BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 090079-EI
Filed: October 16, 2009

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PROGRESS ENERGY FLORIDA'S POST-HEARING BRIEF AND POSITIONS IN SUPPORT OF ITS PETITION FOR BASE RATE INCREASE

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DOCUMENT NUMBER-DATE
10641 OCT 16 8
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TABLE OF CONTENTS

DOCUMENT NUMBER-DATE
10641 OCT 16 8
FPSC-COMMISSION CLERK

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PROGRESS ENERGY FLORIDA'S POST-HEARING BRIEF AND POSITIONS IN SUPPORT OF ITS PETITION FOR BASE RATE INCREASE

Progress Energy Florida ("PEF" or the "Company"), pursuant to Order Number PSC-09-0638-PHO-EI, submits its Post-hearing Brief and Positions in Support of its Petition for Base Rate Increase and states the following:

I. Introduction.

On March 20, 2009, PEF filed its petition, testimony, exhibits, and Minimum Filing Requirements ("MFRs") in support of its requested base rate increase of $499 million. PEF needs this additional rate relief to continue to provide its customers with the safe, reliable electric service that the Florida Public Service Commission (the "Commission" or "PSC") and its customers expect. PEF has incurred and will incur real, immediate, and identifiable capital investment costs. Specifically, these capital investments include (1) the Bartow Repowering Project ($130 million in revenue requirements) which commenced commercial operation in June 2009, (2) the Steam Generator Replacement ("SGR") project at Crystal River Unit 3 ("CR3") ($48 million in revenue requirements) which is currently underway, and (3) the electrostatic precipitators at Crystal River Units 4 and 5 ("CR4" and "CR5") ($15 million in revenue requirements) which will be installed in a 2010 outage. No party disputed the prudence of these projects, nor did any party challenge the costs of these projects. The need for PEF's rate increase also stems from the lower sales and lower customer growth forecasted by the Company for the test period. Simply put, with the decreased sales, accounting for $170 million of the total requested increase, sales revenues are not covering the fixed costs to provide safe, reliable electric service. Again, no party disputes the reasonableness of PEF's sales and load forecasts.

Indeed, with respect to PEF's requested rate relief, there are only three material areas of dispute: (1) the appropriate treatment of the calculated theoretical depreciation reserve variance; (2) the appropriate capital structure and return on equity ("ROE"), and (3) certain operating and maintenance ("O&M") expenses challenged by intervener witnesses.[1] (Tr. 56; 70-73; 79). Some but not all interveners also challenged the Company's recommended cost of service methodology. The preponderance of the evidence on these issues, nevertheless, supports PEF's requested rate relief.

Interveners propose to amortize the theoretical depreciation reserve variance to the Company's book depreciation reserve of about $646 million to customers over a four-year period. As explained in detail below, the "theoretical" variance exists only in a Depreciation Study calculation, it does not exist on the Company's books, but the amortization proposals will result in real reductions in and a restatement of the book depreciation reserves, annual $161 (or $100) million reductions in depreciation expense, resulting in real reductions in cash flow to the Company that will have a material, adverse impact on the Company's credit rating. These are

[1] There are no real service issues (Issue 6 in the Prehearing Order) despite the repeated questions of PEF witnesses by counsel for the Attorney General ("AG") regarding customer comments during the customer service hearings in this proceeding. (e.g., Tr. 155-63; 702-13). As explained by PEF's witnesses, and further detailed in the Customer Service Hearing Report filed by PEF and entered into evidence, only 21 of the 300 customers who appeared at the service hearings had service-related complaints. (Tr. 158, Hearing Ex. 270). PEF contacted each of those 21 customers and addressed their reliability or service concerns. (Hearing Ex. 270). These service or reliability related concerns represent a very small percentage of the more than 1.6 million customers PEF serves. (Tr. 704). Moreover, the evidence shows that PEF's quality and reliability of electric service is not just adequate, it is exceptional. PEF regularly monitors transmission and distribution reliability, and the Company shows regular improvement in those areas and benchmarks well against the industry. (Tr. 557-558; Tr. 658-660). PEF also performs well for generation reliability. (Tr. 373). Even the latest JD Power Customer Satisfaction Survey results from 2009 shows that the Company has continued to provide excellent customer service and has shown an improvement in score when compared to the same time period in 2008. (Hearing Ex. 265). The evidence demonstrates PEF provides safe, reliable electric service to its customers.

radical proposals that, if accepted, require this Commission to implement something neither this Commission nor any other regulatory commission in this country have ever approved.

Intervener witnesses claim this amortization is necessary to correct intergenerational inequities resulting from current customers paying more than they should have paid. This simply is not true. There is no evidence that any customers have overpaid. OPC admitted this in its opening statement, acknowledging that "as it turns out today, [depreciation rates] are higher than they should have been, *not* because [the Commission] made a mistake, *not* because the Company did something wrong, *but because circumstances changed. … [w]hat we know today, had we known then, the rates would have been lower.*" (Tr. 61, L. 6-9, 16-22) (emphasis added). The regulatory decisions of this Commission and the Federal Energy Regulatory Commission ("FERC"), and Generally Accepted Accounting Principles ("GAAP"), all provide that changes in depreciation rates based on changed circumstances are applied prospectively, over the remaining life of the depreciable plant in service. Even intervener witnesses admit this is the normal method for addressing depreciation reserve variances. (Tr. 2160-2161; 2042; 3196). This method is consistent with the fundamental axiom of depreciation that the cost of service for electric plant is matched to the life of that electric plant. This method is exactly what PEF proposes in its Depreciation Study.

It bears emphasis too, that interveners' proposed amortizations create intergenerational inequity. Their proposed amortizations of the theoretical to book depreciation reserve variance result in a windfall to customers during the four-year amortization period at the expense of past and future customers. Even interveners admit that, while the proposed amortization reduces rates in the short-term, the reduction in the depreciation book reserve increases rate base that the Company is entitled to recover a return of and on over the long-term. The four-year amortization thus yields higher rate base returns during the four-year period followed immediately by a dramatic and long-term increase in customer rates. (Tr. 3927-28). The interveners' proposed amortizations "rob Peter to pay Paul" and that is not fair to past customers who see none of the windfall current customers receive, and it is not fair to future customers who will have to pay for the windfall to current customers. This is not sound regulatory policy, and accordingly, the interveners' proposed amortizations should be rejected.

The Company's requested ROE and capital structure are necessary to maintain its credit rating and ensure cost-effective access to equity and debt capital during the largest capital expenditure program in the Company's history and a continuing, tight and volatile capital market. Interveners, on the other hand, have recommended a drastically low ROE that even they do not fully support. The evidence, as demonstrated below, supports the Company's recommended ROE and capital structure.

PEF's requested O&M expenses are reasonable and necessary to the Company's ability to continue to provide safe, reliable, and efficient electric service to its customers. PEF presented the witnesses responsible for carrying out the Company's business operations with respect to the actual O&M dollars required to provide safe and reliable electric service to its customers. This testimony was supported by detailed information to support the requested O&M expenses. By contrast, the intervener witnesses ignore this testimony and make recommended adjustments based solely on comparing historical figures with the Company's projected future O&M needs. Their approach ignores the realities of running and maintaining a generation, transmission, and distribution system as large as PEF's system, a system that in fact is larger, and more complex, than it was historically, and that faces increasing costs of operation and maintenance. Simply put, the Company's requested O&M expenses are necessary to continue to provide the above average service that PEF's CEO and President, Mr. Vincent Dolan, testified the Company and its customers expect the Company to provide. (Tr. 188-189).

The appropriate cost of service methodology recommended by PEF is a "12 CP and 50% AD" method, supported by the Company's Allocated Class Cost of Service and Rate of Return Study. (Tr. 1495-96; Hearing Ex. 47, MFR Schedule E) This cost of service methodology gives more weight to energy responsibility in allocating the cost of service to customer classes and is driven by the Company's current generation investment. Contrary to interveners' arguments, the 12 CP and 50% AD method most fairly allocates costs among rate classes. Indeed, even under the 12 CP and 50% AD method, given the Commission's practice of limiting rate increases to no more than 150%, there are several rate classes that will still not bear their full responsibility of the proposed rate increase. This means that the Company's Residential and General Service non-demand customers must bear a higher percentage of the rate increase.

As OPC admitted, these issues (ROE, depreciation, O&M, and cost of service) are the only true issues in dispute in this rate case. (Tr. 56). In an attempt to divert the Commission's determination of these issues based on the record evidence, however, interveners made two further unsupported claims throughout the hearing. First, some interveners claim that the Company's initial filing failed to meet the burden of proof. Second, the interveners claim that, even despite the Company's evidence with respect to the necessary costs of doing business, the Commission should deny the Company recovery of its costs based on general economic conditions. Both arguments are addressed below and are without merit or legal support.

In sum, the Company needs $499 million in additional base rate revenues to continue to provide the safe, reliable, and efficient electric service customers expect from the Company. This need is demonstrated by the Company's petition, MFRs, testimony, exhibits, and discovery responses. Accordingly, the Commission should approve the Company's requested base rate increase.[2]

II. Post-Hearing Positions and Statement of Issues.

ISSUE 1: DROPPED

TEST PERIOD AND FORECASTING

ISSUE 2: Is PEF's projected test period of the twelve months ending December 31, 2010 appropriate?

PEF: *Yes. The twelve months ended December 31, 2010 is the appropriate test year.* (Category 1 Stipulation)

ISSUE 3: What are the appropriate inflation, customer growth, and other trend factors for use in forecasting?

PEF: *The appropriate inflation, customer growth and other trend factors for use in forecasting are those included in the MFRs, as filed.* (Category 2 Stipulation)

ISSUE 4: Are PEF's forecasts of customer growth, KWH by revenue class, and system KW, as reflected in the MFRs as filed, for the projected test year appropriate?

PEF: *Yes.* (Category 2 Stipulation)

ISSUE 5: Are PEF's forecasts of billing determinants by rate class, as reflected in the MFRs as filed, for the projected test year appropriate?

PEF: *Yes.* (Category 2 Stipulation)

QUALITY OF SERVICE

ISSUE 6: Is the quality and reliability of electric service provided by PEF adequate?

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[2] PEF proposes to make an adjustment to reduce Administrative and General expense by $1,170,000. This adjustment includes the removal of $555,000 for the elimination of a workforce strategy program, $544,000 for items that should have been recorded below the line, and $220,000 for the elimination of employee service awards in 2010. The total of these three proposed adjustments is $1,319,000, and when applying the appropriate jurisdictional factor of .88755, the jurisdictional adjustment is $1,170,000. PEF conceded these adjustments in Mr. Toomey's rebuttal testimony when it recognized the need to make those adjustments. Although PEF withdrew Mr. Toomey's rebuttal testimony, it recognizes that these adjustments are still appropriate and thus the positions in this brief include these adjustments. PEF maintains that it is otherwise entitled to the requested rate relief, as shown by the evidence in the record.

PEF: *Yes. PEF has gone beyond the provision of adequate service, steadily improving performance in several key areas. Today, the Company provides high quality, reliable electric service that is in the top quartile in the industry in many indices.*

DEPRECIATION STUDY

ISSUE 7: Should the current-approved depreciation rates, capital recovery schedules, and amortization schedules be revised?

PEF: *Yes. The parties' positions on how they should be revised are set forth in subsequent issues.* (Category 1 Stipulation)

ISSUE 8: What are the appropriate capital recovery schedules?

PEF: *None, as PEF has not proposed any capital recovery schedules.*

ISSUE 9: Is PEF's calculation of the average remaining life appropriate?

PEF: *Yes, PEF calculated the average remaining life consistent with Commission rules and precedent.*

ISSUE 10: What are the appropriate depreciation parameters (remaining life, net salvage percent, and reserve percent), amortizations, and resulting rates for each production unit, including but not limited to coal, steam, combined cycle, etc.?

PEF: *The appropriate depreciation parameters, amortizations and resulting rates for each production unit are those set forth in the 2009 Depreciation Study filed as Exhibit No. EMR-2 to the testimony of Mr. Robinson.*

ISSUE 11: What life spans should be used for PEF's coal plants?

PEF: *The appropriate life span for PEF's Crystal River Units 1 and 2 coal-fired plants is 53 years, and the appropriate life span for Crystal River Units 4 and 5 is 52 years.*

ISSUE 12: What life spans should be used for PEF's combined cycle plants?

PEF: *The appropriate life span for PEF's combined cycle plants is 30 years.*

ISSUE 13: What are the appropriate depreciation parameters (remaining life, net salvage percent, and reserve percent), amortizations, and resulting rates for each transmission, distribution, and general plant account?

PEF: *The appropriate depreciation parameters, amortizations and resulting rates for each transmission, distribution and general plant account are those set forth in the 2009 Depreciation Study filed as Exhibit No. EMR-2 to the testimony of Mr. Robinson.*

ISSUE 14: Based on the application of the depreciation parameters that the Commission has deemed appropriate to PEF's data, and a comparison of the calculated theoretical reserves to the book reserves, what are the resulting differences?

PEF: *When compared with the hypothetical reserve calculated in PEF's Depreciation Study, the book reserve shows a positive net variance as set forth in the 2009 Depreciation Study filed as Exhibit No. EMR-2, Table 5f-Future (Pro Forma).*

ISSUE 15: What, if any, corrective reserve measures should be taken with respect to the differences identified in Issue 14?

PEF: *The Commission should take no corrective reserve measures with respect to these differences. The variance should be treated consistent with the Depreciation Study filed by PEF in this docket and with well established Commission precedent and be amortized over the composite average remaining life of the depreciable plant assets. PEF's Depreciation Study filed in this docket, including the depreciation rates contained therein, should be approved by the Commission.*

ISSUE 16: What should be the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules?

PEF: *The implementation date should be January 1, 2010.* (Category 1 Stipulation).

FOSSIL DISMANTLEMENT COST STUDY

ISSUE 17: Should the current-approved annual dismantlement provision be revised?

PEF: *Yes, the annual dismantlement provision should be revised in accordance with PEF's 2008 Fossil Dismantlement Study.*

ISSUE 18: What, if any, corrective reserve measures should be approved?

PEF: *The dismantlement reserve balances should be adjusted as reflected on page 47 of Exhibit PT-10 (Hearing Exhibit 126).*

ISSUE 19: What is the appropriate annual provision for dismantlement?

PEF: *PEF's 2008 Fossil Plant Dismantlement Study shows PEF will need to accrue $3.8 million (system) annually beginning in 2010 in order to ensure that sufficient funds will be available to cover the costs of dismantlement of the Company's fossil plant generating sites.*

ISSUE 20: Are PEF's assumptions in the fossil dismantlement study with regard to site restoration reasonable?

PEF: *Yes, PEF's assumptions are consistent with industry standards and with Commission Rule 25-6.04364. Burns & McDonnell specifically reviewed each of PEF's generating units and sites and reasonably estimated the costs to dismantle each unit.*

ISSUE 21: DROPPED

NUCLEAR DECOMMISSIONING COST STUDY

ISSUE 22: Should the currently approved annual nuclear decommissioning accruals be revised?

PEF: *No. The issues associated with PEF's nuclear decommissioning study should be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford the Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF will not be required to prepare a new site-specific nuclear decommissioning study. However, PEF will be required to update the current study with the most currently available escalation rates.* (Category 1 Stipulation).

ISSUE 23: What is the appropriate annual decommissioning accrual in equal dollar amounts necessary to recover future decommissioning costs over the remaining life Crystal River Unit 3 (CR3)?

PEF: *No. The issues associated with PEF's nuclear decommissioning study should be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford the Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF will not be required to prepare a new site-specific nuclear decommissioning study. However, PEF will be required to update the current study with the most currently available escalation rates.* (Category 1 Stipulation).

