BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 050078-EI

Submitted for filing: August 5, 2005

REBUTTAL TESTIMONY OF
JAVIER PORTUONDO

On behalf of PROGRESS ENERGY FLORIDA

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REBUTTAL TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name.

A. My name is Javier Portuondo.

Q. Did you submit direct testimony in this case on April 29, 2005?

A. Yes, I submitted direct testimony that addressed the development of Progress Energy Florida, Inc.'s ("PEF's" or "the Company's") Minimum Filing Requirements (MFRs) from its 2005 - 2006 budget process and the various ratemaking adjustments described and supported in my testimony.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to certain assertions and positions contained in the testimony of Florida Retail Federation ("FRF") witness Sheree Brown, Office of Public Counsel ("OPC") witnesses Donna DeRonne and Hugh Larkin, White Springs Agricultural Chemicals ("White Springs") witness Michael Gorman, and joint OPC and Florida Industrial Power Users Group ("FIPUG") witness Jacob Pous. My responses will address, in the order listed, the following areas of my direct testimony and sponsored MFR schedules where the intervenor witnesses have raised issues:

- Depreciation Reserve Variance
- Nuclear Decommissioning Reserve
- Fossil Dismantlement Expense
- Gain on Sale of the Winter Park Distribution System
- PEF's Adjustment to the Equity Component of Capital Structure

- Electric Plant In Service
- Construction Work In Progress in Rate Base
- Plant Held for Future Use
- Last Core Nuclear Fuel and End-of-Life Material & Supplies Reserve
- Working Capital Adjustments
- Deferred Income Taxes
- Amortization of Rate Case Expense
- Other Net Operating Income Adjustments

In addition, I will provide accounting and regulatory support for the updated sales forecast and revised cost of service presented in the rebuttal testimony of John B. Crisp and William Slusser. I will do so through an exhibit to my testimony that summarizes and incorporates Mr. Crisp's updated forecast and Mr. Slusser's jurisdictional cost allocation into certain key MFR schedules which utilize information from the sales forecast as an input.

Q. Have you prepared any exhibits for use in conjunction with your rebuttal testimony?

A. Yes. . I have prepared or sponsored the preparation of the following exhibits to my testimony:

- Exhibit No. ____ (JP-12), Analysis of Cost of Service Associated with Winter Park.
- Exhibit No. ___ (JP-13), Impact of Revised Sales Forecast and Winter Park Treated as Wholesale.
- Exhibit No. ___ (JP-14), Proposed Adjustments 2006 Test Year: System and Retail.

- Exhibit No. ___ (JP-15), Payroll and Payroll Taxes.
- Exhibit No. ___ (JP-16), EOL Nuclear M&S and Last Core Nuclear Fuel.
- Exhibit No. ___ (JP-17), Storm Impact.
- Exhibit No. ___ (JP-18), Revised Schedule A-1.
- Exhibit No. ___ (JP-19), Revised Schedule D-1a.
- Exhibit No. ___ (JP-20), Progress Energy Florida Plant in Service Balance.

These exhibits are true and accurate.

<u>Depreciation Reserve Variance</u>

Q. Intervenor witnesses Larkin and Pous have cited or quoted from a number of Commission orders in support of their proposition that the depreciation reserve variance calculated by PEF should be refunded to customers over a substantially shorter period than the average remaining life of the related assets. Would you provide your assessment of the regulatory policy described in these Commission orders in terms of consistency with the witnesses' proposition?

A. My review of the Commission orders referenced by Mr. Larkin and Mr. Pous has shown that they have been either very selective in using the portions of those orders which, in the absence of context, appear to support their radical proposal, or they have simply misconstrued the orders in general. The following is brief discussion of each of the Commission's depreciation orders referenced in the testimony of these two witnesses.

- <u>Order PSC-02-0655-AS-EI</u>, issued May 14, 2002, approving the Stipulation and Settlement in PEF's last rate case. The Commission in this order approved a settlement between the parties that would result in a rate reduction of $125 million annually to customers. In addition to providing a $125 million annual rate reduction to customers, the settlement approved by the Commission also provided for a reduction in PEF's depreciation expense. Mr. Pous claims this demonstrates the lack of a "rigid adherence to 'remaining life' concepts ... ." (Pous Testimony, page19, lines 19-20.) In actuality, it demonstrates no such thing. To the contrary, the Commission required PEF to file an abbreviated depreciation study, which was performed on an average remaining life basis, to ensure that the reduction in depreciation expense was consistent with sound depreciation theory and not a departure from remaining life depreciation results. This was confirmed again by PEF's current depreciation study, which continues to show that going-forward depreciation rates should be lower than the Company's previous rates approved in 1997. Further, OPC, Mr. Pous' client, agreed in paragraph 10 of the settlement agreement approved by the Commission to the use of remaining life depreciation to address that part of the depreciation expense that was suspended under the agreement when the agreement expired.

- Order No. 19901, issued August 30, 1988, regarding Gulf Power's depreciation study. The reference to this order in Mr. Pous' testimony provides an example of the distortion that can occur when context is ignored. The context in which Order No. 19901 was issued begins almost four years earlier with the issuance of Commission Order No. 13681 on September 17, 1984, which addressed Gulf Power's request for approval of new depreciation rates. Prior to this request, Gulf's depreciation rates had been based on the "whole life" methodology but, pursuant to Commission rule 25-6.0436(7), Gulf's then-current depreciation study was required to be based on the average remaining life methodology. This one-time transition from whole life to remaining life depreciation produced a significant reserve deficiency, which provided the Commission an opportunity to articulate its policy on reserve variances in its 1984 order, Gulf's first depreciation order under the remaining life methodology. The following quotation from Order No. 13681 expresses this Commission policy:

> "While it is possible to make the reserve correction of these accounts through the new depreciation rates allowed for embedded plant, we have chosen to amortize this reserve deficit over the composite <u>remaining life</u> of the associated investment. ... We are ordering a 19-year amortization schedule for use in recovering the reserve deficit associated with the Transmission, Distribution and General Plant accounts." (Emphasis added.)

Ignoring this statement of general policy by the Commission on the treatment of overall reserve variances, Mr. Pous instead refers to an issue in Gulf's next depreciation study regarding a surplus in one particular reserve account related to the Job Development Investment Tax Credit (JDIC). In Order No. 19901 cited by Mr. Pous, the Commission simply authorized a reserve account transfer which allowed the account surplus created by the implementation of the JDIC to be used as a contribution toward the 19-year remaining life amortization of the overall reserve deficiency that the Commission established in Order No. 13681 from Gulf's prior depreciation proceeding.

- <u>Order PSC-01-2270-PAA-EI</u>, issued November 19, 2001, regarding the depreciation study for the Marianna Division of Florida Public Utilities

Company. Far from supporting the severe departure from remaining life depreciation principles that witnesses Pous and Larkin espouse, this case deals with corrective action taken by the Commission to remedy a negative reserve balance created when specific plant investments, which in fact had not been made, were removed from a reserve account. As in the discussion of Order No. 19901 above, the Commission simply authorized a reserve transfer which applied a surplus from another reserve account to offset the deficiency in the corrected plant account. Importantly, the surplus was not flowed back to ratepayers through a foreshortened amortization, as the intervenor witnesses propose, but instead was used to maintain the utility's depreciation rates based on remaining life principles.

- Order No. 19438, issued June 6, 1988, regarding a change in Tampa Electric Company's depreciation rates. In this order, as in the 1988 Gulf depreciation order discussed above, the Commission was addressing a prior order in which it had found that the most efficient mechanism for addressing the unique depreciation impact on customers from implementation of the JDIC was through a depreciation reserve adjustment. As before, the adjustment was well below the threshold of policy making, but was rather the application of a mechanism, or tool, tailored to address a specific situation created by a federal tax initiative. Other specialized amortization schedules approved by the Commission in this order were designed to address unrecovered investment in specific assets that were being taken out of service earlier than would normally be the case if not for a change in technology, federal and state regulations, or other equipment-specific issues.

- Order No. 14929, issued September 11, 1985, establishing new depreciation rates for GTE. One might have expected depreciation experts such as the intervenor witnesses to appreciate the unique circumstances of the telephone and communication industry as a whole regarding the difficulty in estimating the useful lives of depreciable assets because of premature obsolescence resulting from, as the Commission put it, "substantial developments in the area of technology and competition". It is virtually common knowledge that the telephone industry has and continues to be plagued with technical obsolescence that drives significant retirements much earlier than would have been initially expected, a problem that is exacerbated by the anticipation of wide-spread competition. As the Commission stated in the cited order, "we believe it is our duty and in the best interest of the Company and ratepayers to move forward with represcription of the Company's intrastate depreciation rates." The circumstances and facts in this case, and the regulatory response required, have no relevance to PEF's current depreciation study.
- Order No. 22115, issued October 31, 1989, regarding the establishment of new depreciation rates for City Gas Company. The intervenor witnesses have again ignored the context in which this order was issued. Instead, they have focused on the implementation specifics of a Commission policy without regard to the policy itself. In this case, the policy that gave rise to the recovery schedule discussed in Order No. 22115 was addressed in Order No. 13538 issued in the predecessor proceeding. In that order, the Commission stated: "We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite

remaining life of the embedded plant, which is estimated to be 24 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit." The policy described by the Commission in which reserve variances attributable to changes in prospective life and salvage values are amortized over the assets' remaining life is instructive, since this is precisely the kind of changes that brought about the reserve variance in the Company's current depreciation study.

- Order No. PSC-97-0499-FOF-EI, issued April 29, 1997, regarding Florida Power & Light's proposal for plant life extensions. Like many of the other orders quoted in Mr. Pous' testimony, this order addresses a specific deficiency associated with a specific facility. It should be clear at this point that it is not unusual for the Commission to establish accelerated amortization schedules to address equipment or facility-specific reserve issues. It is another thing entirely to suggest that amortization be accelerated well ahead of the composite remaining lives of all depreciable equipment and facilities to address the non-specific, overall net variance from every reserve account.
- Order No. PSC-93-1839-FOF-EI, issued December 27, 1993, regarding the depreciation study for the Marianna Division of Florida Public Utilities Company. Not surprisingly, Mr. Pous has taken a statement from the Commission's order out of context. He quotes from the order as follows: "According to our Staff such deficiencies should be recovered as fast as possible, unless such recovery prevents the Company from earning a fair and reasonable return on its investment." This statement, of course, reflects the

opinion of the Commission staff at that time, not the Commission itself. Suffice it to say that the Commission did not order a change in the rates of customers as a means to accelerate the write-down of this reserve variance, as the intervenor witnesses have proposed in the present case. Instead, the Commission employed the practice of reserve transfers to address the matter in that case, as it has done in many of the cases cited by the intervenor witnesses.

- Order No. 13427, issued June 15, 1984, in the Commission's investigation of the appropriate accounting and ratemaking treatment of nuclear power generators. This order has no relevance to a discussion regarding the treatment of depreciation reserve variances. In the order, the Commission states: "Further, our principle purpose in the case was not to correct deficiencies in revenue recovery, but to correct an accounting and ratemaking problem. We determined that the current method of recovery of decommissioning costs was deficient from both an accounting standpoint and a ratemaking standpoint." The issue of reserve variances in PEF's depreciation study is neither an accounting nor a ratemaking problem, since the Commission satisfactorily dealt with the accounting and ratemaking aspects of this issue in many proceedings over the years using sound remaining life depreciation principles. Moreover, the statement quoted by Mr. Pous concerns the then-pending question of whether the Commission should establish a funded or unfunded nuclear decommissioning reserve. This is not an issue pending before the Commission in this proceeding.

Finally, I reference the orders directly below in summary fashion because they are unremarkable and repetitive of the comments and points that I make above. Said simply, the orders below add nothing to the Commission policy and practices disclosed by the other cases cited by the intervenor witnesses that I have discussed previously.

- Order No. 18736, issued January 26, 1988, regarding Untied Telephone's request for accelerated amortization.
- Order No. 23833, issued December 4, 1990, regarding Alltel Florida's request for depreciation rates.
- Order No. 24004, issued January 22, 1991, regarding Gulf Telephone's 1990 depreciation study.
- Order No. 12290, issued July 22, 1983, regarding Southern Bell Telephone's represcription of depreciation rates.
- Order No. 12857, issued January 10, 1984, regarding United Telephone's new depreciation rates.
- Order No. 12864, issued January 12, 1984, regarding North Florida Telephone's revision of depreciation rates.
- Order No. 18642, issued January 4, 1988, regarding Gulf Telephone's 1987 depreciation study.

Q. What conclusion should be drawn from an analysis of the Commission orders cited by the intervenor witnesses to support their proposal to accelerate PEF's overall reserve variance rapidly, without regard to the composite remaining lives of the underlying plant assets?

A. The cases referenced by intervenor witnesses Larkin and Pous are not inconsistent with, and in many instances actually support, PEF's remaining life treatment of its depreciation reserve variance. Specifically, these cases make clear that the

Commission's use of intra-reserve account transfers to address specific equipment or facility reserve issues is entirely different from and unsupportive of the intervenor witnesses' proposal to accelerate the amortization of the non-specific, total net reserve variance, without regard to the composite remaining lives of the depreciable equipment and facilities.

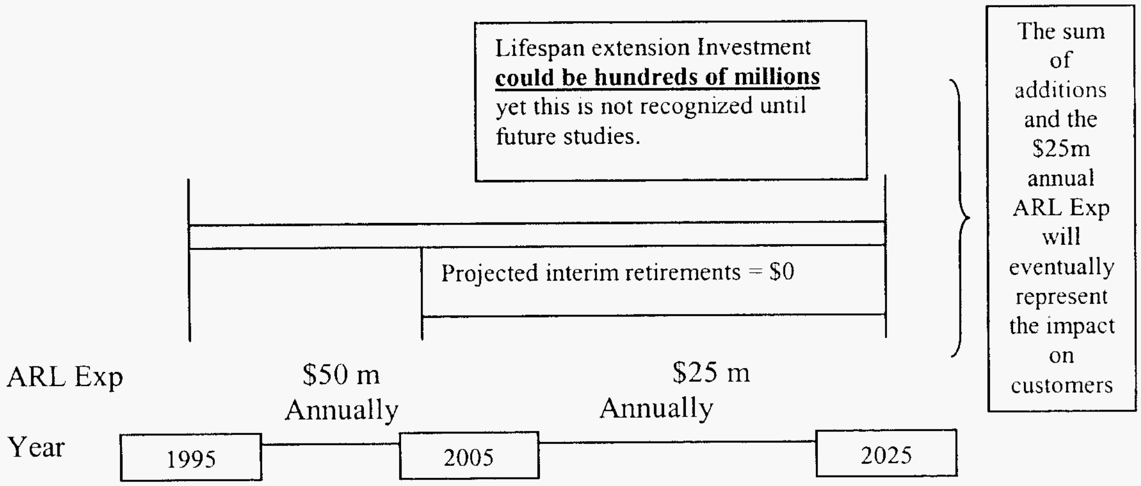
Moreover, the witnesses' proposal is plainly contrary to the Commission's policy, as clearly articulated in Order No. 13681, that a reserve variance which is "attributable to changes in the prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant." This policy clearly supports, if not requires, PEF's remaining life treatment of the reserve variance in this case, since the Company's entire reserve surplus is the direct result of changes to the prospective lives and salvage values of the embedded plant.

Q. Do you agree with the intervenors' assertion that the "theoretical reserve" represents an over collection from customers?

A. No. Rates charged to customers are based on the expected lifespan of the facilities dedicated to electric service. The fact that over time, a facility that was expected to be in operation for 20 years may now be able to continue operating for 30 years does not mean that customers have over paid. The use of the "theoretical reserve" is a poor test for such a determination because it ignores the future investment that will be necessary to permit those facilities to continue to operate an additional 10 years. The theoretical calculation only utilizes the current level of investment and the level of interim retirements projected for those assets. It ignores the major investment that may be required 5 or 10 years out in order to achieve this life extension as well as interim additions related to the interim retirements.

Therefore, it is an incomplete view of the impact of a facilities' life extension. This can be illustrated below:

Example:



Orig Life 20 yrs. New life 30 yrs
Invest. $1 billion
Accum. $0 Accum Bk. $500 million
Theoretical <u>$333 million</u>
Variance <u>$167 million</u>

The example above demonstrates that customers during the first 10 years have not over paid. The payments on which rates were set are based on the service received from assets operating during the most efficient period of their lifespan. The change in the ARL expense ($50m to $25m) resulting from the ARL calculation under the intervenors' application of the "theoretical reserve" ignores the impact on future customers necessary to achieve the benefits of a longer useful life that intervenors wish to give to past customers. Future customers will need to cover the improvements both necessary to address the interim retirements considered in the ARL calculation as well as those capital improvements directed specifically at driving a longer useful life from these facilities. The impact on future customers will be greater than past customers under intervenors' proposals because they have to cover the costs over a shorter period of time. So, the application of the Commission policy to address depreciation variances over the remaining life of the investment serves to equalize the impact on customers and provide intergenerational equity.

__Nuclear Decommissioning Reserve__

Q. The testimonies of White Springs witness Gorman and OPC witness Pous urge the Commission to require the entire balance of one of the two trust funds established by PEF's nuclear decommissioning trust instrument to be withdrawn and refunded to customers over a five-year period. Please comment on this proposal.

A. I won't belabor my response with a description of the lengths to which this Commission has gone to ensure that nuclear decommissioning funds are insulated from proposals like Mr. Gorman makes in his testimony. Instead, I will address the results of this effort by the Commission, which, in PEF's case, is the nuclear decommissioning trust agreement the Company entered into pursuant to the Commission's mandate for the safeguarding of nuclear decommissioning funds. First, however, I will briefly describe why Mr. Gorman's and Mr. Pous' proposals fail to square with the rules of the Nuclear Regulatory Commission (NRC).

