Before the
Florida Public Service Commission

In re: Petition to Recover Costs of Crystal River Unit 3 Uprate through the Fuel Clause	**DOCKET NO. 070052-EI** **Submitted for filing:** **June 19, 2007**

Direct Testimony and Exhibits of

Jeffry Pollock

On behalf of the

Florida Industrial Power Users Group
(FIPUG)

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June 2007

J. POLLOCK
INCORPORATED

Before the
Florida Public Service Commission

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Table of Contents

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Direct Testimony of Jeffry Pollock

I. INTRODUCTION AND QUALIFICATIONS

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12655 Olive Blvd., Suite 335, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J.Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments including energy procurement and regulatory matters in both the United States and several Canadian provinces.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). The participating FIPUG members are customers of Progress Energy Florida (PEF) and take service under various rate schedules.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A My testimony addresses PEF'S proposal to recover the Crystal River Unit 3 (CR3) uprate costs through the fuel clause.

Q DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A Yes. I have supervised the preparation of, or prepared the four exhibits to my Direct Testimony listed on the Table of Contents.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS PROCEEDING.

A PEF's proposed fuel clause recovery should be rejected for the following reasons. First, it would be a direct violation of the Settlement in PEF's 2005 base rate case (Docket No. 050078). Among other things, the Settlement required that base rates remain frozen through December 2009. Second, the proposed uprate does not qualify for cost recovery through the fuel clause because (a) the costs are not fuel-related and they are not volatile; (b) nuclear uprates are neither new nor innovative; and (c) the additional capacity to be provided by the uprate is needed by PEF to meet its projected peak demands and to maintain the required reserve margins. Third, collecting these costs through the fuel clause would create a double–recovery, because PEF's base rate already reflects the recovery of nuclear capacity costs. Fourth, the proposed fuel clause recovery is improper because (a) the costs at issue are properly classified as demand-related; (b) it would result in cost shifting because demand-related costs would be recovered on an energy, or kWh basis, and (c) the proposed 10-year amortization period would fail to match the costs of the uprate (which is expected to last through 2036), with the projected benefits, which are also projected to occur through 2036 the projected remaining life of CR3, (if PEF's planned license extension is granted).

Should the Commission, nevertheless, allow special cost recovery, the nuclear uprate costs properly allocable to PEF's retail customers should be recovered through the Capacity Cost Recovery Clause (CCRC). With the exception of the transmission portion of PEF's request, the costs should be amortized over the expected remaining life of CR3. Additional transmission costs should be amortized over a period not less than 40 years, consistent with the expected useful life of PEF's transmission facilities.

III. DOCKET NO 050078 SETTLEMENT

Q DID YOU PARTICIPATE IN DOCKET NO. 050078?

A Yes. I participated in this matter on behalf of FIPUG. Specifically I advised FIPUG on the relevant issues and supported the negotiations that ultimately resulted in the Stipulation and Settlement Agreement. Thus, I am familiar with the terms of the Agreement.

Q PLEASE EXPLAIN YOUR ASSERTION THAT PEF'S PROPOSED RECOVERY OF NUCLEAR UPRATE COSTS THROUGH THE FUEL CLAUSE WOULD BE A DIRECT VIOLATION OF THE DOCKET 050078 SETTLEMENT.

A The Agreement requires that PEF's base rates remain frozen through December 31, 2009 (or June 30, 2010, if PEF elects to extend the Agreement). Specifically it states that:

> "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 a 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." (*Stipulation and Settlement Agreement* at 4-5)

The proposed nuclear uprate costs are clearly those that would traditionally and historically be recovered in base rates. PEF may not circumvent the requirement by recovering base rate costs through the fuel clause. Further, as explained later, PEF's base rates already recover nuclear capacity-related costs. Thus, further recovery of these costs through the fuel clause would be double-recovery.

Q ARE THERE ANY EXCEPTIONS TO THE BASE RATE FREEZE PROVIDED FOR IN THE AGREEMENT?

A Yes, but none of those exceptions permit the recovery of CR3 uprate costs in fuel charges. The Agreement provides that PEF could petition the Commission for a base rate increase if its 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 earning surveillance report. Next, PEF could petition for a base rate increase in the event that it was unable to recover costs associated with any catastrophic storms. Finally, PEF was allowed, by the Commission approved settlement agreement, to adjust base rates to recover the full non-fuel cost of Hines Unit 4, and at the same time, it would be allowed to roll-in to Hines Unit 2's 2006 full revenue requirements (excluding non-fuel O&M expense) to base rates. This adjustment would occur when Hines Unit 4 begins commercial operation, which is currently planned for December 2007.

Q WHAT WERE SOME OF THE OTHER ASPECTS OF THE SETTLEMENT AGREEMENT?

A. The 2005 base rate case initiated by PEF sought a base rate increase of $206 million. After full discovery the Commission approved a settlement which added Hines Unit 3 into the rate base with no increase in rates. The settlement has apparently had no serious adverse impact on PEF. **Exhibit ___ (JP-1)** is a copy of PEF's Rate of Return report for the 12 months ended December 31, 2006. Referring to page 11, PEF had sufficient cash flow to pay $235 million in dividends to its parent public utility, add $734 million in new construction to its rate base from operating revenues, and have $123 million left over while still earning 11% after taxes on the equity component of its capital structure. It would be very difficult to characterize the nuclear uprate as an extraordinary circumstance giving rise to the need for new cash to preserve PEF's financial integrity.

Q IS PEF EARNING LESS THAN A 10% RETURN ON COMMON EQUITY FROM ITS RETAIL OPERATIONS?

A No. As can be seen in **Exhibit ____ (JP-1)**, PEF's earned return on common equity was 11.00% in 2006. Thus, PEF does not qualify for a base rate adjustment under the terms of the Stipulation in Docket No. 050078.

Q ARE ANY OF THE OTHER EXCEPTIONS THAT ALLOW PEF TO ADJUST BASE RATES RELEVANT?

A No. PEF could seek higher base rate recovery of costs associated with any catastrophic storms. However, this particular exception is not relevant to the issues in this proceeding. The other exceptions are to allow the recovery of Hines Unit 2 and Unit 4 costs when the latter unit begins commercial operation. I shall discuss the relevance of these further exceptions later in this testimony.

IV. FUEL CLAUSE RECOVERY IS IMPROPER

Q WHAT IS THE BASIS FOR YOUR ASSERTION THAT THE NUCLEAR UPRATE COSTS DO NOT QUALIFY FOR FUEL CLAUSE RECOVERY?

A First, the nuclear uprate costs are not fuel-related and they are not volatile. Specifically, the nuclear uprate costs consist of three capital components:

Power uprate	$250 million
Transmission system modifications	$ 89 million
Modification to address point of discharge (POD) issues	$ 43 million

Total $382 million

None of the above components are fuel-related costs as previously defined by the Commission. Fuel-related costs eligible for recovery through the fuel clause include:

1. The invoice price of fuel.
2. Any revisions to the invoice price.
3. Any quality and/or quantity adjustments to the invoice price.
4. Transportation costs to the utility's system, including detention or demurrage.
5. Federal and state taxes and purchasing agents' commissions.
6. Port charges.
7. All quantity and/or quality inspections performed by independent inspectors.
8. All additives blended with fuel prior to burning or injected into the boiler firing chamber along with fuel.
9. Inventory adjustments due to volume and/or price adjustments.
10. Fossil fuel-related costs normally recovered through base rates, but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on case-by-case basis after Commission approval. (*In re: Cost recovery Methods for Fuel-Related Expenses, Docket No. 0850001- EI-B; Order No. 14546* dated July 8, 1985.) The Commission also found that costs eligible for fuel clause recovery must be volatile. Clearly, capital investments associated with generation and transmission

capacity additions are not volatile.

Q WOULDN'T THE NUCLEAR UPRATE COSTS QUALIFY FOR FUEL COST RECOVERY UNDER ITEM 10 ABOVE?

A No. Clearly, the proposed modifications anticipated to the transmission system are only incidentally related to the uprate project itself. However, it is a mis-leading and inaccurate over-simplification to assert that the sole purpose of the CR3 power uprate project is to reduce fuel costs. In its April 2007 *Ten-Year Site Plan* PEF has included the CR3 power uprate project as capacity that will be used to provide a reasonable reserve margin. Thus, PEF forecasts that this additional capacity is needed.

Further, the Stipulation in Docket No. 050078 anticipated that PEF would continue to make substantial investments in new electric generation and other infrastructure, and that the Stipulation would mitigate the impact of high energy prices. Specifically, the Stipulation states:

> 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; (*Stipulation and Settlement Agreement* at 1).
>
> 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: (*Stipulation* and Settlement Agreement at 3).

Q PEF ASSERTS THAT THE CR3 POWER UPRATE PROJECT IS INNOVATIVE. DO YOU AGREE WITH PEF'S CHARACTERIZATION?

A No. Nuclear uprate projects are neither new nor innovative. As such, it is unnecessary to provide incentives, such as fuel clause recovery of the nuclear uprate capital costs, to encourage a utility to act in a prudent manner for the benefit of its ratepayers.

Q ARE NUCLEAR PLANT UPRATES NEW AND INNOVATIVE MEASURES?

A No. The Nuclear Regulatory Commission (NRC) published a report in June 2005 entitled, *Power Uprates for Nuclear Plants*. A copy of this report is enclosed as **Exhibit ____ (JP-2)**. As can be seen, the Report lists all of the nuclear uprate projects that the NRC has approved. As can be seen, the NRC has approved more than 100 uprates since 1977. This includes a 24 MW uprate of CR3 in 2002 (see Item 90). An additional 11 uprate projects are under review. Given that over 100 nuclear uprate projects have been approved, it would be misleading at best to claim that the pending CR3 uprate is new and innovative. For this reason, and because the settlement in Docket No. 050078 anticipated additional construction expenditures, PEF's request for fuel clause recovery should be denied.