RATE BASE

ISSUE 24: Has the company removed all non-utility activities from rate base?

PEF: *Yes, all non-utility activities have been appropriately removed from rate base.*

ISSUE 25: Should any adjustments be made to rate base related to the Bartow Repowering Project?

PEF: *No. This stipulation does not prejudice the rights of any intervener to contest the legality of including the Bartow project in rates during 2009. The new rates resulting from Docket No. 090079-EI, which will reflect the rate base and revenue requirement impact of the Bartow project, will supercede the rate change resulting from Order No. PSC-09-0415-PAA-EI as of the effective date of the new rates.* (Category 1 Stipulation).

ISSUE 26: Should an adjustment be made to reflect any test year or post test year revenue requirement impacts of "The American Recovery and Reinvestment Act" signed into law by the President on February 17, 2009?

PEF: *No.* (Category 1 Stipulation).

ISSUE 27: Is PEF's requested level of Plant in Service for the projected 2010 test year appropriate?

PEF: *Yes. PEF's requested level of Electric Plant in Service for 2010 of $10,381,341,000 is appropriate.*

ISSUE 28: What adjustments, if any, should be made to accumulated depreciation to reflect revised depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study?

PEF: *No adjustments should be made.*

ISSUE 29: Is PEF's requested level of Accumulated Depreciation and Amortization in the amount of $4,437,117,000 for the 2010 projected test year appropriate?

PEF: *Yes. PEF's requested level of Accumulated Depreciation for 2010 of $4,437,117,000 is appropriate.*

ISSUE 30: Is PEF's requested level of CWIP – No AFUDC in the amount of $151,145,000 for the projected 2010 test year appropriate?

PEF: *Yes. PEF's requested level of CWIP-No AFUDC for 2010 of $151,145,000 is appropriate.*

ISSUE 31: Is PEF's requested level of Plant Held for Future Use in the amount of $25,723,000 for the projected 2010 test year appropriate?

PEF: *Yes. PEF's requested level of Plant Held for Future Use for 2010 of $25,723,000 is appropriate.*

ISSUE 32: Is PEF's requested level of Nuclear Fuel – No AFUDC (net) in the amount of $126,566,000 for the projected 2010 test year appropriate?

PEF: Yes. PEF's requested level of Nuclear Fuel-No AFUDC for 2010 of $126,566,000 is appropriate.*

ISSUE 33: Should an adjustment be made to PEF's requested storm damage reserve, annual accrual of $14.9 million, and target level of $150 million?

PEF: *No, PEF's requested storm damage annual accrual of $14.9 million (jurisdictional) and its target reserve level of $152.5 million are appropriate given the likelihood of storms impacting PEF's service territory and the increase in T&D infrastructure across PEF's territory.*

ISSUE 34: Should any adjustments be made to PEF's fuel inventories?

PEF: *No adjustment should be made to PEF's requested level of non-nuclear fuel inventories in the amount of $347,235,000 (system). The appropriate jurisdictional amount is a fall-out based on the jurisdictional separation factor approved in Issue 89.* (Category 2 Stipulation).

ISSUE 35: Should unamortized rate case expense be included in Working Capital?

PEF: *Yes. $1,688,000 of unamortized rate case expense should be included in working capital. This 13-month average balance is based on total rate case expense of $2,251,077 amortized over 24 months.*

ISSUE 36: Has PEF appropriately reflected the impact of SFAS 143 (Asset Retirement Obligations) in its proposed working capital calculation?

PEF: *Yes, PEF has appropriately removed the impact of SFAS 143 (Asset Retirement Obligations) from its proposed working capital.*

ISSUE 37: Is PEF's requested level of Working Capital Allowance in the amount of ($9,041,000) for the projected test year appropriate?

PEF: *Yes. PEF's requested level of Working Capital Allowance for 2010 of ($9,041,000) was appropriate at the time of PEF's original filing. However, an adjustment is necessary to correct the balance of unamortized rate case expense, based on the updated rate case expense estimate of $2,251,077 provided in response to Staff Interrogatory 267, which decreases Working Capital Allowance by ($1,099,000), resulting in an appropriate adjusted level of Working Capital Allowance for the 2010 projected test year of ($10,140,000).*

ISSUE 38: Is PEF's requested level of Rate Base in the amount of $6,238,617,000 for the 2010 projected test year appropriate?

PEF: *Yes. PEF's requested level of Rate Base for 2010 of $6,238,617,000 was appropriate at the time of PEF's original filing. However, with the adjustment described in Issue 37 of ($1,099,000), the appropriate adjusted level of Rate Base for the 2010 projected year is $6,237,518,000.*

COST OF CAPITAL

ISSUE 39: What is the appropriate amount of accumulated deferred taxes to include in the capital structure for the projected test year?

PEF: *At the time of PEF's original filing, the appropriate amount of accumulated deferred taxes to include in the capital structure was $389,297,000. However, as a result of changes identified in PEF's position on Issue 38, the appropriate adjusted level of rate base for the 2010 projected year is $6,237,518,000. When synchronizing rate base to capital structure, the appropriate amount of accumulated deferred income taxes to include in capital structure for the 2010 projected test year is $389,229,000.*

ISSUE 40: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the projected test year?

PEF: *At the time of PEF's original filing, the appropriate amount of unamortized investment tax credits to include in the capital structure was $3,610,000. However, as a result of changes identified in PEF's position on Issue 38, the appropriate adjusted level of rate base for the 2010 projected year is $6,237,518,000. When synchronizing rate base to capital structure, the appropriate amount of unamortized investment tax credits to include in capital structure for the 2010 projected test year is $3,609,000 and the appropriate cost rate is 9.74%.*

ISSUE 41: Should PEF's requested pro forma adjustment to equity to offset off-balance sheet purchased power obligations be approved?

PEF: *Yes.*

ISSUE 42: What is the appropriate equity ratio that should be used for PEF for purposes of setting rates in this proceeding?

PEF: *The appropriate equity ratio is 50.52% equity as reflected in MFR D-1a.*

ISSUE 43: Have rate base and capital structure been reconciled appropriately?

PEF: *Yes specific adjustments have been made where appropriate and the pro-rata adjustment has been appropriately been made across all sources of capital.*

ISSUE 44: What is the appropriate capital structure for the projected test year?

PEF: *The appropriate capital structure is shown in MFR D-1a.*

ISSUE 45: What is the appropriate cost rate for short-term debt for the projected test year?

PEF: *The appropriate cost rate for short-term debt is 5.25% as presented in MFR D-3.*

ISSUE 46: What is the appropriate cost rate for long-term debt for the projected test year?

PEF: *The appropriate cost rate for long-term debt is 6.42% as presented in MFR D-4a.*

ISSUE 47: What is the appropriate return on equity (ROE) for the projected test year?

PEF: *The appropriate return on equity for the projected test year is 12.54%.*

ISSUE 48: What is the appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with the projected capital structure?

PEF: * The appropriate weighted average cost of capital is 9.210% as calculated in MFR D-1a.*

NET OPERATING INCOME

ISSUE 49: Is PEF's projected level of total operating revenues in the amount of $1,517,918,000 for the 2010 projected test year appropriate?

PEF: *Yes. PEF's requested level of operating revenues for 2010 of $1,517,918,000 is appropriate.*

ISSUE 50: What are the appropriate adjustments to reflect the base rate increase for the Bartow Repowering Project authorized in Order No. PSC-09-0415-PAA-EI?

PEF: *The appropriate adjustment to reflect the base rate increase for the Bartow Repowering project would be to adjust present revenues to include the authorized increase. No adjustment should be made to the proposed revenues as they reflect the Company's total cost of service including the revenue requirements for the Bartow repowering project in the 2010 test period.*

ISSUE 51: Has PEF made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 52: Has PEF made the appropriate test year adjustments to remove fuel and purchased power revenues and expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 53: Has PEF made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 54: Has PEF made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 55: DROPPED

ISSUE 56: Has PEF made the appropriate adjustment to remove Aviation cost for the test year?

PEF: *Yes, PEF has appropriately removed aviation costs of $3,126,000 as reflected in MFR C-2.*

ISSUE 57: Should an adjustment be made to advertising expenses?

PEF: *An adjustment has been appropriately made to remove image-building advertising expense in the amount of $3,388,000 as reflected in MFR C-2.*

ISSUE 58: DROPPED

ISSUE 59: Is PEF's proposed allowance of $2,412,100 for directors and officers liability insurance appropriate?

PEF: *No. PEF provided the system amount of directors and officers (D&O) liability insurance in response to OPC Interrogatory No. 310 of $2,200,000.*

ISSUE 60: Is PEF's proposed allowance of $3,669,000 for 2010 injuries and damages expense appropriate?

PEF: *No. PEF's original filing includes injuries and damages (FERC Acct 925) of $9,821,000 on a system basis. In addition to injuries and damages, this account includes corporate insurance in the amount of $5,637,097. When removing the corporate insurance, the remaining injuries and damages budget in 2010 is $4,184,000 on a system basis and $3,669,000 on a jurisdictional basis (as noted in this issue). In response to OPC Interrogatory No. 386, PEF explained that $450,000 had been classified as "salaries and wages" that should have been classified as "injuries and damages". When including this amount, total system injuries and damages is appropriately $4,634,000, and the jurisdictional amount is $4,064,000.*

ISSUE 61: Is PEF's proposed allowance of $23,228,000 for 2010 A&G office supplies and expenses appropriate?

PEF: *No. As explained in response to OPC Interrogatory No. 386, PEF budgeted $1,208,000 to Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense. In addition, an adjustment is proposed to reduce A&G Office Supplies and Expense by $1,319,000. MFR C-4, page 12, shows system A&G office supplies and expense as $26,783,000. With these adjustments, the appropriate amount of A&G Office Supplies and Expense on a system basis is $26,672,000 and the jurisdictional amount is $23,130,000.*

ISSUE 62: Should an adjustment be made to PEF's proposed 2010 allowance for O&M expense to reflect productivity improvements, if any?

PEF: *No, such an adjustment is inappropriate. The Company has supported all of its 2010 O&M expenses through the testimony of its witnesses, and its budgets already reflect the productivity improvements the Company has implemented.*

ISSUE 63: Should an adjustment be made to PEF's requested level of salaries and employee benefits for the 2010 projected test year?

PEF: *Yes, as explained in response to OPC Interrogatory No. 386, PEF budgeted $1,208,000 to Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense. In addition, PEF budgeted $450,000 to Salaries and Wages that should have been budgeted to A&G

Injuries and Damages. Therefore, Salaries and Wages should be reduced by $1,658,000 (system) and $1,454,000 (jurisdictional).*

ISSUE 64: Are PEF's proposed increases to average salaries for 2010 appropriate?

PEF: *Yes, PEF's proposed increases in average salaries are based on market studies and are designed to maintain total compensation packages that are competitive so that the Company can attract and retain qualified employees.*

ISSUE 65: Are PEF's proposed increases in employee positions for 2010 appropriate?

PEF: *Yes, PEF's proposed increase of thirty-six new positions is appropriate.*

ISSUE 66: Should the proposed 2010 allowance for incentive compensation be adjusted?

PEF: *No adjustment for incentive compensation is warranted.*

ISSUE 67: Should the Company's proposed 2010 allowance for employee benefit expense be adjusted?

PEF: *No adjustment for employee benefit expense is warranted.*

ISSUE 68: Should an adjustment be made to the accrual for property damage for the 2010 projected test year?

PEF: *No.*

ISSUE 69: Should an adjustment be made to PEF's 2010 generation O&M expense?

PEF: *No.*

ISSUE 70: Should an adjustment be made to PEF's 2010 transmission O&M expense?

PEF: *No.*

ISSUE 71: Should an adjustment be made to PEF's 2010 distribution O&M expense?

PEF: *No.*

ISSUE 72: DROPPED

ISSUE 73: What is the appropriate amount and amortization period for PEF's rate case expense for the 2010 projected test year?

PEF: *The appropriate amount for rate case expense is $2,251,000, amortized over a two year period beginning January, 2010.*

ISSUE 74: Should an adjustment be made to bad debt expense for the 2010 projected test year?

PEF: *No.* (Category 2 Stipulation).

ISSUE 75: What adjustments, if any, should be made to the 2010 projected test year depreciation expense to reflect revised depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study?

PEF: *No adjustment should be made to PEF's depreciation expense as reflected in its 2009 Depreciation Study.*

ISSUE 76: What is the appropriate amount of depreciation and fossil dismantlement expense for the 2010 projected test year?

PEF: *PEF's requested level of depreciation and dismantlement expenses for the 2010 projected test year of $354,755,000 and $3,114,000, respectively, are appropriate. PEF updated its dismantlement costs in response to Staff's Interrogatory No. 319. The updated cost is higher than in PEF's original filing, however PEF does not seek to recover this increase. PEF believes its fossil dismantlement accrual is appropriate and reasonable given the inherent uncertainty and volatility with regard to inflation and scrap value assumptions as well as the time frame between dismantlement filings.*

ISSUE 77: What is the appropriate amount of nuclear decommissioning expense for the 2010 projected test year?

PEF: *The appropriate amount is $0.* (Category 1 Stipulation).

ISSUE 78: What adjustments, if any, should be made to the amortization of End of Life Material and Supplies inventories?

PEF: *No adjustments should be made.* (Category 2 Stipulation).

ISSUE 79: What adjustments, if any, should be made to the amortization of the costs associated with the last core of nuclear fuel?

PEF: *No adjustments should be made.* (Category 2 Stipulation).

ISSUE 80: Should an adjustment be made to taxes other than income taxes for the 2010 projected test year?

PEF: *No adjustment to taxes other than income taxes for 2010 is necessary based on PEF's original filing of $129,587,000.*

ISSUE 81: Is it appropriate to make a parent debt adjustment as per Rule 25-14.004, Florida Administrative Code?

PEF: *No, it is not appropriate to make a parent-debt adjustment. The equity contributions made to PEF by the parent were from equity issuances at the parent, not debt. Equity issued in 2008, 2009 and 2010 at the parent will be greater than contributions made to PEF in 2009 and 2010.*

ISSUE 82: Should an adjustment be made to Income Tax expense for the 2010 projected test year?

PEF: *Yes. Based on the adjustments to reduce rate case expense by $269,000 and A&G office supplies and expense by $1,157,000 (jurisdictional) as explained in the Rebuttal Testimony of Peter Toomey Exhibit PT-17, an adjustment should be made to increase income tax expense by $550,000 based on the statutory income tax rate of 38.575%. Therefore, with this adjustment, income tax expense is $45,040,000.*

ISSUE 83: Is PEF's requested level of Operating Expenses in the amount of $1,249,372,000 for the 2010 projected test year appropriate?

PEF: *No. PEF's requested level of Operating Expense of $1,249,372,000 must be adjusted to reduce A&G Office Supplies and Expense and Rate Case Expense. With these adjustments, the level of Operating Expense is $1,248,488,000.*

ISSUE 84: Is PEF's projected net operating income in the amount of $268,546,000 for the 2010 projected test year appropriate?

PEF: *No. PEF's net operating income must be adjusted to reflect the decrease in operating expense of $876,000 as explained in Issue No. 83. With this adjustment, the projected net operating income is $269,422,000.*

ISSUE 85: Has PEF appropriately accounted for affiliated transactions? If not, what adjustment, if any, should be made?

PEF: *Yes, PEF has appropriately accounted for affiliate transactions. There are no adjustments necessary.*

REVENUE REQUIREMENTS

ISSUE 86: What is the appropriate projected test year revenue expansion factor and the appropriate net operating income multiplier, including the appropriate elements and rates for PEF?

PEF: *The appropriate projected test year revenue expansion factor is 61.207% and the appropriate net operating income multiplier is 1.63381.* (Category 2 Stipulation).

