOI multiplier is 1.6315. PEF used an NOI multiplier of 1.6313 for calculating the total and the transmission facilities revenue requirements. As a result, the transmission facilities jurisdictional revenue requirement was understated by $1,000 and the total jurisdictional revenue requirement was understated by $7,000. The total jurisdictional revenue requirement using the appropriate NOI multiplier is $52,361,000 versus the $52,354,000 requested by PEF in its petition. The Hines Unit 4 revenue requirement calculation is based on projected final costs for the project and projected O&M expenses once the unit is in operation. In staff's opinion, the $7,000 of additional revenue requirement is insignificant and within an acceptable margin of error given the nature of the projections. Therefore, no adjustment should be made to the $52,354,000 Hines Unit 4 revenue requirement requested by PEF in its petition.

As discussed in Issue 3, staff is recommending that PEF be allowed to recover the Hines Unit 4 and related transmission facilities cost overruns. No adjustment to the revenue requirement calculation in Exhibit JP-3 is necessary. Therefore, staff recommends that the appropriate jurisdictional base rate revenue requirement for Hines Unit 4 and the related transmission facilities is $52,354,000 as calculated in Exhibit JP-3.

[10]Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

Issue 5: What are the appropriate revised base rates?

Recommendation: The appropriate base rates are shown on Attachment C. PEF should file, for administrative approval, revised tariff sheets to reflect the Commission vote. (Draper)

Staff Analysis: As shown in Exhibit JP-4 of PEF's filing, retail rates will increase 7.45 percent. This percentage increase will be uniformly applied to PEF's demand and energy charges including its delivery voltage credits, demand credits, power factor adjustment, and premium distribution service rates. Delivery voltage credits apply when a commercial customer takes service under a delivery voltage above standard distribution secondary voltage (primary or transmission delivery voltage) and receives a credit for the avoided transformer costs. Demand credits apply to interruptible or curtailable customers who receive a credit for receiving non-firm service. PEF states that total interruptible and curtailable credits paid to non-firm customers will increase from $22.1 million to $23.7 million. The power factor adjustment applies to commercial customers with a demand of 1,000 kw or more. Finally, the premium distribution service is an optional service for customers who require additional reliability.

This increase will be partially offset by a decrease in the fuel cost recovery factor, beginning in January 2008, due to the transfer of the Hines Unit 2 revenue requirements from the fuel cost recovery clause to base rates. Under PEF's proposal, the 1,000 kwh residential bill would increase in December 2007 from the current $110.34 to $113.14, by $2.80, or 2.5 percent. In January 2008, PEF projects the 1,000 kwh residential bill to decrease to $108.07, due to a reduction in its fuel and purchased power costs.

Attachment C shows the current base rates and the proposed base rates adjusted for the increase due to including the revenue requirements for Hines Unit 2 and Unit 4. The current and proposed base rates are shown in cents/kWh and $/kWh. PEF should file, for administrative approval, revised tariff sheets to reflect the Commission's vote. In the event the Commission approves an alternate percentage increase to base rates, PEF shall file worksheets to show the revised calculation for staff review.

Issue 6: What is the appropriate effective date for the revised base rates?

Recommendation: The revised base rates shall apply to electric usage occurring on and after December 1, 2007. Starting with meter reading dates on or after December 1, 2007, PEF shall prorate customers' bills so that the current base rates apply to November 2007 usage and that the revised base rates apply to December 2007 usage. In addition, starting with the first billing cycle in November, PEF shall include bill inserts to notify its customers of the proposed base rate increase. (Draper, Brown)

Staff Analysis: The stipulation states that beginning on the commercial in-service date of Hines Unit 4, PEF will increase its base rates to recover the full revenue requirements of the installed cost of Unit 4. The stipulation further provides that PEF will transfer the 2006 revenue requirements associated with Hines Unit 2 from the fuel clause to base rates in December 2007. PEF proposes to revise its bases rates beginning with the first billing cycle of December 2007 since the anticipated in-service date for Hines Unit 4 is December 1, 2007. Therefore, under PEF's proposal, customer usage during the month of November will be billed under the increased base rates. For example, a customer whose meter is read on December 1, will be billed for November usage under the increased base rates.