V. DOUBLE-RECOVERY

Q YOU PREVIOUSLY STATED THAT THE PROPOSED FUEL CLAUSE RECOVERY OF THE CR3 POWER UPRATE PROJECT WOULD BE A DIRECT VIOLATION OF THE SETTLEMENT IN DOCKET NO. 050078. WOULD THAT STILL BE THE CASE, EVEN IF THE SPECIFIC CR3

POWER UPRATE-RELATED COSTS WERE NOT REFLECTED IN PEF'S BASE RATES?

A Yes. The Settlement does not require that nuclear uprate costs specifically be recognized in base rates as a condition for the base rate freeze. Specifically, it states that:

> "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." (Settlement and Stipulation Agreement at 4-5)

The CR3 power uprate costs are the same as other costs that PEF is currently recovering in base rates. For example, PEF is recovering a full return on and a return of the CR3 plant, which includes capitalized labor, equipment and cooling towers to dissipate the heat generated by the nuclear reactor. In addition, PEF's base rates also recover a return on and a return of transmission costs. Thus, all three components of the CR3 power uprate project are similar in nature to costs that PEF is currently recovering in its base rates. Any attempt to recover the same type of costs through the fuel clause would circumvent this specific provision of the rate case settlement and result in a double-recovery.

Q DOES IT NECESSARILY FOLLOW THAT, BECAUSE NUCLEAR UPRATE COSTS WERE NOT SPECIFICALLY CONSIDERED IN PEF'S 2005 BASE RATE CASE, PEF IS SOMEHOW NOT RECOVERING THEM THROUGH BASE RATES?

A No. The fact that a particular cost component may not have been specifically recognized in setting base rates does not mean that the utility is not recovering any new costs, such as the CR3 power uprate project.

Q PLEASE EXPLAIN

A A utility's base rates are set to recover non-fuel costs during a specific test year based on the amount of test year electricity sales. Base rate recovery includes equipment and labor costs, including both internal and third-party providers. However, once set, revenues and costs will change. Revenues will increase because of customer growth and higher sales. Capital additions will be made to serve that growing demand for electricity. However, these will be offset to some extent by the depreciation and retirement of existing investments. Operating expenses will also change. Some will increase while others will decrease.

To the extent that the company experiences sales growth, the additional sales will generate additional base revenue, thus offsetting further increases in base rate costs—such as the costs associated with projects that were not specifically recognized in the prior base rate case. This fundamental ratemaking principle is illustrated in **Exhibit____ (JP-3)**. This exhibit assumes that when base rates are set the utility has a base rate revenue requirement of $50,000 and electricity sales of 1,000 megawatthours (MWh). This results in an average base rate cost of $50 per MWh. Subsequent to the rate case, the utility's sales grow by 3%, from 1,000 MWh to 1,030 MWh. Because base rates are fixed at $50 per MWh, base rates generate $5,150. This is $1,500 above the level of base rate recovery assumed during the test year. In Year 2, the utility continues to experience a 3% growth in sales. This means it will recover

over $3,000 of additional base rate costs not otherwise reflected in the test year—when the utility's base rates were last set.

Thus, the application of fundamental ratemaking principles clearly demonstrates that a utility can recover increased base rate costs without the need for separate cost recovery. Because nuclear uprate costs are no different than the costs that were used to set PEF's current base rates, and because PEF is selling more electricity than during the test year in its last rate case, and recognizing PEF's recent earnings, allowing PEF to collect CR3 nuclear uprate project costs through the fuel clause would result in a double-recovery.

Q WOULD REJECTING PEF'S PROPOSAL TO COLLECT NUCLEAR UPRATE COSTS THROUGH THE FUEL CLAUSE DENY PEF THE OPPORTUNITY TO RECOVER NUCLEAR UPRATE COSTS?

A No. Given the ratemaking dynamics as discussed earlier, there is no rational basis to assert that piecemeal recovery (through the fuel clause) of particular new investments (e.g., CR3 nuclear uprate costs) is needed to allow a utility to recover these costs.

Q DO YOU HAVE ANY PEF-SPECIFIC EXAMPLES WHERE ADDITIONAL INVESTMENT WAS ADDED WITHOUT THE NEED TO IMPLEMENT HIGHER RATES?

A Yes. The Settlement and Stipulation in the 2005 rate case contemplated both sales and revenue growth and continuing rate base investment to serve the growing load. Acknowledging these terms, PEF agreed to continue the existing base rates despite the many additions to rate base, such as Hines Unit 3, that had occurred since the prior case. Despite the additional investments, PEF's actual ROE was still above the 10% ROE floor. This clearly demonstrates that PEF has sufficient revenues to recover nuclear uprate costs without fuel clause recovery.

Further, PEF will have more than ample cost recovery due to the ratemaking treatment of Hines Units 2 and 4. As previously stated, Hines Unit 2 will be rolled-in to base rates at its 2006 cost of service, while Hines Unit 4 will be rolled-in to base rates at 100% of its cost of service on its commercial operation date, which is estimated to occur this December. However, between 2006 and 2008, when Hines Unit 2 costs would be reflected in base rates, PEF will have depreciated a portion of Unit 2 investment, thereby reducing the associated revenue requirement. By holding base rates constant while reducing the revenue requirement, PEF will generate additional margins, which can be used to offset higher costs. A similar benefit will be realized with Hines Unit 4 after it begins commercial operation.

Given the dynamics of ratemaking and these specific facts applicable to PEF, PEF does not need a "piecemeal" rate increase to recover nuclear uprate costs just because they were incurred subsequent to its last rate case. If PEF is unable to earn at least a 10% ROE, then the door is open to a base rate adjustment. Further, PEF will have an opportunity to seek cost recovery after the termination of the base rate freeze. Most of the costs will be incurred after 2010.

VI. PEF'S PROPOSED COST RECOVERY IS IMPROPER

Q PLEASE EXPLAIN WHY PEF'S PROPOSED COST RECOVERY OF CR3 NUCLEAR UPRATE PROJECT COSTS IS IMPROPER.

A First, all of the proposed uprate costs are fixed costs and relate directly to the rated capacity of the nuclear unit. Thus, they are properly considered demand-related costs. Demand-related costs should be allocated and recovered on a demand basis under all accepted conventions of cost causation, cost of service ratemaking, and long standing Commission practice.

PEF is proposing to recover these costs through the fuel clause. Under the fuel clause, costs are recovered relative to loss-adjusted MWh sales. In effect, this would allocate demand-related costs on an all energy basis. Such an approach is improper because it would shift cost responsibility among customer classes that is inconsistent with basic cost causation principles. Further, it would be inconsistent with PEF's allocation of other nuclear and transmission base rate costs, which are allocated among customer classes on a demand basis. The second reason for rejecting PEF's cost recovery proposal is that it proposes to amortize the CR3 nuclear uprate project costs over 10 years. However, despite the 10-year amortization period, the company is projecting fuel savings through 2036, or 28 years. This claim assumes that the Company will be successful at extending the life of CR3 to 2036. PEF admits (in response to OPC's 1st set of Interrogatories 5, 7 and 8) that the MUR modification, the transmission upgrades, and the cooling towers are designed for the extended life of the plant. Thus, it would be fundamentally improper to allow PEF to recover capital costs over 10 years for plant investment and related capacity that will be in service through 2036 because it would require current ratepayers to subsidize investments that will benefit ratepayers well into the future. These capital costs should be recovered over the expected remaining life of the assets.

Q PLEASE EXPLAIN HOW FUEL CLAUSE RECOVERY OF CR3 NUCLEAR UPRATE COSTS WOULD RESULT IN IMPROPER COST SHIFTING BETWEEN CUSTOMER CLASSES.

A Nuclear base rate costs are allocated to customer classes using a methodology which reflects primarily the coincident peak demands of the different classes. Specifically, PEF uses the Twelve Coincident Peak and One-Thirteenth Average Demand (12CP&1/13th AD) method to allocate nuclear base rate costs. This is the same method PEF uses to allocate all production demand-related costs. **Exhibit ___ (JP-4)** (which is an excerpt from PEF's CCRC filing in Docket No. 060001-EI) comparison between the demand allocation factors (column 10) and the energy corresponding allocation factors if nuclear uprate costs were recovered through the demand fuel clause (shown in column 8 under Annual Average Demand). As can be seen, the demand allocation factors are significantly different than the energy allocation factors, for all customer classes. The differences 16% (for the General Service Demand Class) to 83% (for the Lighting Class). Thus, fuel clause recovery would not be consistent with the cost-causation that is reflected in PEF's demand allocation method. PEF's fuel clause recovery proposal would create significant and inappropriate shifts in the cost responsibility of all customer classes.

Q DOES THE COMMISSION DIFFERENTIATE BETWEEN THE ALLOCATION OF NUCLEAR BASE RATE COSTS AND OTHER

TYPES OF PRODUCTION DEMAND-RELATED COSTS?

A No. The Commission has previously authorized the recovery of post-9/11 security measures through the Capacity Cost Recovery Clause (CCRC). Under the CCRC, these costs are allocated in the same manner as all other production base rate costs; that is, using the allocation methodology previously approved in the utility's most recent base rate case.

In addition, the Commission recently adopted a new rule authorizing the recovery of pre-construction and construction costs of new nuclear plants. Under this new rule, pre-construction and construction costs of new nuclear plants would be recovered through the CCRC. (Docket No. 060508-EI - Proposed Adoption of New Rule Regarding Nuclear Power Plant Cost Recovery.) This rule was adopted on March 20, 2007 and became effective April 8, 2007.

There is no justification to treat nuclear uprate costs any differently than all other nuclear base rate costs. Because recovery through the fuel clause would unnecessarily shift cost responsibility by customer class and would be inconsistent with the Commission's treatment of post-9/11 security costs and nuclear pre-construction and construction costs, PEF's proposal should be rejected.

Q WHY ELSE IS IT INAPPROPRIATE TO RECOVER NUCLEAR BASE RATE COSTS ON THE BASIS OF LOSS-ADJUSTED SALES?

A As previously stated, the capacity of the proposal uprate is needed to enable PEF to meet its projected peak demands and to provide appropriate reserve margins. Thus, this cost should be treated no differently than any other production demand-related costs.

Q PEF ASSERTS THAT THE NUCLEAR UPRATE COSTS WILL SAVE FUEL COSTS. IS THIS A REASON FOR RECOVERING THE NUCLEAR UPRATE COSTS THROUGH THE FUEL CLAUSE?