ISSUE 87: Is PEF's requested annual operating revenue increase of $499,997,000 for the 2010 projected test year appropriate?

PEF: *Yes. The requested increase of $499,997,000 is appropriate, subject to the adjustments to net operating income and rate base described herein.*

COST OF SERVICE AND RATE DESIGN

ISSUE 88: Has PEF correctly calculated revenues at current rates for the projected test year?

PEF: *Yes. PEF appropriately calculated revenues using test period billing determinants as developed from the sales forecast filed with its March 2009 filing.*

ISSUE 89: Is PEF's proposed separation of costs and revenues between the wholesale and retail jurisdictions appropriate?

PEF: *Yes. PEF's proposed separation of costs and revenues between wholesale and retail jurisdictions is appropriate for the jurisdictional cost of service study.*

ISSUE 90: What is the appropriate Cost of Service Methodology to be used to allocate base rate and cost recovery costs to the rate classes?

PEF: *The appropriate cost of service methodology is "12 CP and 50% AD" method for allocating production capacity costs and the 12 CP method for allocating transmission costs.*

ISSUE 91: If the Commission approves a cost allocation methodology other than the 12 CP and 1/13th Average Demand, should all cost recovery factors be adjusted to reflect the new cost of service methodology?

PEF: *Yes. The Commission's practice has been to use the same cost allocation method approved in a utility's last base rate proceeding to allocate costs in the utility's cost recovery clauses for each functional cost.*

ISSUE 92: How should any change in revenue requirements approved by the Commission be allocated among the customer classes?

PEF: *The appropriate allocation of any change in revenue requirements, after recognizing any additional revenues from service charges, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. The appropriate allocation should recognize the combination of the Curtailable and Interruptible rate classes for the purpose of establishing base rate and billing adjustment charges. It should also recognize any customer migration that may occur between the GS and GSD rate schedules as a result of the final rate design.*

ISSUE 93: Is PEF's proposed treatment of unbilled revenue due to any recommended rate change appropriate?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 94: Is PEF's proposed charge for Investigation of Unauthorized Use appropriate?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 95: Should the Commission approve PEF's proposal to eliminate its IS-1, IST-1, CS-1, and CST-1 rate schedules and transfer the current customers to otherwise applicable rate schedules?

PEF: *Yes. These rate schedules, which are proposed to be eliminated, have been closed to new customers since April 1996. At that time, existing customers were grandfathered under these schedules to avoid the possibility of hardship from immediate transfer to comparable, cost-effective rate schedules. It is now appropriate to bring this interim grandfathering to a close.*

ISSUE 96: Is PEF's proposal to grandfather certain terms and conditions for existing IS-1, IST-1, CS-1, and CST-1 customers transferred to the IS-2, IST-2, CS-2, and CST-2 rate schedules appropriate?

PEF: *Yes. Grandfathering certain terms and conditions is appropriate to avoid placing an undue burden on the transferred customers.*

ISSUE 97: Should PEF's proposal to close the RST-1 rate to new customers be approved?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 98: Are PEF's proposed customer charges appropriate?

PEF: *Yes.*

ISSUE 99: Are PEF's proposed service charges appropriate?

PEF: *Yes. The proposed service charges will more appropriately assign costs to the customers imposing such cost.*

ISSUE 100: Is PEF's proposed charge for Temporary Service appropriate?

PEF: *Yes.*

ISSUE 101: Is PEF's proposed Premium Distribution Service charge appropriate?

PEF: *Yes.*

ISSUE 102: DROPPED

ISSUE 103: Are PEF's proposed monthly fixed charge carrying rates to be applied to the installed cost of customer-requested distribution equipment, lighting service fixtures, and lighting service poles, for which there are no tariffed charges, appropriate?

PEF: *The methodology used by PEF to calculate the monthly fixed charge carrying rates is appropriate. To the extent any of the inputs used by PEF in the calculation are modified at the revenue requirements Agenda, PEF should recalculate the monthly fixed charge carrying rates using the approved inputs.* (Category 1 Stipulation)

ISSUE 104: Are PEF's proposed delivery voltage credits appropriate?

PEF: *Yes.* (Category 2 Stipulation).

ISSUE 105: Are PEF's power factor charges and credits appropriate?

PEF: *Yes. PEF's proposed power factor charge and credit of $0.25 kilovolt-ampere reactive (kVAR) is appropriate.* (Category 2 Stipulation)

ISSUE 106: Is PEF's proposed lump sum payment for time-of-use metering costs appropriate?

PEF: *Yes. PEF's proposed $90 lump sum payment contained in the RST-1 rate for time-of-use metering costs is appropriate.* (Category 2 Stipulation).

ISSUE 107: What is the appropriate method of designing time of use rates for PEF?

PEF: *The appropriate methodology is that used by PEF, which designed those schedules in the same manner as has been prescribed by the Commission since their inception.*

ISSUE 108: What are the appropriate charges under the Firm, Interruptible, and Curtailable Standby Service rate schedules?

PEF: *PEF's proposed Standby Service charges were appropriately developed in accordance with Commission prescribed methodology.*

ISSUE 109: What is the appropriate level of the interruptible credit?

PEF: *There should be no change in the current level of the interruptible credit in this docket. Any change in the credit should be addressed in the DSM goals docket or the conservation clause docket.*

ISSUE 110: Should the interruptible credit be load factor adjusted?

PEF: *There should be no change in the application of the credit in this docket. Any change in the application of the credit should be addressed in the DSM goals docket or the conservation clause docket.*

ISSUE 111: What are the appropriate energy charges?

PEF: *Energy charges should be set in combination with demand charges to produce the target revenue requirements and to the extent practical provide for uniform percentage increases throughout the class.*

ISSUE 112: What are the appropriate demand charges?

PEF: *Demand charges should be set at a level to at least recover distribution costs and be set in combination with energy charges to produce the target revenue requirements and to the extent practical provide for uniform percentage increases throughout the class.*

ISSUE 113: What are the appropriate lighting charges?

PEF: *The appropriate lighting charges are those presented in the tariff sheets contained in MFR E-14.*

ISSUE 114: Should PEF's proposal to revise its Leave Service Active (LSA) provision (tariff sheet No. 6.110) be approved?

PEF: *Yes.*

ISSUE 115: What is the appropriate effective date for PEF's revised rates and charges?

PEF: *The appropriate effective date for the revised rates is the first billing cycle for the month of January, 2010. The appropriate effective date for revised service charges is January 1, 2010.*

ISSUE 115A: Are the rates proposed by Progress Energy Florida fair, just, reasonable, and compensatory as those terms are used in Chapter 366, Florida Statutes, including specifically Section 366.03, 366.041(1), 366.05(1), and 366.06?

PEF: *Yes, for all the reasons set forth in PEF's petition, testimony, exhibits, and MFRs.*

ISSUE 115B: In fulfilling its mandate under Section 366.01, Florida Statutes, to regulate public utilities in the public interest and for the protection of the public welfare, and its mandate under Section 366.041(1) to fix fair, just, reasonable, and compensatory rates that consider among other things the value of such service to the public and that do not deny the utility a reasonable return upon its rate base, should the Commission grant any part of PEF's proposal to increase its base rates in this docket?

PEF: *Yes, the Commission should grant all of PEF's proposal to increase its base rates, for all the reasons set forth in PEF's petition, testimony, exhibits, and MFRs.*

OTHER ISSUES

ISSUE 116: Should any of the $13,078,000 interim rate increase granted by Order No. PSC-09-0413-PCO-EI be refunded to the ratepayers?

PEF: *No.*

ISSUE 117: Should PEF be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records which will be required as a result of the Commission's findings in this proceeding?

PEF: *Yes.* (Category 1 Stipulation).

ISSUE 118: DROPPED

ISSUE 119: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the Stipulation approved by Order No. PSC-05-0945-S-EI to a future period violate the terms of the Stipulation and order?

PEF: *No, nothing in the Stipulation precludes the creation of a regulatory asset and the deferral of pension expenses.*

ISSUE 120: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the Stipulation and order to a future period constitute retroactive ratemaking?

PEF: *No, the deferral of these expenses to a future period does not constitute retroactive ratemaking.*

ISSUE 121: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the revenue sharing provisions of the Stipulation and order to a future period result in double recovery of those expenses?

PEF: *No, the deferral of these expenses to a future period does not result in any double recovery.*

ISSUE 122: Should this docket be closed?

PEF: *Yes.*

III. Argument.

A number of issues in this proceeding have been stipulated or have not been disputed by any party. Among the most significant of these issues are the following substantial capital investments by the Company: (1) the Bartow Repowering Project, (2) the Steam Generator Replacement project, and (3) the ESP replacement project. The parties do not dispute the prudence or costs of any of these capital investments. (Tr. 516; 331-366; 403-513). Likewise, no party has challenged the Company's sales and load forecast. (Tr. 986-1000). These issues represent the bulk of the Company's requested $499 million rate increase.

There are only four material issues in dispute in this proceeding: (1) the appropriate treatment of the calculated theoretical to book depreciation reserve variance, (2) the appropriate capital structure and ROE, (3) the appropriate level of O&M expense, given various O&M adjustments recommended by intervener witnesses, and (4) the appropriate cost allocation methodology to allocate the Company's costs among its rate classes. As shown below, the preponderance of the evidence presented at the final hearing shows that the Company's requested rate increase, as well as its requested change in cost allocation methodology, should be approved by this Commission.

IV. The Company's Requested Annual Depreciation Expense Should be Approved. (Issues 7-20, 28-29, 75-76, 87)

PEF retained Earl Robinson, a certified depreciation specialist with over thirty years of experience preparing depreciation studies, to prepare its Depreciation Study. (Tr. 1097; Hearing Ex. 83). Mr. Robinson reviewed and analyzed PEF's plant-in-service to prepare a comprehensive depreciation study of PEF's generation, transmission, distribution, and general plant assets. (Tr. 1127). The Company's Depreciation Study was prepared in accordance with the Commission's applicable depreciation rules and generally accepted utility industry depreciation methods. (Tr. 3534). Indeed, the Company's depreciation rates were prepared using the Straight Line Method, Broad Group Procedure, and the Average Remaining Life ("ARL") depreciation methods and techniques. (Tr. 1102). The Straight Line Method, Broad Group Procedure, and ARL depreciation methods and techniques are generally accepted utility industry depreciation standards. (Tr. 1112). The Commission has consistently followed these depreciation methods, including application of the ARL technique to recover the costs of depreciable plant over the average remaining life of depreciable plant, for over twenty years. (Tr. 3544; 3726-27).

OPC's and FIPUG's depreciation witnesses, Jacob Pous and Jeffry Pollock, agree these are standard depreciation methods. Mr. Pous agrees that the straight-line method is normally employed for utility depreciation proceedings, the average life group procedure is used by the vast majority of utilities, and that most utilities rely on a remaining life technique in utility rate matters. (Tr. 2033). Mr. Pollock apparently agrees too, contending the remaining life technique is prescribed by Commission rule. (Tr. 3196). There is no reasonable basis to dispute the Company's Depreciation Study based on these standard and generally accepted depreciation methods and techniques and, as discussed in more detail below, there is no reasonable basis to depart from the application of them in this proceeding.

The Company's Depreciation Study provides recommended average remaining life depreciation rates related to the Company's historical plant-in-service as of December 31, 2007. Pro forma depreciation rates were developed by updating the Company's December 31, 2007 historical plant-in-service with the 2008 and 2009 budget activity. (Tr. 1127). The Company's book depreciation reserves were updated to December 31, 2009 and, applying the same depreciation methods, techniques, and average remaining life, depreciation rates were determined for the depreciable plant as of December 31, 2009. (Tr. 1127-28). The proposed depreciation rates are therefore based on PEF's actual and expected plant-in-service. The Company's depreciable plant-in-service is $12,020,397,963 as of December 31, 2009 compared to a depreciable plant-in-service of $9,536,876,227 as of December 31, 2007. (Tr. 1128). This is an increase in depreciable plant investment of almost $2.5 billion and it is a major contributing factor to the increase in the Company's required annual depreciation expense. (Tr. 1128, 1223-24). Based on the Company's Depreciation Study, that increase in annual depreciation expense is $97,355,430. (Hearing Ex. 84). After the removal of items recovered under the cost recovery clauses and other adjustments, the increase in the Company's annual deprecation expense is $60,851,576. (Hearing Ex. 125).

Intervener witnesses do not challenge the $2.5 billion investment the Company has made in depreciable plant. Intervener witnesses also do not challenge the use of the Straight Line

Method, Broad Group Procedure, and Average Remaining Life Technique as generally accepted depreciation methods or their use in the Company's Depreciation Study. Instead, the intervener witnesses recommend (1) a radical departure from the ARL with respect to the variance between the theoretical reserve and the Company's book depreciation reserve, and (2) different remaining life and net salvage depreciation estimates for some but not all Company depreciable property accounts. Based on the evidence, sound regulatory policy, and well recognized depreciation principles, their recommendations must be rejected.

A. There is no valid reason based on the evidence, sound regulatory policy, and depreciation principles to depart from the generally accepted application of average remaining life to address the variance between the theoretical and book depreciation reserve.

The Company's Depreciation Study includes a calculation of the theoretical reserve as of December 31, 2009 under the Commission's rule and a comparison of the theoretical to book depreciation reserve. This comparison demonstrates a variance of the Company's book depreciation reserve over the theoretical reserve of approximately \$646 million. (Tr. 3545). OPC, through its witness Mr. Pous, proposes to amortize this \$646 million for PEF's customers over four years, resulting in a decrease in annual depreciation expense of \$161 million. (Tr. 2013; 2021). That's almost half the annual net income of the Company each year over four years. (Hearing Ex. 47, MFR Schedule F, p. 275). The further effect of this proposal is that \$161 million a year will be paid to customers out of the depreciation book reserve. (Tr. 2151, L. 2-5). At the end of the four years, OPC agreed the depreciation book reserve would have to be <u>restated</u> to reflect the annual \$161 million adjustment. (Tr. 2151, L. 6-10). All interveners except FIPUG join in this recommendation. FIPUG, through its witness Mr. Pollock, proposes an amortization of \$300 million of this variance over three years, or a reduction in the annual depreciation expense of $100 million a year. (Tr. 3204).[3] Regardless of the proposal before the Commission, these recommendations are based on nothing more than the mere existence of a variance or imbalance between the theoretical reserve and the book depreciation reserve in that calculation. (Tr. 2152-2153; Tr. 2155-2160; Tr. 3224-3225).

The interveners' proposals are a radical departure from the admittedly standard, generally accepted industry method of using average remaining life depreciation rates followed in Florida and around the country. OPC witness Pous admits that average remaining life depreciation rates are the <u>normal</u> treatment for reserve imbalances by utilities and regulatory commissions. (Tr. 2161, L. 3-10). Mr. Pous further admitted that he has not made a similar reserve imbalance adjustment in any other proceedings outside the current PEF and Florida Power & Light Company ("FPL") base rate proceedings and the prior 2005 PEF base rate proceeding despite having testified in over 400 cases in the United States and Canada. (Tr. 2160, L. 17-22, Tr. 2195, L. 7-10). He also admits that depreciation rates could be established on a going-forward basis using average remaining life rates without doing the calculation of the theoretical versus book depreciation reserve. (Tr. 2161, L. 11-15). The reason is that average remaining life depreciation rates automatically adjust depreciation rates to account for any variance between the theoretical reserve and the book depreciation reserve over the remaining life of the depreciable property. (Tr. 3544-46; 3738-39). This self-adjustment mechanism is explained in the following exchange between Staff counsel and PEF witness Mr. Garrett:

> Q. Switching gears, would you agree, basically, that the remaining life depreciation rate formula measure the amount remaining to be recovered divided by the number of years left in which to recover, is that correct?
>
> A. Yes, I would agree with that.