The NRC's comprehensive rules regarding the obligations and responsibilities of nuclear plant licensees make it clear that once funds are placed in a decommissioning trust, disbursements of the kind proposed by Mr. Gorman are impermissible. An example of the NRC's restrictions of fund disbursements is found in 10 CFR § 50.75(h)(2) which states:

> Disbursements or payments from the trust, escrow account, Government fund, or other account used to segregate and manage the funds, other than for payment of ordinary administrative costs (including taxes) and other incidental expenses of the fund (including legal, accounting, actuarial, and trustee expenses) in connection with the operation of the fund, <u>are restricted to decommissioning expenses or transfer to another financial assurance method acceptable under paragraph (e) of this section until final decommissioning has been completed.</u> (Emphasis added.)

In addition, 10 CFR § 50.82(a)(8)(i) specifies three conditions, each of which must be satisfied, for the use of decommissioning trust funds. Directly on point is subsection (A), which states that such funds may be used by licensees if "the withdrawals are for expenses for legitimate decommissioning activities within the definition of decommissioning in 50.2." Without quoting the lengthy definitions in section 50.2, suffice it to say that the use of the trust funds proposed by Mr. Gorman and Mr. Pous is not a "legitimate decommissioning activity."

Moreover, even if the NRC's rules did not prohibit the use of decommissioning funds for a utility rate refund as proposed by Mr. Gorman and Mr. Pous, the trust agreement entered into by PEF in compliance with the Commission's external funding requirements does. In this regard, Section 1.02 of the agreement states: "Purposes of the funds. The Funds are established for the exclusive purpose of providing funds for the decommissioning of the Unit [CR3]." Thereafter, Section 2.01 adds specificity to the "exclusive purpose" provision by stating:

> Use of Assets. The assets of each Fund shall be used exclusively (a) to satisfy, in whole or in part, any expenses or liabilities incurred with respect

> to the decommissioning of the Unit, including [numerous examples omitted], (b) to pay the administrative costs and other incidental expenses of each Fund, (c) to make investments (including common trust funds) as directed by the investment manager(s) pursuant to Section 3.03(a) or the Trustee pursuant to Section 3.03(b), and (d) to be distributed upon termination of this Agreement pursuant to Article 6 hereof.

Finally, and to similar effect, the Special Terms contained in Exhibit A to the trust agreement provides the following restrictions:

> Section 3. Limitations on Use of Assets. The assets of the Qualified Trust Fund shall be used exclusively as follows:
>
> (a) To satisfy, in whole or in part, the liability of the Company for Qualified Decommissioning Costs through payments by the Trustee pursuant to Section 2.02 of the Agreement; and
>
> (b) To pay the administrative costs and other incidental expenses of the Qualified Trust Fund; and
>
> (c) To the extent the assets of the Qualified Trust Fund are not currently required for (a) and (b) above, to invest the assets of the Qualified Trust Fund.

Individually and collectively, the above restrictions demonstrate conclusively that PEF's decommissioning trust funds are, as they should be, beyond the reach of those who would use these funds for purposes other than the singular purpose for which they are intended.

Fossil Dismantlement Costs

Q. White Springs witness Gorman also faults PEF's fossil plant dismantlement cost study because it does not include the value of land on which a plant is situated in the net salvage value of the plant to be dismantled. Do you believe this to be a valid criticism?

A. Not at all. Mr. Gorman's has based his assertion that the value of land should have been included in PEF's dismantlement study on a novel concept of salvage that I find to be poorly conceived and supported. One does not dismantle land and, in the same sense, one does not salvage land. Salvage involves property that consists of the equipment and material associated with the plant subject to dismantlement. In the simplest terms, it involves the kind of property that can be put on the truck of a salvage contractor. Therefore, since land is not salvage, it follows that the value of land is not salvage value.

This layman's concept of the distinction between land and salvage is borne out by the definitions in rules promulgated by the relevant regulatory agencies. For example, the FERC Uniform System of Accounts defines salvage value as follows:

> Salvage value means the amount received for property retired, less any expense incurred in connection with the sale or in preparing the property for sale; or, if retained, the amount at which the <u>material</u> is charged to <u>Material and Supplies</u>, or other appropriate amount. (Emphasis added.) (18 CFR, Part 101.)

Even more significantly, it is evident from this Commission's rule on fossil plant dismantlement that land is not the subject of dismantlement. This can seen in the definition of "dismantlement" and "dismantlement costs" found in Rule 25-6.04364(2), F.A.C.

> (b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the <u>materials and equipment</u> that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or usable condition.
>
> (c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any <u>attendant gross salvage amount</u>, upon final retirement of the site or unit from service. (Emphasis added).

These definitions confirm what would be commonly understood in any event; namely, that the subject of dismantlement is material and equipment, and that the value in question is the salvage attendant (*i.e.*, related to, associated with, or accompanying) the dismantlement process of removing and disposing plant (*i.e.*, materials and equipment), and restoring the site. Land is simply not a part of the dismantlement process in general or salvage in particular, and its value is not a component of dismantlement costs nor the dismantlement studies that identify these costs.

<u>Gain on Sale of the Winter Park Distribution System</u>

Q. Are you familiar with PEF's recent sale of its electric distribution system in Winter Park to the City?

A. Yes I am. I provided testimony in the Winter Park valuation arbitration and was involved in finalizing the closing on the Winter Park sale.

Q. What was the total purchase price paid by the City for PEF's Winter Park system?

A. The total purchase price was $43,072,447, which consists of the following categories:

Equipment and fixtures:	$8,218,447
Stranded costs:	$7,689,000
CWIP true-up:	$2,800,000
Half joint-use attachment inventory:	$15,000
Real estate and easements:	$10,000,000
Going concern:	$12,000,000
Separation and reintegration:	$2,000,000
Maps, manuals, records:	$350,000
Total	$43,072,447

Q. Will you please briefly explain each of these categories that comprise the total purchase price for PEF's Winter Park system?

A. Certainly. As the name suggests, the equipment and fixtures category is the price for the actual electrical distribution equipment sold to Winter Park. The stranded costs award was made pursuant to FERC Order 888 to reimburse PEF for its cost in generation assets built or purchased, in part, to serve customers in Winter Park. The CWIP true-up was a payment to PEF for construction work in progress that was not included in the equipment and fixtures category noted above.

The joint-use attachment inventory payment was to reimburse PEF for half the cost of a field inventory conducted by PEF to account for the joint use attachments in Winter Park, which was required to facilitate the system transfer.

The real estate and easement category involves a real property parcel and the Company's distribution easements within the City, together with an assemblage value for the package sale of the easements. The going concern payment was made to compensate PEF for the lost income earning potential for the distribution system that was sold to Winter Park. This was determined in the arbitration by the difference in earning potential the City received from buying the electric distribution system from PEF rather than building its own electric distribution system within the City.

The separation and reintegration payment compensated PEF for its costs to physically separate the Winter Park distribution system from the remainder of PEF's distribution system and to reconnect and reintegrate its remaining distribution system outside the City. Lastly, the maps, manuals, and records payment compensated PEF for certain system maps, distribution service manuals, and customer records provided to the City as part of the system transfer.

Q. Are you familiar with the testimony of Ms. Brown and Ms. DeRonne regarding the sale of PEF's Winter Park distribution system to the City?

A. Yes I am.

Q. Can you summarize Ms. Brown's testimony on this issue?

A. Ms. Brown contends that PEF has received a gain of approximately $29.8 million from the sale of its electric distribution system in Winter Park. She further contends that this gain should be paid to PEF's ratepayers by amortizing the gain over a five-year period, thereby reducing test year revenue requirements by $5.96 million.

Q. Does Ms. Brown recognize that any part of the Winter Park purchase price should not be allocated to PEF's ratepayers?

A. Yes, on page 48 of her testimony, Ms. Brown excludes the portion of the purchase price for separation and reintegration and CWIP and, by doing so, she recognizes that these items should be excluded from any proposed gain to be allocated to ratepayers because those payments were made to reimburse PEF for costs it incurred as part of the system transfer.

Q. Should Ms. Brown have excluded any other portions of the purchase price from the gain that she proposes to flow to PEF's ratepayers?

A. Yes, as its name suggests, the payment for stranded <u>costs</u> award was made to compensate PEF for costs caused by the system transfer, just like separation and reintegration costs that Ms. Brown excluded from her proposed gain amount. Furthermore, the payment Winter Park made to PEF for half the joint use inventory was designed to simply reimburse PEF for costs incurred in the system transfer which, using her own logic, Ms. Brown should have excluded the gain amount as well.

Q. Had Ms. Brown excluded these items, what would her total proposed gain amount have been?

A. $22,096,000.

Q. Is it PEF's position that this $22,096,000 gain should be allocated to ratepayers?

A. No. The entire purchase price, including the $22,096,000 gain using Ms. Brown's figures, should be allocated to the shareholders because it is their electric distribution system that was sold to the City of Winter Park, as I explain below and as this Commission has recognized in the context of the sale of other utility systems.

Q. Can you summarize Ms. DeRonne's testimony on this issue?

A. Yes. Like Ms. Brown, Ms. DeRonne contends that the gain on the Winter Park transaction should be provided to PEF's ratepayers over a five-year period. Unlike Ms. Brown, however, Ms. DeRonne states that she is unable to calculate the adjustment necessary to provide the gain to PEF's ratepayers.

Q. Do you agree with Ms. Brown and Ms. DeRonne that PEF has realized a gain that should be provided to PEF's ratepayers?

A. No, I do not. The proceeds from the Winter Park system sale do not constitute a gain on the sale of specific, isolated utility assets or parcels which, under Commission precedent, should be provided to PEF's ratepayers. Instead, any gain from the Winter Park system transaction should be allocated to PEF's shareholders, as Commission precedent also recognizes.

Customers pay for service, they do not invest in the Company and, therefore, they do not receive or hold any interest in the Company. They also take on none of the risks of success or failure of the Company's business by simply paying for the electric service they receive. On the other hand, the shareholders do invest in the Company, they do have an interest in the Company as a result, and they do assume the risk of success or failure of the Company's business. This fundamental distinction between the interests of customers and shareholders drives the determination that the gain (or loss) on the sale of the Company's electric distribution system within the City of Winter Park should be allocated to the Company's shareholders.

Q. Will you please explain what you mean when you refer to Commission precedent supporting the position that any gain from the Winter Park transaction should be allocated to PEF's shareholders?

A. Yes. First, it is important to note that there have been sales of single (or multiple) isolated units of utility property (such as pieces of equipment, parcels of land, or structures) where the Commission has amortized the gain on sale over five years and allocated the gain to ratepayers. However, when the Commission has addressed the sale of entire utility systems, the Commission has consistently attributed the gains on sale to the utility investors.

For example, in the case of In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, Order No. PSC-03-1440-FOF-WS, issued December 22, 2003 in Docket No. 020071-WS, the Commission agreed with the utility that gains on the sale of water systems to the Cities of Maitland and Altamonte Springs, respectively, should be attributed to shareholders. The utility's expert in that case made a number of arguments that the Commission found to be "very persuasive." A summary of his key arguments follows:

1. The cost of service includes the cost of resources consumed or used during a given period of time. The Uniform System of Accounting then limits operating expenses to the costs of providing service and requires the sale of

systems to be recorded in income accounts reflecting gains or loss, thus, signifying shareholder's capital withdrawn from the utility.

2. Regulators allow utilities a reasonable return on capital for only original cost book values. Since book value is less than replacement value, ratepayers are shielded from price increases that might otherwise reflect the increased costs of replacement value. Neither depreciation nor return reflect the higher costs which investors face replacing these assets upon retirement, thus, this is a risk borne by shareholders.

3. Customers' rights cease with their payment for service received. Payments for service do not entitle ratepayers to receive any interest in the property of the utility serving them.

4. Investors bear the risk of success or failure of the business. This includes weather impacts, customer usage changes, management's ability to control costs, inflation, regulatory lag, etc., all of which will be reflected in the capital markets which regulators cannot control. Failure to allocate gains or losses on sales to investors will thus have adverse impacts on the utility's ability to raise capital at reasonable costs.

5. Commission rulings requiring ratepayers to bear the cost and risk of plant abandonments were distinguished because there was a finding of prudence; utilities bore the risk of loss on imprudent abandonments.

6. Commission rulings in electric utility cases were distinguished because the gains were associated with specific assets rather than the sale of facilities, service territory, and customers.

7. Whether a utility has uniform stand-alone rates is irrelevant because there is no relation of rates to any particular element of cost of service (i.e. customers only pay for service).

8. The payment of depreciation does not entitle ratepayers to the gain on sale if the depreciation booked by the utility was not in excess of the amount required to reflect the useful lives of the assets. The purchaser of the utility's assets is paying for the remaining useful life not for the value that has already been consumed.

9. Investors are risk averse and therefore would attempt to avoid the confiscation of capital by the assignment of gains to ratepayers. Allocating gains to shareholders does not allow the utility to recover more than the cost of service because the sale of assets is outside the cost of providing service.

In finding these arguments "very persuasive," the Commission specifically mentioned that customers pay for service only, that customers pay rates based on original cost rather than replacement cost value, and shareholders bear risk of regulatory lag. The Commission concluded by ordering the allocation of the entire gain on sale to the utility's shareholders.

Q. In that case, did OPC argue before the Commission that the entire gain on the sale received by the utility should be allocated to the utility's customers?

A. Not at all. To the contrary, OPC, through its expert witness, agreed that everything above the full depreciable allowance should be attributed to shareholders, recognizing that it would be unfair to attribute any gain to the customer above the net book value ("NBV"). OPC also agreed that ratepayers do not obtain an ownership interest in utility property through the payment of rates.

Q. Are there other Commission orders addressing the gain on sale of a utility system where the Commission allocated the gain to the utility's shareholders?

A. Yes there are. In the case of In re: Lehigh Utilities, Order No. PSC-93-0301-FOF-WS, issued February 25, 1993 in Docket No. 911188-WS, the Commission, in declining to share the gain on the sale of a water and wastewater facility with the customers, stated:

> [w]e agree with the utility that ratepayers do not acquire a proprietary interest in utility property that is being used for utility service. We also agree that it is the shareholders who bear the risk of loss in their investments, not the Lehigh ratepayers. Further, we find that Lehigh's ratepayers did not contribute to the utility's recovery of its investment in [the facility]. Based on the foregoing, we find no adjustment for the gain on the sale of SAS to be appropriate.
>
> (emphasis added).

Similarly, in the case of In re: Southern States Utilities, Inc., Order No. PSC-93-0423-FOF-WS, issued March 22, 1993 in Docket No. 920199-WS, involving the SAS system at issue in Lehigh Utilities, the Commission held:

> We agree . . . that customers who did not reside in the SAS service area did not contribute to recovery of any return on investment in the SAS system. Further, when this system was acquired by St. John's County, SSU's investment in the SAS system and its future contributions to profits were forever lost. Thus, the gain on sale serves to compensate the utility's shareholders for the loss of future earnings. Arguably, if the sale of this

system had been accompanied by a loss, any suggestion that the loss be absorbed by the remaining SSU customers would be met with great opposition. However, the rationale for sharing a loss is basically the same as the rationale for sharing a gain. Since SSU's remaining customers never subsidized the investment in the SAS system, they are no more entitled to share in the gain from that sale than they would be required to absorb a loss from it.

(emphasis supplied). In both proceedings where the gain on sale arose from the sale of a utility system the Commission ordered the allocation of that gain to the utility's shareholders.

Q: Hasn't the Commission established a clear precedent in the electric utility context that gains and losses on sales should be amortized over 5 years as a credit to the customers' cost of service?

A: Yes, but this policy also extends to water and wastewater utilities, and only in the context of the sale of an *individual* water utility asset. This policy was cited in the cases of In re: Application for rate increase in Charlotte County by Rotunda West Utility Corp., Order No. PSC-96-0663-FOF-WS, issued May 13, 1996 in Docket No. 950336-WS, and In re: Betmar Utilities, Inc., Order No. 24225, issued March 12, 1991 in Docket No. 900688-WS. In both these proceedings, involving water and wastewater utilities, the Commission awarded the gain on sale to the ratepayers because only a particular asset had been sold. The sale of only one specific asset is quite different, however, from the sale of an entire distribution system. Indeed, in the Utilities, Inc. of Florida case discussed above, the Commission agreed with the utility's argument that the electric utility cases in which the gain on sale was awarded to the ratepayers involved gains "associated with specific assets, rather than the sale of facilities, service territory, and the customers," and thus should be distinguished from the sale of an entire system. The gain on the sale of the entire electrical distribution system in Winter Park, including PEF's facilities, service territory, and customers, should not, therefore, be subject to the Commission policy regarding gain on sale of specific assets. The gain from this sale should be awarded to PEF's shareholders, based on the Commission precedent established in the water and wastewater context.

Q: **Is there any reason why the principles the Commission has applied in the context of gain on sale of water and wastewater systems should not apply to the gain on sale of an electrical distribution system?**

A: No, the principles used by the Commission to award shareholders the gain on sale of complete systems in the context of water and wastewater utilities are analogous to the gain on sale of complete electrical systems. As noted above, the Commission has made the distinction between gain from the sale of specific water and wastewater utility assets (whereby the gain flows to the ratepayers) and gain on the sale of a complete system (whereby the gain is awarded to the shareholders). In the electric utility context, the only issue that has arisen involves gains from the sale of individual assets, not gains from the sale of complete systems. Therefore, the Commission should apply the entirely analogous water and wastewater precedent to PEF's gain on the sale of the entire electrical distribution system in Winter Park, and award the gain to PEF's shareholders. Exhibit No.___ (JP-12) & (JP-13) outlines the impact on revenue requirement from the sale of the Winter Park Distribution System.