A No. The concept of allocating base rate costs (which are traditionally allocated using a demand-based cost allocation method) on the basis of fuel savings has not only been rejected by the utility that originally proposed such an allocation, but it has also been rejected by the Commission.

Specifically, Florida Power and Light Company (FPL) initially allocated its investment in St. Lucie Unit 2 relative to loss-adjusted kWh sales on the grounds that the unit would produce substantial fuel savings. However, in its last base rate case (Docket No. 050045-EI), FPL rejected that approach and allocated the St. Lucie 2 base rate costs using the same methodology as all other production demand-related costs. (Docket No. 050045-EI, *Testimony of Rosemary Morley* at 17-18.)

This Commission has also rejected the concept of allocating production demand-related costs relative to fuel savings. This was the premise underlying the Equivalent Peaker (EP) method of allocation. Under the EP method, capital costs in excess of the cost of a combustion turbine were assumed to be related to fuel cost savings and thus, were allocated on energy. However, in Docket No 891345-EI, the Commission stated that:

> "The equivalent peaker method implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours beyond the break-even point. (Gulf

Power Company, Order. No. 234573 at 48)".

In other words, the Commission recognized that the extra plant costs associated with generating units that provide fuel cost savings is at odds with the planning process because all production from a specific plant (i.e., kWh sales) is not the critical factor in deciding what type of capability to install.

Q WHY ELSE SHOULD THE COMPANY'S COST RECOVERY PROPOSAL BE REJECTED?

A PEF concedes that the nuclear uprate costs will last for the duration of the extended life of CR3, which is projected to have a 28 year remaining useful life. This assumes that the company is successful in extending the life of CR3 to 2036. Thus, its proposal to recover these costs over just 10 years would fail to match the costs of the nuclear uprate project with the associated life long benefits. The mismatch would be even more severe with the projected transmission upgrades. Transmission investments typically have useful lives ranging from 40 to 58 years. Thus, by accelerating cost recovery to only 10 years, current ratepayers would be paying the entirety of the costs while the vast majority of benefits would inure to future ratepayers (for an additional 18 years). The failure to match the recovery of the costs with the benefits, thus, would create intergenerational inequities and should be rejected.

Q WHAT CONSIDERATION HAS PEF GIVEN TO THE FACT THAT CR3 IS JOINTLY OWNED WITH SEVERAL MUNICIPALITIES?

A PEF witness, Mr. Waters, acknowledges at page 6 of his testimony that actually the CR3 capacity dedicated to retail service is 788 MW not the

900 MW alleged in the petition. In other words, retail customers are responsible for approximately 88% of the CR3 capacity. Nevertheless, PEF is proposing to recover 100% of the CR3 uprate costs from retail customers. In his deposition, Mr. Waters indicated that the issue of participation by the other CR3 owners had not yet been resolved.

Q IF THE COMMISSION WERE TO ALLOW PEF TO RECOVER CR3 NUCLEAR UPRATE PROJECT COSTS THROUGH A SEPARATE COST RECOVERY MECHANISM, HOW SHOULD PEF'S PROPOSAL BE MODIFIED?

A If the Commission, nevertheless, approves PEF'S request for a separate cost recovery of CR3 nuclear uprate costs, then its proposal should be modified in several respects. First, the nuclear uprate costs should be amortized over the remaining useful life of CR3. This would property match the cost recovery with the associated benefits, which are projected to occur through 2036. Regardless of the treatment accorded to the nuclear uprate and POD costs, transmission costs should be amortized over a period not less than 40 years, consistent with the useful life of transmission facilities. Second, only the portion of CR3 costs allocable to retail customers should be collected. Finally, consistent with this Commission's treatment of other nuclear-related base rate costs, recovery should be through the CCRC, rather than the fuel clause. This would provide a more appropriate allocation of these cost-shifting among PEF's various customer classes.

Q DOES THE CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is, 12655 Olive Blvd, Suite 335, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J.Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and in 2 Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J.POLLOCK, INCORPORATED.

A J.Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J.Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial, and institutional energy consumers. Currently, J.Pollock has offices in St. Louis, Missouri and Austin, Texas.

Progress Energy

February 14, 2007

Mr. John Slemkewicz,
Public Utility Supervisor
Electric and Gas Accounting Section
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Dear Mr. Slemkewicz:

Pursuant to Commission Rule 25-6.1352, enclosed please find Progress Energy Florida, Inc.'s Rate of Return report for the twelve months ended December 31, 2006.

The report includes the Company's actual rate of return computed on an end-of-period rate base, the Company's adjusted rate of return computed on an average rate base, the Company's end-of-period required rates of return, and certain financial integrity indicators for the twelve months ended December 31, 2006. The separation factors used for the jurisdictional amounts were developed from the cost of service prepared in compliance with the stipulation and settlement agreement approved in Docket No. 050078-EI, Order No. PSC-05-0945-S-EI.

This report also includes Schedule 6, the supplemental information associated with the Sebring rider as required by the FPSC in Docket No. 920949-EU, Order No. 92-1468-FOF-EI, and as modified by Docket No. 930868-EI, Order No. PSC-93-1519-FOF-EI.

If you have any questions, please feel free to contact Cindy Lee at (727) 820-5535.

Sincerely,

Will Garrett

Will Garrett
Controller, Progress Energy Florida

dc
Attachment
xc: Mr. Harold McLean, Office of the Public Counsel

	(1) Actual Per Books	(2) FPSC Adjustments	(3) FPSC Adjusted	(4) Pro Forma Adjustments	(5) Pro Forma Adjusted
I. Average Rate of Return (Jurisdictional)					
Net Operating Income (a) (b)	$412,261,757	($41,238,497)	$371,023,261	$0	$371,023,261
Average Rate Base	$4,587,753,119	($235,950,825)	$4,351,802,294	$0	$4,351,802,294
Average Rate of Return	8.99%		8.53%		8.53%
II. Year End Rate of Return (Jurisdictional)					
Net Operating Income	$412,261,757	($41,238,497)	$371,023,261	$0	$371,023,261
Year End Rate Base	$4,762,106,993	($389,004,469)	$4,373,102,524	$0	$4,373,102,524
Year End Rate of Return	8.66%		8.48%		8.48%

Footnotes
(a) Column (1) includes AFUDC earnings.
(b) Column (2) includes reversal of AFUDC earnings.

III. Required Rates of Return	Average Capital Structure	End of Period Capital Structure
FPSC Adjusted Basis		
Low Point	8.38%	8.42%
Mid Point	8.98%	9.04%
High Point	9.58%	9.65%
Pro Forma Adjusted Basis		
Low Point	8.38%	8.42%
Mid Point	8.98%	9.04%
High Point	9.58%	9.65%

IV. FINANCIAL INTEGRITY INDICATORS		
A. T.I.E. with AFUDC	5.62	(System Per Books Basis)
B. T.I.E. without AFUDC	5.48	(System Per Books Basis)
C. AFUDC to Net Income	6.70%	(System Per Books Basis)
D. Internally Generated Funds	118.07%	(System Per Books Basis)
E. STD/LTD to Total Investor Funds		
LT Debt-Fixed to Total Investor Funds	32.75%	(FPSC Adjusted Basis)
ST Debt to Total Investor Funds	0.00%	(FPSC Adjusted Basis)
F. Return on Common Equity	11.00%	(FPSC Adjusted Basis)
	11.00%	(Pro Forma Adjusted Basis)
G. Current Allowed AFUDC Rate	8.85%	Docket 050078-EI Order PSC-05-0945-S-EI

I am aware that Section 837-06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

Will Garrett

Will Garrett, Controller Progress Energy Florida

2-14-07

Date

ROGRESS ENERGY FLORIDA
/erage Rate of Return - Rate Base
ecember 2006

	Plant in Service	Accum Depr & Amort	Net Plant in Service	Future Use & Appd Unrecov Plant	Const Work in Progress	Nuclear Fuel (Net)	Net Utility Plant	Working Capital	Total Average Rate Base
stem Per Books	$8,937,593,885	$4,261,567,212	$4,676,026,672	$9,046,653	$517,484,715	$65,427,615	$5,267,985,655	$21,355,957	$5,289,341,612
ss Recoverable:									
ARO	10,906,932	(22,104,148)	33,011,080	0	0	0	33,011,080	(378,098,125)	(345,087,045)
ECCR	49,419	25,669	23,749	0	16,426	0	40,175	(8,547,435)	(8,507,260)
ECRC	3,005,530	149,554	2,855,976	0	11,130,036	0	13,986,013	8,258,825	22,244,838
FUEL	282,818,047	50,068,828	232,749,219	0	0	0	232,749,219	183,638,210	416,387,429
SCRC	0	0	0	0	0	0	0	134,285,504	134,285,504
Regulatory Base - System	$8,640,813,956	$4,233,427,309	$4,407,386,647	$9,046,653	$506,338,252	$65,427,615	$4,988,199,167	$81,818,979	$5,070,018,146
Regulatory Base - Retail	$7,921,788,092	$3,924,782,247	$3,997,005,845	$6,851,795	$454,935,490	$63,032,671	$4,521,825,800	$65,927,319	$4,587,753,119
SC Adjustments									
CWIP - AFUDC	0	0	0	0	(237,359,872)	0	(237,359,872)	0	(237,359,872)
GAIN/LOSS ON SALE OF PLANT	0	0	0	0	0	0	0	(2,264,364)	(2,264,364)
CAPITAL LEASE	(4,181,826)	0	(4,181,826)	0	0	0	(4,181,826)	4,181,826	(0)
IUC DECOM UNFUNDED - WHOLESALE	0	(2,286,276)	2,286,276	0	0	0	2,286,276	0	2,286,276
ITO START UP COSTS	0	0	0	0	0	0	0	93,703	93,703
ECTION 1341 INC TAX ADJUSTMENT	0	0	0	0	0	0	0	1,293,432	1,293,432
Total FPSC Adjustments	(4,181,826)	(2,286,276)	(1,895,550)	0	(237,359,872)	0	(239,255,422)	3,304,597	(235,950,825)
FPSC Adjusted	$7,917,606,266	$3,922,495,971	$3,995,110,295	$6,851,795	$217,575,618	$63,032,671	$4,282,570,378	$69,231,915	$4,351,802,294