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[3] Mr. Pollock departed from this recommendation somewhat when he took the stand, asserting that the amortization should be over four years, or $400 million at a $100 million annual reduction in depreciation expense. (Tr. 3226-27). He did not, however, change his pre-filed direct testimony on this point so it is unclear exactly which proposal he now recommends to the Commission. (Tr. 3155-56).

Q. And the measurement of the amount remaining to be recovered involves the reserve, is that correct?

A. Yes.

Q. The relative adequacy of the reserve causes the remaining life depreciation rate formula to self-adjust, is that correct?

A. Yes, I would agree with that.

Q. So, if there is a reserve surplus, the depreciation rate would naturally be lower than it would be otherwise --- that it would be otherwise be because a lesser amount is needed to be recovered in the future, is that correct?

A. Yes, I would agree with that. In fact, we have quantified what we think that benefit is and provided it as an exhibit in my rebuttal testimony.

(Tr. 3882, L. 18-25, Tr. 3883, L. 1-12). The application of average remaining life depreciation rates therefore matches the recovery of the cost of the depreciable property to the remaining time that depreciable property is providing service to customers. (Tr. 3548). All interveners and this Commission recognize that the matching of the recovery of the cost of depreciable plant to the remaining service life of that plant is a fundamental depreciation principle. (Tr. 2177, L. 17-21; Order No. PSC-98-1723-FOF-EI, Docket 971570-EI, at *16 (Dec. 18, 1998)). Indeed, apart from his recommended amortization, OPC witness Mr. Pous uses the average remaining life technique too. (Tr. 2161, L. 16-19).

There must be some reason for this Commission to depart from the accepted, normal treatment of reserve variance or imbalances through the application of average remaining life depreciation rates. Intervener witnesses recognize this and argue that (1) the existence of a variance or imbalance of the book depreciation reserve over the theoretical reserve means that customers have paid more than they should have paid resulting in an unacceptable level of intergenerational inequity and (2) the magnitude of the variance calls for a departure from the Company's proposed average remaining life approach. (Tr. 2146, L. 17-19; Tr. 2147, L. 9-1; Tr.

3198; 3204). Both arguments are wrong and unsupported by the evidence. In fact, OPC repudiated the argument that the existence of the variance or imbalance between the book depreciation reserve and the theoretical reserve means customers have paid more than they should have paid in its opening arguments in this case. Further, the recommended departure from generally accepted application of the average remaining life depreciation rates here will require the Commission to do something no other commission in this country has done. (Tr. 3918-19). The recommendation is also inconsistent with prior Commission orders, GAAP, the FERC depreciation principles, and sound regulatory policy because it does not resolve intergenerational inequity but in fact creates intergeneration inequity between current customers and past and future customers.

1. Customers have not paid more than they should have paid simply because a variance or imbalance of the book depreciation reserve exists over the theoretical reserve.

Intervener witnesses' argument that intergeneration inequity exists, because a variance of the book depreciation reserve over the theoretical reserve means customers have paid more than they should have, is simply wrong. Intervener witnesses rely on nothing more than the existence of the variance or imbalance resulting from the comparison of the theoretical reserve calculation to the book depreciation reserve to make this claim. (Tr. 2151, L. 11-18; Tr. 3198, L. 8-11). But the mere calculation of the theoretical reserve itself cannot mean that customers have paid more or less than they should have paid.

To begin with, there is no such thing as a theoretical depreciation reserve. It does not exist on the Company's books, hence, the name "theoretical" reserve. (Tr. 3535). Rather, it is a calculation made at a single point in time and included in the depreciation studies once every four years. (Tr. 3538; Tr. 2157, L. 9-14). As Mr. Pous testified, the "theoretical reserve is the calculated balance that would be in the accumulated provision for depreciation (FERC account

108), often called the reserve, *at a point in time* if *current* depreciation parameters (i.e., current life and salvage estimates) *had been applied from the outset*." (Tr. 2151, L. 19-25, Tr. 2152, L. 1-15) (emphasis added). The "current" depreciation parameters are the proposed depreciation parameters. The assumption in the theoretical reserve calculation is that the proposed depreciation parameters "had been applied from the outset," or that they have always been in effect. (Tr. 3536; Tr. 2152, L. 10-25, Tr. 2153, L. 1-10). Mr. Pous conceded that this theoretical calculation therefore takes the proposed rates, which are not in effect, and applies them over the historical plant activity, (Tr. 2155, L. 1-25, Tr. 2156, L. 1), resulting in their application from the point the calculation is made forward and backwards. (Tr. 2157, L. 15-25, Tr. 2158, L. 1-8, Tr. 2159, L. 17-25, Tr. 2160, L. 1-4).[4] But there were different, historical depreciation rates in effect "backwards" during the period of the historical plant activity period – not the proposed depreciation rates – and those historical rates were what were paid by customers, not the proposed depreciation rates. (Tr. 3551; 3731-32).

As a result, as Mr. Garrett explains, customers have paid exactly what the Commission has established as the cost of service for depreciation, and that has been reflected in the Company's accumulated depreciation reserves that serve to reduce the recovery of investments on a prospective basis. (Tr. 3905-3906). Mr. Pous must admit too, as he did, that depreciation rates were in effect over the entire historical time period and that customers paid the legal rates adopted by the Commission in the past. (Tr. 2156, L. 25, Tr. 2157, L. 1-8). It necessarily follows that customers have not paid more than they should have simply because the calculation

[4] Mr. Pous made these admissions only after being impeached with his answers to the same questions in his deposition at the hearing. (Tr. 2152-60). The fact that he gave different answers initially at the hearing to the very same questions in his deposition demonstrates his lack of credibility on this point and does not take away from the fundamental mathematical way the theoretical reserve calculation comparison to the book reserve works. Indeed, even as he attempted to evade his answers to the same questions in his deposition he admitted that the calculation is theoretically correct going forward "but it is also theoretically going backwards under certain conditions." (Tr. 2153, L. 16-18).

of the theoretical reserve reveals a variance or imbalance of the book depreciation reserve over the theoretical reserve.

The reasons for the variance or imbalance of the theoretical reserve compared to the book depreciation reserve further demonstrate that customers have not paid more than they should have paid in depreciation rates in the past. Intervener witnesses ignore these reasons in their testimony. But the undisputed evidence is that the variance of the depreciation book reserve over the theoretical reserve results from changes in depreciation estimates, in particular, extensions in the estimated service lives of PEF's production plant. (Tr. 3733-34; 3539-40).

Over seventy (70) percent of the calculated theoretical reserve variance to the book depreciation reserve arises in the Company's production plant accounts involving the Company's power plants. (Tr. 3539; Tr. 3736, L. 5-7). As PEF explained, the service lives of many of its production plant units were extended based on additional experience and operation of the units since the last depreciation study performed by the Company. These extensions included an additional fourteen (14) years for the Company's coal-fired steam units, Crystal River Units 4 and 5, and extensions of several years for its Anclote oil-fired steam plant, its Crystal River Units 1 and 2 coal-fired steam plants, and several of its combustion turbine peaking units. (Tr. 3736, L. 9-13; Hearing Ex. 216). These extended service lives drive the calculated theoretical reserve calculation up because that calculation assumes that the proposed service live extension estimates were always factored into the Company's depreciation rates, which of course is not true because these service life estimates are changing only now with the Company's proposed depreciation rates. (Tr. 3736, L. 13-18; Tr. 3539-40).

A change in depreciation estimates, like the changes in service lives for the Company's production plant reflected in the Company's current proposed rates, does not mean that customers have overpaid in the past. Depreciation itself, as Mr. Pous admits, is an estimation process. (Tr. 2164, L. 10-12). As with any estimation process, actual values may differ from predicted values and, as Mr. Pous admitted too, even he would be lucky if his own depreciation estimates were accurate. (Tr. 2164, L. 13-21). The utility system also changes daily, monthly, and yearly with additional investment and retirements and changes to the utility system. (Tr. 2164, L. 22-25, Tr. 2165, L. 1). These changes will also affect the depreciation estimates in the future, just as they have affected the current proposed rates since the last depreciation study was performed for PEF. As a result, the calculation of the theoretical reserve comparison to the book depreciation reserve does not mean customers have overpaid depreciation rates when those rates are changing because of changes in the utility system over time that affect depreciation rates and the inherent inaccuracy in depreciation estimates themselves.

OPC agreed with this position in its opening statement to this Commission. As OPC explained, "You heard a lot about depreciation and how unfair it is that we're proposing that there be a return to the customers of the excess depreciation that they've paid. ... We're asking you to make a correction in rates that, *as it turns out today*, are higher than they should have been, *not* because [the Commission] made a mistake, *not* because the company did something wrong, but *because circumstances changed*. We know today – *what we know today, had we known then*, the rates would have been lower." (Tr. 61, L. 6-9, 16-22) (emphasis added). OPC admits that the reserve variance is *not* the result of a mistake by the Commission in setting past depreciation rates, and *not* the result of some error by the Company in its depreciation estimates or rates. Rather, OPC admits the theoretical to book depreciation reserve variance exists simply "because circumstances changed," yielding different depreciation estimates than would have been the case had we known then what we know now. This is not an argument that customers have paid more than they should have based on what were the best depreciation estimates and rates at the time. Rather, it is an argument that customers have allegedly overpaid through the retroactive application of what we know now (i.e. the proposed rates) to the past. In hindsight one can always say that the depreciation rates should have been different based on additional knowledge and experience but that does not mean, as OPC acknowledges, that the Company or the Commission did anything "wrong" in setting the prior depreciation rates that customers paid.

OPC witness Pous and FIPUG witness Pollock premise their intergenerational inequity argument supporting their proposed amortizations of the depreciation theoretical to book depreciation reserve variance on the false claim that customers have paid more than they should have in depreciation rates.[5] As explained above, the evidence in this proceeding demonstrates that claim is simply inaccurate. There is no intergenerational inequity. The continued use of the average remaining life depreciation rates will provide full recovery of the total plant in service investment over the remaining time that plant is in service. (Tr. 3548, L. 14-23). That means customers will be paying rates for service for the period of time the plant assets are providing customers the electric service they are paying for. (Id.) This is the matching principle that is fundamental to what depreciation rates are supposed to accomplish. (Tr. 3543). It is not inequitable for customers to pay for exactly what they are getting in terms of electric service. (Tr. 3548, L. 21-23).

2. The magnitude of the theoretical to book depreciation reserve variance alone is no justification for amortization of the variance over a period shorter than average remaining life.

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[5] Mr. Pous made a further argument that intergenerational inequity required that the alleged excess depreciation reserve be returned as quickly as possible based on his assertion in response to a question by Commissioner Skop that the Company's own projections demonstrated a 33 percent turnover in customers on a net basis if average remaining life depreciation rates are used. (Tr. 2198, L. 11-25, Tr. 2199, L. 1-10). The only evidence to support this claim is Mr. Pous' reliance on page 2-3 of the Company's 2009 Ten Year Site Plan. (Tr. 2045, L. 4-6). That page shows the growth in customers over the historical and projected periods of time and Mr. Pous acknowledges in his pre-filed direct testimony that this number "*does not identify how many customers left or will leave the system.*" (Tr. 2045, L. 7-8) (emphasis added). Mr. Pous' later answer to Commissioner Skop's question that there is a 33 percent "*turnover*" in customers based on this information is misleading and rank speculation on his part unsupported by any evidence and in fact contradicted by the evidence he does cite.

Intervener witnesses contend that the theoretical to book depreciation reserve variance of $646 million is material and therefore should be addressed for that reason alone. (Tr. 2042; 3204). Intervener witnesses ignore the fact that the average remaining life depreciation rates *automatically* adjust to address any such reserve variance. (Tr. 3544-45; 3738-39). In fact, the Company's depreciation study demonstrates that the average remaining life depreciation rates are reducing the theoretical to book depreciation reserve variance by $68 million in the two years between the end of 2007 and the end of 2009. (Tr. 3735, L. 17-21; Hearing Ex. 84). The average remaining life depreciation rates will continue to self-adjust to ensure that customers pay only for the plant investment over the life of that investment.

Intervener witnesses further admit that there is no definition of a "material" reserve variance or imbalance. Indeed, they acknowledge there will always be some variance between the theoretical and book depreciation reserve that must be accepted. (Tr. 2042). Even the depreciation manual prepared by the National Association of Regulatory Utility Commissioners ("NARUC") that the interveners rely on states that a "material" theoretical to book depreciation reserve variance is subjective. (Hearing Ex. 275, page 189).[6] There is no evidence or authority, then, to support their claim that the mere fact that the dollar amount of the variance between the book depreciation reserve and theoretical reserve is $646 million is in any way material under industry depreciation standards. This amount represents only 14.7 percent of the book depreciation reserve and it is declining as a result of the application of average remaining life depreciation rates. (Tr. 3548, L. 7-9). The only industry evidence in the record is that book to theoretical depreciation reserve variances of 10 to 15 percent are not uncommon. (Tr. 3548, L.

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[6] Further, the NARUC manual does not direct commissions to take any particular action with respect to a theoretical to book depreciation reserve variance, material or otherwise. Rather, the NARUC manual indicates that one should understand what is causing the variance and then simply lists common options to address any such variance as the application of the average remaining life depreciation method or amortizations. The NARUC manual is silent as to when either option should be employed. (Hearing Ex. 275)

6-7). Moreover, if the impact of longer production plant service lives reflected in over 70 percent of the reserve variance that exists in the Company's production plant accounts is acknowledged and therefore discounted the variance is clearly much lower than 14.7 percent. (Tr. 3539; Tr. 3545, L. 18-21). The mere dollar amount here, therefore, does not demonstrate a "material" variance that calls for a departure from average remaining life depreciation rates. Rather, as noted above, because the variance is driven by changes in depreciation estimates over time, the matching principle dictates that the average remaining life depreciation rates employed in the Company's depreciation study appropriately link customer payments of depreciation expense to the service lives of the assets providing them electric service.

This matching principle underlying depreciation will be abrogated if the interveners' amortization proposals are accepted. There is no sound reason to depart from this fundamental regulatory depreciation policy. Indeed, the argument the interveners offer for why this Commission should depart from this fundamental depreciation policy and amortize the claimed "material" book to theoretical depreciation reserve variance for the benefit of customers is that recessionary economic conditions warrant such action. (Tr. 3863-65). The Commission has rejected this argument before and should do so again.

In Order No. PSC-98-1723-FOF-EI, the Commission rejected FPC's (PEF's) request that it be allowed the flexibility to accelerate the amortization of customer service system assets in light of potential technological changes and competition. Order No. PSC-98-1723-FOF-EI, Docket No. 971570-EI, 1998 Fla. PUC LEXIS 2356, 98 FPSC 12:405 (Dec. 18, 1998). The Commission explained that "*[o]ne of the basic axioms of depreciation is to match capital recovery with consumption.*" (Id. at *16) (emphasis added). The Commission then expressed its concern with adjusting depreciation expense "*in response to economic conditions*," because "each step made in accord with this practice makes the next step easier and *can lead to the* *design of depreciation rates that will no longer reflect the matching principle but rather the level of the companies' earnings.*" (Id. at *17) (emphasis added).[7] The interveners' reliance on the recessionary economic conditions to support their proposed amortizations implicates the exact concerns the Commission addressed in Order No. PSC-98-1723-FOF-EI. Indeed, designing depreciation rates based on the impact of economic conditions and not the matching of costs to the service life of plant in service further violates the principle of the FERC Uniform System of Accounts that utilities "must use a method of depreciation that *allocates* in a *systematic and rational manner* the *service value of depreciable property over the service life of the property.*" FERC, Uniform Systems of Accounts," Section 22, paragraph A. (emphasis added).[8] This argument should be rejected for the same reason, because it requires the Commission to depart from and abrogate a "basic axiom" of depreciation regulatory policy followed by the Commission and followed under the FERC Uniform System of Accounts.