PEF's Adjustment to the Equity Component of Capital Structure

Q. FRF witness Brown claims the Commission should remove the adjustment to the equity component of capital structure made by PEF pursuant to the settlement agreed to by the parties and approved by the Commission in its investigation of an extended outage at the Company's Crystal River 3 nuclear unit. Would removal of the equity adjustment be appropriate at this time?

A. No, it would not. The CR3 equity adjustment fulfills an important role in assisting PEF's effort toward achieving the balance of debt and equity in its capital structure needed to secure vital capital on favorable terms for the Company's expanding investment requirement in the near and longer term. In addition, the formulation of the Company's financial plans and strategies currently being implemented include the adjustment as a significant component. Ms. Brown's conclusion that the CR3 equity adjustment should be summarily eliminated displays an insensitivity to the disruptive effect such a harsh action would have. I would urge the Commission to take these considerations into account in deciding this important issue.

Electric Plant In Service

Q. OPC witness Larkin contends that an adjustment should be made to PEF's test year Electric Plant In Service ("EPIS") based on his review of actual results for the first four months of 2005. Do you agree with his proposed adjustment?

A. No I do not. The analysis of PEF's results through April 2005 prepared by Mr. Larkin as support for his adjustment fails to take into account the Company's

Construction Work In Process ("CWIP"). Had he done so, the reason for the lower than estimated monthly EPIS balance would have been apparent. This is because the estimated and actual combined EPIS and CWIP balances show little variance, which indicates that the EPIS variances are only the result of timing differences in the schedule closing of CWIP to EPIS, particularly in view of the fact that there have been no significant changes in the Company's planned capital projects since the case was filed. As my Exhibit No. __ (JP-20) shows, when the capital expenditures that remain in CWIP balances are included with the monthly EPIS balances, and an adjustment is included for the March 2005 FAS 143 asset write-off described in my direct testimony, the EPIS balance through April 2005 is actually higher than the estimate from the Company's initial filing. The adjustment for the FAS 143 write-off is necessary to make a valid comparison with the projected EPIS balances in Mr. Larkin's exhibit schedule because, although the write-off was made in March 2005, it was not included in the initial MFRs. The account to which the FAS write-off was entered was excluded from rate base and therefore has no effect on the test year.

Construction Work in Progress in Rate Base

Q. FRF witness Brown and OPC witness Larkin contend that PEF has improperly included Construction Work in Progress (CWIP) in test year rate base. How do you respond to this contention?

A. The witnesses are apparently under the impression that CWIP may only be included in rate base using the financial integrity test. This is incorrect. The Commission has long recognized that a utility's investment reflected in CWIP is entitled to a return, either through AFUDC if the CWIP meets the eligibility requirements of Rule 25-6.0141, F.A.C., or through inclusion in rate base for CWIP that is ineligible to earn AFUDC, irrespective of financial integrity considerations. See, for example, Order No. 13771, Docket No. 830470-EI, and Order No. 11437, Docket No. 820097-EI. The CWIP included in PEF's test year rate base is non-AFUDC bearing and therefore qualifies for rate base treatment.

The Commission's policy also helps to ensure a reasonable distribution between AFUDC-bearing and rate base CWIP. A balanced approach is particularly appropriate in this case because many of the projects for which CWIP has been included in rate base involve the replacement of existing assets already used and useful in serving customers. In addition, a reasonable distribution of CWIP in rate base balances future AFUDC returns with a current cash return, which is vital to utilities such as PEF who are in the midst of a significant construction program and therefore must raise substantial amounts of capital.

__Plant Held for Future Use__

Q. Mr. Larkin asserts that PEF's FERC Form 15 for 2003 and 2004 show the same balance for Plant Held For Future Use ("PHFFU") as the Company has included in its filing for the test year, and that these Form 1s show an scheduled in-service date of May 2005 for the majority of the PHFFU, which he asks the Commission to disallow. Can you explain the discrepancy between the PHFFU in PEF's filing and the information in the two FERC Form 1s?

A. Yes. I note that Mr. Larkin prefaced his proposed disallowance with the statement "if the Company's FERC Form 1 is correct". Therein lies the problem. I have been able to determine that the projected in-service dates shown in the FERC Form had not been updated with the then-current estimate of in-service dates for the property, so I can understand why Mr. Larkin may have made his disallowance proposal. However, I can state with certainty that none of the PHFFU included in the test year has been placed in service. The property remains in PHFFU and continues to meet the criteria for this classification.

In addition, the properties that comprise the PHFFU is of particular strategic value to the Company. The properties are linear, and many of the parcels are adjacent to each other, making them well configured for use as right-of-way in future expansions of the Peninsula's transmission grid. The Commission will no doubt appreciate the increasing difficulty in acquiring right-of-way suitable for this kind of transmission corridor, given the state's rapidly growing population and stringent permitting standards. Because of the state's unique geographic layout, the availability of north-south electrical pathways is even more limited and, hence, more valuable. However, the attractiveness of the property as a potential major transmission corridor also contributes to the difficulty in pinpointing a precise in-service date for the property. The specific need for such a pathway could be triggered by a number of factors that could come into play in the near-term or further into the future, including such considerations as electrical grid capacity constraints, local electrical demand growth, local generation additions, NERC/FRCC criteria, voltage support, or system stability. Despite this element of timing uncertainty, PEF is confident that it is not only prudent, but highly desirable to maintain ownership and control of this property for future use by the Company's and/or the state's transmission grid.

Last Core Nuclear Fuel and End-of-Life Materials & Supplies Reserves

Q. Are you familiar with the proposed adjustment that Ms. Brown recommends regarding the Last Core Nuclear Fuel and EOL M&S reserves?

A. Yes. Ms. Brown states that PEF has incorrectly assumed a beginning reserve balance for the Test Year that is significantly less than the actual reserve balances. Ms. Brown acknowledges that the 2006 beginning balances were restated in MFR Schedule B-21, however, based on the annual accrual amounts approved in Order No. PSC-02-0022-PAA-EI. The amount of the Last Core Nuclear Fuel reserve is less than the projected 2005 reserve balance based on continuing the accrual of $1.1 million prior to the implementation of revised base rates. The EOL reserve is less than the projected 2005 reserve balance and even $250,000 less than it was end of year 2004. These amounts imply that no accruals were made for 2005.

Q. Do you agree with the proposed adjustment that Ms. Brown recommends regarding the Last Core Nuclear Fuel and EOL M&S reserves

A. Yes. I do concur that rate base and short term debt have been understated and that an adjustment needs to be made to reflect the error in the budget assumptions. However, I do not agree with the amount or the implications surrounding the adjustment. PEF assumed an annual accrual of $1.0 million for the Last Core Nuclear Fuel reserve and $1.5 million for the EOL M&S reserves. The proper accrual that should have been made in the budget was a debit to the O&M expense and a credit to the reserve account. Instead, a debit was booked to the O&M account but the credit was booked to short-term debit. In order for this entry to be corrected, we would need to debit short term debt in the amount of $4,333,340 and credit the reserve account for the same amount. Details are illustrated on Exhibit No.___ (JP-16). This adjustment would result in a reduction to the revenue requirement of $671,841.

<u>Working Capital Adjustments</u>

Q. OPC witness Larkin proposes a variety of adjustments to the working capital component of PEF's test year rate base. What is your response to his proposed adjustments?

A. To begin with, there are several of Mr. Larkin's adjustments with which I agree and have shown in my Summary Exhibit No. __ (JP-14). These are:

- Prepayments for Non-Utility Advertising: This prepaid balance should not have been included in test year working capital. The adjustment to remove this item is $2,304,839 system and $2,119,000 retail.
- Employee Receivables and Merchandise Inventory: This entry under Account 143, "Other Accounts Receivable" in the amount of $1,233,648 also should have been excluded from test year working capital. Likewise, the entries to Employee Accounts Payable in the total amount of $261,110 should be excluded as well. The net amount to be removed from working capital is $972,538 system and $796,000 retail.
- Turbine Inventory: I would first like to point out that these turbines are not spares as referred to by Mr. Larkin but rather the actual turbines to be used by Hines Unit 4 upon commercial in-service. Having cleared up this misunderstanding I do agree that an adjustment should be made to exclude these two turbines from test year working capital by moving them from

Hines Unit 4 inventory to an AFUDC-bearing CWIP account. This adjustment reduces working capital in the amount of $46,782,000 system and $38,263,000 retail.

- Allocation of Unbilled Revenue: The Company agrees that the retail allocation of unbilled revenues should be reduced, but believes that the allocation factor based on only the first five months of 2005 proposed by Mr. Larkin is not representative of a full annual period, since unbilled revenues typically fluctuate over the course of a year. The retail portion of PEF's 13-month average unbilled revenues for 2003 was 85%, and the 13-month average for 2004 was 84%, or 84.5% for the two-year period, which the Company proposes as the adjusted retail allocation factor. This results in a reduction to retail working capital of $4,346,000.

Q. What is your reaction to the remaining working capital adjustment proposed by Mr. Larkin?

A. His remaining proposed adjustments to test year working capital are not well founded and should be rejected for the following reasons:

- Over and Under-Recoveries from Adjustment Clauses: The asymmetrical and disparate treatment proposed by Mr. Larkin for including adjustment clause over-recoveries in working capital and excluding under-recoveries is blatantly improper and illogical. Over-recoveries should be excluded from working capital because, like under-recoveries, the cost of carrying these balances is dealt with through the assignment of interest in the adjustment clause proceedings. Conversely, including an over-recovery in working capital would have the effect of charging the Company twice; once through the payment of interest charges in the adjustment clause proceedings, and again in base rates through the loss of a return on the working capital offset by the over-recovery. This double charge result is precisely the point made by Mr. Larkin to explain why under-recoveries should be excluded from working capital. Over-recoveries and under-recoveries are two sides of the same coin.

In this case, however, Mr. Larkin is wrong in his contention that PEF's over-recovery should be included in working capital for a much more simple and practical reason -- he apparently neglected to read the quote from the Commission order included in his testimony. Had he done so, he would have seen in the first line that the Commission had described its policy "to include *net* fuel and conservation over recoveries in working capital." The over-recovery on which Mr. Larkin bases his contention is the Company's conservation clause over-recovery of $8,144,000, which is shown on MFR Schedule B-1, line 4. Lines 5 and 6, however, show that PEF had substantial under-recoveries in its environmental and fuel clauses of $17.0 million and $43.5 million, respectively, for a net under-recovery in excess of $52 million. I feel confident the current Commission would have revisited the statement in the 1993 order cited by Mr. Larkin, which clearly overlooked the unintended consequences it could have caused. The facts in this case, however, demonstrate that the statement simply has no application.

- Removal of Recoverable Job Orders: Mr. Larkin believes an adjustment to PEF's test year working capital is warranted because the Company's adjustment to remove the account for recoverable job orders resulted in an increase to working capital. Since accounts of this type typically add to the level of working capital, one might normally expect to see working capital decrease when such an account is removed. In this case, however, the opposite is true. The recoverable job order has a negative balance. This means that while the negative balance was included, it reduced the level of working capital. Conversely, when it was removed from working capital consistent with standard ratemaking practices, working capital increased.

However, this is not the end of the accounting exercise. The reason the recoverable job order account had a negative balance is that job orders related to the 2004 hurricanes were transferred from the job order account in working capital and reclassified as a regulatory asset. The amount of the hurricane job order exceeded the balance of the account, which left a negative balance after the transfer. The key point in terms of PEF's rate case filing, however, is that the transfer had no net effect on overall test year rate base because the reclassified regulatory asset was also removed from the Company's filling, just as it would have been if the hurricane-related job orders had remained in working capital. In other words, when all of the accounting had been completed and the Company's case was filed, the transfer and reclassification of these job orders, and the negative working capital account balance it created, was transparent to ratepayers.

- Affiliate Receivables: Mr. Larkin is incorrect in his characterization of PEF's accounts receivable from associated companies. These accounts, totaling \$11 million, involve utility-related services provided to PEF, the majority of which are from Progress Energy Carolina and Progress Energy Service Company. I would note that affiliate accounts payable in the total amount of \$119.1 million are also included in working capital.

- Derivative Accounts: The derivative accounts reflected on PEF's balance sheet represent the Mark-to-Market (MTM) impact of derivative instruments entered into for the benefit of customers in accordance with the Commission's order authorizing PEF and other IOUs to develop hedging programs that would help reduce volatility in fuel prices and where possible, reduce fuel costs. Order No. PSC-02-1484-FOF-EI, Docket No. 011605. The balance sheet impacts of these transactions are completely offsetting and therefore have no impact on rate base.

Q. Are you familiar with the proposed adjustment to working capital that Ms. Brown recommends regarding storm assets?

A. Yes. Ms. Brown states that the working capital component of rate base has been overstated by an improper jurisdictional allocation in the removal of the storm damage reserve that is to be recovered through the Storm Cost Recovery Surcharge ("SCRS").

Q. Do you agree with the proposed adjustment that Ms. Brown recommends regarding PEF's storm assets?

A. Yes. Ms. Brown is correct in stating that the removal of the storm damage reserve should not have had a portion allocated to the wholesale jurisdiction, since the amount of $139 million is only the retail portion of the regulatory storm asset. The full $139 million should have been deducted from the jurisdictional rate base. The adjustment would result in a reduction to the revenue requirement of $2 million.

Working Capital Impact	$ 12,732,000

Revenue Factor	1.632
	$ 20,778,624
WACC - As Filed	0.0950
	$ 1,973,969

Q. Are there any other adjustments to working capital that you would like to address?

A. Yes. During my subsequent review of accrued interest in PEF's initial filing, I have concluded that the forecasted interest accrual was inadvertently charged against short-term debt rather than the accrued interest account in both 2005 and the 2006 test year. As a result, the accrued interest account in working capital was understated and short-term debt was overstated. Therefore, the Company proposes an adjustment to increase accrued interest by $11,387,000 system and $9,313,000 retail. This represents the cumulative effect for both 2005 and 2006 on the 13-month average accrued interest balance included in working capital in PEF's initial filing.

Deferred Income Taxes

Q. Mr. Larkin claims that PEF improperly included deferred income tax debits in its capital structure which offset a portion of deferred income tax credits that serve as a source of cost-free capital, thereby reducing the benefit to ratepayers from these deferred credits. Do you agree that including the Company's deferred income tax debits in its capital structure was improper?

A. No I don't. Mr. Larkin's position on this issue sounds like an echo from his position that under-recoveries from the cost recovery clauses are properly excluded from working capital, but that over-recoveries should be included because to do otherwise would increase costs to the ratepayer. I attempted to explain in my earlier response this working capital issue that over and under-recoveries were simply mirror images of each other that required consistent treatment. Deferred income tax debits and credits are no different.

Mr. Larkin is quick to recognize that the deferred debits represent funds advanced by ratepayers before PEF is required to pay the related income taxes and that they should receive a form of return while the Company has the use of these funds. And without question, they should. I am at a loss to understand how Mr. Larkin can recognize the correctness of that result so clearly, and yet contend that when the Company advances funds for the same purpose, providing it a return of those funds would be improper. The fact that PEF's return will partially offset and reduce the ratepayers' return is just one example of an economic truism that occurs throughout the ratemaking process. Mr. Larkin's contention that PEF's deferred income tax debits should be removed from its capital structure is contrary to the basic regulatory principle that funds furnished for a legitimate utility purpose are entitled to a return. His contention that the denial of a return on funds advanced should apply to PEF and not to others similarly situated is contrary to basic principles of fairness. I urge the Commission to reject Mr. Larkin's proposed departure from sound, accepted regulatory principles.

<u>Amortization of Rate Case Expense</u>

Q. OPC witness DeRonne and FRF witness Brown disagree with PEF's deferral of its rate case expense for amortization beginning in 2006 and its use of a two-year amortization period. Why has the Company treated rate case expense in this manner?

A. The Company has used deferral accounting so that the amortization of rate case expense can begin in 2006 in conjunction with the implementation of the rates set in this proceeding. The use of deferral accounting for this purpose is appropriate because the Company's rate case expense is properly attributed to the period when the rates for which the expense is incurred will be in effect. This is consistent with the Commission's normal practice of beginning the amortization of rate case expense in the test year.

A two-year amortization period is appropriate because, in the Company's estimation, that is the most likely period the rates set in this proceeding will be in effect before they are reset in PEF's next base rate proceeding. The establishment of an amortization period based on the expected interval between rate cases is also consistent with Commission practice.

Ms. DeRonne contends that if rate case expense is to be amortized, a period longer than two years should be used based on the extended period between 1992, the Company's last fully litigated rate case, and this proceeding. However, the stark contrast between the period following the 1992 rate case and the period in which PEF operates today belies her suggestion that the prior period is in any way representative of current conditions. For the most part, the remainder of the decade following the implementation of rates from the 1992 rate case was a relatively slow period of generation construction, traditionally the primary trigger for base rate proceedings. In fact, the only base load generating unit placed in service by the Company during this period was the Tiger Bay combined cycle unit, and that came about through a unique buyout of a QF purchase power agreement. However, since 1999, the pendulum has swung well in the other direction and PEF now finds itself in the midst of a rapid generation expansion program. Attendant with this need for significant plant additions is the likelihood of a more frequent need for base rate relief to recognize these highly capital intensive additions.

The beginnings of this pattern can be seen in PEF's 2002 rate case settlement agreement, which provided an innovative means for recognizing the capital investment in Hines Unit 2 through the fuel adjustment clause when the unit was placed in service. This approach provided an alternative to PEF seeking base rate relief when Hines 2 came on line two years later.

With the impending expiration of the settlement's rate freeze, PEF now finds itself before the Commission again to address the recovery of another new generating addition, Hines Unit 3, with a scheduled in-service date almost exactly two years after Hines Unit 2. This is a pattern that will continue over the coming years as new generation is placed in-service essentially every other year, including the scheduled in-service date of Hines Unit 4 in late 2007, two years after Unit 3. Recognizing this pattern, the Company's selection of a two-year amortization period is entirely reasonable and appropriate.