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 4 of 15

OGRESS ENERGY FLORIDA
erage Rate of Return - Income Statement
cember 2006

Schedule 2
Page 2 of 3

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
tem Per Books (a)	$4,560,623,120	$2,530,408,291	$675,343,794	$403,781,163	$309,074,331	$237,704,366	($41,675,714)	($6,410,000)	$0	$4,108,226,231	$452,396,889
s Recoverable:											
ARO	0	0	0	(3,324)	0	0	(41,000)	0	0	(44,324)	44,324
ECCR	60,879,845	0	61,159,893	9,884	15,632	639,294	(757,165)	0	0	61,067,537	(187,692)
ECRC	23,287,033	0	22,855,612	164,160	16,767	96,628	0	0	0	23,133,167	153,866
FUEL	2,545,554,024	2,499,587,326	0	9,006,611	1,748,311	13,582,865	0	0	0	2,523,925,314	21,628,710
SCRC	122,445,779	0	0	122,357,617	0	34,008	0	0	0	122,391,625	54,154
Regulatory Base - System	$1,808,456,439	$30,820,965	$591,328,290	$272,246,015	$307,293,621	$223,351,570	($40,877,549)	($6,410,000)	$0	$1,377,752,912	$430,703,527
Regulatory Base - Retail	$1,648,480,434	$6,329,237	$541,123,476	$249,315,284	$298,425,089	$203,740,235	($37,576,812)	($5,892,838)	$0	$1,255,463,669	$393,016,765
C Adjustments											
ORPORATE AIRCRAFT ALLOCATION	0	0	(668,934)	0	0	258,041	0	0	0	(410,892)	410,892
RANCHISE FEE & GROSS REC TAX REVENUE	(200,515,907)	0	0	0	0	(77,349,011)	0	0	0	(77,349,011)	(123,166,896)
RANCHISE FEES & GROSS REC TAX - TOI	0	0	0	0	(198,830,948)	76,699,038	0	0	0	(122,131,910)	122,131,910
AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	355,660	0	0	(921,995)	(566,335)	566,335
IST./PROMOTIONAL ADVERTISING	0	0	(2,460,994)	0	0	949,328	0	0	0	(1,511,665)	1,511,665
ITEREST ON TAX DEFICIENCY	0	0	(329,843)	0	0	127,237	0	0	0	(202,606)	202,606
IISCELLANEOUS INTEREST EXPENSE	0	0	75,155	0	0	(28,991)	0	0	0	46,164	(46,164)
EMOVE ASSOC/ORGANIZATION DUES	0	0	(70,367)	0	0	27,144	0	0	0	(43,223)	43,223
EMOVE DEFERRED TAX AFUDC DEBT	0	0	0	0	0	0	7,316	0	0	7,316	(7,316)
EMOVE ECONOMIC DEVELOPMENT	0	0	(25,827)	0	0	9,963	0	0	0	(15,864)	15,864
EVENUE SHARING	0	0	0	0	0	0	0	0	0	0	0
TO START UP COSTS	0	0	1,001	0	0	(386)	0	0	0	615	(615)
EBRING - RIDER REVENUE	(3,769,894)	0	0	0	0	(1,454,237)	0	0	0	(1,454,237)	(2,315,657)
EBRING - TRANSITION DEPRECIATION	0	0	0	(3,371,989)	0	1,300,745	0	0	0	(2,071,244)	2,071,244
TORM COSTS - 2004			0			0				0	0
ITEREST SYNCHRONIZATION - FPSC	0	0	0	0	0	23,410,597	0	0	0	23,410,597	(23,410,597)
Total FPSC Adjustments	(204,285,801)	0	(3,479,818)	(3,371,989)	(198,830,948)	24,305,129	7,316	0	(921,995)	(182,292,297)	(21,993,504)
FPSC Adjusted	$1,444,194,633	$6,329,237	$537,643,666	$245,943,295	$99,594,141	$228,045,364	($37,569,496)	($5,892,838)	($921,995)	$1,073,171,373	$371,023,261

notes:

(a) The addition of earnings from AFUDC charges would increase the system NOI by $21,891,699
and Jurisdictional NOI by $19,244,992

rent Month

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
em Per Books											
Excluding AFUDC Earnings and Recoverable	$135,478,356	$2,872,723	$52,309,390	$25,109,767	$19,635,082	$17,071,516	($3,449,194)	($965,000)	$0	$112,584,285	$22,894,070
idictional Per Books											
Excluding AFUDC Earnings and Recoverable	$130,846,993	$570,029	$48,129,253	$22,395,536	$19,210,959	$18,611,562	($3,170,682)	($887,143)	$0	$104,859,515	$25,987,478

OGRESS ENERGY FLORIDA
erage Rate of Return - Adjustments
cember 2006

lotes	Rate Base Adjustments	P=Pro Forma F=FPSC	System	Retail
(1)	CWIP - AFUDC	F	($269,944,276)	($237,359,872)
(1)	GAIN/LOSS ON SALE OF PLANT	F	(2,152,235)	(2,264,364)
(2)	CAPITAL LEASE-EPS	F	(4,181,826)	(4,181,826)
(2)	CAPITAL LEASE-WORKING CAPITAL	F	4,181,826	4,181,826
(1)	NUC. DECOM. UNFUNDED - WHOLESALE	F	2,286,276	2,286,276
(2)	RTO START UP COSTS	F	100,452	93,703
(1)	SECTION 1341 INC TAX ADJUSTMENT	F	1,407,470	1,293,432
	Total		($268,302,313)	($235,950,825)

			System		Retail	
otes	Income Statement Adjustments (to NOI)	P=Pro Forma F=FPSC	Amount	Income Tax Effect	Amount	Income Tax Effect
(2)	CORPORATE AIRCRAFT ALLOCATION	F	($743,438)	$286,781	($668,934)	$258,041
(1)	FRANCHISE FEE. & GROSS REC TAX REVENUE	F	200,515,907	(77,349,011)	200,515,907	(77,349,011)
(1)	FRANCHISE FEES & GROSS REC TAX - TOI	F	(198,830,948)	76,699,038	(198,830,948)	76,699,038
(1)	GAIN/LOSS ON SALE OF PLANT	F	(1,043,318)	402,460	(921,995)	355,660
(1)	INST./PROMOTIONAL ADVERTISING	F	(2,700,663)	1,041,781	(2,460,994)	949,328
(1)	INTEREST ON TAX DEFICIENCY	F	(361,966)	139,628	(329,843)	127,237
(1)	MISCELLANEOUS INTEREST EXPENSE	F	572,046	(220,667)	75,155	(28,991)
(1)	REMOVE ASSOC/ORGANIZATION DUES	F	(77,220)	29,788	(70,367)	27,144
(1)	REMOVE DEFERRED TAX AFUDC DEBT	F	0	8,000	0	7,316
(1)	REMOVE ECONOMIC DEVELOPMENT	F	(28,342)	10,933	(25,827)	9,963
(2)	REVENUE SHARING	F	0	0	0	0
(2)	RTO START UP COSTS	F	1,404	(542)	1,001	(386)
(1)	SEBRING - RIDER REVENUE	F	3,769,894	(1,454,237)	3,769,894	(1,454,237)
(1)	SEBRING - TRANSITION DEPRECIATION	F	(3,371,989)	1,300,745	(3,371,989)	1,300,745
	STORM COSTS 2004	F	0	0	0	0
(1)	INTEREST SYNCHRONIZATION - FPSC	F	0	25,830,915	0	23,410,597
	Total		($2,298,633)	$26,725,613	($2,318,940)	$24,312,445

es: (1) Docket No. 910890-EI, Order No. PSC 92-0208-FOF-EI
(2) N/A

OGRESS ENERGY FLORIDA
d of Period Rate of Return - Rate Base
cember 2006

	Plant In Service	Accum Depr & Amort	Net Plant In Service	Future Use & Appd Unrecov Plant	Const Work In Progress	Nuclear Fuel (Net)	Net Utility Plant	Working Capital	Total Period End Rate Base
tem Per Books	$9,225,480,896	$4,339,981,105	$4,885,499,791	$7,422,007	$641,485,881	$58,409,362	$5,592,817,041	$21,355,957	$5,614,172,998
s Recoverable:									
ARO	10,906,932	(22,088,037)	32,994,969	0	0	0	32,994,969	(378,098,125)	(345,103,156)
ECCR	49,419	27,001	22,418	0	112,155	0	134,573	(8,547,435)	(8,412,863)
ECRC	3,698,169	143,598	3,554,571	0	30,248,528	0	33,803,098	8,258,825	42,061,923
FUEL	286,837,855	57,616,067	229,221,788	0	0	0	229,221,788	183,638,210	412,859,998
SCRC	0	0	0	0	0	0	0	134,285,504	134,285,504
Regulatory Base - System	$8,923,988,523	$4,304,282,476	$4,619,706,046	$7,422,007	$611,125,198	$58,409,362	$5,296,662,613	$81,818,979	$5,378,481,592
Regulatory Base - Retail	$8,115,847,278	$4,041,610,316	$4,074,236,962	$5,621,313	$560,042,428	$56,278,971	$4,696,179,674	$65,927,319	$4,762,106,993
;C Adjustments									
:WIP - AFUDC	0	0	0	0	(390,413,515)	0	(390,413,515)	0	(390,413,515)
;AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	0	0	(2,264,364)	(2,264,364)
CAPITAL LEASE	(54,363,739)	0	(54,363,739)	0	0	0	(54,363,739)	54,363,739	(0)
IUC. DECOM. UNFUNDED - WHOLESALE	0	(2,286,276)	2,286,276	0	0	0	2,286,276	0	2,286,276
:TO START UP COSTS	0	0	0	0	0	0	0	93,703	93,703
;ECTION 1341 INC TAX ADJUSTMENT	0	0	0	0	0	0	0	1,293,432	1,293,432
Total FPSC Adjustments	(54,363,739)	(2,286,276)	(52,077,463)	0	(390,413,515)	0	(442,490,978)	53,486,509	(389,004,469)
FPSC Adjusted	$8,061,483,539	$4,039,324,040	$4,022,159,499	$5,621,313	$169,628,913	$56,278,971	$4,253,688,696	$119,413,828	$4,373,102,524