The PEF stipulation allows for the Hines Unit 2 revenue requirements to be included in base rates on December 1, but staff does not believe the stipulation provides for November usage to be billed under the higher base rates. Typically in base rate increases, the Commission requires utilities to provide customers a 30-day notice to allow customers to adjust their usage in light of the new rates. Therefore, staff recommends that beginning with meter readings on and after December 1, PEF shall prorate customers' bills so that the current base rates apply to November 2007 usage and that the revised base rates apply to December 2007 usage.

The following example illustrates staff's proposal. PEF shall assume a typical billing month of 30 days. For a customer whose meter is read on December 1, PEF shall bill 29 days of usage under the current base rates, and 1 day of usage under the revised base rates. The proration factor for a December 1 meter reading date is 0.97 (29/30). PEF shall then multiply the proration factor to the customer's total usage for the billing period to determine usage for November to be billed under the current rates and usage for December to be billed under the revised rates. For a customer whose meter is read on December 15, PEF shall bill 15 days of usage under the current base rates, and 15 days of usage under the revised base rates. The proration factor for a December 15 meter reading date is 0.5 (15/30).

Beginning with the first billing cycle in November, PEF shall include bill inserts in customer bills notifying customers of the proposed base rate increase. For residential customers, PEF shall also state the impact on the 1,000 kwh residential bill. PEF shall provide staff a copy of the bill insert for staff review.

The language in this stipulation differs from the language approved in the FPL rate case stipulation,[11] which provided for an adjustment of base rates following the commercial in-service

[11]Order No. PSC-05-0902-S-EI, issued on September 14, 2005, in Docket No. 050045-EI and 050188-EI, In re: Petition for rate increase by Florida Power & Light Company.

date of Turkey Point Unit 5. The FPL stipulation states that "FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement **to meter readings made on and after** the commercial in service date of such power plant" (emphasis added). The PEF stipulation does not include this clear language that the increased base rates shall apply to meter readings made on and after the commercial in-service date of Hines Unit 4.

Issue 7: Should this docket be closed?

Recommendation: Yes. If the Commission approves PEF's petition and no protest is filed within 21 days of the issuance of the order, this docket should be closed upon the issuance of a consummating order. If a protest is timely filed, the revised rates should remain in effect, with revenues held subject to refund pending resolution of the protest. (Brown)

Staff Analysis: If the Commission approves PEF's petition and no protest is filed within 21 days of the issuance of the order, this docket should be closed upon the issuance of a consummating order. If a protest is timely filed, the revised rates should remain in effect, with revenues held subject to refund pending resolution of the protest.

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	188,858	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

Progress Energy Florida
Hines Unit 4 - Revenue Requirements
Year 2008

Docket No. _________-E1
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)	

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

Rate Schedule	Type of Charge	cents / kWh (Settlement) Current/Prior Rate	cents / kWh Proposed / Approved Rate	$/kWh Actual Billing Rate (CSS) (Settlement) Current/Prior Rate	$/kWh Actual Billing Rate (CSS) Proposed / Approved Rate
SC-1	Initial Connection - $	61.00	61.00	61.00	61.00
	Reconnection - $	28.00	28.00	28.00	28.00
	Transfer of Account - No LSA Contract - $	28.00	28.00	28.00	28.00
	Transfer of Account - LSA Contract Required - $	10.00	10.00	10.00	10.00
	Reconnect After Disconnect For Non-Pay - $	40.00	40.00	40.00	40.00
	Reconnect After Disconnect For Non-Pay After Hours -$	50.00	50.00	50.00	50.00
	Late Payment Charge	> $5.00 or 1.5%	> $5.00 or 1.5%	> $5.00 or 1.5%	> $5.00 or 1.5%
	Returned Check Charge	$25 if <= $50 $30 if <= $300 $40 if <= $800 5% if > $800	$25 if <= $50 $30 if <= $300 $40 if <= $800 5% if > $800	$25 if <= $50 $30 if <= $300 $40 if <= $800 5% if > $800	$25 if <= $50 $30 if <= $300 $40 if <= $800 5% if > $800
TS-1	Temporary Service Extension - Monthly $	227.00	227.00	227.00	227.00
RS-1	Customer Charge - $ per Line of Billing				
RST-1	Standard	8.03	8.03	8.03	8.03
RSS-1	Seasonal (RSS-1)	4.20	4.20	4.20	4.20
	Time of Use				
	Single Phase	14.84	14.84	14.84	14.84
	Three Phase	14.84	14.84	14.84	14.84
	Customer CIAC Paid	8.03	8.03	8.03	8.03
	TOU Metering CIAC - $ One Time Charge	132.00	132.00	132.00	132.00
	Energy and Demand Charge - cents per KWH				
	Standard				
	0 - 1,000 KWH	3.315	3.588	0.03315	0.03588
	Over 1,000 KWH	4.315	4.588	0.04315	0.04588
	Time of Use - On Peak	10.431	11.208	0.10431	0.11208
	Time of Use - Off Peak	0.526	0.565	0.00526	0.00565