Q. Ms. Brown has suggested that, if a two-year amortization period for rate case expense is used, a mechanism should be established for transforming revenues related to rate case expense into a regulatory asset after two years if no rates from the next rate case have been implemented. What do you think of her suggestion?

A. I disagree. As with the other proposals for "color-coding" revenues that surface from time to time, Ms. Brown's proposal is contrary to, and made unnecessary by, rate of return regulation. Rather than quote from primers on utility regulation, suffice it to say that Ms. Brown's suggestion is not a good one. In this regard, I would note that Ms. Brown herself may not be a true advocate of her suggestion, since she did not propose including a comparable mechanism with the longer amortization period she prefers over a two-year period, which would provide a safeguard in the event her amortization period is too long and new rates are set before the period ends.

<u>**Other Net Operating Income Adjustments**</u>

Q. OPC witness DeRonne proposes an adjustment to reduce PEF's test year expense for uncollectible accounts based on a bad debt factor she calculates from the Company's experience with uncollectible accounts from 2001 through 2004. Do you believe the Commission should accept her proposed adjustment?

A. No I do not. My disagreement with Ms. DeRonne is not with her mathematical skills; I believe she has correctly calculated the average bad debt factor over the four-year period she selected. My disagreement concerns her premise for using a four-year historic average, which is that the conditions during that period which gave rise to uncollectible accounts are representative of the 2006 test year and beyond when the rates will be in effect. In a situation where recent and current experience indicates the charge-offs are expected to increase over the near-term, which is PEF's expectation, a historic average charge-off experience will dampen and distort the more current expectation. I believe Ms. DeRonne's bad debt factor will do just that. I acknowledge that there is a considerable degree of judgment in developing a factor that gauges the current and near-term direction of charge-offs, but I believe more confidence should be placed in the judgment of professionals engaged full time with monitoring and managing uncollectible accounts about where that situation is headed, rather than in a mathematical calculation of where that situation has been in the past.

Q. Ms. DeRonne has also proposed an adjustment to PEF's test year property tax expense for the items listed in her Exhibit No. __ (DD-1). What is your response to those adjustments?

A. I agree with two of Ms. DeRonne's property tax adjustments, the first of which concerns the transfer of two Hines 4 turbines from inventory to CWIP that I addressed previously. The other involves a Company adjustment made in its initial filing to remove the above-market portion of a certain affiliate transaction. However, it is now apparent that we overlooked a follow-up adjustment that should have been made to the property tax calculation. Adjusting test year property taxes for these two items results in a retail reduction of $1,376,000.

I do not agree with Ms. DeRonne's other two adjustments, which concern the property tax aspects of Mr. Larkin's proposed reductions to test year EPIS and Plant Held For Future Use that I addressed earlier in my testimony. I disagree with these two property tax adjustments for the reasons given earlier in my response to Mr. Larkin.

Q. FRF witness Brown contends that PEF has overstated the number of employees in developing its test year payroll and benefits expenses. How do you respond to these contentions?

A. Ms. Brown's contention regarding the number of employees is based on a misinterpretation of PEF's response to an OPC interrogatory stating that no employee <u>positions</u> would be added in 2005 and 2006, from which she mistakenly concluded that the number of positions included in test year payroll and benefits expense should equal the number of actual employees at the end of 2004.

PEF's payroll expense is based on employee *positions*, which includes authorized but temporarily unfilled positions. The reorganization not only resulted in the elimination of a number of positions, but also a number of vacancies in the remaining positions, which the Company is in the process of filling. The test year payroll expense included in PEF's filing has already been adjusted for the reduction in employee positions from the reorganization, as well as for the temporarily vacant, but soon to be filled, positions by the application of a vacancy factor to test year base payroll expense. A further adjustment, therefore, would be unnecessary and inappropriate.

Q. Ms. Brown also contends that PEF's allocation of test year payroll and payroll taxes between expense and capital is inconsistent and allocates too much to expense. Would please address this issue?

A. The rebuttal testimony of Mr. Bazemore addresses this issue in greater detail. The information provided by the Company that she describes in her testimony was the result of inadvertent errors in our responses to certain interrogatories. The interrogatory responses were corrected when the errors were discovered. I have attempted to sort through and clarify the payroll information related to her allocation issue in my Exhibit No. __ (JP-15). Based on the information from our corrected interrogatory responses, which is included in my exhibit, it should be apparent that the allocations of payroll and payroll taxes are consistent with each other and with the Company's recent experience.

Q. Mr. Portuondo as a result of the Commission's recent decision in the 2004 Hurricane Cost Recovery proceeding and discovery question by intervenor's in this proceeding did you include an adjustment for this issue?

A. Yes, my Exhibit No.__ (JP-17) details the adjustment necessary to reflect the decision of the Commission in Docket No. 041272, Order No. PSC-05-0748-FOF-EI. In that order the Commission's decision, as it related to base rate, only impacted the amount of capital to be recognized for base rate. This necessitated that PEF increase total Net Electric Plant In-Service through a charge to Accumulated Depreciation in the amount of $8.4 million, in addition to the amount that had already been estimated by the Company of $1.4 for a minimum amount of removal of $10 million. Additionally, PEF has updated the total projected Electric Plant In-Service for the result through June 31, 2005, defined by the Commission as the cut-off point in their order.

Implementation of PEF's Updated Sales Forecast

Q. You stated at the outset of your testimony that you provide support for the implementation of the updated sales forecast and the jurisdictional separation study provided in the rebuttal testimonies of Company witness John B. Crisp and William Slusser, respectively. How will this be accomplished?

A. My Exhibits No. __ (JP-13, 18 & 19) provide summaries that include the effects of both Mr. Crisp's and Mr. Slusser's rebuttal testimonies. My exhibit also breaks out each of the adjustments to PEF's initial filing that it has proposed or agreed to through the testimony of the Company's rebuttal witnesses or through its discovery responses, the net result of which is a revised revenue deficiency of $209,105,000.

Q. Do you have any additional comments regarding the testimony of the intervenor witnesses filed in this case?

A. Yes, I have one final comment. I wish to make clear that the absence of a specific response in my rebuttal testimony to any other portions of the intervenor witnesses' testimony not addressed above should not be taken to imply my concurrence or acquiescence. I have included responses to the intervenor witnesses where I determined that additional information or clarification was necessary or appropriate beyond that provided in my direct testimony or the direct and rebuttal testimony of other Company witnesses.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Progress Energy Florida
Analysis of Cost of Service
Associated with Winter Park

Line	Description	No. of Customers	Annual Lines of Billing	$000's 2006 Test Year Amount	Comments	Total Company for Allocations Units	Total Company for Allocations $000's
1	**Revenues**						
2	Sales of Electric - Retail, Base				E-13c format for WP in isolation		
3	RS	11,995	143,950	$ 8,728			
4	GS1	1,625	19,505	1,073			
5	GS2	109	1,299	27			
6	GSD	1,147	13,774	5,496			
7	LS	79	5,115	39			
8	Subtotal Sales of Electric	14,955	183,643	15,363			
9							
10	Other Operating Revenues						
11	Late Payment Charges			12	Based on Rate Base	5,025,908	8,175
12	Service Charges			218	Based on % of Total Annual Lines of Billing	19,104,741	22,635
13	Equipment Rental			67	Based on % of Total Annual Lines of Billing	19,104,741	6,924
14	Street Light Facilities			247	WP billing units priced in E-13d format		
15	Pole Attachment Revenues			59	Per Joint Use Dept records using 2005 rates		
16	Amortization of Stranded Cost			(1,855)	Per WP Arbitration Agmnt - $2,030 @ 91.4%		
17	Subtotal Other Operating Revenue			(1,252)			
18							
19	**Total Revenues**			**14,111**			
20							
21							
22	**Operating Expenses**	Labor	Non-Labor	Total			
23	Transmission O&M	$ 30	$ 11	$ 41	Per Distribution Finance Organization		
24							
25	Distribution O&M						
26	FERC 583	8	7	15	Per Distribution Finance Organization		
27	FERC 585	20	19	39	Per Distribution Finance Organization		
28	FERC 588	-	24	24	Per Distribution Finance Organization		
29	FERC 593	165	56	221	Per Distribution Finance Organization		
30	FERC 594	60	37	97	Per Distribution Finance Organization		
31	Subtotal Distribution O&M	253	143	396			
32							
33	Customer Accounts						
34	FERC 903 - Delinquent Accts	2	-	2	Per Distribution Finance Organization		
35	- Billing - Postage, Printing		71	71	Based on Total Customers	1,603,580	7,652
36	FERC 904 - Bad Debt Expense		25	25	Based on Bad Debt Factor for 2006 per C-11	0.001743	
37	Subtotal Customer Accts O&M	2	96	98			
38							
39	Admin & General O&M - FERC 926		97	97	Based on Payroll Benefits Burden	34.00%	
40	Subtotal O&M Expenses	285	347	632			
41							
42							
43	Other Taxes						
44	Property Tax			267	Gross Plant @ 75% * millage rate of 1.83%	1.37%	
45	Payroll Tax			27	Based on Payroll Tax Burden	9.55%	
46	Revenue Taxes			10	Regulatory Assessment Fee	0.00072	
47	Subtotal Other Taxes			304			
48							
49	Depreciation Expense					Depr Rates:	
50	Distribution						
51	FERC 360			-	EPIS times depreciation rate	0.00%	
52	FERC 361			2	EPIS times depreciation rate	1.86%	
53	FERC 362			50	EPIS times depreciation rate	2.57%	
54	FERC 364			212	EPIS times depreciation rate	8.29%	
55	FERC 365			91	EPIS times depreciation rate	3.34%	
56	FERC 366			1	EPIS times depreciation rate	1.78%	
57	FERC 367			64	EPIS times depreciation rate	3.56%	
58	FERC 368			184	EPIS times depreciation rate	3.80%	
59	FERC 369.1			33	EPIS times depreciation rate	5.45%	
60	FERC 369.2			102	EPIS times depreciation rate	3.48%	
61	FERC 370			56	EPIS times depreciation rate	4.57%	
62	FERC 373			27	EPIS times depreciation rate	5.85%	
63							
64	Transmission FERC 355			1		2.72%	
65	Subtotal Depreciation Expense			823			
66							
67	**Total Operating Expenses**			**1,759**			
68							
69	Pretax Income			12,352			
70	Income Taxes			4,707	Statutory Rate * Pretax + Interest Synch	38.575%	
71	**Net Operating Income**			**7,645**			

Progress Energy Florida
Analysis of Cost of Service
Associated with Winter Park

$000's

Line	Description	2005 YE Balance	2006 YE Balance	2006 Test Year 13 Mo Avg	6/30/05 JE for Sale	Ongoing Capital 2005	2005	Adjust for MMR
1	**Electric Plant in Service**							
2	Distribution							
3	FERC 360	202	204	203	201	1	2	
4	FERC 361	92	93	93	92	0	1	
5	FERC 362	1,924	1,943	1,934	1,914	10	19	
6	FERC 364	2,549	2,575	2,562	2,536	13	26	
7	FERC 365	2,700	2,727	2,714	2,686	14	27	
8	FERC 366	67	68	68	67	0	1	
9	FERC 367	1,780	1,798	1,789	1,771	9	18	
10	FERC 368	4,824	4,873	4,848	4,799	25	48	
11	FERC 369.1	604	610	607	601	3	6	
12	FERC 369.2	2,910	2,939	2,925	2,895	15	29	13 mo Avg
13	FERC 370	662	669	1,231	659	3	7	565
14	FERC 373	455	460	458	453	2	5	
15								
16	Transmission FERC 355	10	30	20		10	20	
17	Subtotal Electric Plant in Service	18,782	18,991	19,452	18,674	108	209	565
18								
19	**Accumulated Reserve for Depreciation**							
20	Distribution							
21	FERC 360	-	-	-	-	-	-	
22	FERC 361	(72)	(73)	(73)	(70)	(2)	(2)	
23	FERC 362	(1,828)	(1,878)	(1,853)	(1,779)	(49)	(50)	
24	FERC 364	(1,738)	(1,950)	(1,844)	(1,527)	(211)	(212)	
25	FERC 365	(1,679)	(1,770)	(1,724)	(1,589)	(90)	(91)	
26	FERC 366	(15)	(16)	(16)	(14)	(1)	(1)	
27	FERC 367	(1,977)	(2,041)	(2,009)	(1,914)	(63)	(64)	
28	FERC 368	(1,347)	(1,531)	(1,439)	(1,164)	(183)	(184)	
29	FERC 369.1	(495)	(528)	(511)	(462)	(33)	(33)	
30	FERC 369.2	(1,382)	(1,484)	(1,433)	(1,281)	(101)	(102)	13 mo Avg
31	FERC 370	(666)	(697)	(694)	(636)	(30)	(30)	(13)
32	FERC 373	(453)	(479)	(466)	(426)	(27)	(27)	
33		-	-			-	-	
34	Transmission FERC 355	(0)	(1)	(0)		(0)	(1)	
35	Subtotal Accumulated Reserve	(11,652)	(12,448)	(12,063)	(10,862)	(790)	(796)	(13)
36								
37	**Net Plant**			7,389				
38								
39	Other Rate Base Items							
40	(no other changes anticipated)							
41								
42	**Total Rate Base**			7,389				
43								
44								
45								
46	**Interest Synchronization Adjustment**							
47	Debt Component of Cost of Capital			2.038%				
48	Times Rate Base = Interest Effect			(151)				
49	Income Tax Effect			58				
50								
51								
52								
53	**Cost of Capital (Specific to WP):**							
54	Customer Deposits @ 1.11% of Total based on sales			1,126				
55								
56	Accumulated Deferred Income Taxes			396				
57	(Diff in Book and Tax Basis of Assets * Tax Rate							
58	at time of sale)							
59	Total WP Specific Cost of Capital			1,522				

Progress Energy Florida
Docket No. 050078-EI
2006 Test Year Fully Adjusted
Impact of Revised Sales Forecast and Winter Park Treated as Wholesale

		Original Case as Filed			Revised Case - Sales Forecast & Winter Park			Difference - Sales Forecast & Winter Park		
LINE NO.	DESCRIPTION	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR
1	**Development of Rate Base:**									
2										
3	Electric Plant in Service	$9,029,688	$8,363,233	0.92619	$9,010,235	$8,287,345	0.91977	($19,453)	($75,888)	(0.00642)
4	Less: Accum Deprec & Amort	4,394,317	4,051,946	0.92209	4,382,255	4,007,544	0.91449	(12,062)	(44,402)	(0.00759)
5	Net Plant in Service	4,635,372	4,311,287	0.93008	4,627,981	4,279,801	0.92477	(7,391)	(31,486)	(0.00532)
6	CWIP Not Bearing AFUDC	98,597	82,105	0.83273	98,598	81,294	0.82449	1	(811)	(0.00823)
7	Plant Held for Future Use	7,922	6,054	0.76426	7,922	6,000	0.75740	0	(54)	(0.00685)
8	Uamortized Nuclear Fuel	63,933	57,413	0.89802	63,933	56,631	0.88579	0	(782)	(0.01223)
9	Working Capital	220,083	183,593	0.83420	220,083	180,004	0.81789	0	(3,589)	(0.01631)
10	Total Rate Base	$5,025,908	$4,640,452	0.92331	$5,018,518	$4,603,730	0.91735	($7,390)	($36,722)	(0.00596)
11										
12										
13	**Development of Return:**									
14										
15	**Operating Revenues**									
16	Sales of Electricity	$1,483,276	$1,389,674	0.93690	$1,451,180	$1,357,574	0.93550	($32,096)	($32,100)	(0.00140)
17	Other Operating Revenues	131,911	92,548	0.70159	133,337	93,702	0.70274	1,426	1,154	0.00115
18	Total Operating Revenues	1,615,187	1,482,222	0.91768	1,584,517	1,451,275	0.91591	(30,670)	(30,947)	(0.00177)
19										
20	**Operating Expenses**									
21	Operation & Maintenance	673,859	612,136	0.90840	673,224	607,421	0.90226	(635)	(4,715)	(0.00615)
22	Depreciation & Amortization	330,521	310,893	0.94062	329,698	308,295	0.93509	(823)	(2,598)	(0.00553)
23	Taxes Other Than Income	122,653	113,631	0.92644	122,349	112,557	0.91997	(304)	(1,074)	(0.00647)
24	Other Operating Expenses	(80)	(74)	0.92619	(80)	(74)	0.91977	0	1	(0.00642)
25	Income Taxes - Federal	196,792	180,199	0.91568	187,282	172,553	0.92136	(9,511)	(7,646)	0.00567
26	Income Taxes - State	32,724	29,965	0.91568	31,143	28,694	0.92137	(1,582)	(1,271)	0.00569
27	Provision for Deferred Income Taxes	(79,910)	(74,012)	0.92619	(79,910)	(73,499)	0.91977	0	513	(0.00642)
28	Investment Tax Credit	(5,937)	(5,499)	0.92619	(5,937)	(5,461)	0.91977	0	38	(0.00642)
29	Total Operating Expenses	1,270,623	1,167,239	0.91864	1,257,768	1,150,488	0.91471	(12,854)	(16,751)	(0.00393)
30										
31	**Net Operating Income**	$344,564	$314,983	0.91415	$326,749	$300,788	0.92055	($17,816)	($14,196)	0.00640
32										

Progress Energy Florida
Docket No. 050078-EI
2006 Test Year Fully Adjusted
Impact of Revised Sales Forecast and Winter Park Treated as Wholesale