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 6 of 15

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 7 of 15

ɔGRESS ENERGY FLORIDA
ǀ of Period - Income Statement
ːember 2006

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
om Per Books (a)	$4,560,623,120	$2,530,408,291	$675,343,794	$403,781,163	$309,074,331	$237,704,366	($41,675,714)	($6,410,000)	$0	$4,106,226,231	$452,396,889
ː Recoverable:											
ARO	0	0	0	(3,324)	0	0	(41,000)	0	0	(44,324)	44,324
ECCR	60,879,845	0	61,159,893	9,884	15,632	639,294	(757,165)	0	0	61,067,537	(187,692)
ECRC	23,287,033	0	22,855,612	164,160	16,767	96,628	0	0	0	23,133,167	153,866
FUEL	2,545,554,024	2,499,587,326	0	9,006,811	1,748,311	13,582,865	0	0	0	2,523,925,314	21,628,710
SCRC	122,445,779	0	0	122,357,617	0	34,008	0	0	0	122,391,625	54,154
Regulatory Base - System	$1,808,456,439	$30,820,965	$591,328,290	$272,246,015	$307,293,621	$223,351,570	($40,877,549)	($6,410,000)	$0	$1,377,752,912	$430,703,527
Regulatory Base - Retail	$1,648,480,434	$6,329,237	$541,123,476	$249,315,284	$298,425,089	$203,740,235	($37,576,812)	($5,892,838)	$0	$1,255,463,669	$393,016,765
ꞇ Adjustments											
ɔRPORATE AIRCRAFT ALLOCATION	0	0	(668,934)	0	0	258,041	0	0	0	(410,892)	410,892
ʀANCHISE FEE & GROSS REC TAX REVENUE	(200,515,907)	0	0	0	0	(77,349,011)	0	0	0	(77,349,011)	(123,166,896)
ʀANCHISE FEES & GROSS REC TAX - TOI	0	0	0	0	(198,830,948)	76,699,038	0	0	0	(122,131,910)	122,131,910
AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	355,660	0	0	(921,995)	(566,335)	566,335
ST./PROMOTIONAL ADVERTISING	0	0	(2,460,994)	0	0	949,328	0	0	0	(1,511,665)	1,511,665
TEREST ON TAX DEFICIENCY	0	0	(329,843)	0	0	127,237	0	0	0	(202,606)	202,606
ISCELLANEOUS INTEREST EXPENSE	0	0	75,155	0	0	(28,991)	0	0	0	46,164	(46,164)
EMOVE ASSOC/ORGANIZATION DUES	0	0	(70,367)	0	0	27,144	0	0	0	(43,223)	43,223
EMOVE DEFERRED TAX AFUDC DEBT	0	0	0	0	0	0	7,316	0	0	7,316	(7,316)
EMOVE ECONOMIC DEVELOPMENT	0	0	(25,827)	0	0	9,963	0	0	0	(15,864)	15,864
EVENUE SHARING	0	0	0	0	0	0	0	0	0	0	0
TO START UP COSTS	0	0	1,001	0	0	(386)	0	0	0	615	(615)
EBRING - RIDER REVENUE	(3,769,894)	0	0	0	0	(1,454,237)	0	0	0	(1,454,237)	(2,315,657)
EBRING - TRANSITION DEPRECIATION	0	0	0	(3,371,989)	0	1,300,745	0	0	0	(2,071,244)	2,071,244
TORM COSTS - 2004			0			0				0	0
ITEREST SYNCHRONIZATION - FPSC	0	0	0	0	0	23,410,597	0	0	0	23,410,597	(23,410,597)
Total FPSC Adjustments	(204,285,801)	0	(3,479,810)	(3,371,989)	(198,830,948)	24,305,129	7,316	0	(921,995)	(182,292,297)	(21,993,504)
FPSC Adjusted	$1,444,194,633	$6,329,237	$537,643,666	$245,943,295	$99,594,141	$228,045,364	($37,569,496)	($5,892,838)	($921,995)	$1,073,171,373	$371,023,261

notes:

(a) The addition of earnings from AFUDC charges would increase the system NOI by $21,891,699
and Jurisdictional NOI by $19,244,992

ROGRESS ENERGY FLORIDA
nd of Period Rate of Return - Adjustments
ecember 2006

Notes	Rate Base Adjustments	P=Pro Forma F=FPSC	System	Retail
(1)	CWIP - AFUDC	F	($448,161,874)	($390,413,515)
(1)	GAIN/LOSS ON SALE OF PLANT	F	(2,152,235)	(2,264,364)
(2)	CAPITAL LEASE	F	(54,363,739)	(54,363,739)
(2)	CAPITAL LEASE	F	54,363,739	54,363,739
(1)	NUC. DECOM. UNFUNDED - WHOLESALE	F	2,286,276	2,286,276
(2)	RTO START UP COSTS	F	100,452	93,703
(1)	SECTION 1341 INC TAX ADJUSTMENT	F	1,407,470	1,293,432
	Total		($446,519,912)	($389,004,469)

			System		Retail	
lotes	Income Statement Adjustments (to NOI)	P=Pro Forma F=FPSC	Amount	Income Tax Effect	Amount	Income Tax Effect
(2)	CORPORATE AIRCRAFT ALLOCATION	F	($743,438)	$286,781	($668,934)	$258,041
(1)	FRANCHISE FEE & GROSS REC TAX REVENUE	F	200,515,907	(77,349,011)	200,515,907	(77,349,011)
(1)	FRANCHISE FEES & GROSS REC TAX - TOI	F	(198,830,948)	76,699,038	(198,830,948)	76,699,038
(1)	GAIN/LOSS ON SALE OF PLANT	F	(1,043,318)	402,460	(921,995)	355,660
(1)	INST./PROMOTIONAL ADVERTISING	F	(2,700,663)	1,041,781	(2,460,994)	949,328
(1)	INTEREST ON TAX DEFICIENCY	F	(361,966)	139,628	(329,843)	127,237
(1)	MISCELLANEOUS INTEREST EXPENSE	F	572,046	(220,667)	75,155	(28,991)
(1)	REMOVE ASSOC/ORGANIZATION DUES	F	(77,220)	29,788	(70,367)	27,144
(1)	REMOVE DEFERRED TAX AFUDC DEBT	F	0	8,000	0	7,316
(1)	REMOVE ECONOMIC DEVELOPMENT	F	(28,342)	10,933	(25,827)	9,963
(2)	REVENUE SHARING	F	0	0	0	0
(2)	RTO START UP COSTS	F	1,404	(542)	1,001	(386)
(1)	SEBRING - RIDER REVENUE	F	3,769,894	(1,454,237)	3,769,894	(1,454,237)
(1)	SEBRING - TRANSITION DEPRECIATION	F	(3,371,989)	1,300,745	(3,371,989)	1,300,745
	STORM COSTS 2004	F	0	0	0	0
(1)	INTEREST SYNCHRONIZATION - FPSC	F	0	25,830,915	0	23,410,597
	Total		($2,298,633)	$26,725,613	($2,318,940)	$24,312,445

es (1) Docket No. 910890-EI, Order No. PSC 92-0208-FOF-EI
(2) N/A

ROGRESS ENERGY FLORIDA
verage Rate of Return - Capital Structure
ro Forma Adjusted Basis
ecember 2006

Schedule 4
Page 1 of 4

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio	Low Point Cost Rate	Low Point Weighted Cost	Mid Point Cost Rate	Mid Point Weighted Cost	High Point Cost Rate	High Point Weighted Cost
ommon Equity	$2,633,063,251	$2,138,567,182	($553,271,829)	$1,040,820,380	$2,626,115,733	60.35% ***	10.75%	6.49%	11.75%	7.09%	12.75%	7.69%
eferred Stock	33,496,700	27,205,933	(7,242,830)	0	19,963,104	0.46%	4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ng Term Debt - Fixed	2,532,888,290	2,057,205,337	(547,674,194)	(220,846,764)	1,288,684,378	29.61%	5.74%	1.70%	5.74%	1.70%	5.74%	1.70%
ort Term Debt *	(74,286,975)	(60,335,690)		60,335,690	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
stomer Deposits												
Active	150,338,406	122,104,466	(32,506,947)	0	89,597,519	2.06%	6.21%	0.13%	6.21%	0.13%	6.21%	0.13%
Inactive	686,568	557,629	(148,453)	0	409,176	0.01%						
vestment Tax Credit												
Post '70 Total	26,895,584	21,844,524	(5,815,502)									
Equity **					10,779,316	0.25%	10.70%	0.03%	11.69%	0.03%	12.68%	0.03%
Debt **					5,249,706	0.12%	5.74%	0.01%	5.74%	0.01%	5.74%	0.01%
ferred Income Taxes	406,707,668	330,326,919	(87,940,434)	107,478,530	349,865,015	8.04%						
S 109 DIT - Net	(61,220,561)	(49,723,182)	13,237,426	(2,375,898)	(38,861,654)	-0.89%						
Total	$5,648,568,933	$4,587,753,119	($1,221,362,763)	$985,411,938	$4,351,802,294	100.00%		8.38%		8.98%		9.58%

aily Weighted Average
ost Rates Calculated Per IRS Ruling
Equity Ratio Including Debt Associated With Qualifying Facilities Contracts (Based on FPSC Capital Structure) 53.97%
Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 9 of 15

ROGRESS ENERGY FLORIDA
nd of Period - Capital Structure
ro Forma Adjusted Basis
ecember 2006