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

Rate Schedule	Type of Charge	cents / kWh (Settlement) Current/Prior Rate	cents / kWh Proposed / Approved Rate	$/kWh Actual Billing Rate (CSS) (Settlement) Current/Prior Rate	$/kWh Actual Billing Rate (CSS) Proposed / Approved Rate
GS-1,	Customer Charge - $ per Line of Billing				
GST-1	Standard				
	Unmetered	5.99	5.99	5.99	5.99
	Secondary	10.62	10.62	10.62	10.62
	Primary	134.31	134.31	134.31	134.31
	Transmission	662.48	662.48	662.48	662.48
	Time of Use				
	Single Phase	17.42	17.42	17.42	17.42
	Three Phase	17.42	17.42	17.42	17.42
	Customer CIAC Paid	10.62	10.62	10.62	10.62
	Primary	141.12	141.12	141.12	141.12
	Transmission	669.28	669.28	669.28	669.28
	TOU Metering CIAC - $ One Time Charge	132.00	132.00	132.00	132.00
	Energy and Demand Charge - cents per KWH				
	Standard	3.648	3.920	0.03648	0.03920
	Time of Use - On Peak	10.431	11.208	0.10431	0.11208
	Time of Use - Off Peak	0.526	0.565	0.00526	0.00565
	Premium Distribution Charge - cents per KWH	0.504	0.542	0.00504	0.00542
	Meter Voltage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.7%	1.67%	1.67%
GS-2	Customer Charge - $ per Line of Billing				
	Standard				
	Unmetered	5.99	5.99	5.99	5.99
	Metered	10.62	10.62	10.62	10.62
	Energy and Demand Charge - cents per KWH				
	Standard	1.369	1.471	0.01369	0.01471
	Premium Distribution Charge - cents per KWH	0.101	0.109	0.00101	0.00109

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

Rate Schedule	Type of Charge	cents / kWh (Settlement) Current/Prior Rate	cents / kWh Proposed / Approved Rate	$/kWh Actual Billing Rate (CSS) (Settlement) Current/Prior Rate	$/kWh Actual Billing Rate (CSS) Proposed / Approved Rate
GSD-1	Customer Charge - $ per Line of Billing				
GSDT-1	Standard				
	Secondary	10.62	10.62	10.62	10.62
	Primary	134.31	134.31	134.31	134.31
	Transmission	662.48	662.48	662.48	662.48
	Time of Use				
	Secondary	17.42	17.42	17.42	17.42
	Secondary - Customer CIAC paid	10.62	10.62	10.62	10.62
	Primary	141.12	141.12	141.12	141.12
	Primary - Customer CIAC paid	134.31	134.31	134.31	134.31
	Transmission	669.28	669.28	669.28	669.28
	Transmission Customer CIAC paid	662.48	662.48	662.48	662.48
	Demand Charge - $ per KW				
	Standard	3.45	3.71	3.45	3.71
	Time of Use				
	Base	0.85	0.91	0.85	0.91
	On Peak	2.57	2.76	2.57	2.76
	Delivery Voltage Credits - $ per KW				
	Primary	0.27	0.29	0.27	0.29
	Transmission	1.01	1.09	1.01	1.09
	Premium Distribution Charge - $ per KW	0.74	0.80	0.74	0.80
	Energy Charge - cents per KWH				
	Standard	1.503	1.615	0.01503	0.01615
	Time of Use - On Peak	3.316	3.563	0.03316	0.03563
	Time of Use - Off Peak	0.526	0.565	0.00526	0.00565
	Meter Voltage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Power Factor - $ per KVar	0.20	0.21	0.20	0.21
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.7%	1.67%