		Original Case as Filed			Revised Case - Sales Forecast & Winter Park			Difference - Sales Forecast & Winter Park		
LINE NO.	DESCRIPTION	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR
33	**Electric Plant in Service:**									
34	**Intangible Plant:**									
35	303-Intangible Plant	$118,563	$115,104	0.97082	$118,563	$114,611	0.96667	$0	($493)	(0.00415)
36	**Production:**									
37	310-316-Steam	1,775,637	1,621,084	0.91296	1,775,637	1,597,340	0.89959	0	(23,744)	(0.01337)
38	320-325-Nuclear	810,693	766,872	0.94595	810,693	757,500	0.93439	0	(9,372)	(0.01156)
39	340-346-Other	1,476,104	1,368,621	0.92718	1,476,104	1,358,167	0.92010	0	(10,454)	(0.00708)
40	Total Production	4,062,433	3,756,577	0.92471	4,062,433	3,713,007	0.91399	0	(43,570)	(0.01073)
41	**Transmission:**									
42	350-Land and Land Rights	62,946	44,962	0.71429	62,946	44,438	0.70597	0	(524)	(0.00832)
43	352-Structure and Improvements	22,630	16,164	0.71429	22,630	15,976	0.70597	0	(188)	(0.00832)
44	353-Station Equipment	458,973	340,171	0.74116	458,973	336,317	0.73276	0	(3,854)	(0.00840)
45	354-Towers & Fixtures	69,076	49,340	0.71429	69,076	48,765	0.70597	0	(575)	(0.00832)
46	355-Poles & Fixtures	296,819	212,013	0.71429	296,797	209,531	0.70597	(21)	(2,482)	(0.00832)
47	356-O.H. Conductor and Devices	247,433	176,739	0.71429	247,433	174,680	0.70597	0	(2,059)	(0.00832)
48	357-U.G. Conduit	7,263	5,188	0.71429	7,263	5,127	0.70597	0	(61)	(0.00832)
49	358-U.G. conductors & Devices	9,543	6,816	0.71429	9,543	6,737	0.70597	0	(79)	(0.00832)
50	359-Roads and Trails	1,923	1,374	0.71429	1,923	1,358	0.70597	0	(16)	(0.00832)
51	Adjustment - Transmission Enhancement Projects	6,346	4,533	0.71429	6,346	4,480	0.70597	0	(53)	(0.00832)
52	Total Transmission	1,182,950	857,300	0.72471	1,182,929	847,409	0.71637	(21)	(9,891)	(0.00835)
53	**Distribution:**									
54	360-Land and Land Rights	21,634	21,548	0.99602	21,431	21,345	0.99597	(203)	(203)	(0.00005)
55	361-Structure and Improvements	21,864	21,777	0.99602	21,771	21,684	0.99597	(93)	(93)	(0.00005)
56	362-Station Equipment	376,299	374,795	0.99600	374,365	372,845	0.99594	(1,934)	(1,950)	(0.00006)
57	364-Poles & Fixtures	491,147	490,021	0.99770	488,585	487,449	0.99768	(2,562)	(2,572)	(0.00003)
58	365-O.H. Conductors	504,251	502,710	0.99694	501,538	499,975	0.99689	(2,714)	(2,735)	(0.00006)
59	366-U.G. Conduits	180,793	180,347	0.99753	180,726	180,274	0.99750	(68)	(73)	(0.00003)
60	367-U.G. Conductors	467,486	466,593	0.99809	465,697	464,796	0.99807	(1,789)	(1,797)	(0.00002)
61	368-Line Transformers	429,492	429,492	1.00000	424,644	424,644	1.00000	(4,848)	(4,848)	-
62	369-Services	479,834	479,834	1.00000	476,302	476,302	1.00000	(3,532)	(3,532)	-
63	370-Meters	128,663	127,218	0.98877	127,432	125,954	0.98840	(1,231)	(1,264)	(0.00037)
64	371-Installations on customers' premises	3,772	3,731	0.98918	3,772	3,730	0.98883	0	(1)	(0.00035)
65	372-Leased property on customers' premises	0	0	0.00000	0	0	0.00000	0	0	-
66	373-Street Lighting	278,305	278,169	0.99951	277,848	277,709	0.99950	(458)	(460)	(0.00001)
67	Adjustment - Charging Practices	(50,722)	(50,601)	0.99761	(50,722)	(50,599)	0.99758	0	2	(0.00003)
68	Adjustment - MMR Project	(3,386)	(3,386)	1.00000	(3,386)	(3,386)	1.00000	0	0	-
69	Adjustment - Distribution Enhancement Projects	7,298	7,281	0.99761	7,298	7,280	0.99758	0	(1)	(0.00003)
70	Total Distribution	3,336,732	3,329,529	0.99784	3,317,300	3,310,002	0.99780	(19,432)	(19,527)	(0.00004)
71	**General Plant:**									
72	389-399 General Plant	333,184	308,581	0.92615	333,184	306,142	0.91884	0	(2,439)	(0.00732)
73	Adjustment - Organization Realignment	(4,174)	(3,858)	0.92421	(4,174)	(3,826)	0.91670	0	32	(0.00751)
74	Total General Plant	329,010	304,723	0.92618	329,010	302,316	0.91887	0	(2,407)	(0.00732)
75	**Total Electric Plant in Service**	$9,029,688	$8,363,233	0.92619	$9,010,235	$8,287,345	0.91977	($19,453)	($75,888)	(0.00642)
76										

LINE NO.	DESCRIPTION	Original Case as Filed SYSTEM	RETAIL	RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR
77	**Accumulated Depreciation:**									
78	**Intangible Plant:**									
79	303-Intangible Plant	$109,051	$106,128	0.97320	$109,051	$105,711	0.96938	$0	($417)	(0.00382)
80	**Production:**									
81	310-316-Steam	1,378,164	1,250,506	0.90737	1,378,164	1,231,711	0.89373	0	(18,795)	(0.01364)
82	320-325-Nuclear	523,262	493,887	0.94386	523,262	487,851	0.93233	0	(6,036)	(0.01154)
83	340-346-Other	486,010	444,005	0.91357	486,010	441,926	0.90929	0	(2,079)	(0.00428)
84	Adjustment - Unfunded Nuc Decom - Whls	(2,286)	0	0.00000	(2,286)	0	0.00000	0	0	-
85	Total Production	2,385,151	2,188,398	0.91751	2,385,151	2,161,488	0.90623	0	(26,910)	(0.01128)
86	**Transmission:**									
87	350-Land and Land Rights	14,579	10,413	0.71429	14,579	10,292	0.70597	0	(121)	(0.00832)
88	352-Structure and Improvements	7,272	5,194	0.71429	7,272	5,134	0.70597	0	(60)	(0.00832)
89	353-Station Equipment	146,894	109,872	0.74797	146,894	108,623	0.73947	0	(1,249)	(0.00850)
90	354-Towers & Fixtures	55,130	39,380	0.71429	55,130	38,920	0.70597	0	(460)	(0.00832)
91	355-Poles & Fixtures	116,409	83,150	0.71429	116,409	82,182	0.70597	1	(968)	(0.00832)
92	356-O.H. Conductor and Devices	115,900	82,786	0.71429	115,900	81,822	0.70597	0	(964)	(0.00832)
93	357-U.G. Conduit	5,024	3,589	0.71429	5,024	3,547	0.70597	0	(42)	(0.00832)
94	358-U.G. conductors & Devices	7,381	5,272	0.71429	7,381	5,211	0.70597	0	(61)	(0.00832)
95	359-Roads and Trails	933	666	0.71429	933	659	0.70597	0	(7)	(0.00832)
96	Adjustment - Transmission Enhancement Projects	61	44	0.71429	61	43	0.70597	0	(1)	(0.00832)
97	Total Transmission	469,583	340,366	0.72483	469,583	336,433	0.71645	1	(3,933)	(0.00838)
98	**Distribution:**									
99	360-Land and Land Rights	199	199	0.99602	199	199	0.99597	0	0	(0.00005)
100	361-Structure and Improvements	6,573	6,547	0.99602	6,500	6,474	0.99597	(73)	(73)	(0.00005)
101	362-Station Equipment	115,947	115,483	0.99600	114,094	113,630	0.99594	(1,853)	(1,853)	(0.00006)
102	364-Poles & Fixtures	232,222	231,688	0.99770	230,378	229,843	0.99768	(1,844)	(1,845)	(0.00003)
103	365-O.H. Conductors	244,981	244,232	0.99694	243,257	242,499	0.99689	(1,724)	(1,733)	(0.00006)
104	366-U.G. Conduits	32,774	32,693	0.99753	32,758	32,676	0.99750	(16)	(17)	(0.00003)
105	367-U.G. Conductors	130,191	129,942	0.99809	128,182	127,934	0.99807	(2,009)	(2,008)	(0.00002)
106	368-Line Transformers	225,290	225,290	1.00000	223,850	223,850	1.00000	(1,440)	(1,440)	-
107	369-Services	146,126	146,126	1.00000	144,182	144,182	1.00000	(1,944)	(1,944)	-
108	370-Meters	58,795	58,134	0.98877	58,100	57,426	0.98840	(694)	(708)	(0.00037)
109	371-Installations on customers' premises	1,117	1,105	0.98905	1,117	1,104	0.98869	0	(1)	(0.00036)
110	372-Leased property on customers' premises	0	0	0.00000	0	0	0.00000	0	0	-
111	373-Street Lighting	156,374	156,298	0.99951	155,908	155,831	0.99950	(466)	(467)	(0.00001)
112	Adjustment - Charging Practices	(1,793)	(1,789)	0.99761	(1,793)	(1,789)	0.99758	0	0	(0.00003)
113	Adjustment - MMR Project	(58,940)	(58,940)	1.00000	(58,940)	(58,940)	1.00000	0	0	-
114	Adjustment - Distribution Enhancement Projects	105	105	0.99761	105	105	0.99758	0	0	(0.00003)
115	Total Distribution	1,289,960	1,287,113	0.99779	1,277,897	1,275,024	0.99775	(12,063)	(12,089)	(0.00004)
116	**General Plant:**									
117	389-399 General Plant	140,572	129,941	0.92437	140,573	128,888	0.91687	1	(1,053)	(0.00749)
118	**Total Accumulated Depreciation**	$4,394,317	$4,051,946	0.92209	$4,382,255	$4,007,544	0.91449	($12,062)	($44,402)	(0.00759)
119										
120	**Net Plant in Service**	$4,635,372	$4,311,287	0.93008	$4,627,981	$4,279,801	0.92477	($7,391)	($31,486)	(0.00532)
121										

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LINE NO.	DESCRIPTION	Original Case as Filed			Revised Case - Sales Forecast & Winter Park			Difference - Sales Forecast & Winter Park		
		SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR
122	**CWIP**									
123	Production	$184,604	$170,705	0.92471	$184,605	$168,726	0.91399	$1	($1,979)	(0.01072)
124	Transmission	46,251	33,036	0.71429	46,251	32,652	0.70597	0	(385)	(0.00832)
125	Distribution	13,591	13,562	0.99784	13,591	13,562	0.99780	0	(1)	(0.00004)
126	General	25	23	0.92421	25	23	0.91670	0	(0)	(0.00751)
127	Adjustment - Charging Practices	(2,539)	(2,533)	0.99761	(2,539)	(2,533)	0.99758	0	0	(0.00003)
128	Adjustment - Transmission Enhancement Projects	1,154	824	0.71429	1,154	815	0.70597	0	(10)	(0.00832)
129	Adjustment - Distribution Enhancement Projects	1,327	1,324	0.99761	1,327	1,324	0.99758	0	(0)	(0.00003)
130	Total CWIP	244,413	216,942	0.88760	244,414	214,568	0.87789	1	(2,374)	(0.00972)
131	**Less CWIP Bearing Interest**									
132	Production	145,815	134,837	0.92471	145,815	133,274	0.91399	0	(1,563)	(0.01072)
133	Transmission	0	0	0.00000	0	0	0.00000	0	0	-
134	Distribution	0	0	0.00000	0	0	0.00000	0	0	-
135	General	0	0	0.00000	0	0	0.00000	0	0	-
136	Total CWIP Bearing Interest	145,815	134,837	0.92471	145,815	133,274	0.91399	0	(1,563)	(0.01072)
137	**CWIP Not Bearing Interest**	98,597	82,105	0.83273	98,598	81,294	0.82449	1	(811)	(0.00823)
138										
139	**Plant Held for Future Use**	7,922	6,054	0.76426	7,922	6,000	0.75740	0	(54)	(0.00685)
140										
141	**Unamortized Nuclear Site**	63,933	57,413	0.89802	63,933	56,631	0.88579	0	(782)	(0.01223)
142										
143	**Working Capital**									
144	Net of Current Assets and Current Liabilities	293,900	270,987	0.92203	293,900	268,253	0.91273	0	(2,734)	(0.00930)
145	Preliminary Survey and Investigation Charges		0	0.00000		0	0.00000	0	0	-
146	Prepayments	2,364	2,188	0.92558	2,364	2,172	0.91916	0	(15)	(0.00642)
147	Clearing Accounts	(269)	(245)	0.90840	(269)	(243)	0.90226	0	2	(0.00614)
148	Unamortized Deferred O & M		0	0.00000		0	0.00000	0	0	-
149	Injuries and Damages Reserve	(22,894)	(21,347)	0.93246	(22,894)	(21,253)	0.92838	0	94	(0.00407)
150	Operating Provisions	(8,535)	(26,166)	3.06589	(8,535)	(27,155)	3.18179	0	(989)	0.11591
151	Other Deferred Credits & Debits	(3,804)	(3,147)	0.82725	(3,804)	(3,130)	0.82288	0	17	(0.00437)
152	Adjustment - Last Core Nuclear Fuel	168	168	1.00000	168	168	1.00000	0	0	-
153	Adjustment - PFC Coal Inventory	28,387	25,868	0.91126	28,387	25,515	0.89883	0	(353)	(0.01244)
154	Adjustment - End of Life Nuclear M&S	409	409	1.00000	409	409	1.00000	0	0	-
155	Adjustment - Incremental Storm Reserve	(22,000)	(21,328)	0.96945	(22,000)	(21,309)	0.96859	0	19	(0.00086)
156	Adjustment - Gain/Loss on Sale of Property	(127)	(118)	0.92913	(127)	(117)	0.92126	0	1	(0.00787)
157	Adjustment - Organization Realignment	(47,000)	(43,438)	0.92421	(47,000)	(43,085)	0.91670	0	353	(0.00751)
158	Adjustment - Retail Rate Case Expenses	2,250	2,250	1.00000	2,250	2,250	1.00000	0	0	-
159	Adjustment - Section 1341	1,407	1,303	0.92608	1,407	1,294	0.91969	0	(9)	(0.00640)
160	Adjustment - Remove RTO Start-up	(4,173)	(3,791)	0.90846	(4,173)	(3,765)	0.90223	0	26	(0.00623)
161	Total Working Capital	220,083	183,593	0.83420	220,083	180,004	0.81789	0	(3,589)	(0.01631)
162										
163	**Total Adjusted Rate Base**	$5,025,908	$4,640,452	0.92331	$5,018,518	$4,603,730	0.91735	($7,390)	($36,722)	(0.00596)
164										
165										
166										
167										

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LINE NO.	DESCRIPTION	Original Case as Filed			Revised Case - Sales Forecast & Winter Park			Difference - Sales Forecast & Winter Park		
		SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR
168	**Operating Revenues:**									
169										
170	**Sales of Electricity**									
171	Class- Retail	$1,563,108	$1,563,108	1.00000	$1,531,012	$1,531,012	1.00000	($32,096)	($32,096)	-
172	Class-Wholesale	93,571	0	0.00000	93,571	0	0.00000	0	0	-
173	Non-Class	406	376	0.92471	406	371	0.91399	0	(4)	(0.01072)
174	Adjustment - Mobile Meter Reading	3,171	3,171	1.00000	3,171	3,171	1.00000	0	0	-
175	Adjustment - Adj Rev to Rate Simulation	1,001	1,001	1.00000	1,001	1,001	1.00000	0	0	-
176	Adjustment - Franchise & Gross Receipts Tax	(174,424)	(174,424)	1.00000	(174,424)	(174,424)	1.00000	0	0	-
177	Adjustment - Sebring	(3,558)	(3,558)	1.00000	(3,558)	(3,558)	1.00000	0	0	-
178	**Total Sales of Electricity**	1,483,276	1,389,674	0.93690	1,451,180	1,357,574	0.93550	(32,096)	(32,100)	(0.00140)
179										
180	**Other Operating Revenues**									
181	4500001 Interest - Deliq A/C & LPC	8,175	7,548	0.92331	8,163	7,489	0.91735	(12)	(60)	(0.00596)
182	4510001 Service Charges	22,635	22,635	1.00000	22,417	22,417	1.00000	(218)	(218)	-
183	4540000 Rent from Elec Prop	59,071	58,949	0.99795	58,698	58,565	0.99774	(373)	(384)	(0.00021)
184	456 Amort of Stranded Costs				2,030	1,855	0.91399	2,030	1,855	0.91399
185	456000T Wheeling Revenues	40,946	2,390	0.05836	40,945	2,362	0.05768	(1)	(28)	(0.00068)
186	4560021 Other Electric Revenue	1,085	1,027	0.94651	1,085	1,014	0.93495	0	(13)	(0.01156)
187	4560022 Commission Tax Coll	0	0	0.00000	0	0	0.00000	0	0	-
188	4560011 Conservation	0	0	0.00000	0	0	0.00000	0	0	-
189	4560030 Unbilled Revenue	0	0	0.00000	0	0	0.00000	0	0	-
190	4560099 Def Fuel Revenues	0	0	0.00000	0	0	0.00000	0	0	-
191	SubTotal Account 456	42,031	3,416	0.08128	44,060	5,232	0.11874	2,029	1,815	0.03745
192										
193	**Total Other Operating Revenues**	131,911	92,548	0.70159	133,337	93,702	0.70274	1,426	1,154	0.00115
194										
195	**Total Operating Revenues**	$1,615,187	$1,482,222	0.91768	$1,584,517	$1,451,275	0.91591	($30,670)	($30,947)	(0.00177)
196										
197										
198	**Operation & Maintenance Expenses:**									
199										
200	**Production Expenses**									
201										
202	**Steam Generation-Operation**									
203	50000 Supervision & Engineering	$2,494	$2,269	0.90957	$2,494	$2,235	0.89604	$0	($34)	(0.01354)
204	50100 Fuel Non-Recoverable	3,995	3,879	0.97087	3,995	3,826	0.95765	0	(53)	(0.01322)
205	50200 Steam Expenses	7,307	6,597	0.90279	7,307	6,496	0.88892	0	(101)	(0.01387)
206	50400 Steam Transfer Credit	0	0	0.00000	0	0	0.00000	0	0	-
207	50500 Electric Expenses	304	246	0.80893	304	240	0.79046	0	(6)	(0.01847)
208	50600 Miscellaneous Expenses	24,698	21,860	0.88512	24,698	21,497	0.87038	0	(364)	(0.01474)
209	50700 Rents									
210	**Total Steam Generation-Operation**	38,799	34,851	0.89825	38,799	34,293	0.88388	0	(558)	(0.01437)
211										