3. The adoption of the Intervener Witnesses' proposed amortizations of the theoretical to book depreciation reserve variance violates GAAP.

The proposal by OPC to reduce depreciation expense by $161 million a year to give customers the full $646 million theoretical to book depreciation reserve variance over four years admittedly requires the Company to *re-state* depreciation book reserves. (Tr. 2151, L. 6-10). The $161 million annual reduction in depreciation expense drives depreciation expense below current depreciation expense levels. That means the Company must re-state existing book

[7] The Commission also noted its belief that "depreciation reserve deficits should be written-off as soon as economically practicable." (Id. at *17). But this belief is premised on the approval of "faster write-off[s] of perceived reserve deficits and of unrecovered net plant" which was not considered in conflict with the matching principle because "those deficits did not relate to existing plant" but rather related to plant that was no longer in service. (Id. at *16). As explained below, the Commission has frequently amortized the recovery of obsolete plant that was retired early because the plant was no longer in service. But that is not the situation represented by the book depreciation variance from the theoretical reserve in this proceeding.

[8] The Uniform System of Accounts for Public Utilities and Licensees as found in the Code of Federal Regulations, Title 18, Subchapter C, Part 101 for Major Utilities are incorporated by reference in the Commission's rules. Rule 25-6.014(1), F.A.C.

depreciation reserves to reflect the amount the annual $161 million reduction drops depreciation expense below the existing depreciation expenses. The annual $161 million reduction in depreciation expense also means customers during the four year amortization period will pay nothing for the benefit of service from the base rate portions of the $2.5 billion in additional investment in depreciable plant the Company has made.

To explain the full impact of this annual $161 million reduction in depreciation expense, with no change in depreciation rates, current depreciation expense levels are approximately $346 million. (Tr. 3856, L. 15-16). With the Company's increase in depreciable plant investment of $2.5 billion since 2007, the depreciation expense will increase by approximately $97 million before cost recovery clause and other adjustments, and by $60,851,576 when those adjustments are made. (Hearing Exs. 84 and 125). OPC's proposed annual $161 million reduction in depreciation expense eliminates this increase in depreciation expense. This means that the Company receives <u>no</u> payments from customers for four years for the base rate portions of the additional $2.5 billion investments in depreciation plant the Company has incurred since 2007. It further drives depreciation expense over $90 million *below* the current annual depreciation expense. This means that, under OPC's proposal, customers during this four-year amortization period will receive service from depreciable plant already in service that they will not pay for. (Tr. 3904, L. 14-25, Tr. 3805, L. 1-4). This also means, as OPC acknowledges, that depreciation book reserves have to be re-stated below previously recorded book depreciation levels. (Tr. 2151, L. 6-10). This is not GAAP. (Tr. 3805, L. 5-14). In fact, it violates GAAP. (Tr. 3752-53).

The interveners' amortization proposals also violate GAAP for another reason. The evidence demonstrates that the theoretical reserve variance over the book depreciation reserve that the interveners want to amortize over four years results from changes in depreciation estimates, e.g. changes in service lives, and is not the result of accounting errors or erroneously charged depreciation rates. (Tr. 2157; 3225-26). OPC admitted this much in its opening statement to this Commission. (Tr. 61). Changes in depreciation estimates must be recognized in financial statements on a prospective basis under GAAP and not through the restatement of prior period results. (Tr. 3717, L. 20-24). The only GAAP authority actually cited to the Commission provides that a:

> change in accounting estimate shall be accounted for in (a) the period of change if the change affects that period only or (b) the period of change and future periods if the change affects both. A change in accounting estimate shall not be accounted for by restating or retrospectively adjusting amounts reported in financial statements of prior periods or by reporting pro forma amounts for prior periods.

Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections" (FAS154, paragraph 9). (Tr. 3752). A change in accounting estimate is defined to include "a change that has the effect of ... altering the subsequent accounting for existing or future assets or liabilities" and further "result[s] from new information." Examples include "service lives and salvage values of depreciable assets." (FAS154-2d) (Tr. 3752). Because the theoretical to book depreciation reserve variance that interveners propose to amortize results from changes in depreciation estimates, GAAP requires such changes to be reflected prospectively in rates and not through the restatement of depreciation reserves as interveners propose. (Tr. 3752-53; 3922-23). Even Mr. Pous agreed that GAAP applies changes in depreciation estimates, e.g. service lives and net salvage, prospectively. (Tr. 2165, L. 18-22). He simply argued GAAP does not dictate ratemaking. (Id.)[9] But there is no valid justification in the record for the Commission to depart from GAAP in establishing rates in this case. The evidence demonstrates the theoretical

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[9] OPC questioned Mr. Garrett about whether the Commission would violate GAAP if the Commission decided to adopt Mr. Pous' proposal in totality and that became a final order. (Tr. 3823-3824). As Mr. Garrett explained, the Commission has latitude to establish the cost of service in rates but the reduction of accumulated depreciation reserve in establishing rates does not make that GAAP. (Tr. 3824, L. 6-13). Under FAS 71 the regulatory body cannot reduce liabilities unless they created them. (Id. at L. 14-16).

to book depreciation reserve variance exists not because customers paid more than they should have in the past due to errors or mistakes, but rather the variance exists because depreciation estimates have changed with additional experience and knowledge operating the utility system and changes to the system. (Tr. 3733-34; 3539-40). As a result, the Commission should follow GAAP and apply the changes in depreciation estimates prospectively through the average remaining life depreciation rates.

4. The adoption of the Intervener Witnesses' proposed amortizations of the theoretical to book depreciation reserve variance is inconsistent with FERC depreciation policy and practice.

This Commission requires utilities such as PEF to maintain its accounts in accordance with the Uniform System of Accounts for Public Utilities and Licensees as found in the Code of Federal Regulations, Title 18, Subchapter C, Part 101 for Major Utilities, which are incorporated by reference in the Commission's rules. Rule 25-6.014(1), F.A.C. FERC depreciation accounting policy and practices are therefore relevant to the Commission's regulatory policy and practices because the Commission requires Florida utilities to follow the same uniform system of accounts followed by FERC. With respect to theoretical to book depreciation reserve variances or imbalances, the FERC policy is clear that such variances or imbalances are addressed prospectively by an upward or downward adjustment in the depreciation rate.

The FERC has determined that the over- or under- accrued provisions for depreciation should be corrected prospectively by an upward or downward adjustment in the depreciation rate. For example, in 2008 the FERC rejected a utility request to decrease accumulated depreciation below amounts previously accrued because the over accrual was not shown to result from an accounting error but rather was the result of a change in estimates in setting depreciation rates. The FERC ruling explained that changes in estimates should be addressed prospectively by changes in deprecation rates. Startrans IO, LLC, Docket Nos. EC08-33-000, EC08-33-001, March 31, 2008, Hearing Ex. 228). This is a long-standing FERC policy, dating back to the 1970's. The FERC made clear its policy that, because of the estimates inherent in depreciation accounting, "it is the Commission's policy that over or under provisions for depreciation are corrected prospectively by an upward or downward adjustment in the depreciation rate," rather than by transfers to or from the accumulated provision for depreciation. See Michigan Wisconsin Pipe Line Company, Docket No. RP83-27-002, 1983 FERC LEXIS 1967, April 8, 1983, quoting Equitable Gas Company, 56 FPC 1655 at 1657 (1976). (Hearing Ex. 228)

The FERC reaffirmed this policy in 1992, holding that a utility's depreciation study was not a basis to adjust the recorded balance in the utility's depreciation reserve. The FERC noted that accumulated depreciation was dependent on a number of assumptions and that, as new events occur and more experience is acquired or additional information is obtained, depreciation estimates will change. The FERC then stated that it "does not use depreciation studies to adjust past depreciation charges that were properly recorded in prior periods based on the depreciation practices and information at the time they were recorded. Changes in depreciation estimates resulting from new information or subsequent developments or from better insight or improved judgment should be accounted for in the period of change and future periods, but not through retroactive restatement of prior period's depreciation amounts." Carnegie Natural Gas Company, Docket No. FA89-16-000, August 7, 1992. (Hearing Ex. 228). PEF's 2009 Depreciation Study is consistent with this policy. The intervener witnesses' proposed amortizations of the theoretical to book depreciation reserve variance are not consistent with this policy.

5. **The adoption of the Intervener Witnesses' proposed amortizations of the theoretical to book depreciation reserve variance is inconsistent with Commission depreciation policy and practice.**

Interveners argued that this Commission has repeatedly required the elimination of a depreciation reserve imbalance, a surplus or a deficiency, through other mechanisms than remaining life recovery, citing as many as thirty-one Commission orders. (Hearing Ex. 286). They never explain, however, the context of these orders or what they actually provide. They must admit, though, that there is no Commission order approving a proposal like their proposal to take money out the depreciation book reserve and amortize it over a period shorter than average remaining life based simply on the calculated theoretical to book depreciation reserve variance. (Tr. 2162, L. 16-25, Tr. 2163, Tr. 2164, L. 1-4). Indeed, in response to a question from Commissioner Skop, Mr. Pous conceded he was unable to cite any specific authority where the Commission had approved a depreciation reserve adjustment outside of a settlement agreement. (Tr. 2191, L. 7-22). In fact, Mr. Pous admitted that one cannot find any other commission in the country where he made a reserve imbalance adjustment proposal and the commission ruled on that proposal. (Tr. 2160, L. 23-25, Tr. 2161, L. 1-2). Interveners clearly are proposing that the Commission do something that neither this Commission nor any other commission in the country has ever done.

There is no dispute that the average remaining life depreciation rates will resolve any alleged depreciation reserve variance over the remaining life of the depreciable plant by adjusting the prospective depreciation rate to match the recovery of the cost of the depreciable plant with the plant's remaining service life. Mr. Pous calls this the "normal" way such reserve variances are addressed (Tr. 2160-2161; 2042), and Mr. Pollock points to the requirement to apply average remaining life under the Commission's depreciation rule. (Tr. 3196). The Commission has also noted that average remaining life is the rule rather than the exception when addressing depreciation reserve variances in orders that were addressed by Mr. Robinson and Mr. Garrett in rebuttal. (Tr. 3554-56; 3742-52). For example, in a 1984 Gulf Power Company

Order, Order No. 13681, the Commission stated that: "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 remaining life of the associated investment* ....." Order No. 13681, Docket No. 830585-EI (Sept. 17, 1984) (emphasis added). Similarly, in Order No. 16269 involving West Florida Natural Gas Corporation's application for new depreciation rates, the Commission noted that the effect of prior rates and allocations resulted in surpluses in some accounts and deficits in others but "[b]ecause these imbalances have *not* been brought about *by technological changes*, such as those *seen in the telephone industry*, we believe that *the appropriate treatment is to apply the standard remaining life rate to write-off each account's imbalance over the remaining life*." Order No. 16269, Docket No. 850669-GU (June 20, 1986) (emphasis added). There is no reason in the record before this Commission to depart from the average remaining life depreciation rates here to address the depreciation reserve variance.

In fact, when the Commission has departed from average remaining life to address depreciation reserve variances in the past the Commission has done so under circumstances <u>not</u> present in evidence in this proceeding. For example, the Commission has amortized depreciation reserve deficiencies created when rapid technological changes or competition renders existing plant obsolete requiring retirements much earlier than the estimated service lives. This was the case in Order No. 14929 involving General Telephone Company cited by Mr. Pous and addressed in rebuttal by Mr. Robinson and Mr. Garrett. (Tr. 3555-56; Tr. 3746, L. 1-15).[10] Indeed, this is the case for 20 of the additional 31 orders -- which are orders for telephone and communication utilities -- that Mr. Pous cited in his exhibit for Commission support of some

[10] <u>See also</u> Order Nos.: 23922; 25679; PSC-93-1554-FOF-TL; PSC-95-0475-FOF-EI, 12857; 12857; 12654; 12864; 13528; 13918; 16963; 17061; 17134; 17213; 18642; 24005; 25679; PSC-92-0604; PSC-95-0400-FOF-TL; 24004; 18642; PSC-94-0326-FOF-TL; 23822; 12290; 12866; 12857; 13495; 13538; 20330; 22115; and PSC-95-1239-FOF-TL.

method other than average remaining life to address depreciation reserve variances. (Hearing Ex. 286). Under circumstances where plant assets are retired because they are obsolete they are *no longer in service*. Recovery of the costs of such plant over an amortization period shorter than average remaining life is therefore appropriate because average remaining life recovery generally applies to plant still in service. (Tr. 3555). Similar circumstances have occurred when utility property was retired and taken out of service to comply with environmental requirements, such as the regulation of PCB and asbestos. See, e.g. Order No. 17903, Docket No. 870085-EI (July 24, 1987). The circumstances of the recovery of retired, obsolete plant is what the NARUC depreciation manual logically must mean when it references amortization as one of the common methods to address depreciation reserve variances because amortization in this instance more closely follows the matching principle underlying depreciation. See Order No. PSC-98-1723-FOF-EI; see also Order No. 23957, Docket No. 891335-EI, *2 (Jan. 4, 1991) ("The goal of reserve sensitive rate design is to reconcile the asset investment not yet recovered through depreciation expenses to the time remaining in which to collect it."). In this case, however, the theoretical to book depreciation reserve variance applies to all plant in service that will continue to provide service to customers over the remaining life of the plant. (Tr. 3543, L. 19-20). Average remaining life depreciation rates therefore appropriately match the recovery of plant cost to the continued in service life of the Company's plant.

Other circumstances in which the Commission addressed depreciation reserve variances through methods other than average remaining life are equally inapplicable to the interveners' amortization proposals in this proceeding. First, there are several Commission orders that involved the change from whole life to remaining life depreciation methodology by utilities. See, e.g., Order No. 19901, Docket No. 880053-EI, and its precursor Order No. 13681, Docket

No. 830585-EI.[11] The one-time transition from whole life to remaining life depreciation produced depreciation reserve variances. Even then, the Commission expressed the policy "where possible" to make reserve corrections through new depreciation rates by amortizing the reserve variance over the composite remaining life of the associated investment. Order No. 13681; (Tr. 3743, L. 1-14). Second, the Commission has employed reserve transfers to offset depreciation reserve deficiencies with surpluses or to apply surpluses created by federal tax credits, e.g. the Job Development Investment Tax Credit (JDIC), to reserve deficiencies. Order No. 19901, Docket No. 880053-EI; Order No. 19438, Docket No. 860868-EI; Order No. PSC-93-1839-FOF-EI, Docket No. 930453-EI. The Commission's depreciation rule itself authorizes the investigation of depreciation rates for the "possibility" of corrective reserve account transfers. Rule 25-6.0436(7)(b), F.A.C. But this reserve transfer policy is limited to moving dollars between FERC property accounts and cannot involve transfers beyond FERC accounts in the same function, i.e. production, transmission, distribution, and general plant functions. Order No. PSC-94-1199-FOF-EI, Docket No. 931231-EI.[12] Indeed, the Commission has indicated that such reserve transfers "do not represent a "restatement" of reserve;" rather they "represent a reallocation among accounts in accord with he currently perceived life and salvage patterns." See In Re: Florida Power Corporation Petition to reverse reserve transfers, 1992 Fla. PUC Lexis 1083, Order No. PSC-92-0680-FOF-EI (July 21, 1992) at *9. Third, the Commission has approved accelerated depreciation when faced with potential changes in the regulatory environment as a result of deregulation that occurred elsewhere in isolated areas in the country. In Order No. PSC-97-0499-FOF-EI, the Commission expressly stated that the approved accounting adjustments "will facilitate the establishment of a level "accounting" playing field

[11] See also Order Nos.: 14929; 17564; 18202; and 19783.