Schedule 4
Page 2 of 4

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio	Low Point		Mid Point		High Point	
							Cost Rate	Weighted Cost	Cost Rate	Weighted Cost	Cost Rate	Weighted Cost
mmon Equity	$2,682,292,656	$2,212,890,214	($603,970,786)	$1,040,820,380	$2,649,739,808	60.59% ***	10.75%	6.51%	11.75%	7.12%	12.75%	7.73%
eferred Stock	33,496,700	27,634,762	(7,412,851)	0	20,221,911	0.46%	4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ng Term Debt - Fixed	2,509,780,089	2,070,567,425	(555,416,674)	(214,015,134)	1,301,135,618	29.75%	5.79%	1.72%	5.79%	1.72%	5.79%	1.72%
ort Term Debt *	46,890,541	38,684,675		(38,684,675)	(0)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
stomer Deposits												
Active	159,270,769	131,398,311	(35,246,770)	0	96,151,542	2.20%	6.21%	0.14%	6.21%	0.14%	6.21%	0.14%
Inactive	779,017	642,688	(172,397)	0	470,291	0.01%						
estment Tax Credit												
Post '70 Total	23,386,508	19,293,858	(5,175,456)									
Equity **					9,492,488	0.22%	10.70%	0.02%	11.69%	0.03%	12.68%	0.03%
Debt **					4,625,914	0.11%	5.79%	0.01%	5.79%	0.01%	5.79%	0.01%
ferred Income Taxes	380,395,307	313,825,954	(84,181,836)	102,392,661	332,036,779	7.59%						
S 109 DIT - Net	(64,037,484)	(52,830,895)	14,171,555	(2,112,487)	(40,771,827)	-0.93%						
Total	$5,772,254,101	$4,762,106,993	($1,277,405,214)	$888,400,745	$4,373,102,524	100.00%		8.42%		9.04%		9.65%

aily Weighted Average
ost Rates Calculated Per IRS Ruling
Equity Ratio Including Debt Associated With Qualifying Facilities Contracts (Based on FPSC Capital Structure) 54.05%
Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 10 of 15

Schedule 5

PROGRESS ENERGY FLORIDA
Financial Integrity Indicators
December 2006

A: TIMES INTEREST EARNED WITH AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Debt	$5,056,905
Income Taxes	$193,440,642
Total	**$874,734,506**
Interest Charges	
(before deducting AFUDC-Debt)	$155,524,490
T.I.E. with AFUDC	5.62

B: TIMES INTEREST EARNED WITHOUT AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Equity	($16,834,794)
Income Taxes	$193,440,642
Total	**$852,842,808**
Interest Charges	
(before deducting AFUDC-Debt)	$155,524,490
T.I.E. without AFUDC	5.48

C: PERCENT AFUDC TO NET INCOME AVAILABLE FOR COMMON SHAREHOLDERS

AFUDC - Debt	$5,056,905
Less: DIT	($8,000)
Subtotal	**$5,064,905**
AFUDC - Other	$16,834,794
Total AFUDC	**$21,899,699**
Net Income Available	
For Common Shareholders	$326,724,531
Percent AFUDC to Available Net Income	**6.70%**

D: PERCENT INTERNALLY GENERATED FUNDS

Net Income	$328,236,391
Common Dividends	($234,650,392)
Preferred Dividends	($1,511,860)
AFUDC (Debt & ECS Other)	($21,891,699)
Depreciation & Amortization	$409,873,656
Deferred Income Taxes	($42,363,927)
Investment Tax Credits	($6,410,000)
Deferred Fuel (Net)	$403,584,738
Nuclear Fuel Amortization	$23,466,052
Nuclear Refueling	$13,506,021
Other - Incl Nuclear Decommissioning	($14,968,992)
Funds Provided from Operations	**$856,871,988**
Other Funds Provided -	
Incl Change in Working Capital	($4,357,207)
Total Funds Provided	**$852,514,781**
Construction Expenditures (excluding AFUDC)	$734,481,800
Percentage Internally Generated Funds	**116.07%**

E: SHORT TERM DEBT / LONG TERM DEBT AS PERCENT OF TOTAL INVESTOR CAPITAL - FPSC

Common Equity	$2,626,115,733
Preferred Stock	$19,963,104
Long Term Debt - Fixed Rate	$1,288,684,378
Short Term Debt	$1
Total	**$3,934,763,215**
% Long Term Debt - Fixed Rate	**32.75%**
% Short Term Debt	**0.00%**

F: FPSC ADJUSTED AVERAGE JURISDICTIONAL AND PRO FORMA RETURN ON COMMON EQUITY

	Pro Forma	FPSC
Average Earned Rate of Return	8.53%	8.53%
Less Reconciled Average		
Retail Weighted Cost Rates for:		
Preferred Stock	0.02%	0.02%
Long Term Debt - Fixed Rate	1.70%	1.70%
Short Term Debt	0.00%	0.00%
Customer Deposits	0.13%	0.13%
Investment Tax Credit (at Midpoint)		
Equity	0.03%	0.03%
Debt	0.01%	0.01%
Subtotal	**1.89%**	**1.89%**
Total	**6.64%**	**6.64%**
Divided by Common Equity Ratio	**60.35%**	**60.35%**
Jurisdictional Return on Common Equity	**11.00%**	**11.00%**

?ROGRESS ENERGY FLORIDA
=nd of Period - Capital Structure
=PSC Adjusted Basis
)ecember 2006

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio	Low Point Cost Rate	Low Point Weighted Cost	Mid Point Cost Rate	Mid Point Weighted Cost	High Point Cost Rate	High Point Weighted Cost
:ommon Equity	$2,682,292,656	$2,212,890,214	($603,970,786)	$1,040,820,380	$2,649,739,808	60.59% ***	10.75%	6.51%	11.75%	7.12%	12.75%	7.73%
'referred Stock	33,496,700	27,634,762	(7,412,851)	0	20,221,911	0.46%	4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ong Term Debt - Fixed	2,509,780,089	2,070,567,425	(555,416,674)	(214,015,134)	1,301,135,618	29.75%	5.79%	1.72%	5.79%	1.72%	5.79%	1.72%
hort Term Debt *	46,890,541	38,684,675		(38,684,675)	(0)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ustomer Deposits												
Active	159,270,769	131,398,311	(35,246,770)	0	96,151,542	2.20%	6.21%	0.14%	6.21%	0.14%	6.21%	0.14%
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ıvestment Tax Credit												
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AS 109 DIT - Net	(64,037,484)	(52,830,895)	14,171,555	(2,112,487)	(40,771,827)	-0.93%						
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)aily Weighted Average
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Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

Schedule 5

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December 2006

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Earnings Before Interest	$676,236,960
AFUDC - Equity	($16,834,794)
Income Taxes	$193,440,642
Total	$852,842,808
Interest Charges	
(before deducting AFUDC-Debt)	$155,524,490
T.I.E. without AFUDC	5.48

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Preferred Stock	$19,963,104
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Short Term Debt	$1
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F: RETURN ON COMMON EQUITY

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Short Term Debt	0.00%	0.00%
Customer Deposits	0.13%	0.13%
Investment Tax Credit (at Midpoint)		
Equity	0.03%	0.03%
Debt	0.01%	0.01%
Subtotal	1.89%	1.89%
Total	6.64%	6.64%
Divided by Common Equity Ratio	60.35%	60.35%
Jurisdictional Return on Common Equity	11.00%	11.00%

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 14 of 15

ROGRESS ENERGY FLORIDA
FUDC Rate Computation Report
alculation of Jurisdictional Capital Structure
ecember 2006

Schedule A & B
(combined)

		System Per Books	AFUDC Adjustments to System	AFUDC Adjusted System	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	Adjusted Retail	Ratio	Cost Rate	Weighted Cost
mmon Equity	(1)	$2,633,063,251	$0	$2,633,063,251	$2,089,913,458	($513,290,428)	$1,040,820,380	$2,617,443,410	60.15%	11.75%	7.07%
eferred Stock	(2)	33,496,700	0	33,496,700	26,586,982	(6,529,850)	0	20,057,121	0.46%	4.51%	0.02%
ng Term Debt - Fixed	(2)	2,532,888,290	0	2,532,888,290	2,010,402,645	(493,762,230)	(220,846,764)	1,295,793,601	29.78%	5.74%	1.71%
ort Term Debt	(3)	(74,286,975)	131,500,140	57,213,165	45,411,201	(11,153,158)	(34,258,042)	1	0.00%	0.00%	0.00%
stomer Deposits											
Active	(4)	150,338,406	0	150,338,406	119,326,514	(29,307,030)	0	90,019,484	2.07%	6.22%	0.13%
Inactive	(4)	686,568	0	686,568	544,942	(133,840)	0	411,103	0.01%		
estment Tax Credit											
Post '70 Total	(5)	26,895,584	0	26,895,584	21,347,548	(5,243,036)					
Equity	(5)							10,799,004	0.25%		
Debt	(5)							5,305,508	0.12%		
ferred Income Taxes	(4)	406,707,668	0	406,707,668	322,811,778	(79,283,759)	107,478,530	351,006,548	8.07%		
S 109 DIT - Net	(4)	(61,220,561)	0	(61,220,561)	(48,591,949)	11,934,361	(2,376,898)	(39,033,486)	-0.90%		
Total		$5,648,568,933	$131,500,140	$5,780,069,073	$4,587,753,119	($1,126,769,031)	$890,818,206	$4,351,802,294	100.00%		8.93%

otnotes:
Common Equity cost rate is mid-point authorized in Docket No. 910890-EI.
Cost rates are year end.
Balances and cost rates are daily weighted average for 13 months.
Balances and cost rates are 13 month average.
Post '70 ITC credits assigned a zero-cost rate per FPSC Order No. 19282, Docket No. 880157-EI.