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LINE NO.		DESCRIPTION	Original Case as Filed SYSTEM	Original Case as Filed RETAIL	Original Case as Filed RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	Revised Case - Sales Forecast & Winter Park RETAIL	Revised Case - Sales Forecast & Winter Park RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	Difference - Sales Forecast & Winter Park RETAIL	Difference - Sales Forecast & Winter Park RETAIL FACTOR
212	**Steam Generation - Maintenance**										
213	51000	Supervision & Engineering	2,971	2,703	0.90997	2,971	2,667	0.89758	0	(37)	(0.01239)
214	51100	Structures	215	171	0.79732	215	169	0.78646	0	(2)	(0.01086)
215	51200	Boiler Plant	20,933	18,480	0.88280	20,933	18,228	0.87078	0	(252)	(0.01202)
216	51300	Electric Plant	2,969	2,424	0.81648	2,969	2,391	0.80536	0	(33)	(0.01112)
217	51400	Miscellaneous Expenses	16,660	14,834	0.89037	16,660	14,632	0.87825	0	(202)	(0.01212)
218	**Total Steam Generation - Maintenance**		43,748	38,612	0.88261	43,748	38,086	0.87059	0	(526)	(0.01202)
219											
220	**Steam Generation Adjustments**										
221	Adjustment - Organization Realignment		(2,165)	(2,001)	0.92421	(2,165)	(1,985)	0.91670	0	16	(0.00751)
222	Adjustment - Progress Fuels Corp.		1,819	1,766	0.97087	1,819	1,742	0.95765	0	(24)	(0.01322)
223	**Total Steam Generation Adjustments**		(346)	(235)	0.67893	(346)	(243)	0.70142	0	(8)	0.02249
224											
225	**Total Steam Generation**		82,201	73,228	0.89085	82,201	72,137	0.87758	0	(1,091)	(0.01327)
226											
227											
228	**Nuclear Generation-Operation**										
229	51700	Supervision & Engineering	381	361	0.94913	381	357	0.93753	0	(4)	(0.01160)
230		Supervision & Engineering-Tallahassee Buy Back	6	0	0.00000	6	0	0.00000	0	0	-
231	51800	Fuel Non-Recoverable	1,595	1,580	0.99096	1,595	1,574	0.98686	0	(7)	(0.00410)
232		Fuel Non-Recoverable-Tallahassee Buy Back	24	0	0.00000	24	0	0.00000	0	0	-
233	51900	Coolants & Water	3,010	2,857	0.94913	3,010	2,822	0.93753	0	(35)	(0.01160)
234		Coolants & Water-Tallahassee Buy Back	44	0	0.00000	44	0	0.00000	0	0	-
235	52000	Steam Expenses	10,536	10,000	0.94913	10,536	9,878	0.93753	0	(122)	(0.01160)
236		Steam Expenses-Tallahassee Buy Back	155	0	0.00000	155	0	0.00000	0	0	-
237	52100	Steam From Oth Source	0	0	0.00000	0	0	0.00000	0	0	-
238		Steam From Oth Source -Tallahassee Buy Back	0	0	0.00000	0	0	0.00000	0	0	-
239	52200	Steam Transfer Credit	0	0	0.00000	0	0	0.00000	0	0	-
240		Steam Transfer Credit-Tallahassee Buyback	0	0	0.00000	0	0	0.00000	0.00000	0	-
241	52300	Electric Expenses	11	11	0.94913	11	10	0.93753	0	(0)	(0.01160)
242		Electric Expenses-Tallahassee BuyBack	0	0	0.00000	0	0	0.00000	0	0	-
243	52400	Miscellaneous Expenses	34,387	32,638	0.94913	34,387	32,239	0.93753	0	(399)	(0.01160)
244		Miscellaneous Expenses-Tallahassee Buy Back	507	0	0.00000	507	0	0.00000	0	0	-
245	52500	Rents	0	0	0.00000	0	0	0.00000	0	0	-
246		Rents-Tallahassee Buy Back	0	0	0.00000	0	0	0.00000	0.00000	0	-
247	**Total Nuclear Generation-Operation**		50,655	47,447	0.93666	50,655	46,880	0.92547	0	(567)	(0.01120)
248											
249											
250											

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251	**Nuclear Generation - Maintenance**										
252	52800	Supervision & Engineering	9,283	9,055	0.97548	9,283	8,952	0.96435	0	(103)	(0.01113)
253		Supervision & Engineering-Tall Buy Back	140	0	0.00000	140	0	0.00000	0	0	-
254		D/A Wholesale - Stratified	193	0	0.00000	193	0	0.00000	0	0	-
255	52900	Structures	712	676	0.94913	712	668	0.93753	0	(8)	(0.01160)
256		Structures-Tallahassee Buy Back	10	0	0.00000	10	0	0.00000	0	0	-
257	53000	Maint Of Reactor Plt Equipment	16,310	15,835	0.97087	16,310	15,620	0.95765	0	(216)	(0.01322)
258		Maint Of Reactor Plt Equipment-Tall Buy Back	246	0	0.00000	246	0	0.00000	0	0	-
259		D/A Wholesale - Stratified	404	0	0.00000	404	0	0.00000	0	0	-
260	53100	Electric Plant	2,577	2,502	0.97087	2,577	2,468	0.95765	0	(34)	(0.01322)
261		Electric Plant-Tallahassee Buy Back	39	0	0.00000	39	0	0.00000	0	0	-
262		D/A Wholesale - Stratified	64	0	0.00000	64	0	0.00000	0	0	-
263	53200	Miscellaneous Expenses	1,039	986	0.94913	1,039	974	0.93753	0	(12)	(0.01160)
264		Miscellaneous Expenses-Tallahassee Buy Back	15	0	0.00000	15	0	0.00000	0	0	-
265	**Total Nuclear Generation - Maintenance**		31,033	29,054	0.93625	31,033	28,681	0.92422	0	(373)	(0.01203)
266											
267	**Nuclear Generation - Adjustments**										
268	Adjustment - Nuclear Fuel Last Core (Retail)		(336)	(336)	1.00000	(336)	(336)	1.00000	0	0	-
269	Adjustment - Nuclear M&S Inventory End of Life (Retail)		(819)	(819)	1.00000	(819)	(819)	1.00000	0	0	-
270	Adjustment - Organization Realignment		(277)	(256)	0.92421	(277)	(254)	0.91670	0	2	(0.00751)
271	**Total Nuclear Generation Adjustments**		(1,432)	(1,411)	0.98534	(1,432)	(1,409)	0.98389	0	2	(0.00145)
272											
273	**Total Nuclear Generation**		80,256	75,090	0.93563	80,256	74,152	0.92394	0	(938)	(0.01169)
274											
275											
276	**Other Power Generation-Operation**										
277	54600	Supervision & Engineering	6,753	6,210	0.91961	6,753	6,173	0.91409	0	(37)	(0.00552)
278	54700	Fuel Non-Recoverable	3,088	2,998	0.97087	3,088	2,958	0.95765	0	(41)	(0.01322)
279	54800	Generation Expenses	230	212	0.92303	230	211	0.91680	0	(1)	(0.00623)
280	54900	Miscellaneous Expenses	9,426	8,581	0.91036	9,426	8,547	0.90674	0	(34)	(0.00362)
281	55000	Rents									
282	**Total Other Power Generation-Operation**		19,497	18,001	0.92330	19,497	17,888	0.91747	0	(114)	(0.00583)
283											
284	**Other Power Generation-Maintenance**										
285	55100	Supervision & Engineering	20,999	19,656	0.93605	20,999	19,441	0.92581	0	(215)	(0.01024)
286	55200	Structures	47	42	0.88901	47	42	0.88979	0	0	0.00078
287	55300	Generation & Elec Equipment	788	701	0.88901	788	701	0.88979	0	1	0.00078
288	55400	Miscellaneous Expenses	2,193	1,998	0.91099	2,193	1,988	0.90662	0	(10)	(0.00437)
289	**Total Other Power Generation-Maintenance**		24,027	22,396	0.93213	24,027	22,172	0.92281	0	(224)	(0.00932)
290											
291	**Other Power Generation Adjustments**										
292	Adjustment - Organization Realignment		(166)	(153)	0.92421	(166)	(152)	0.91670	0	1	(0.00751)
293											
294	**Total Other Power Generation**		43,357	40,244	0.92819	43,357	39,907	0.92043	0	(336)	(0.00776)
295											

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296	**Other Power Supply Expenses**										
297	55500	Purchased Power - Non-recoverable	13,464	0	0.00000	13,464	0	0.00000	0	0	-
298	55600	System Control & Load Dispatch	2,839	2,586	0.91103	2,839	2,560	0.90172	0	(26)	(0.00931)
299		Adjustment - Organization Realignment	(164)	(152)	0.92421	(164)	(150)	0.91670	0	1	(0.00751)
300		**Total Other Power Supply Expenses**	16,139	2,435	0.15087	16,139	2,410	0.14931	0	(25)	(0.00156)
301											
302	**Total Production O&M Expenses**		221,953	190,997	0.86053	221,953	188,606	0.84976	0	(2,391)	(0.01077)
303											
304											
305	**Transmission O&M Expenses**										
306	**Transmission-Operation**										
307	56000	Supervision & Engineering	1,832	1,328	0.72477	1,832	1,313	0.71642	0	(14)	(0.00835)
308	56100	Load Dispatching	4,258	3,042	0.71429	4,258	3,006	0.70597	0	(35)	(0.00832)
309	56200	Station Expenses	278	205	0.73678	278	202	0.72845	0	(2)	(0.00833)
310	56300	OH Line Expenses	70	50	0.71429	70	49	0.70597	0	(1)	(0.00832)
311	56400	UG Line Expenses	0	0	0.00000	0	0	0.00000	0	0	-
312	56500	Trans of Electricity by Others	0	0	0.00000	0	0	0.00000	0	0	-
313	56600	Miscellaneous Expenses	11,244	8,149	0.72477	11,203	8,026	0.71642	(41)	(123)	(0.00835)
314	56700	Rents	0	0	0.00000	0	0	0.00000	0	0	-
315		**Total Transmission-Operation**	17,681	12,773	0.72239	17,640	12,597	0.71410	(41)	(176)	(0.00829)
316											
317	**Transmission - Maintenance**										
318	56800	Supervision & Engineering	0	0	0.00000	0	0	0.00000	0	0	-
319	56900	Structures	0	0	0.71429	0	0	0.70597	0	(0)	(0.00832)
320	57000	Station Equipment	4,723	3,479	0.73678	4,723	3,440	0.72845	0	(39)	(0.00833)
321	57100	Overhead Lines	5,143	3,674	0.71429	5,143	3,631	0.70597	0	(43)	(0.00832)
322	57200	Underground Lines	0	0	0.00000	0	0	0.00000	0	0	-
323	57300	Miscellaneous Expenses	100	72	0.72477	100	72	0.71642	0	(1)	(0.00835)
324		**Total Transmission - Maintenance**	9,966	7,226	0.72505	9,966	7,143	0.71673	0	(83)	(0.00832)
325											
326	**Transmission Adjustments**										
327		Adjustment - *Transmission Enhancement Projects*	10,000	7,143	0.71429	10,000	7,060	0.70597	0	(83)	(0.00832)
328		Adjustment - Organization Realignment	(893)	(825)	0.92421	(893)	(819)	0.91670	0	7	(0.00751)
329		**Total Transmission Adjustments**	9,107	6,318	0.69371	9,107	6,241	0.68531	0	(76)	(0.00840)
330											
331	**Total Transmission O&M**		36,754	26,316	0.71601	36,713	25,981	0.70767	(41)	(335)	(0.00833)
332											
333											

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Impact of Revised Sales Forecast and Winter Park Treated as Wholesale

LINE NO.		DESCRIPTION	Original Case as Filed SYSTEM	RETAIL	RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR
334	**Distribution O&M Expenses**										
335	**Distribution-Operation**										
336	58000	Supervision & Engineering	4,874	4,864	0.99784	4,874	4,863	0.99780	0	(0)	(0.00004)
337	58100	Load Dispatching	3,372	3,358	0.99602	3,372	3,358	0.99597	0	(0)	(0.00005)
338	58200	Station Expenses	483	481	0.99600	483	481	0.99594	0	(0)	(0.00006)
339	58300	Overhead Lines	1,935	1,930	0.99752	1,920	1,915	0.99748	(15)	(15)	(0.00004)
340	58400	Underground Lines	1,585	1,583	0.99872	1,585	1,583	0.99870	0	(0)	(0.00002)
341	58500	Street Lighting	4,018	4,018	1.00000	3,979	3,979	1.00000	(39)	(39)	-
342	58600	Meter Expenses	7,868	7,868	1.00000	7,868	7,868	1.00000	0	0	-
343	58700	Customer Installation Exp	0	0	0.00000	0	0	0.00000	0	0	-
344	58800	Miscellaneous Expenses	34,502	34,427	0.99784	34,478	34,402	0.99780	(24)	(25)	(0.00004)
345	58900	Rents	463	462	0.99784	463	462	0.99780	0	(0)	(0.00004)
346	**Total Distribution-Operation**		59,099	58,991	0.99817	59,021	58,911	0.99814	(78)	(80)	(0.00003)
347											
348	**Distribution-Maintenance**										
349	59000	Supervision & Engineering	948	946	0.99784	948	946	0.99780	0	(0)	(0.00004)
350	59100	Structures	47	46	0.99602	47	46	0.99597	0	(0)	(0.00005)
351	59200	Station Expenses	2,349	2,339	0.99600	2,349	2,339	0.99594	0	(0)	(0.00006)
352	59300	Overhead Lines	16,495	16,454	0.99752	16,274	16,232	0.99748	(221)	(221)	(0.00004)
353	59400	Underground Lines	338	337	0.99872	241	240	0.99870	(97)	(97)	(0.00002)
354	59500	Line Transformers	1,598	1,598	1.00000	1,598	1,598	1.00000	0	0	-
355	59600	Street Lighting	0	0	0.00000	0	0	0.00000	0	0	-
356	59700	Meters	1	1	0.98877	1	1	0.98840	0	(0)	(0.00037)
357	59800	Miscellaneous Distribution Plant	0	0	0.00000	0	0	0.00000	0	0	-
358	**Distribution - Maintenance**		21,774	21,721	0.99757	21,456	21,403	0.99752	(318)	(318)	(0.00004)
359											
360	**Distribution Adjustments**										
361	Adjustment - Distribution Charging Practices		30,014	29,942	0.99761	30,014	29,941	0.99758	0	(1)	(0.00003)
362	Adjustment - Distribution Enhancement Projects		18,700	18,655	0.99761	18,700	18,655	0.99758	0	(1)	(0.00003)
363	Adjustment - Organization Realignment		(3,523)	(3,256)	0.92421	(3,523)	(3,230)	0.91670	0	26	(0.00751)
364	**Total Distribution Adjustments**		45,191	45,342	1.00333	45,191	45,367	1.00389	0	25	0.00055
365											
366											
367	**Total Distribution O&M**		126,065	126,054	0.99992	125,669	125,681	1.00010	(396)	(373)	0.00018
368											
369											
370	**Customer Account Expense**										
371	90100	Supervision	1,370	1,352	0.98647	1,370	1,352	0.98638	0	(0)	(0.00009)
372	90200	Meter Reading	9,217	8,992	0.97559	9,217	8,990	0.97536	0	(2)	(0.00023)
373	90300	Customer Receipts & Collections Expense	25,166	24,926	0.99046	25,093	24,853	0.99043	(73)	(72)	(0.00003)
374	90400	Uncollectible Accounts	6,298	6,298	1.00000	6,269	6,269	1.00000	(29)	(29)	-
375	90500	Miscellaneous	8,786	8,621	0.98117	8,786	8,619	0.98101	0	(1)	(0.00016)
376	Adjustment - Mobile Meter Reading		(13,877)	(13,877)	1.00000	(13,877)	(13,877)	1.00000	0	0	-
377	**Total Customer Account Expense**		36,960	36,311	0.98244	36,858	36,206	0.98232	(102)	(105)	(0.00012)
378											