[12] See also Order Nos.: PSC-99-0073-FOF-EI; 860756; 17903; 19815; 19901; 23835; 25619; PSC-93-0007-FOF-TL; PSC-93-0801-FOF-TL; PSC-98-1763-FOF-GU; PSC-93-1808-FOF-EI; 22585; and PSC-01-2270-PAA-EI.

between [the utility] and possible non-regulated competitors." See In re: Florida Power and Light Co., Order No. PSC-97-0499-FOF-EI, Docket No. 971660-EI. None of these circumstances are present on the record before this Commission.[13]

Finally, interveners rely heavily on prior base rate proceeding settlements approved by the Commission that involved accelerated depreciation among numerous other settlement provisions. (Tr. 2191-92; 3789-92; 3881-82; 3993-94). Indeed, these settlements are their only authority for what they propose in this base rate proceeding. (Id.) But settlements are not binding authority on the Commission. See, e.g., Order No. PSC-94-0172-FOF-TL, Docket No. 920260-TL, 910163-TL, 910727-TL, 900960-TL, 911034-TL (Feb. 11, 1994) ("The Commission, even if it so desired, cannot be bound to a specific course of action through the approval of a stipulation."); Order No. PSC-99-2131-S-EI, Docket No. 990250-EI, Docket No. 990947-EI (Oct. 28, 1999) ("The stipulation binds the parties, and not the Commission.").

However, the depreciation expense elements of these settlements cannot be viewed in isolation from the settlement terms as a whole. They accordingly do not reflect the parties' recognition of any particular regulatory principal; rather, they merely reflect the "give and take" that takes place in any settlement to reach agreement on the settlement as a whole. (Tr. 3994; 3789). Indeed, this Commission has recognized that any settlement involves such "give and take" to reach an end result, explaining in a prior Order that "[i]n reviewing the Settlement and reaching our decision to approve it, we are cognizant of the fact that the parties have made trade-offs in the spirit of compromise. We believe this is an important point to remember when analyzing the Settlement." Order No. PSC-94-0172-FOF-TL at *6.

This is also important to remember in the context of PEF's prior settlement in 2002, which among its provisions included no established ROE and revenue sharing provisions, terms

[13] Interveners also cited nuclear decommissioning orders (see, e.g. Order 13427), which clearly do not provide support to their amortization proposal in this proceeding.

that are not available under traditional regulation. (Tr. 3903); Order No. PSC-99-2131-S-EI, at *5 (noting in approving a Gulf Power Company rate case stipulation that the stipulation included a revenue sharing mechanism that "requires a fundamental change in its traditional rate base and rate of return regulation."). The interveners' reliance on one element of the PEF stipulation (and FPL stipulation), therefore, ignores the fact that element is a part of a whole settlement that cannot be viewed or relied on in isolation from the settlement as a whole. This is not authority then for the Commission to take action on their proposal absent the context of the settlement as a whole and any attempt to do so undermines future settlements.

6. The adoption of the Intervener Witnesses' proposed amortizations of the theoretical to book depreciation reserve variance is inconsistent with sound regulatory policy.

Interveners cannot demonstrate that customers have paid more than they should have in prior depreciation rates such that it is inequitable if the alleged depreciation book to theoretical reserve variance is not amortized to them over four years. (See above at pp. 28-32). Their proposals further undermine the "basic axiom" of depreciation regulatory policy that matches costs recovery with the plant in service for the sake of the effect of economic conditions, which this Commission has rejected before. See Order No. PSC-98-1723-FOF-EI, discussed above at p. 34. They are left with nothing more than the argument that customers are, nevertheless, better off if their rates can be reduced by this proposal. Even on this point, they are wrong.

The evidence demonstrates that the only consideration the interveners gave to the effect of their proposal was the sole impact of the annual reduction in depreciation expense of $161 million over four years on the Company's cash flow (which they analyzed incorrectly as discussed below). (Tr. 3924, L. 5-21; Tr. 4140). The intervener witnesses admitted that their proposals, if accepted, would increase rate base annually by the amount of the reduction in depreciation expense and that the Company was entitled to an opportunity to earn a return on that increase rate base. (Tr. 2166, L. 19-25; Tr. 2167, L. 1-8; Tr. 3227, L. 3-10). But they did not perform any calculations showing the impact of that $161 million reduction in the reserve on rate base and the increase in return on rate base. (Tr. 2167, L. 9-15; Tr. 3227-28). They also failed to address the impact of their proposals on depreciation rates going forward, if their proposed amortizations were accepted. (Tr. 2167, L. 16-20; Tr. 3227, L. 11-21). Had they done so they would realize that customers as a whole are not better off if their proposals are accepted and this is another reason why their proposals are not sound regulatory policy.

First, interveners overlook the current benefit reflected in the Company's proposed revenue requirements related to the calculated theoretical to book depreciation reserve variance. Higher book depreciation reserves serve to lower the rate base eligible for a return and customers receive the benefit of that lower rate base. (Tr. 3740, L. 11-14). This benefit is derived from the application of the average remaining life depreciation rates and lowers 2010 revenue requirements by $127 million. (Tr. 3740, L. 14-18; Hearing Ex. 230). Interveners ignore this undisputed benefit to customers.

Second, the interveners ignore the impact on customer rates during and after the four year amortization periods that they propose. During the four year period of annual reductions in depreciation expense, rate base is increased accordingly, thereby increasing the return the Company is entitled to the opportunity to receive. (Tr. 3924, L. 5-21). This return is approximately $48 million each year, based on the interveners' proposal. (Id.) In addition, with the proposed reduction in annual depreciation expense, cash flow will be dramatically lowered, and the Company will be required to fund additional investment and operations through the capital markets at an additional cost. (Tr. 4140-41). The opportunity to earn this return and the additional capital costs caused by the proposed reductions in cash flow may likely lead to another base rate proceeding in each of the next four years. (Tr. 3966-68; 4007). Further, at the end of this four year amortization period, the Company's rate base would increase by $646 ($300 or $400) million, if any of the intervener proposals are adopted, and the Company will be entitled to recover that amount through an increase in revenue requirements by as much as $258.6 (or $145.1) million in 2014, the first year after the four-year amortization is completed. (Tr. 3741, L. 1-7; Hearing Ex. 230). This impact is illustrated by the following undisputed chart provided by Dr. Vilbert:

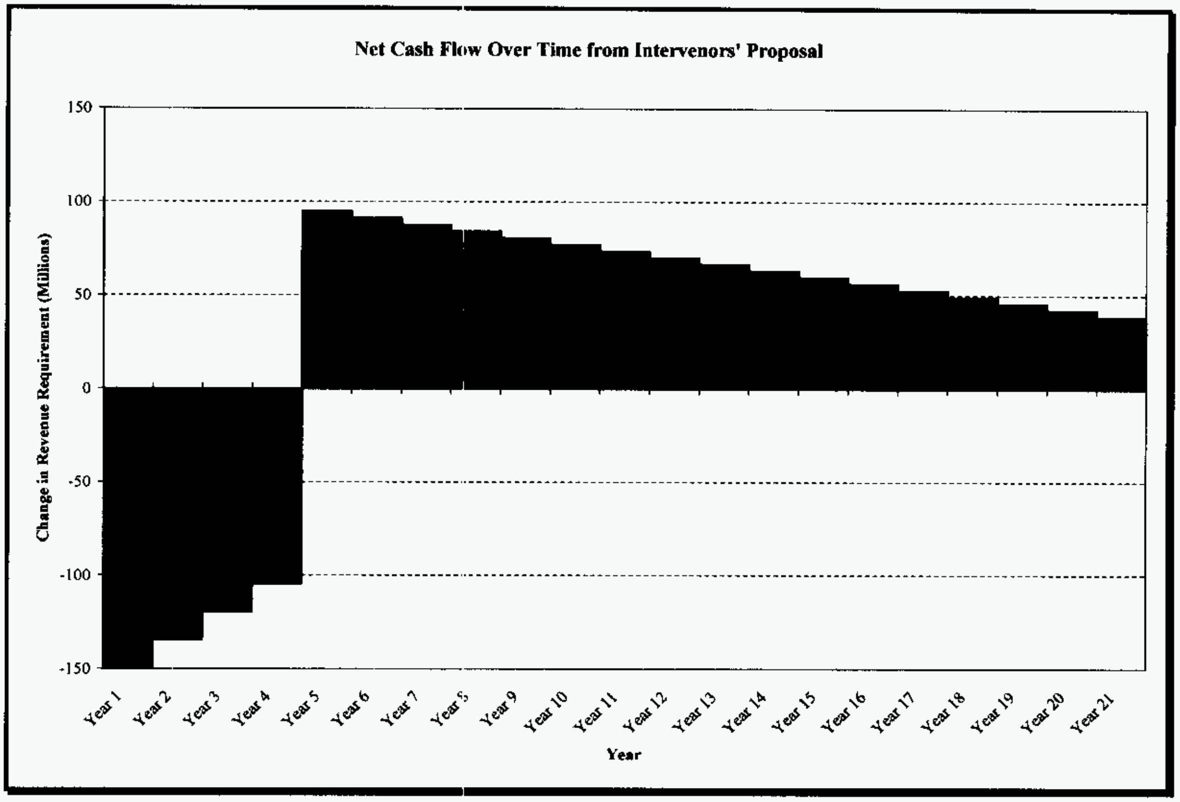

Figure 1

(Tr. 3927). As this chart demonstrates, at the end of the four-year amortization period there is an immediate, dramatic swing in revenue requirements as the Company's customers have to pay the Company back the funds drawn from the depreciation book reserve by the interveners' proposals. This increase in revenue requirements caused solely by the proposed amortization will be incurred by customers beginning in year five and continuing for the service life of the plant assets.

The interveners' proposals indisputably create a set of "winners" and "losers" among the Company's customers. (Tr. 3932). Customers over the four-year amortization periods, if accepted, receive lower revenue requirements at the expense of past and future customers. (Id.) This does not resolve any supposed intergenerational inequity among customers; it in fact creates intergenerational inequity among customers. (Tr. 3917). Their proposals also create sharp spikes down and up in revenue requirements and, hence, rates. Neither of these effects are consistent with sound regulatory policy. (Tr. 3932-34). Accordingly, for these additional reasons the interveners' proposed amortizations of the theoretical to book depreciation reserve should be rejected.

B. The Company's Depreciation Study establishes reasonable depreciation estimates and rates that should be approved.

The Company's 2009 Depreciation Study was prepared based on the Company's continuing property records ("CPR") through the end of December 2007 with pro forma adjustments to account for the changes in the Company's depreciable assets through 2009. (Tr. 3534; Tr. 3726, L. 9-12). The Company's Depreciation Study employed the Straight Line Method, Broad Group procedure, and Average Remaining Life technique to determine the appropriate depreciation rate for the depreciable asset property groups over the remaining lives of those assets in order to determine the depreciation expense necessary for the Company to recover its capital investment in the property used and useful for electric service to its customers. (Tr. 1102; Tr. 3726, L. 12-17). The Straight Line Method, Broad Group procedure, and Average Remaining Life Technique used in the Company's 2009 Depreciation Study are the most widely used depreciation method, procedure, and technique in the utility industry. None of the interveners dispute this. (Tr. 2033, L. 2-3, 8-9, 21-22). Mr. Pous only challenges the (1) calculation of interim retirement rates for production plant accounts, (2) the service lives for some but not all of the Company's production plant, (3) the average remaining life for only two of the mass property FERC accounts, and (4) the Company's net salvage estimates for some but not all Company FERC account mass property groups. None of these challenges are supported by evidence demonstrating that the Company's calculations and estimates are unreasonable.

1. The Company's Depreciation Study employs a more accurate method of determining interim retirement rates that more closely matches the retirement experience in the Company's production plant accounts.

The Commission is faced with a choice between methods of calculating interim retirement rates for the Company's production plant accounts. The Company's depreciation expert employs an actuarial survivor curve analysis while Mr. Pous proposes that a simple constant interim retirement percentage be used. (Tr. 3563 and 2065). The choice is not difficult. The sole authority cited by Mr. Pous for using a simple constant interim retirement percentage ironically supports the Company's method as the more accurate application instead of the method that he proposes. Also, the Company's method more accurately reflects the Company's retirement experience.

Mr. Pous relies on the dated, 1961 California PUC U-4 publication to support his use of the constant interim retirement percentage to calculate the interim retirement rates for PEF's FERC production plant accounts. (Tr. 2066). However, this publication actually supports the Company's use of the actuarial analysis of mortality data for interim retirements. The publication specifically states that "[i]n *more accurate applications* this correction (Interim Retirement Rate) may be developed from an actuarial analysis of mortality data for the interim retirements." (Hearing Ex. 286, OPC-LFE-POUS000029; Tr. 3570-71). Further, developing a survivor curve by actuarial analysis is listed as the preferable method in terms of accuracy. (Id. at OPC-LFE-POUS000032). The evidence demonstrates that the Company's interim retirement rate calculation method is the more accurate method and thus the more reasonable one to apply.

Further, the Company's interim retirement rate calculations more closely match the Company's actual retirement experience. The constant interim retirement rate that Mr. Pous proposes does not recognize that the rate of interim retirements will continue to increase as the property continues to age. (Tr. 3566; Hearing Ex. 220). This is a matter of straightforward logic and experience that is not offset by Mr. Pous' claim that the FERC production property accounts include different properties. (Tr. 2061). All property, including property included in the Company's production plant FERC accounts, will experience increasing levels of interim retirements as the property ages. (Tr. 3566-67; Hearing Ex. 220). For this additional reason, the Company's proposed interim retirement rates for its FERC production plant accounts are reasonable and should be accepted.

2. The Company's estimated service lives for its production plant are reasonable and should be adopted.

The Company's estimated service lives for its production plants in the Company's Depreciation Study are based on the Company's estimates based on the Company's experience with and operations of the generation units. (Tr. 3557, L. 2-5). The interveners challenge some but not all of the estimated service lives for the Company's production plants as "artificially short" and propose their own recommended service lives. (Tr. 2057-59; 3198-3203). Notably, their own recommendations demonstrate that the Company's estimated service lives for the challenged plants are reasonable and that there are no single, uniform industry standard service lives for any of the challenged units. As a result, the Company's estimated service lives should be accepted.

The challenged units are the Company's Anclote oil-fired steam units, the Company's Crystal River coal units, and the Company's combined cycle generation units. PEF's estimated service life for its Anclote oil-fired steam units is an average of 46 years based on a proposed retirement date of 2022. (Tr. 3400; Hearing Ex. 217). The estimated service lives for PEF's

Crystal River coal units, Units 1 and 2, is an average of 53 years based on a retirement date of 2020 and the estimated service lives for its other coal units, Crystal River Units 4 and 5, is an average of 52 years based on an estimated retirement date of 2035. (Id.) PEF's estimated service lives for its combined cycle units at the Hines Energy Complex and at Bartow is 30 years. (Id.) These service lives based on the estimated retirement dates for all these units are included in the Company's Depreciation Study at Sections 6, 7, and 9 of the Study. (Hearing Ex. 84).