 SCHEDULE 6

PROGRESS ENERGY FLORIDA
Rate of Return Report
SUMMARY OF SEBRING RIDER STATUS
For the Month of December 2006

PART I - SUMMARY

		Total Period	
Dollars to be Recovered:			
Medium Term Note - Principal		$30,700,000	
Medium Term Note - Interest		19,615,117	
Final Principal True-up		198,104	
Other Interest Expense (Net)	Note a	9,373	
		50,522,594	
Regulatory Assessment Fee	Note a	42,108	
Total		$50,564,702	
Period - April 1, 1993 - March 31, 2008		15	Years
15 Year KWH Sales Forecasted	Note a	3,262,361,000	KWH
		Period to Date	
Dollars Recovered and Other Credits:			
Principal and Interest		$45,102,716	
Regulatory Assessment Fee		35,639	
Interest and Other Adjustments	Note b	916,070	
Total		$46,054,425	
KWH Sales to date		2,823,387,354	KWH
Length of period elapsed	13 Years	8	Months

PART II - CURRENT STATUS

	Sales Statistics - KWH		SR-1 Net Revenues		
	Actual	Forecast	Actual $	Forecast $	Difference $
Oct 06	22,072,769	22,171,000	$283,845	$337,643	($53,798)
Nov 06	19,864,698	19,541,000	$255,703	$297,590	(41,887)
Dec 06	19,569,478	19,706,000	$251,571	$300,103	(48,533)
Jan 07		21,231,000	$0	$323,327	
Feb 07		20,424,000	$0	$311,038	
Mar 07		19,096,000	$0	$290,814	

Rider (SR-1) Rate 1.293 Cents per KWH Effective August 2006 Billings

Over/(Under) Recovery Balance -	December
Beginning Month Balance	$ 1,373,226
SR-1 Revenues (Net of Reg Assessment Fees)	251,571
Payment of Principal and Interest	-
Final Principal True-up	
Adjustments:	
Interest on Balance	6,571
Interest Adjustment	0
Revenue Adjustments - Back Billing Error	0
EOM Balance Available for next payment of Principal & Interest	$ 1,631,367
Next Principal and Interest Payment:	
Amount Due	$1,983,429
Date Due	01-Apr-07

Notes:

a. Updated per FPSC Order No. PSC-93-1519-FOF-EI and September 1996 update filed with the FPSC.

b. Other adjustments (net) may include true-up adjustments from final close-out transactions.

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Backgrounder
Office of Public Affairs
Telephone: 301/415-8200 E-mail: opa@nrc.gov

Power Uprates for Nuclear Plants

Background

Utilities have been using power uprates since the 1970s as a way to increase the power output of their nuclear plants. The NRC has completed 102 such reviews to date, resulting in a gain of approximately 12,650 MWt (megawatts thermal) or 4,216 MWe (megawatts electric) at existing plants (see Table 1). Collectively, an equivalent of about four nuclear power plant units has been gained through implementation of power uprates at existing plants. NRC licensees have indicated they plan to ask for power uprates over the next four years, that if approved, would add another 2,841 MWt (947 MWe) to the nation's generating capacity.

Discussion

To increase the power output of a reactor, typically a more highly enriched uranium fuel is added. This enables the reactor to produce more thermal energy and therefore more steam, driving a turbine generator to produce electricity. In order to accomplish this, components such as pipes, valves, pumps, heat exchangers, electrical transformers and generators, must be able to accommodate the conditions that would exist at the higher power level. For example, a higher power level usually involves higher steam and water flow through the systems used in converting the thermal power into electric power. These systems must be capable of accommodating the higher flows.

In some instances, licensees will modify and/or replace components in order to accommodate a higher power level. Depending on the desired increase in power level and original equipment design, this can involve major and costly modifications to the plant such as the replacement of main turbines. All of these factors must be analyzed by the licensee as part of a request for a power uprate, which is accomplished by amending the plant's operating license. The analyses must demonstrate that the proposed new configuration remains safe and that measures continue to be in place to protect the health and safety of the public. These analyses are reviewed by the NRC before a request for a power uprate is approved.

Power uprates can be classified in three categories: (1) measurement uncertainty recapture power uprates, (2) stretch power uprates, and (3) extended power uprates.

1) Measurement uncertainty recapture power uprates are power increases less than two percent and are achieved by using enhanced techniques for calculating reactor power. This involves the use of state-of-the-art devices to more precisely measure feedwater flow which is used to calculate reactor power. More precise measurements reduce the degree of uncertainty in the power level which is used by analysts to predict the ability of the reactor to be safely shut down under some accident conditions.

2) Stretch power uprates are typically on the order of up to seven percent and usually involve changes to instrumentation settings. Stretch power uprates generally do not involve major plant modifications. This is especially true for boiling-water reactor plants. In some limited cases where plant equipment was operated near capacity prior to the power uprate, more substantial changes may be required.

3) Extended power uprates are usually greater than stretch power uprates and have been approved for increases as high as 20 percent. Extended power uprates usually require significant modifications to major pieces of plant equipment such as the high pressure turbines, condensate pumps and motors, main generators, and/or transformers.

Review Process

Power uprates are submitted to NRC as license amendment requests. The applications and reviews are complex and involve many areas of NRC including various technical divisions of the Office of Nuclear Reactor Regulation and the Office of the General Counsel. Some reviews may also involve the Office of Nuclear Regulatory Research and the Advisory Committee on Reactor Safeguards. In evaluating a power uprate request, NRC reviews data and accident analyses submitted by a licensee to confirm that the plant can operate safely at the higher power level. Reviews of power uprate requests are a high priority and are therefore, being conducted on accelerated schedules.

Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002, covers analyses of the effect of the power uprate on things such as electrical equipment, major plant systems, and emergency operating procedures. The RIS outlines the staff's information needs for reviewing measurement uncertainty recapture power uprate applications and is intended to result in a more efficient and effective review process. Standardization of licensee's submittals, improvements in the quality of submittals, and more focused reviews by the staff could improve the timeliness of power uprate reviews.

Based on results of its industry survey, NRC expects to receive only one stretch power uprate over the next five years. Therefore, NRC's efforts for improving the power uprate application and review processes initially focused on measurement uncertainty and extended power uprates. Efficiencies gained there will be applied to improve the stretch power uprate review process.

Reviews of extended power uprate applications were initially estimated to take up to 18 months, but have been completed more quickly. The Duane Arnold, Dresden 2 and 3, and Quad Cities 1 and 2 extended power uprates were completed in just under 12 months. This included coordination and review with the NRC's Advisory Committee for Reactor Safeguards -- an independent panel of technical experts from diverse fields that advises the Commission.

The NRC issued a review standard for extended power uprates, RS-001, in December 2003. The standard is a first-of-a-kind document that provides a comprehensive process and technical guidance for reviews by the NRC staff, and also provides useful information to licensees considering applying for an extended uprate. The NRC's Advisory Committee on Reactor Safeguards endorsed RS-001 as an "excellent review standard." The staff is currently using this standard to review the proposed uprates for Vermont Yankee (20 %), Waterford (8 %), Browns Ferry Unit 1 (20 %) , Browns Ferry Units 2 and 3 (15 %), and Beaver Valley Units 1 and 2 (8 %). The staff will closely monitor these uprate reviews to identify any issues related to using RS-001.

To keep the public informed of its activities, NRC publishes a notice in the *Federal Register* (1) when it receives a request from a licensee for a power uprate, giving the public the opportunity to request a hearing; (2) after a finding of no significant environmental impact is made, if applicable; and (3) if a power uprate is approved. A press release is also issued if a power uprate is approved.

Plant-Specific Applications Under Review

The NRC usually has several applications for power uprates under review at any given time. An updated list of applications under review can be found on the NRC's Web site at this address: http://www.nrc.gov/reactors/operating/licensing/power-uprates/pending-applications.html .

Steam Dryer Issues Following Uprates

Since 2002, steam dryer cracking and flow-induced vibration damage on components and supports for the main steam and feedwater lines have been observed at the Dresden and Quad Cities nuclear power plants, both of which use boiling water reactors, following implementation of extended power uprates. NRC staff have determined these issues do not pose an immediate safety concern, given the plants' current operating conditions. However, steam dryers and other internal main steam and feedwater components must maintain structural integrity to avoid generating loose parts that could impact safety system or reactor plant operation. The NRC has corresponded with and met with nuclear industry groups concerning these issues since the first occurrences, and continues to examine its regulatory options based on industry actions and the information available.

Future Actions

Licensees have told NRC they plan to submit 18 power uprate applications in the next four years as follows:

- 10 extended power uprates
- 1 stretch power uprate
- 7 measurement uncertainty recapture power uprates

Based on the information provided, planned power uprates are expected to result in an increase of about 2,841 MWt. An updated list of anticipated future applications can be found on the NRC's Web site at this address:
http://www.nrc.gov/reactors/operating/licensing/power-uprates/expected-applications.html .

Tables

- Table 1 - Approved Power Uprates as of November 2004
- Table 2 - Power Uprates Currently Under Review as of November 2004
- Table 3 - Expected Future Submittals for Power Uprates as of October 2004

Table 1 - Approved Power Uprates

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

NO.	Plant	% Uprate	Mwt	Year Approved	TYPE
1	Calvert Cliffs 1	5.5	140	1977	S
2	Calvert Cliffs 2	5.5	140	1977	S
3	Millstone 2	5	140	1979	S
4	H. B. Robinson	4.5	100	1979	S
5	Fort Calhoun	5.6	80	1980	S
6	St. Lucie 1	5.5	140	1981	S
7	St. Lucie 2	5.5	140	1985	S
8	Duane Arnold	4.1	65	1985	S
9	Salem 1	2	73	1986	S
10	North Anna 1	4.2	118	1986	S
11	North Anna 2	4.2	118	1986	S
12	Callaway	4.5	154	1988	S
13	TMI-1	1.3	33	1988	S
14	Fermi 2	4	137	1992	S
15	Vogtle 1	4.5	154	1993	S
16	Vogtle 2	4.5	154	1993	S
17	Wolf Creek	4.5	154	1993	S