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LINE NO.	DESCRIPTION	Original Case as Filed SYSTEM	RETAIL	RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR
379	**Customer Service & Information Expense**									
380	90700 Supervision	1,205	1,205	1.00000	1,205	1,205	1.00000	0	0	-
381	90800 Customer Assistance	2,708	2,708	1.00000	2,708	2,708	1.00000	0	0	-
382	90900 Information & Instructional Advertising	0	0	1.00000	0	0	1.00000	0	0	-
383	91000 Miscellaneous	477	477	1.00000	477	477	1.00000	0	0	-
384	Adjustment - Organization Realignment	(94)	(87)	0.92421	(94)	(86)	0.91670	0	1	(0.00751)
385	**Total Customer Service & Information Expense**	4,295	4,303	1.00166	4,295	4,303	1.00182	0	1	0.00016
386										
387										
388	**Sales Expense**									
389	91100 Sales Supervision	12	12	1.00000	12	12	1.00000	0	0	-
390	91200 Demonstration & Selling	2,450	2,450	1.00000	2,450	2,450	1.00000	0	0	-
391	91300 Advertising	700	700	1.00000	700	700	1.00000	0	0	-
392	91600 Miscellaneous Sales Expense	512	512	1.00000	512	512	1.00000	0	0	-
393	Adjustment - Economic Development	(29)	(29)	1.00000	(29)	(29)	1.00000	0	0	-
394	**Total Sales Expense**	3,645	3,645	1.00000	3,645	3,645	1.00000	0	0	-
395										
396										
397	**Administrative & General Expense**									
398	92000 Salaries	70,186	61,676	0.87872	70,187	61,174	0.87158	1	(502)	(0.00714)
399	92100 Office Supplies	19,866	18,360	0.92421	19,866	18,211	0.91670	0	(149)	(0.00751)
400	92200 Administrative Expense Transferred Credit	0	0	0.00000	0	0	0.00000	0	0	-
401	92300 Outside Service	28,427	26,272	0.92421	28,427	26,059	0.91670	0	(213)	(0.00751)
402	92420 Property Insurance - Storm Damage	6,000	5,817	0.96949	6,000	5,812	0.96862	0	(5)	(0.00087)
403	92430 Property Insurance - Insurance	3,787	3,508	0.92619	3,787	3,483	0.91977	0	(24)	(0.00642)
404	92431 Property Insurance - Nuclear	(326)	(305)	0.93535	(326)	(302)	0.92391	0	4	(0.01143)
405	92500 Insurance & Damages	12,283	11,352	0.92421	12,283	11,260	0.91670	0	(92)	(0.00751)
406	92600 Pension & Benefits	57,106	52,376	0.91716	57,009	51,861	0.90970	(97)	(515)	(0.00746)
407	92800 Regulatory Commission	300	0	0.00019	300	0	0.00018	0	(0)	(0.00000)
408	92900 Duplicate Charges	(462)	(421)	0.91079	(462)	(417)	0.90339	0	3	(0.00740)
409	93000 Miscellaneous	6,373	5,890	0.92421	6,373	5,842	0.91670	0	(48)	(0.00751)
410	93100 Rents	7,192	6,647	0.92421	7,192	6,593	0.91670	0	(54)	(0.00751)
411	93500 Maintenance	1,018	941	0.92421	1,018	933	0.91670	0	(8)	(0.00751)
412	Adjustment - Retail Rate Case Expenses	1,500	1,500	1.00000	1,500	1,500	1.00000	0	0	-
413	Adjustment - Advertising	(4,205)	(3,886)	0.92421	(4,205)	(3,855)	0.91670	0	32	(0.00751)
414	Adjustment - Industry Association Dues	(308)	(285)	0.92421	(308)	(282)	0.91670	0	2	(0.00751)
415	Adjustment - Interest on Tax Deficiency	367	340	0.92619	367	338	0.91977	0	(2)	(0.00642)
416	Adjustment - Corporate Aircraft	(1,067)	(986)	0.92421	(1,067)	(978)	0.91670	0	8	(0.00751)
417	Adjustment - Organization Realignment	(12,150)	(11,229)	0.92421	(12,150)	(11,138)	0.91670	0	91	(0.00751)
418	Adjustment - Dist Charging Practices	4,254	4,244	0.99761	4,254	4,244	0.99758	0	(0)	(0.00003)
419	Adjustment - Miscellaneous Interest Expense	45	42	0.92619	45	41	0.91977	0	(0)	(0.00642)
420	Adjustment - Incremental Storm Reserve	44,000	42,657	0.96949	44,000	42,619	0.96862	0	(38)	(0.00087)
421	**Total Administrative & General Expense**	244,187	224,510	0.91942	244,091	222,999	0.91359	(96)	(1,511)	(0.00583)
422										
423	**Total Operations & Maintenance Expense**	$673,859	$612,136	0.90840	$673,224	$607,421	0.90226	($635)	($4,715)	(0.00615)
424										

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LINE NO.	DESCRIPTION	Original Case as Filed SYSTEM	Original Case as Filed RETAIL	Original Case as Filed RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	Revised Case - Sales Forecast & Winter Park RETAIL	Revised Case - Sales Forecast & Winter Park RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	Difference - Sales Forecast & Winter Park RETAIL	Difference - Sales Forecast & Winter Park RETAIL FACTOR
425	**Depreciation & Amortization Expense**									
426										
427										
428	**Total Production Plant**	$133,230	$122,608	0.92026	$133,229	$121,219	0.90986	($1)	($1,389)	(0.01040)
429										
430										
431	**Transmission Plant**									
432	350 Land & Land Rights	567	405	0.71429	567	401	0.70597	0	(5)	(0.00832)
433	352 Structures & Improvements	430	307	0.71429	430	303	0.70597	0	(4)	(0.00832)
434	353 Substation Equipment	7,588	5,590	0.73678	7,588	5,526	0.72845	0	(64)	(0.00833)
435	354 OH Towers & Fixtures	1,188	849	0.71429	1,188	839	0.70597	0	(10)	(0.00832)
436	355 Poles & Fixtures	8,176	5,840	0.71429	8,176	5,772	0.70597	0	(68)	(0.00832)
437	356 OH Conductors & Devices	5,676	4,054	0.71429	5,676	4,007	0.70597	0	(47)	(0.00832)
438	357 UG Conduit	92	66	0.71429	92	65	0.70597	0	(1)	(0.00832)
439	358 UG Conductors & Devices	108	77	0.71429	108	76	0.70597	0	(1)	(0.00832)
440	359 Roads & Trails	15	10	0.71429	15	10	0.70597	0	(0)	(0.00832)
441	Adjustment - Transmission Enhancement Projects	404	289	0.71429	404	285	0.70597	0	(3)	(0.00832)
442	**Total Transmission Plant**	24,243	17,487	0.72133	24,243	17,285	0.71297	0	(203)	(0.00836)
443										
444										
445										
446	**Distribution Plant**									
447	360 Land & Land Rights	7	7	0.99602	7	7	0.99597	0	(0)	(0.00005)
448	361 Structures & Improvements	408	407	0.99602	406	404	0.99597	(2)	(2)	(0.00005)
449	362 Substation Equipment	9,629	9,591	0.99600	9,579	9,541	0.99594	(50)	(50)	(0.00006)
450	364 OH Poles, Towers & Fixtures	40,862	40,768	0.99770	40,650	40,555	0.99768	(212)	(213)	(0.00003)
451	365 OH Conductors & Devices	16,851	16,800	0.99694	16,760	16,708	0.99689	(91)	(92)	(0.00006)
452	366 UG Conduit	3,213	3,205	0.99753	3,212	3,204	0.99750	(1)	(1)	(0.00003)
453	367 UG Conductors & Devices	16,648	16,616	0.99809	16,584	16,553	0.99807	(64)	(63)	(0.00002)
454	368 Line Transformers	16,317	16,317	1.00000	16,133	16,133	1.00000	(184)	(184)	-
455	369 Services		0	0.00000		0	0.00000	0	0	-
456	369.1 Overhead Services	4,353	4,353	1.00000	4,320	4,320	1.00000	(33)	(33)	-
457	369.2 Underground Services	13,924	13,924	1.00000	13,822	13,822	1.00000	(102)	(102)	-
458	370 Metering Equipment	5,895	5,829	0.98877	5,839	5,771	0.98840	(56)	(58)	(0.00037)
459	371 Installations on Customer Premises	174	172	0.98918	174	172	0.98883	0	(0)	(0.00035)
460	372 Leased Equip on Customer Property	0	0	0.00000	0	0	0.00000	0	0	-
461	373 Street Light 8 Signal Systems	16,090	16,082	0.99951	16,063	16,055	0.99950	(27)	(27)	(0.00001)
462	Adjustment - Dist Charging Practices	(1,964)	(1,959)	0.99761	(1,964)	(1,959)	0.99758	0	0	(0.00003)
463	Adjustment - Mobile Meter Reading	9,239	9,239	1.00000	9,239	9,239	1.00000	0	0	-
464	Adjustment - Dist Enhancement Projects	693	691	0.99761	693	691	0.99758	0	(0)	(0.00003)
465	**Total Distribution Plant**	152,339	152,040	0.99804	151,517	151,216	0.99801	(822)	(825)	(0.00003)
466										
467										
468										

LINE NO.		DESCRIPTION	Original Case as Filed SYSTEM	RETAIL	RETAIL FACTOR	Revised Case - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR	Difference - Sales Forecast & Winter Park SYSTEM	RETAIL	RETAIL FACTOR
469	**General Plant**										
470	389	Land & Land Rights	0	0	0.00000	0	0	0.00000	0	0	-
471	390	Structures & Improvements	3,142	2,904	0.92421	3,142	2,880	0.91670	0	(24)	(0.00751)
472	391	Office Equipment & Furniture	1,479	1,367	0.92421	1,479	1,356	0.91670	0	(11)	(0.00751)
473	392	Transportation Equipment	(0)	(0)	0.92421	(0)	(0)	0.91670	0	0	(0.00751)
474	393	Stores Equipment	444	410	0.92421	444	407	0.91670	0	(3)	(0.00751)
475	394	Tools, Shop & Garage Equipment	596	551	0.92421	596	546	0.91670	0	(4)	(0.00751)
476	395	Laboratory Equipment	0	0	0.00000	0	0	0.00000	0	0	-
477	396	Power Operated Equipment	365	337	0.92421	365	335	0.91670	0	(3)	(0.00751)
478	397	Communication Equipment	4,609	4,260	0.92421	4,609	4,225	0.91670	0	(35)	(0.00751)
479	398	Miscellaneous Equipment	364	344	0.94591	364	343	0.94065	0	(2)	(0.00526)
480	**Total General Plant**		10,999	10,174	0.92493	10,999	10,092	0.91749	0	(82)	(0.00744)
481											
482											
483	**Intangible Plant**										
484	303	Franchise Costs	86	86	1.00000	86	86	1.00000	0	0	-
485	303	Intangible Plant Production	9,190	8,498	0.92471	9,190	8,398	0.91399	0	(100)	(0.01072)
486	303	Sebring Transition	3,558	3,558	1.00000	3,558	3,558	1.00000	0	0	-
487	303	Amort of Storm Damage	434	0	0.00000	434	0	0.00000	0	0	-
488	Adjustment - Remove Sebring		(3,558)	(3,558)	1.00000	(3,558)	(3,558)	1.00000	0	0	-
489	**Total Intangible Plant**		9,710	8,584	0.88404	9,710	8,484	0.87380	0	(100)	(0.01025)
490											
491											
492	**Total Depreciation & Amortization Expense**		$330,521	$310,893	0.94062	$329,698	$308,295	0.93509	($823)	($2,598)	(0.00553)
493											
494											
495											
496	**Taxes Other Than Income**										
497	Payroll Taxes		$19,574	$18,091	0.92421	$19,547	$17,919	0.91670	($27)	($172)	(0.00751)
498	Property Taxes - Excluding Tallahassee		100,324	92,919	0.92619	100,057	92,029	0.91977	(267)	(890)	(0.00642)
499	Property Taxes - Tallahassee D/A Whls		137	0	0.00000	137	0	0.00000	0	0	-
500	Revenue Taxes		175,142	175,142	1.00000	175,132	175,130	1.00000	(10)	(12)	-
501	Adjustment - Organization Realignment		(74)	(68)	0.91892	(74)	(68)	0.91892	0	0	-
502	Adjustment - Dist Charging Practices (Payroll Taxes)		1,503	1,499	0.99761	1,503	1,499	0.99758	0	(0)	(0.00003)
503	Adjustment - Exclude Franchise & GRT (Revenue Taxes)		(173,952)	(173,952)	1.00000	(173,952)	(173,952)	1.00000	0	0	-
504	**Total Taxes Other Than Income**		$122,653	$113,631	0.92644	$122,349	$112,557	0.91997	($304)	($1,074)	(0.00647)
505											
506											
507	**Other Operating Expenses**										
508	Gain/Loss on Sale of Property		($80)	($74)	0.92619	($80)	($74)	0.91977	$0	$1	(0.00642)
509	**Total Other Operating Expenses**		($80)	($74)	0.92619	($80)	($74)	0.91977	$0	$1	(0.00642)
510											

Progress Energy Florida
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Impact of Revised Sales Forecast and Winter Park Treated as Wholesale

Docket No. 05-0078-EI
Exhibit No. ___ (JP -13)
Witness: Javier Portuondo

LINE NO.	DESCRIPTION	Original Case as Filed			Revised Case - Sales Forecast & Winter Park			Difference - Sales Forecast & Winter Park		
		SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR	SYSTEM	RETAIL	RETAIL FACTOR
511	**Income Taxes:**									
512										
513	**State & Federal Current Income Taxes:**									
514	Operating Revenues	$1,615,187	$1,482,222	0.91768	$1,584,517	$1,451,275	0.91591	($30,670)	($30,947)	(0.00177)
515										
516	Less: O&M Expenses	673,859	612,136	0.90840	673,224	607,421	0.90226	(635)	(4,715)	(0.00615)
517	Less: Deprecation Expenses	330,521	310,893	0.94062	329,698	308,295	0.93509	(823)	(2,598)	(0.00553)
518	Less: Taxes Other than Income	122,653	113,631	0.92644	122,349	112,557	0.91997	(304)	(1,074)	(0.00647)
519	Less: Miscellaneous Other Expenses	(80)	(74)	0.92619	(80)	(74)	0.91977	0	1	(0.00642)
520	Less: Interest Charges	102,428	94,573	0.92331	102,277	93,824	0.91735	(151)	(749)	(0.00596)
521	Income Before Income Taxes	385,806	351,064	0.90995	357,049	329,251	0.92215	(28,757)	(21,813)	0.01220
522	Additional Income and Unallowable Deductions (Net)	218,240	202,132	0.92619	218,239	200,729	0.91977	(1)	(1,403)	(0.00642)
523	Adjustment - Manufacturing Tax Deduction	(9,058)	(8,376)	0.92471	(9,058)	(8,279)	0.91399	0	97	(0.01072)
524	Adjustment - Firm Service Revnue Tax	(3,511)	(3,511)	0.92619	(3,476)	(3,476)	0.91977	35	35	(0.00642)
525	Adjustment - Exclude RAF on Present Class Revenue	1,028	1,028	1.00000	1,016	1,016	1.00000	(12)	(12)	-
526	Adjustment - Exclude Uncoll Acct Exp on Present Class Rev	2,483	2,483	1.00000	2,460	2,460	1.00000	(23)	(23)	-
527	Preliminary Taxable Income	594,988	544,819	0.91568	566,230	521,701	0.92136	(28,758)	(23,118)	0.00568
528										
529	State Income Tax @ 5.5%	32,724	29,965	0.91568	31,143	28,694	0.92137	(1,582)	(1,272)	0.00569
530	*Taxable Income for Federal*	562,264	514,854	0.91568	535,087	493,007	0.92136	(27,176)	(21,846)	0.00568
531	Federal Income Tax @ 35%	196,792	180,199	0.91568	187,282	172,553	0.92136	(9,512)	(7,646)	0.00567
532										
533	**Total Current SIT & FIT**	229,517	210,164	0.91568	218,424	201,247	0.92136	(11,093)	(8,918)	0.00568
534										
535	**Provision for Deferred Income Taxes**	(79,910)	(74,012)	0.92619	(79,910)	(73,499)	0.91977	0	513	(0.00642)
536										
537	**Amortization of ITC**	(5,937)	(5,499)	0.92619	(5,937)	(5,461)	0.91977	0	38	(0.00642)
538										
539	**Total Income Taxes**	$143,670	$130,653	0.90940	$132,577	$122,287	0.92239	($11,093)	($8,367)	0.01299
540										
541										
542	**NET OPERATING INCOME**	$344,564	$314,983	0.91415	$326,753	$300,793	0.92055	($17,815)	($14,195)	0.00640

Progress Energy

Proposed Adjustments 2006 Test Year

System

Line No. Description	Original System as Filed	Sales Forecast & Winter Park	Revised Case Sales Forecast & Winter Park	(1) Employee Loans & Merchandise Inventory	(2) Prepayments Non-Utility Advertising	(3) Unbilled Revenue	(4) Storm Asset	(5) End of Life	(6) Accrued Interest	(7) Property Tax	(8) Turbines	(9) Medical Expenses	(10) Neil Refund	(11) Non-Utility Property Cap Structure	(12) Storm Capital	Fully Adjusted
1 Operating Revenues	$1,483,276	(32,096)	$ 1,451,180													$ 1,451,180
2 Sales of Electricity	131,911	1,426	133,337													133,337
3 Other Operating Revenues	1,615,187	(30,670)	1,584,517	-	-	-	-	-	-	-	-	-	-	-	-	$ 1,584,517
4 Total Operating Revenues																
5																
6 Operating Expenses	673,859	(635)	673,224									(2,835)	(639)			$ 669,750
7 Operation & Maintenance	330,521	(823)	329,698												320	330,018
8 Depreciation & Amortization	122,653	(304)	122,349							(1,376)						120,973
9 Taxes Other Than Income	(80)	-	(80)													(80)
10 Other Operating Expenses	196,792	(9,511)	187,282							455		938	211		(106)	188,780
11 Income Taxes - Federal	32,724	(1,582)	31,143							76		156	35		(18)	31,392
12 Income Taxes - State	(79,910)	-	(79,910)													(79,910)
13 Provision for Deferred Income Taxes	(5,937)	-	(5,937)													(5,937)
14 Investment Tax Credit	$1,270,623	(12,854)	$ 1,257,768	-	-	-		-	-	(845)	-	(1,741)	(393)	-	197	$ 1,254,986
15 Total Operating Expenses		-														
16	$344,564	(17,816)	$326,749	-	-	-		-	-	845	-	1,741	393	-	(197)	$329,531
17 Net Operating Income																
18																
19	$9,029,688	(19,453)	$ 9,010,235												7,012	$ 9,017,247
20 Electric Plant in Service	4,394,317	(12,062)	4,382,255												(9,751)	4,372,504
21 Less: Accum Deprec & Amort	4,635,372	(7,391)	4,627,981	-	-	-	-	-	-	-	-	-	-	-	16,763	4,644,744
22 Net Plant in Service	98,597	1	98,598													98,598
23 CWIP Not Bearing AFUDC	7,922	-	7,922													7,922
24 Plant Held for Future Use	63,933	-	63,933													63,933
25 Uamortized Nuclear Fuel	220,083	-	220,083	(973)	(2,305)		(12,732)	(4,333)	(11,387)		(46,782)					141,571
26 Working Capital	$5,025,908	(7,390)	$ 5,018,518	$ (973)	$ (2,305)	$ -	$ (12,732)	$ (4,333)	$ (11,387)	$ -	$ (46,782)	$ -	$ -	$ -	$ 16,763	$ 4,956,769
27 Total Rate Base																