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

Rate Schedule	Type of Charge	cents / kWh (Settlement) Current/Prior Rate	cents / kWh Proposed / Approved Rate	\$/kWh Actual Billing Rate (CSS) (Settlement) Current/Prior Rate	\$/kWh Actual Billing Rate (CSS) Proposed / Approved Rate
CS-1					
CS-2	Customer Charge - \$ per Line of Billing				
CS-3	Secondary	69.61	69.61	69.61	69.61
CST-1	Primary	193.30	193.30	193.30	193.30
CST-2	Transmission	721.46	721.46	721.46	721.46
	Demand Charge - \$ per KW				
	Standard	5.56	5.97	5.56	5.97
	Time of Use				
	Base	0.83	0.89	0.83	0.89
	On Peak	4.68	5.03	4.68	5.03
	Curtailable Demand Credit				
	CS-1, CST-1 - \$ per KW of Curtailable Demand	2.33	2.50	2.33	2.50
	CS-2, CST-2 - \$ per KW LF adjusted Demand	2.31	2.48	2.31	2.48
	CS-3, CST-3 - \$ per KW of Contract Demand	2.31	2.48	2.31	2.48
	Delivery Voltage Credits - \$ per KW				
	Primary	0.27	0.29	0.27	0.29
	Transmission	1.01	1.09	1.01	1.09
	Premium Distribution Charge - \$ per KW	0.74	0.80	0.74	0.80
	Energy Charge - cents per KWH				
	Standard	0.982	1.055	0.00982	0.01055
	Time of Use - On Peak	1.828	1.964	0.01828	0.01964
	Time of Use - Off Peak	0.526	0.565	0.00526	0.00565
	Meter Voltage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Power Factor - \$ per KVar	0.20	0.21	0.20	0.21
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.67%

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

		cents / kWh		$/kWh Actual Billing Rate (CSS)	
Rate Schedule	Type of Charge	(Settlement) Current/Prior Rate	Proposed / Approved Rate	(Settlement) Current/Prior Rate	Proposed / Approved Rate
IS-1	Customer Charge - $ per Line of Billing				
IS-2	Secondary	255.64	255.64	255.64	255.64
IST-1	Primary	379.34	379.34	379.34	379.34
IST-2	Transmission	907.50	907.50	907.50	907.50
	Demand Charge - $ per KW				
	Standard	4.70	5.05	4.70	5.05
	Time of Use				
	Base	0.74	0.80	0.74	0.80
	On Peak	4.11	4.42	4.11	4.42
	Interruptible Demand Credit				
	IS-1, IST-1 - $ per KW of Billing Demand	3.37	3.62	3.37	3.62
	IS-2, IST-2 - $ per KW LF Adjusted Demand	3.08	3.31	3.08	3.31
	Delivery Voltage Credits - $ per KW				
	Primary	0.27	0.29	0.27	0.29
	Transmission	1.01	1.09	1.01	1.09
	Premium Distribution Charge - $ per KW	0.74	0.80	0.74	0.80
	Energy Charge - cents per KWH				
	Standard	0.650	0.698	0.00650	0.00698
	Time of Use - On Peak	0.922	0.991	0.00922	0.00991
	Time of Use - Off Peak	0.526	0.565	0.00526	0.00565
	Meter Voltage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Power Factor - $ per KVar	0.20	0.21	0.20	0.21
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.67%