18	Susquehanna 2	4.5	148	1994	S
19	Peach Bottom 2	5	165	1994	S
20	Limerick 2	5	165	1995	S
21	Susquehanna 1	4.5	148	1995	S
22	Nine Mile Point 2	4.3	144	1995	S
23	WNP-2	4.9	163	1995	S
24	Peach Bottom 3	5	165	1995	S
25	Surry 1	4.3	105	1995	S
26	Surry 2	4.3	105	1995	S
27	Hatch 1	5	122	1995	S
28	Hatch 2	5	122	1995	S
29	Limerick 1	5	165	1996	S
30	V. C. Summer	4.5	125	1996	S
31	Palo Verde 1	2	76	1996	S
32	Palo Verde 2	2	76	1996	S
33	Palo Verde 3	2	76	1996	S
34	Turkey Point 3	4.5	100	1996	S
35	Turkey Point 4	4.5	100	1996	S
36	Brunswick 1	5	122	1996	S
37	Brunswick 2	5	122	1996	S
38	Fitzpatrick	4	100	1996	S
39	Farley 1	5	138	1998	S
40	Farley 2	5	138	1998	S
41	Browns Ferry 2	5	164	1998	S
42	Browns Ferry 3	5	164	1998	S
43	Monticello	6.3	105	1998	E
44	Hatch 1	8	205	1998	E
45	Hatch 2	8	205	1998	E
46	Comanche Peak 2	1	34	1999	MU
47	LaSalle 1	5	166	2000	S
48	LaSalle 2	5	166	2000	S
49	Perry	5	178	2000	S

50	River Bend	5	145	2000	S
51	Diablo Canyon 1	2	73	2000	S
52	Watts Bar	1.4	48	2001	MU
53	Byron 1	5	170	2001	S
54	Byron 2	5	170	2001	S
55	Braidwood 1	5	170	2001	S
56	Braidwood 2	5	170	2001	S
57	Salem 1	1.4	48	2001	MU
58	Salem 2	1.4	48	2001	MU
59	San Onofre 2	1.4	48	2001	MU
60	San Onofre 3	1.4	48	2001	MU
61	Susquehanna 1	1.4	48	2001	MU
62	Susquehanna 2	1.4	48	2001	MU
63	Hope Creek	1.4	46	2001	MU
64	Beaver Valley 1	1.4	37	2001	MU
65	Beaver Valley 2	1.4	37	2001	MU
66	Shearon Harris	4.5	138	2001	S
67	Comanche Peak 1	1.4	47	2001	MU
68	Comanche Peak 2	0.4	13	2001	MU
69	Duane Arnold	15.3	248	2001	E
70	Dresden 2	17	430	2001	E
71	Dresden 3	17	430	2001	E
72	Quad Cities 1	17.8	446	2001	E
73	Quad Cities 2	17.8	446	2001	E
74	Waterford 3	1.5	51	2002	MU
75	Clinton	20	579	2002	E
76	South Texas 1	1.4	53	2002	MU
77	South Texas 2	1.4	53	2002	MU
78	ANO-2	7.5	211	2002	E
79	Sequoyah 1	1.3	44	2002	MU
80	Sequoyah 2	1.3	44	2002	MU
81	Brunswick 1	15	365	2002	E

82	Brunswick 2	15	365	2002	E
83	Grand Gulf	1.7	65	2002	MU
84	H. B. Robinson	1.7	39	2002	MU
85	Peach Bottom 2	1.62	56	2002	MU
86	Peach Bottom 3	1.62	56	2002	MU
87	Indian Point 3	1.4	42.4	2002	MU
88	Point Beach 1	1.4	21.5	2002	MU
89	Point Beach 2	1.4	21.5	2002	MU
90	Crystal River 3	0.9	24	2002	S
91	D.C. Cook 1	1.66	54	2002	MU
92	River Bend	1.7	52	2003	MU
93	D.C. Cook 2	1.66	57	2003	MU
94	Pilgrim	1.5	30	2003	MU
95	Indian Point 2	1.4	43	2003	MU
96	Kewaunee	1.4	23	2003	MU
97	Hatch 1	1.5	41	2003	MU
98	Hatch 2	1.5	41	2003	MU
99	Palo Verde 2	2.9	114	2003	S
100	Kewaunee	6.0	99	2004	S
101	Palisades	1.4	35	2004	MU
102	Indian Point 2	3.2	101.6	2004	S

Table 2 - Power Uprates Under Review

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

No.	Plant	% Uprate	MWt	Submittal Date	Projected Completion Date	Type
1	Vermont Yankee	20	319	09/10/03	TBD	E
2	Waterford	8	275	11/13/03	April 2005	E
3	Seabrook	5.2	176	03/17/04	Feb. 2005	S
4	Indian Point 3	4.85	148	06/03/04	March 2005	S
5	Browns Ferry 2	15	494	06/25/04	TBD	E
6	Browns Ferry 3	15	494	06/25/04	TBD	E
7	Browns Ferry 1	20	659	06/28/04	TBD	E
8	Palo Verde 1	2.94	114	07/09/04	March 2005	S
9	Palo Verde 3	2.94	114	07/09/04	March 2005	S
10	Beaver Valley 1	8	211	10/04/04	TBD	E
11	Beaver Valley 2	8	211	10/04/04	TBD	E

Table 3 - Expected Future Submittals for Power Uprates

Fiscal Year	Total Uprates Expected	Measurement Uncertainty Recapture Uprates	Stretch Power Uprates	Extended Power Uprates	Megawatts Thermal	Approximate Megawatts Electric
2005	8	4	0	4	1,315	438
2006	3	3	0	0	161	54
2007	6	0	1	5	843	281
2008	1	0	0	1	522	174
TOTAL	**18**	**7**	**1**	**10**	**2,841**	**947**

June 2005

PROGRESS ENERGY FLORIDA

Impact of Sales Growth on Base Rate Recovery

Line	Description	Base Rates Set	Year One Load Growth	Year Two Load Growth
		(1)	(2)	(3)
1	Base Rate Costs	$50,000		
2	Electricity Sales (MWh)	1,000	1,030	1,061
3	Average Base Rate Cost ($/MWh)	$50	$50	$50
4	Base Rate Revenue		$51,500	$53,045
5	Additional Base Rate Cost Recovery		$1,500	$3,045

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Capacity Clause Recovery Factor
Using Current 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2007

Docket No. 070052-EI
CCRC vs. Fuel Clause
Exhibit No. ____ (JP-4)
Page 1 of 1

Exhbit__JP-1P
Section C
Page 4 of 5

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrs x(1))	(4) Delivery Efficiency Factor	(5) Sales at Source (Generation) (mWh) (2)/(4)	(6) Avg 12 CP at Source (MW) (3)/(4)	(7) Annual Average Demand (5)/8760hrs	(8) Annual Average Demand Allocator (%)	(9) 12CP Demand Transmission Allocator (%)	(10) 12CP & 1/13 AD Demand Allocator (%)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	0.550	20,912,280	4,340.45	0.9344227	22,379,893	4,645.06	2,554.78	51.462%	60.948%	60.218%
General Service Non-Demand										
GS-1, GST-1										
Secondary	0.658	1,365,672	236.93	0.9344227	1,461,514	253.56	166.84	3.361%	3.327%	3.330%
Primary	0.658	6,768	1.17	0.9683000	6,990	1.21	0.80	0.016%	0.016%	0.016%
Transmission	0.658	3,247	0.56	0.9783000	3,319	0.58	0.38	0.008%	0.008%	0.008%
								3.384%	3.350%	3.353%
General Service										
GS-2 Secondary	1.000	82,483	9.42	0.9344227	88,272	10.08	10.08	0.203%	0.132%	0.138%
General Service Demand										
GSD-1, GSDT-1										
Secondary	0.789	12,650,152	1,830.27	0.9344227	13,537,933	1,958.72	1,545.43	31.130%	25.700%	26.118%
Primary	0.789	2,404,893	347.95	0.9683000	2,483,624	359.34	283.52	5.711%	4.715%	4.792%
Transmission	0.789	0	0.00	0.9783000	0.00	0.00	0.00	0.000%	0.000%	0.000%
SS-1 Primary	1.264	0	0.00	0.9683000	0.00	0.00	0.00	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.264	17,286	1.56	0.9783000	17,669	1.60	2.02	0.041%	0.021%	0.022%
Transm Del/ Primary Mtr	1.264	8,113	0.73	0.9683000	8,379	0.76	0.96	0.019%	0.010%	0.011%
								36.901%	30.446%	30.943%
Curtailable										
CS-1, CST-1, CS-2, CST-2, SS-3										
Secondary	1.093	0	0.00	0.9344227	0.00	0.00	0.00	0.000%	0.000%	0.000%
Primary	1.093	358,068	37.40	0.9683000	369,811	38.62	42.22	0.850%	0.507%	0.533%
SS-3 Primary		5,761	0.00	0.9683000	5,950	0.00	0.68	0.014%	0.000%	0.001%
								0.864%	0.507%	0.534%
Interruptible										
IS-1, IST-1, IS-2, IST-2										
Secondary	0.927	117,778	14.50	0.9344227	126,044	15.52	14.39	0.290%	0.204%	0.210%
Primary Del / Primary Mtr	0.927	1,874,168	230.80	0.9683000	1,935,545	238.35	220.95	4.451%	3.127%	3.229%
Primary Del / Transm Mtr	0.927	2,169	0.27	0.9783000	2,217	0.27	0.25	0.005%	0.004%	0.004%
Transm Del/ Transm Mtr	0.927	476,752	58.71	0.9783000	487,327	60.01	55.63	1.121%	0.787%	0.813%
Transm Del/ Primary Mtr	0.927	81,181	10.00	0.9683000	83,839	10.32	9.57	0.193%	0.135%	0.140%
SS-2 Primary	0.749	0	0.00	0.9683000	0.00	0.00	0.00	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.749	87,945	13.40	0.9783000	89,896	13.70	10.26	0.207%	0.180%	0.182%
Transm Del/ Primary Mtr	0.749	49,404	7.53	0.9683000	51,021	7.78	5.82	0.117%	0.102%	0.103%
								6.383%	4.539%	4.681%
Lighting										
LS-1 (Secondary)	6.746	326,064	5.52	0.9344227	348,947	5.90	39.83	0.802%	0.077%	0.133%
		40,830,224	7,147.16		43,488,188	7,821.38	4,964.41	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2003
(2) Projected kWh sales for the period January 2006 to December 2006
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2004
(5) Column 2 / Column 4
(6) Column 3 / Column 4
(7) Calculated: Column 6 / 8,760 hours
(8) Column 7/ Total Column 7
(9) Column 8/ Total Column 6
(10) Column 8 x 1/13 + Column 9 x 12/13