Progress Energy

Proposed Adjustments 2006 Test Year

Retail

Line No.	Description	Original System as Filed	Sales Forecast & Winter Park	Revised Case Sales Forecast & Winter Park	(1) Employee Loans & Merchandise	(2) Prepayments Non-Utility Advertising	(3) Unbilled Revenue	(4) Storm Asset	(5) End of Life	(6) Accrued Interest	(7) Property Tax	(8) Turbines	(9) Medical Expenses	(10) Neil Refund	(11) Non-Utility Property Cap Structure	(12) Storm Capital	Fully Adjusted
1	**Operating Revenues**																
2	Sales of Electricity	$ 1,389,674	(32,100)	$ 1,357,574													1,357,574
3	Other Operating Revenues	92,548	1,154	93,702													93,702
4	**Total Operating Revenues**	$ 1,482,222	(30,947)	1,451,275	-	-	-	-	-	-	-	-	-	-	-	-	1,451,275
5																	
6	**Operating Expenses**																
7	Operation & Maintenance	$ 612,136	(4,715)	607,421									(2,579)	(584)			604,258
8	Depreciation & Amortization	310,893	(2,598)	308,295												285	308,580
9	Taxes Other Than Income	113,631	(1,074)	112,557							(1,376)						111,181
10	Other Operating Expenses	(74)	1	(74)													(74)
11	Income Taxes - Federal	180,199	(7,646)	172,553							455		853	193		(94)	173,960
12	Income Taxes - State	29,965	(1,271)	28,694							76		142	32		(16)	28,928
13	Provision for Deferred Income Taxes	(74,012)	513	(73,499)													(73,499)
14	Investment Tax Credit	(5,499)	38	(5,461)													(5,461)
15	**Total Operating Expenses**	$ 1,167,239	(16,751)	$ 1,150,488	-	-	-	-	-	-	(845)	-	(1,584)	(359)	-	175	1,147,875
16																	
17	**Net Operating Income**	$ 314,983	(14,196)	$ 300,788	-	-	-	-	-	-	845	-	1,584	359	-	(175)	303,400
18																	
19																	
20	Electric Plant in Service	$ 8,363,233	(75,888)	$ 8,287,345												5,717	8,293,062
21	Less: Accum Deprec & Amort	4,051,946	(44,402)	4,007,544												(8,345)	3,999,199
22	Net Plant in Service	4,311,287	(31,486)	4,279,801	-	-	-	-	-	-	-	-	-	-	-	14,062	4,293,863
23	CWIP Not Bearing AFUDC	82,105	(811)	81,294													81,294
24	Plant Held for Future Use	6,054	(54)	6,000													6,000
25	Uamortized Nuclear Fuel	57,413	(782)	56,631													56,631
26	Working Capital	183,593	(3,589)	180,004	(796)	(2,119)	(4,346)	(12,732)	(4,333)	(9,313)		(38,263)					108,102
27	**Total Rate Base**	$ 4,640,452	(36,722)	$ 4,603,730	(796)	(2,119)	(4,346)	(12,732)	(4,333)	(9,313)	-	(38,263)	-	-	-	14,062	4,545,891

Progress Energy

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Payroll and Payroll Taxes

	PEF	Affiliates	Total
Payroll Tax Expense - per MFR Schedule C-20	19,574,000	126,869	19,700,869
Clearing Accounts	1,311,896	7,277	1,319,173
Capital	6,640,787	287,720	6,928,507
Clauses	524,481	4,383	528,864
Non Regulated O&M	196,073	8,422	204,495
Total	28,247,237	434,671	28,681,908
	69.3%		
Less Payroll Taxes on Incentive Pay	(1,451,896)		(1,451,896)
Less Payroll Taxes Allocated to PEF from Other Legal Entities	(3,375,833)		(3,375,833)
Other Adjustments	(204,240)	(434,671)	(638,911)
Total - Per MFR C-35	23,215,269	-	23,215,269
	84.3%		

Progress Energy

EOL Nuclear M&S and Last Core Nuclear Fuel

As presented in the Rate Case Filing

2004

	5182300 Nuclear Fuel Misc	5280000 Maintenance Supervision & Engineering	2284021 Last Core Nuclear Fuel	2284022 EOL Nuclear M&S
Jan	126,898	1,108,949		
Feb	134,369	1,116,624		
Mar	150,652	1,116,558		
Apr	126,127	1,102,241		
May	127,417	1,171,697		
Jun	131,270	1,158,289		
Jul	147,970	1,248,838		
Aug	134,310	1,151,797		
Sep	130,051	637,664		
Oct	133,687	867,551	4,216,674	5,750,000
Nov	152,289	848,444	4,216,674	5,750,000
Dec	173,559	951,700	4,216,674	5,750,000
Year End	1,668,598	12,480,353		

2005

	5182300 Nuclear Fuel Misc	5280000 Maintenance Supervision & Engineering	2284021 Last Core Nuclear Fuel	2284022 EOL Nuclear M&S
Jan	123,794	723,720	4,216,674	5,750,000
Feb	131,191	767,193	4,216,674	5,750,000
Mar	135,194	765,342	4,216,674	5,750,000
Apr	128,602	705,711	4,216,674	5,750,000
May	134,492	823,237	4,216,674	5,750,000
Jun	135,384	724,801	4,216,674	5,750,000
Jul	150,060	930,714	4,216,674	5,750,000
Aug	133,878	845,337	4,216,674	5,750,000
Sep	129,251	817,726	4,216,674	5,750,000
Oct	127,059	727,036	4,216,674	5,750,000
Nov	123,790	762,962	4,216,674	5,750,000
Dec	141,736	874,654	4,216,674	5,750,000
Year End	1,594,431	9,468,434	4,216,674	5,750,000

2006

	5182300 Nuclear Fuel Misc	5280000 Maintenance Supervision & Engineering	2284021 Last Core Nuclear Fuel	2284022 EOL Nuclear M&S
Jan	124,997	742,798	4,216,674	5,750,000
Feb	132,637	774,248	4,216,674	5,750,000
Mar	135,748	773,941	4,216,674	5,750,000
Apr	129,300	780,863	4,216,674	5,750,000
May	132,712	788,325	4,216,674	5,750,000
Jun	156,794	957,711	4,216,674	5,750,000
Jul	131,861	750,256	4,216,674	5,750,000
Aug	135,380	789,884	4,216,674	5,750,000
Sep	130,598	823,096	4,216,674	5,750,000
Oct	132,205	830,763	4,216,674	5,750,000
Nov	128,485	799,587	4,216,674	5,750,000
Dec	147,452	803,581	4,216,674	5,750,000
Year End	1,618,170	9,615,052	4,216,674	5,750,000

Adjustment to orginal filing

Year	Month	LC - Ending Balance	EOL - Ending Balance	Total - Ending Balance
2004	Oct	-	-	-
2004	Nov	91,667	125,000	216,667
2004	Dec	183,334	250,000	433,334
	13-mo	137,501	187,500	325,001
2005	Jan	275,001	375,000	650,001
2005	Feb	366,668	500,000	866,668
2005	Mar	458,335	625,000	1,083,335
2005	Apr	550,002	750,000	1,300,002
2005	May	641,669	875,000	1,516,669
2005	Jun	733,336	1,000,000	1,733,336
2005	Jul	825,003	1,125,000	1,950,003
2005	Aug	916,670	1,250,000	2,166,670
2005	Sep	1,008,337	1,375,000	2,383,337
2005	Oct	1,100,004	1,500,000	2,600,004
2005	Nov	1,191,671	1,625,000	2,816,671
2005	Dec	1,283,338	1,750,000	3,033,338
	13-mo	733,336	1,000,000	1,733,336
2006	Jan	1,375,005	1,875,000	3,250,005
2006	Feb	1,466,672	2,000,000	3,466,672
2006	Mar	1,558,339	2,125,000	3,683,339
2006	Apr	1,650,006	2,250,000	3,900,006
2006	May	1,741,673	2,375,000	4,116,673
2006	Jun	1,833,340	2,500,000	4,333,340
2006	Jul	1,925,007	2,625,000	4,550,007
2006	Aug	2,016,674	2,750,000	4,766,674
2006	Sep	2,108,341	2,875,000	4,983,341
2006	Oct	2,200,008	3,000,000	5,200,008
2006	Nov	2,291,675	3,125,000	5,416,675
2006	Dec	2,383,342	3,250,000	5,633,342
	13-mo	1,833,340	2,500,000	4,333,340

Expense	2004	2005	2006
Last Core Nuclear Fuel	$ 183,333	$ 1,100,000	$ 1,100,000
EOL Nuclear M&S	$ 250,000	1,500,000	1,500,000
	$ 433,333	$ 2,600,000	$ 2,600,000
Balance Sheet-13 mo avg.			
Last Core Nuclear Fuel	$ 137,501	$ 733,336	$ 1,833,340
EOL Nuclear M&S	$ 187,500	1,000,000	2,500,000
	$ 325,001	$ 1,733,336	$ 4,333,340
Revenue Factor	1.632	1.632	1.632
	$ 530,238	$ 2,827,938	$ 7,072,011
WACC - As Filed	0.0950	0.0950	0.0950
Revenue Requirement Impact	$ 50,373	$ 268,654	$ 671,841

Progress Energy

Docket No. 050078-EI
Exhibit No. ____(JP-17)
Page 1 of 1

Storm Impact

		System		
		As filed in case	**Adjusted for June true-up**	**Variance**
101	Plant Balance (13-mo average)	46,742,458	53,754,655	7,012,197
108	Accumulated Reserve	(3,398,729)	(3,725,296)	(326,567)
108	Accumulated Reserve-COR	-	10,077,450	10,077,450
	Total Accumulated Reserve (13-mo average)	(3,398,729)	6,352,154	9,750,883
	Net Plant	43,343,729	60,106,809	16,763,080
	Deprec Expense (Year end Total)	2,938,351	3,258,816	320,465

		Retail		
		As filed in case	**Adjusted for June true-up**	**Variance**
101	Plant Balance (13-mo average)	42,043,147	47,759,744	5,716,597
108	Accumulated Reserve	(3,142,252)	(3,420,458)	(278,206)
108	Accumulated Reserve-COR	-	8,623,316	8,623,316
	Total Accumulated Reserve (13-mo average)	(3,142,252)	5,202,858	8,345,110
	Net Plant	38,900,895	52,962,602	14,061,707
	Deprec Expense (Year end Total)	2,807,084	3,092,064	284,980

Docket No. 05-0078-EI
Exhibit No. ___ (JP-18)
Witness: Javier Portuondo

SCHEDULE A-1

FULL REVENUE REQUIREMENTS INCREASE REQUESTED - REVISED 8/5/2005

FLORIDA PUBLIC SERVICE COMMISSION

Explanation: Provide the calculation of the requested full revenue requirements increase.

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Type of Data Shown:

X Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended 12/31/2004
Witness: Portuondo / Slusser

Line No.	(A) Description	Source		(B) As Filed Amount ($000)		(C) Proposed Adjustments Amount ($000)		Impact of Changes
1	Jurisdictional Adjusted Rate Base	Schedule B-1		$ 4,640,452		$ 4,545,891		$ 94,561
2	Rate of Return on rate Base Requested	Schedule D-1a		x 9.50%		x 9.49%		0.01%
3	Jurisdictional Net Operating Income Requested	Line 1 x Line 2		$ 440,937		$ 431,529		$ 9,408
4	Jurisdictional Adjusted Net Operating Income	Schedule C-1		314,983		303,400		$ 11,583
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4		$ 125,954		$ 128,128		$ (2,175)
6	*Earned Rate of Return*	Line 4/ Line 1	6.79%	-	6.67%		-0.11%	
7	Net Operating Income Multiplier	Schedule C-44		x 1.6320		x 1.6320		1.6320
8	*Revenue Increase (Decrease) Requested*	*Line 5 x Line 7*		$ 205,556		$ 209,105		$ (3,549)
9								
10								
11								
12								
13								
14	Note: Totals may not add due to rounding.							

Supporting Schedules: B-1, C-1, D-1a, C-44

Recap Schedules:

Docket No. 05-0078-EI
Exhibit No. ___ (JP-19)
Witness: Javier Portuondo

SCHEDULE D-1a **(REVISED)**

Cost of Capital - 13-Month Average - Revised 8/5/2005

FLORIDA PUBLIC SERVICE COMMISSION

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

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

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

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Class of Capital	Updated Cost of Service Jurisdictional Capital Structure	Specific Adjustments	Adjusted Jurisdictional Capital Structure	Pro-Rata Adjustments Associated with Adjustments	Adjusted Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
1									
2	Common Equity	$ 2,663,385	$ (16,188)	$ 2,647,197	$ (24,035)	$ 2,623,162	57.70%	12.80%	7.39%
3	Preferred Stock	24,848		24,848	(226)	24,622	0.54%	4.51%	0.02%
4	Long Term Debt - Fixed	1,508,739		1,508,739	(13,698)	1,495,041	32.89%	5.73%	1.88%
5	Short Term Debt *	24,951		24,951	(227)	24,724	0.54%	4.04%	0.02%
6	Customer Deposits								
7	Active	100,063		100,063	(908)	99,154	2.18%	5.92%	0.13%
8	Inactive								
9	Investment Tax Credit								
10	Post '70 Total								
11	Equity **	13,379		13,379	(121)	13,258	0.29%	12.72%	0.04%
12	Debt **	7,509		7,509	(68)	7,441	0.16%	5.73%	0.01%
13	Deferred Income Taxes	306,583		306,583	(2,784)	303,799	6.68%		
14	FAS 109 DIT - Net	(45,727)		(45,727)	415	(45,312)	-1.00%		
15	Total	$ 4,603,730	$ (16,188)	$ 4,587,542	$ (41,651)	$ 4,545,891	100.00%		9.49%
16									
17	(A) Reflects Winter Park & Sales Forecast Changes.								
18	(B) Impact of Non-Utility Adjustment.								
19	(C) Impact of Proposed Adjustments exhibit JP-12								
20									
21									

Supporting Schedules:

Docket No. 050078-EI
PEF Witness: Portuondo
Exhibit No. ___ (JP-20)

Progress Energy Florida
Plant In Service Balances

Line No.	Actual	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
1	EPIS	8,391,178.0	8,390,558.0	8,458,966.0	8,371,305.0	8,388,457.0
2	Acquisition Adjustments	(6,307.0)	(6,307.0)	(6,307.0)	17,054.0	17,054.0
3	Other Utility Other Production	2,531.0	2,531.0	2,531.0	2,531.0	2,531.0
4	Subtotal - (Larkin, Schedule B-1, Column 2)	8,387,402.0	8,386,782.0	8,455,190.0	8,390,890.0	8,408,042.0
5	Total Construction Work in Progress	419,736.0	464,964.0	420,439.0	479,280.0	501,138.0
6	Total Electric Plant	8,807,138.0	8,851,746.0	8,875,629.0	8,870,170.0	8,909,180.0
7						
8	**Projected**					
9	EPIS	8,431,043.0	8,501,120.0	8,523,807.0	8,547,308.0	8,570,612.0
10	Acquisition Adjustments	(6,307.0)	19,178.0	19,178.0	19,178.0	19,178.0
11	Other Utility Other Production	2,531.0	5,062.0	5,062.0	5,062.0	5,062.0
12	Subtotal - (Larkin, Schedule B-1, Column 1)	8,427,267.0	8,525,360.0	8,548,047.0	8,571,548.0	8,594,852.0
13	Total Construction Work in Progress	333,517.0	314,009.0	319,229.0	328,461.0	332,746.0
14	Total Electric Plant	8,760,784.0	8,839,369.0	8,867,276.0	8,900,009.0	8,927,598.0
15						
16	**Difference**					
17	EPIS	(39,865.0)	(110,562.0)	(64,841.0)	(176,003.0)	(182,155.0)
18	Acquisition Adjustments	-	(25,485.0)	(25,485.0)	(2,124.0)	(2,124.0)
19	Other Utility Other Production	-	(2,531.0)	(2,531.0)	(2,531.0)	(2,531.0)
20	Subtotal - (Larkin, Schedule B-1, Column 1)	(39,865.0)	(138,578.0)	(92,857.0)	(180,658.0)	(186,810.0)
21	Total Construction Work in Progress	86,219.0	150,955.0	101,210.0	150,819.0	168,392.0
22	Total Electric Plant	46,354.0	12,377.0	8,353.0	(29,839.0)	(18,418.0)
23	Add Adjustment to FAS ARO Asset				77,064.0	77,064.0
24						
25	Amount of Difference Under Actual	46,354.0	12,377.0	8,353.0	47,225.0	58,646.0
26						
27	Percentage Difference Under Actual	0.526%	0.140%	0.094%	0.532%	0.658%