OPC witness Pous and FIPUG witness Pollock challenge PEF management's decisions with respect to the estimated service lives for its coal units and recommend different longer service lives. Pous limits his recommended service life changes to only two of the four PEF coal-fired steam units, Crystal River Units 4 and 5. (Tr. 2058). Pous recommends 60 years for these coal units while Pollock recommends 55 years for all of the Company's coal-fired steam units. (Id.; Tr. 3201). These witnesses clearly do not agree on a uniform standard service life for the Company's coal units and they certainly rely on no such industry standard in their testimony. (Id.) Indeed, Mr. Pous agreed there is no depreciation manual that says coal plants have to have the 60-year service lives he recommends. (Tr. 2169, L. 19-23). The exhibit he provided on estimated service lives further indicates at least one coal plant of the same vintage as Crystal River Units 4 and 5 with an approved estimated retirement date of 2023 and a 40 year service life (Reid Gardner 4). (Hearing Ex. 386, OPC-LFE-POUS000094). Mr. Pous had in fact recommended a 50-year life span for this unit. See In the Matter of the Application of Nevada Power Company for Approval of New and Revised Depreciation Rates, 2007 Nev. PUC LEXIS 152, *232-33 (July, 17, 2007). Given this range of 40 to 60 years for the service lives of coal plants in evidence -- including Mr. Pous' own prior recommendation of 50 years for another coal unit built around the same time as Crystal River

Units 4 and 5 -- the Company's estimated service lives of 52 and 53 years for its coal plants are demonstrably reasonable.

Mr. Pollock challenges PEF's estimated life spans for its combined cycle generation units and recommends 35 years for PEF's combined cycle units. Mr. Pous makes no recommended change. (Tr. 2058).[14] PEF's estimated life span for its combined cycle generation units is 30 years. (Tr. 3400). Finally, Mr. Pous challenges PEF's estimated service life for its oil-fired steam unit at Anclote but Mr. Pollock does not. (Tr. 2058; 3199-3203). Mr. Pous recommends 50 years for only one of PEF's two remaining oil-fired steam units. (Tr. 2058). PEF's estimated service life for the Anclote unit is 46 years. (Tr. 3400). Their own recommendations demonstrate that there is no single, uniform industry standard service lives for any of these units and that PEF's estimated service lives for the units are reasonable.

The interveners ignored this evidence and instead challenged the adequacy of the Company's Depreciation Study in terms of its compliance with the Commission's depreciation rule in this regard.[15] In particular, they argued that the Depreciation Study failed to include substantiating factors utilized in the design of depreciation rates for the specific category of depreciable plant. Rule 25-6.0436(5)(f), F.A.C. Mr. Robinson testified, however, that the Company's Depreciation Study was prepared in accordance with the Commission's Depreciation rules. (Tr. 3534). The Depreciation Study contains an explanation and justification for each category of depreciable plant defining specific factors justifying life and salvage components in

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[14] Mr. Pous does recommend that the Commission order PEF to conduct a study of the operational service lives of its combined cycle units based on nothing more than his personal opinion that they can be operated longer than estimated by the Company. (Tr. 2058). He then refers to this recommendation as support for his claim that his adjustments to the Company's depreciation estimates are "conservative." (Tr. 2058-59). There is no basis to draw any conclusions from a study that has not been requested or performed. This is not evidence of anything.

[15] Notably, while the interveners' attorneys challenged whether the Company's Depreciation Study complied with the Commission's rule the intervener witnesses did not in their pre-filed direct testimony. Only when questioned at the hearing as to whether certain information was included in the Depreciation Study did they claim that it was not included. (Tr. 3229-32; 2179-81).

Sections 5, 6, and 9 for average remaining service lives and Section 8 for net salvage which are summarized under the heading "Plant Considerations/Future Expectations" for each FERC property account in Section 4 of the Depreciation Study. (Hearing Ex. 84). For example, for Account 311, Production Structures & Improvements, there is a description of the property by production plant unit in the account, the production unit in-service dates, a general description of the units, and a reference to the major upgrades undertaken and the increasing burden of air quality standards, including potential carbon regulation, on the Company's decision to maintain and operate the units. (Id.) The interveners did not credibly dispute Mr. Robinson's testimony that the level of detail in his Depreciation Study was consistent with the level of detail provided by other utilities in their depreciation studies. (Tr. 1141-42). But in any event, the interveners' argument elevates form over substance and underscores their lack of any real substantive challenge to the Company's estimated service lives for its production plants.

There is no dispute that Mr. Robinson inspected PEF's property, including generation sites, and interviewed PEF personnel, including personnel from PEF's resource planning department with responsibility for long-term reliability and cost optimization of the PEF generation fleet. (Tr. 1097; 3557; Tr. 3506, 3507, L. 1-10). There is no dispute that PEF's resource planning department provided Mr. Robinson with the Company's estimated termination dates and, hence service, lives for its production units based on the Company's review of the projected retirement dates in the course of its regular integrated resource planning process. (Tr. 3557; Tr. 3403, L. 17-23, Tr. 3404, L. 1-15; Hearing Ex. 216). This information is well known to the Commission, which reviews the Company's Ten Year Site Plan developed from its integrated resource planning process each year. (Tr. 3407; Tr. 3557, L. 17-23).

Mr. Robinson's reliance on the Company for this information in the Depreciation Study is consistent with industry practice in developing depreciation studies. (Tr. 3534). In fact, Mr. Pous relied in part on statements by someone in the industry who actually operates a coal plant for a different company in a different part of the country to arrive at his recommendation of 60 years for the Company's Crystal River Units 4 and 5 coal plants. (Tr. 2168, L. 9-16). The fact that not every detail that goes into the determination of the Company's estimated service lives was included in the Depreciation Study is hardly surprising since Mr. Crisp testified it would fill a room. (Tr. 3432). The Depreciation Study also includes information from the Company's continuing property records but not every purchase order, invoice, work order or other document related to each entry is included in the Depreciation Study either. Such voluminous documentation would actually hamper the review and determination of the Company's depreciation expense and rates. Further, the process begins with <u>Minimum</u> Filing Requirements (MFRs) and testimony, followed by a period of at least 6 months of discovery that interveners and the Commission Staff can and did take full advantage of in this proceeding. Commission Staff alone served over 160 interrogatories and requests for production of documents on depreciation issues. (Tr. 1221, L. 25, Tr. 1222, L. 1-4). Both Mr. Robinson and Mr. Crisp were deposed by the parties and subjected to extensive cross examination at the hearing. (Tr. 1129-1223; 3416-3529). There can be no dispute that interveners had the opportunity and did fully vet the Company's recommended service lives for its production plant.

In sum, the evidence demonstrates that the Company's estimated termination dates and service lives for its production plant reasonably represent the Company's best estimates based on its experience with the operation of these units under existing circumstances and the existing and potential regulatory environment. With respect to its coal plants and the Anclote steam plant, the information provided reflects the impact of clean air and potential carbon regulation on the Company's estimated termination dates. (Tr. 3408-3409; Hearing Ex. 216) The termination dates for Crystal River Units 1 and 2 currently reflect an agreement with the Florida Department of

Environmental Protection ("DEP") with respect to the Company's permit conditions and requirements for continued operation of the units. (Tr. 3409). Similarly, the termination dates for Crystal River Units 4 and 5 were extended 14 years with the addition of flue gas desulfurization ("FGD") systems at the units, but again the evolving clean air and potential carbon policy influence these termination dates. (Id.) Further, the Company's experience with the operation of its coal-fired and combined cycle fleet to meet load – which can vary by as much as two to four thousand megawatt swing from peak to minimum on a day – under existing conditions drives the termination dates for these units as well. (Tr. 3405; Tr. 3511, L. 5-25, Tr. 3512, L. 1-8, Tr. 3517, L. 6-17). Based on the evidence, the Company's estimated termination dates and, hence, service lives for its coal-fired and oil-fired steam generation units and its combined cycle units are reasonable.

3. The Company's estimated average remaining lives for its mass property FERC accounts are reasonable and should be adopted.

The Company's Depreciation Study employs the same method to identify the average remaining life for each of the Company's FERC mass property accounts. Mr. Pous agrees that the method he employed to determine the average remaining life based on the retirement history and experience is the same methodology followed by Mr. Robinson in the Company's Depreciation Study. (Tr. 2172, L. 21-25, Tr. 2173, L. 1-4). He further agreed that he duplicated precisely the mass property remaining life calculations employed by the Company. (Tr. 2173, L. 5-13). Despite this agreement on methodology, however, OPC witness Mr. Pous disputes the results of that method for two of the FERC mass property accounts. (Tr. 2091).

Notably, Mr. Pous does not dispute the results of the Company's methodology that he followed for any of the other FERC mass property accounts. Also, the Company followed this same methodology in its 2005 Depreciation Study and Mr. Pous did not dispute the results of that methodology with respect to any of the Company's mass property FERC accounts in the prior base rate proceeding. (Tr. 3574, L. 11-15). Tellingly, the changes in the estimated service lives for each of the two FERC account mass property groups that Mr. Pous now disputes were only one year shorter than the estimated service lives in the prior depreciation study. (Id.) The two disputed FERC mass property accounts -- FERC Account 364 (Distribution Poles) and FERC Account 368 (Distribution Transformers) -- represent, however, two of the largest FERC mass property accounts. As a result, Mr. Pous' longer alternative service life recommendations for these two accounts have a much larger impact on the Company's level of depreciation expense. (Tr. 3573, L. 19-21). This is an improper, results-driven analysis.

A review of the selected average remaining life survivor curves by Mr. Pous and Mr. Robinson in the Company's Depreciation Study demonstrate that the Company's average remaining life survivor curves more closely and accurately match the Company's actual experience with the property in these two FERC mass property accounts. (Tr. 3580, L. 15-23, Tr. 3581, L. 1-10, Tr. 3584, Hearing Exs. 140, 142, 222, and 223). Beyond the actual retirement experience in these accounts, Mr. Pous relied on and OPC questioned Mr. Robinson regarding depreciation estimates made by Mr. Robinson for the same FERC mass property accounts for different utilities in different parts of the country at different times. (Tr. 2094, L. 14-18; Tr. 2101, L. 12-16; Tr. 3578, L. 10-17; Tr. 3582, L. 13-20). This is an inappropriate comparison -- for example, a Montana company is radically different from Florida with different conditions and information (Tr. 1163, L. 11-24) -- when the Company's own data in its Depreciation Study adequately supports the Company's determinations of the average remaining lives for these accounts. (Hearing Ex. 84). The Company's estimated remaining service lives for these two FERC mass property accounts should be accepted based on the evidence with respect to the Company's experience.

4. The Company's net salvage estimates for its mass property FERC accounts are reasonable and should be adopted.

The Company's estimated net salvage for its FERC mass property accounts -- which is gross salvage less cost of removal -- is contained in Section 8 of the Company's Depreciation Study and explained in Sections 1, 3, and 4 of the same Study. (Hearing Ex. 84). In these sections, Mr. Robinson explains his use of a trend analysis that gives greater weight to the Company's most recent gross salvage and cost of removal experience in each FERC mass property account moving toward projected future net salvage. (Id.). This analysis is not a purely mathematical application; rather it involves the exercise of judgment. (Tr. 3590; Tr. 2172, L. 1-4). A review of the Company's estimated net salvage for each Company FERC mass property account reveals that Mr. Robinson did in fact employ this trend analysis and that the current estimated net salvage parameters are close to the Company's most recent net salvage experience. (Hearing Ex. 84, pp. 1-6, 8-113 (Acct. 364); pp. 1-6, 8-129 (Acct. 368)).

OPC's witness Mr. Pous challenges the Company's recommended net salvage parameters for 15 mass property accounts and takes no position on the recommendations for the remaining mass property accounts despite the fact that the same methodology was employed to estimate the net salvage for each Company FERC mass property account. (Tr. 3595, L. 13-18; Tr. 2170, L. 1-4). Mr. Pous further agreed that all net salvage parameters are estimates, including his own, and that judgment must be exercised in estimating net salvage rather than employing a pure mathematical calculation. (Tr. 2170, L. 16-21, Tr. 2171, L. 25, Tr. 2172, L. 1-4).

The criticism of the Company's Depreciation Study because Mr. Robinson did not strictly apply the mathematical results of his forecast methodology, then, is irrelevant. Even Mr. Pous concedes estimating net salvage is a matter of judgment not math. (Tr. 2172). Further, OPC's repeated criticism that the Company's Depreciation Study lacked an adequate explanation of the estimated net salvage parameters is undermined by Mr. Pous' direct testimony where he clearly understood that determination. For example, Mr. Pous attacked the narrative description of the Company's net salvage estimate for Account 355 while noting that the estimated net salvage reflected the "actual net salvage recorded during the last several years," citing the pages of the Depreciation Study. (Tr. 2119, L. 13-18). This is the exact information that Mr. Robinson indicated was most relevant in estimating net salvage for these accounts. (Hearing Ex. 84, p. 3-10 to 3-11; Tr. 3590).

Mr. Pous' net salvage recommendations are, again, results driven. Mr. Pous focused on the transmission and distribution mass property accounts that had the most value. (Tr. 2170, L. 5-9). He further agreed that for every single one of the 15 Company mass property accounts he reviewed he recommended lower net salvage parameters. (Tr. 2170, L. 10-15). Lower recommended net salvage parameters reduce depreciation expense. Thus, by recommending lower net salvage parameters for the 15 largest mass property accounts, Mr. Pous' recommendations have the largest impact on depreciation expense. This impact on depreciation expense is in fact what he calculated for each FERC mass property account. (Tr. 2119, L. 1-3; Tr. 2121, L. 4-5).

OPC claims the Company's estimated net salvage values are excessively negative. (Tr. 2121, L. 22;Tr. 2124, L 17; Tr. 2126, L. 15). The only support for this assertion is Mr. Pous' own analysis which focuses on older, historical gross salvage values to lower the net salvage estimates (e.g., Tr. 2120, L. 10-12; Tr. 2128, L. 9-12), speculation about the impact of economies of scale on future cost of removal with no actual evidence of such economies of scale in the cost of removal experience (e.g., Tr. 2114, L. 10-22), and speculation about future scrap value "when the economies of China and India eventually again ramp back up." (e.g., Tr. 2117, L. 8-10). This "judgment" is not based on the Company's actual and most recent net salvage experience, which is the basis for the exercise of judgment in estimating net salvage in the Company's Depreciation Study. (Hearing Ex. 84, pp. 3-10 to 3-11, Tr. 3590). The Company's judgment as to the appropriate net salvage based on its most recent experience is not excessively negative as OPC claims, in fact, it is consistent with the net salvage estimates for the other utilities operating in Florida. (Tr. 3615, L. 13-23; Tr. 3616, L. 1-17; Hearing Ex. 224). As a result, the Company's estimated net salvage parameters for its FERC mass property accounts in its Depreciation Study are demonstrably reasonable and should be accepted by the Commission.

5. PEF's Fossil Dismantlement Cost Study is reasonable and consistent with the Commission's rule.

PEF contracted with Burns & McDonnell ("B&McD") to complete the Company's Fossil Dismantlement Cost Study ("Dismantlement Study"). (Hearing Ex. 126) B&McD prepared this study in accordance with the Commission Rule 25-6.04364, F.A.C., which provides certain requirements for each utility's dismantlement study. (Tr. 3680). The purpose of the dismantlement study, as set forth in Rule 25-6.04364, is to provide updated cost estimates of the cost of dismantling each generating unit, such that a reserve "sufficient to meet *all* expenses at the time of dismantlement" can be established. Rule 25-6.04364(1), F.A.C. (emphasis added). B&McD analyzed each of the Company's individual generating units and applied its reasonable engineering judgment to the cost estimates in support of the Dismantlement Study. (Tr. 3692). Consistent with Rule 25-6.04364, B&McD estimated the cost of full dismantlement and site restoration for each unit. (Tr. 3681).

Witness Pous challenged PEF's Dismantlement Study, claiming that the Company overstated its cost estimates by not looking at certain methods of dismantlement (such as re-sale of generating units or use of explosives) and by assuming restoration to greenfield condition. (Tr. 2078-2079; Tr. 2081-2082). Mr. Pous' arguments demonstrate his lack of understanding with respect to the Commission's dismantlement study rule, as well as the analysis that B&McD completed to prepare the Dismantlement Study.