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

Rate Schedule	Type of Charge	cents / kWh (Settlement) Current/Prior Rate	cents / kWh Proposed / Approved Rate	$/kWh Actual Billing Rate (CSS) (Settlement) Current/Prior Rate	$/kWh Actual Billing Rate (CSS) Proposed / Approved Rate
LS-1	Customer Charge - $ per Line of Billing				
	Standard				
	Unmetered	1.09	1.09	1.09	1.09
	Metered	3.13	3.13	3.13	3.13
	Energy and Demand Charge - cents per KWH				
	Standard	1.446	1.554	0.01446	0.01554
	Fixture & Maintenance Charges - $ per fixture	n/a	n/a	n/a	n/a
	Pole Charges - $ per pole	n/a	n/a	n/a	n/a
	Other Fixture Charge Rate - % of Installed Fixture Cost	1.46%	1.46%	1.46%	1.46%
	Other Pole Charge Rate - % of Installed Pole Cost	1.67%	1.67%	1.67%	1.67%
SS-1	Customer Charge - $ per Line of Billing				
	Secondary	92.29	92.29	92.29	92.29
	Primary	215.99	215.99	215.99	215.99
	Transmission	744.15	744.15	744.15	744.15
	Customer Owned	74.42	74.42	74.42	74.42
	Base Rate Energy Customer Charge - cents per KWH	0.633	0.680	0.00633	0.00680
	Distribution Charge - $ per KW				
	Applicable to Specified SB Capacity	1.36	1.46	1.36	1.46
	Generation and Transmission Capacity Charge				
	Greater of : - $ per KW				
	Monthly Reservation Charge				
	Applicable to Specified SB Capacity	0.758	0.814	0.758	0.814
	Peak Day Utilized SB Power Charge of:	0.361	0.388	0.361	0.388

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

		cents / kWh		$/kWh Actual Billing Rate (CSS)	
Rate Schedule	Type of Charge	(Settlement) Current/Prior Rate	Proposed / Approved Rate	(Settlement) Current/Prior Rate	Proposed / Approved Rate
SS-2	Customer Charge - $ per Line of Billing				
	Secondary	278.33	278.33	278.33	278.33
	Primary	402.02	402.02	402.02	402.02
	Transmission	930.19	930.19	930.19	930.19
	Customer Owned	260.45	260.45	260.45	260.45
	Base Rate Energy Customer Charge - cents per KWH	0.633	0.680	0.00633	0.00680
	Distribution Charge - $ per KW				
	Applicable to Specified SB Capacity	1.36	1.46	1.36	1.46
	Generation and Transmission Capacity Charge				
	Greater of : - $ per KW				
	Monthly Reservation Charge				
	Applicable to Specified SB Capacity	0.758	0.814	0.758	0.814
	Peak Day Utilized SB Power Charge of:	0.361	0.388	0.361	0.388
	Interruptible Capacity Credit - $ per KW				
	Grandfathered Prior to 1/1/06				
	Monthly Reservation Credit	0.642	0.690	0.642	0.690
	Daily Demand Credit	0.306	0.329	0.306	0.329
	Effective 1/1/06				
	Monthly Reservation Credit	0.308	0.331	0.308	0.331
	Daily Demand Credit	0.147	0.158	0.147	0.158
SS-3	Customer Charge - $ per Line of Billing				
	Secondary	92.29	92.29	92.29	92.29
	Primary	215.99	215.99	215.99	215.99
	Transmission	744.15	744.15	744.15	744.15
	Customer Owned	74.42	74.42	74.42	74.42
	Base Rate Energy Customer Charge - cents per KWH	0.633	0.680	0.00633	0.00680
	Distribution Charge - $ per KW				
	Applicable to Specified SB Capacity	1.36	1.46	1.36	1.46
	Generation and Transmission Capacity Charge				
	Greater of : - $ per KW				
	Monthly Reservation Charge				
	Applicable to Specified SB Capacity	0.758	0.814	0.758	0.814
	Peak Day Utilized SB Power Charge of:	0.361	0.388	0.361	0.388
	Curtailable Capacity Credit - $ per KW				
	Grandfathered Prior to 1/1/06				
	Monthly Reservation Credit	0.321	0.345	0.321	0.345
	Daily Demand Credit	0.153	0.164	0.153	0.164
	Effective 1/1/06				
	Monthly Reservation Credit	0.231	0.248	0.231	0.248

Schedule E-14 Supplement

Progress Energy Florida
Unit Charge / Unit Cost Data
Proposed Base Rate Increase - Hines 2 and Hines 4

		cents / kWh		$/kWh Actual Billing Rate (CSS)	
Rate Schedule	Type of Charge	(Settlement) Current/Prior Rate	Proposed / Approved Rate	(Settlement) Current/Prior Rate	Proposed / Approved Rate
	Daily Demand Credit	0.110	0.118	0.110	0.118
	Gross Receipts Tax	2.5641%	2.5641%	2.5641%	2.5641%

C:\Documents and Settings\jcost\Local Settings\Temporary Internet Files\OLK5\[Rates - Detailed.xls]Base Rates-Hines 2 &4