First, even Mr. Pous admitted in his testimony that the re-sale option is generally available only in states in which de-regulation has occurred, which is of course not the case in Florida. (Tr. 2079). In any event, the Commission's rule requires full dismantlement, not a sale of the generating unit. (Tr. 3681-3682). With respect to Mr. Pous' argument on use of explosives, Mr. Kopp, the B&McD project manager for the Dismantlement Study explained that the cost estimates were consistent with a variety of demolition techniques, including explosives where appropriate.[16] (Tr. 3683-3685). Mr. Pous is also incorrect in his claim that B&McD included costs to return the sites to a "greenfield" condition. The term "greenfield" means a site that is completely undeveloped. (Tr. 3682). B&McD did not assume that the site would be returned to a completely undeveloped condition because it left underground facilities in place when those facilities were more than 2 feet below the ground. (Id.) Again, B&McD followed the Commission's rule that the site be returned to a marketable or useable condition.

The Commission should approve the cost estimates presented in the Company's Dismantlement Study with no adjustments. Mr. Pous does not recommend that any adjustment to the estimates be made, but he does indicate that if the Commission wants to make an adjustment, they should reduce the costs by 60%, based on a unit in Nevada that allegedly came in 60% lower than its estimate. (Tr. 2086-2087). Not only does Mr. Pous have no basis to reduce any of PEF's estimated dismantlement costs, as explained above, but his reliance on another project in another state to make an across-the-board cost reduction is wholly unwarranted. As Mr. Kopp testified, B&McD did a detailed review of each of PEF's facilities in developing the cost estimates and "that analysis is far superior to comparing another plant in a completely separate state." (Tr. 3701, L. 20-21).

[16] Explosives, while sometimes appropriate for equipment like smoke stacks, would not be feasible for a turbine or boiler building because they are made of steel and thus would not break along a predetermined "fall" line. (Tr. 3684-3685)

V. THE COMPANY'S COST OF CAPITAL IS REASONABLE AND SHOULD BE APPROVED. (ISSUES 41-42, 44-48, 81, 87)

A. Cost Rate for Short-Term Debt.

The Company's short-term debt rate is based on a Commercial Paper ("CP") borrowing rate of 4.5 percent. (Hearing Ex. 47, MFR Schedule D-3, p. 1 of 3). PEF's CP borrowing rate is appropriately based on the three-month projected London Interbank Offered Rate ("LIBOR") for 2010. (Tr. 4183, L. 9-16). Annual commitment facility fees associated with PEF's revolving credit facility and administrative fees are also included in the cost of short-term debt. (Hearing Ex. 39, OPC Interr. 168). These fixed fees applied as a percentage of the average daily outstanding CP balance account for an additional 0.75 percent cost, resulting in a total short-term debt cost of 5.25 percent. (Id.; Hearing Ex. 47, MFR Schedule D-3, p. 1 of 3).

OPC witness Dr. Woolridge calculates the Company's short-term debt rate for 2010 based on spreads above the average three-month LIBOR rate for 2009. (Tr. 2965, L. 1-8). He then adds the fixed fees for 2009 to get a short-term debt rate of 3.06 percent for 2010. (Id.) This short-term debt rate fails to account for the expected short-term debt rate and fixed fees in 2010. Dr. Woolridge also applies the wrong fee since the undisputed evidence is the fixed fee for 2010 is 0.75 percent. (Tr. 4183, L. 9-23, Tr. 4184, L. 1-2; Hearing Ex. 47, MFR Schedule D-3, p. 1 of 3). The Company's short-term debt rate is reasonable and should be approved because it is the only rate that appropriately takes into account the projected short-term debt costs in 2010.

B. Cost Rate for Long-Term Debt.

The Company's long-term cost of debt for 2010 is 6.42 percent. (Hearing Ex. 47, MFR Schedule 4a, p. 1 of 6). OPC witness Dr. Woolridge proposes a long-term debt cost rate using the overall embedded long-term debt cost rate for 2009. (Tr. 2965). Dr. Woolridge justifies using 2009 long-term debt costs for 2010 by claiming the projected yield for PEF's 2010 issuance is not reflective of current market interest rates on 10-year bonds. (Id.). PEF's projected yield is a reflection of expected future interest rates for a mix of 10-year and 30-year bonds -- not current interest rates on only 10-year bonds -- because interest rates are expected to increase in the future and PEF has historically issued a mix of 10-year and 30-year bonds. (Tr. 4154, L. 17-22; Tr. 4155, L. 1-8). As Mr. Sullivan, PEF's Treasurer, testified that, holding the 2010 long-term debt rate at the 2009 embedded long-term debt rate will mean that the new bond issuance in 2010 will have to be issued at a rate below the current yields even Dr. Woolridge references for 10-year A and BBB+ rated utility bonds. (Tr. 4154, L. 11-16). This demonstrates that PEF has appropriately reflected the 2010 long-term debt cost rates. PEF's long-term debt cost rate of 6.42 percent is reasonable and should be adopted.

C. Capital Structure.

PEF is targeting a mid-single A long term credit rating from each of the three rating agencies that perform credit analysis on PEF – Standard & Poor's Rating Service ("S&P"), Moody's Investors Services ("Moody's"), and Fitch Ratings ("Fitch). (Tr. 1233, L. 1-3). This long-term credit rating will correlate to the top tier for short-term debt ratings from each of the rating agencies. (Id. at 4-5). As Mr. Sullivan, PEF's Treasurer testified, this long-term credit rating is a strong credit rating that will provide PEF access to low-cost debt under all market conditions, including the prior and continuing volatile debt and equity markets facing the Company. (Tr. 1233, L. 20-23, Tr. 1236-1241, Hearing Exs. 88 to 90).[17] Having a strong long-term credit rating is necessary because the electric utility industry is a capital intensive industry and access to the capital markets under all market conditions and at a reasonable cost is necessary for PEF to fund its current and future capital investment needs. (Tr. 1233-35). PEF's

[17] As the Treasurer for PEF, Mr. Sullivan is responsible for raising capital to meet PEF's capital needs and for maintaining PEF's capital structure in a manner which supports PEF's target long-term credit rating. (Tr. 1230, L. 16-20).

current and future capital investment needs[18] include the Bartow repowering project, the steam generator replacement project and additional capital to meet federal and state transmission and distribution reliability standards, storm hardening programs, and potentially adding new nuclear generation[19] to PEF's fleet of base load generation assets. (Tr. 127-28; Tr. 1234, L. 8-24, Tr. 1235, L. 1-2).

PEF's current long-term credit rating is not a mid-single A rating from all three rating agencies. (Tr. 1232, L. 14-20). As Mr. Sullivan explained, obtaining a consistent, target credit rating from all three rating agencies is important because not all investors follow all three rating agencies and investors distinguish between companies without split ratings and companies with split ratings, with resulting higher costs of debt for companies with split ratings where the lowest credit rating in essence becomes the critical credit rating when the company seeks access to capital in the capital markets. (Tr. 1233, L. 8-18, Tr. 1242, L. 5-24, Tr. 1243, L. 1-9). To achieve PEF's long-term target credit rating Moody's would need to increase its rating from an A-3 to an A-2 and S&P would need to increase its rating for PEF from BBB+ to an A. This improvement in the senior unsecured credit rating for PEF would also improve the senior secured and short-term debt rating. (Tr. 1261, Tr. 1262, L. 1). Having a strong short term credit rating

[18] Interveners questioned Mr. Dolan extensively regarding Mr. Mulhern's statements during an investment presentation that the Company has some flexibility with respect to capital investments. (Tr. 2543-96). This is no different from any business – the Company does have some flexibility in terms of timing of capital investments. But as a regulated electric utility with an obligation to serve, PEF has much less flexibility than other businesses in terms of deferring or delaying capital investment. (Tr. 1234). Indeed, for the bulk of the capital items the Company is requesting in this proceeding, the costs have already been incurred or are necessary to comply with mandatory requirements. For example, the Bartow Repowering Project is already complete, the SGR project has been started and will be finished during this year's outage, and the NERC transmission projects must be completed to comply with federal and state regulations. (Tr. 320-21; 518; 568). Therefore, the Company has limited flexibility with respect to the capital investments it needs to deliver safe and reliable electric service.

[19] Counsel for FRF, through cross examination, suggested that there was no need to consider the impact of the nuclear project because PEF recovers 11.75% through the nuclear cost recovery clause ("NCRC") as its carrying cost for the Levy nuclear project. (Tr. 1430-31; 1437). However, if the Company does not earn a reasonable return on its other investments, this higher AFUDC rate in the NCRC will be irrelevant to the investment community's perception of PEF. Investors view a company as a whole, rather than piecemeal as suggested by interveners.

provides greater access to the commercial paper market during difficult market conditions and periods of tight credit such as those the Company has faced and continues to face. (Tr. 1237, L. 3-18). There are simply fewer banks and financial institutions today and they have less credit to provide all borrowers, including utilities, than before. (Tr. 1238, L. 1-16, Hearing Exs. 88 and 89). Maintaining access to all capital markets, long and short term, at reasonable rates is essential to PEF successfully completing its sizeable infrastructure investment plans. (Tr. 1239, L. 7-11; Tr. 1239-1240).

To maintain and achieve its long-term credit rating from all three rating agencies PEF must improve its financial risk profile based on the financial metrics applied by the ratings agencies. (Tr. 1248, L. 1-9, Hearing Exs. 96 and 97). This means improving PEF's cash flow and achieving a projected 2010 book capital structure with 50 percent common equity while also taking the off-balance sheet impact of long-term purchase power contracts into account. (Tr. 1243, L. 11-20, Tr. 1249, L. 5-17; Hearing Ex. 47, MFR Schedule D-1a. p. 1 of 3). As Mr. Sullivan explained, rating agencies have expressed the importance of positive cash flow to a utility's credit risk profile. Cash flow is essential to the evaluation of risk of investment in a utility by the equity investor and potential bondholder. (Tr. 1244, L. 13-24). A positive cash flow impact, as Mr. Sullivan further explained, reduces investment risk, enhances the credit profile of the utility, and is more likely to lead to a lower cost of capital for the utility and its customers. (Id.)

No intervener disputed PEF's need for a strong long-term credit rating or PEF's target of a mid-single A long-term credit rating from each rating agency. (Tr. 4131, L. 17-20). No intervener disputed the Company's need for sufficient common equity in the Company's capital structure or its targeted common equity ratio of 50 percent, although they did dispute the capital structure adjustment to account for the impact of purchase power contracts ("PPAs") on the

Company's capital structure. (Tr. 3000-3002; 3207-3213). Finally, no intervener disputed the evidence regarding the importance of cash flow to the Company's credit profile and cost of capital for the utility and its customers. Indeed, they ignored this undisputed evidence and failed to perform any analysis whatsoever of the impact of the proposed $35 million rate reduction on the Company's cash flows, credit profile, and cost of capital. (Tr. 3068; 2166).

1. A common equity ratio of 50 percent on an adjusted basis is necessary because the rating agencies adjust the Company's leverage in their analysis.

PEF proposes a capital structure with 50 percent common equity and the adjustment to equity to account for the rating agency adjustment for the impact of purchase power obligations on the Company's capital structure. Intervener witnesses Dr. Woolridge and Mr. Pollock recommend a capital structure with a common equity ratio of 50 percent without any adjustment for the impact of rating agency adjustments for purchase power obligations. (Tr. 2962, L. 4-8). The dispute centers around the impact of power purchase obligations on the Company's capital structure.[20]

As Mr. Sullivan explained, the rating agencies consider off-balance sheet obligations when assessing a company's credit quality. (Tr. 1245, L. 6-9). S&P, in particular, views long-term PPAs as long-term fixed payments, which are essentially debt-like in nature, and therefore actually imputes debt associated with PPAs when assessing PEF's credit quality. (Tr. 1245, L. 9-12; Tr. 3000; 3209). S&P determines the imputed debt by taking the net present value of capacity payments using a discount rate equivalent to the Company's average cost of debt, and then applies a risk factor to that net present value amount to arrive at the imputed debt amount. (Tr. 1246, L. 1-8). The risk factor used by S&P for PEF is 25 percent. (Id.) This is undisputed.

[20] Dr. Woolridge incorrectly calculates PEF's "real" -- meaning without the adjustment for the PPA imputed debt impact -- recommended common equity ratio as 47.51% based on investor provided capital. (Tr. 2962, L. 6). His calculation does not properly account for the 75.95 percent jurisdictional factor of the equity adjustment for PPAs. The correct ratio is 49.2 percent on a jurisdictional basis, not 47.51 percent. (Tr. 4148, L. 9-14).

The fact that this S&P PPA adjustment off-balance sheet obligation of $711 million for 2010 is also undisputed. (Tr. 1247, L. 1-12).

Interveners' arguments against recognition of the imputed equity to offset the imputed debt from the rating agency adjustments for the PPAs, at their essence, claim this is not a real cost to PEF. They assert that this is an off-balance sheet adjustment and therefore not GAAP, other rating agencies do not specifically quantify the PPA imputed debt adjustment like S&P does, when S&P quantifies the imputed debt adjustment for PEF it does not specify how it calculates the risk factor at 25 percent, and that the S&P adjustment assigns a risk cost to PPA payments that have been consistently recovered by PEF to date under the fuel and purchased power cost recovery clause. (Tr. 3209-3210; 3002). These assertions, while correct, are irrelevant to the matters at hand. All rating agencies acknowledge the debt-like nature of PPA obligations and adjust for them in evaluating the utility credit ratings although their methodologies differ. (Tr. 4151, L. 15-23; Tr. 4152, L. 1-15). S&P understands the cost recovery mechanisms in Florida -- indeed PEF explained them to S&P in an effort to influence S&P to change its risk assessment of the PPA obligations -- that is why S&P's risk assessment for PEF is 25 percent and not some higher percentage. (Tr. 4149-4150; Tr. 1293-1294).[21] The fact that S&P does not explain what makes up the 25 percent risk assessment for PEF's imputed debt is immaterial --- the cost to PEF is what it is. (Tr. 4173, L. 10-25, Tr. 4174-76). Finally, although not GAAP, the off-balance sheet adjustments made by S&P to PEF's book debt are reflected in the footnotes to PEF's financial statements. For example, for 2008, S&P increased PEF's book debt by $693 million and interest expense by $40 million for the effect of the PPAs.

[21] Indeed, S&P's November 2006 article entitled "Request for Comments: Imputing Debt to Purchased Power Obligations" provides that legislatively prescribed PPA obligation recovery mechanisms provide utilities the greatest level of protection and can result in risk factors as low as 0%, however, where PPA capacity costs are recovered through a fuel adjustment clause this risk factor is adjusted to 25 percent. (Tr. 4149, L. 13-23, Tr. 4150, L. 1-11; Hearing Ex. 242).

(Tr. 4151, L. 8-10, Tr. 4177, L. 7-20). It, therefore, cannot be disputed that S&P makes a significant debt adjustment at PEF for PPAs. (Tr. 4150; 4171-74). This imputed debt adjustment indisputably is a financial reality for PEF and, therefore, it is a real cost of service that PEF is entitled to recover. (Tr. 4148, L. 16-20).

The fact that S&P also employs a consolidated method evaluating the entire corporate structure in its credit rating assessment for PEF and that there are no guarantees from S&P (or any rating agency) that S&P will improve PEF's credit rating if an equity adjustment to PEF's capital structure is made for the imputed debt adjustment is also beside the point. (Tr. 1271-72). There are no rating agency "guarantees" and it is unrealistic to expect them. (Tr. 1273, L. 1-4). The rating agencies, however, indisputably provide guidance to utilities with respect to the factors they take into account, including the imputed debt adjustments for PPAs, in determining the utility's credit rating. (Tr. 1242, 1246, 4149-50; Hearing Ex. 94, 97, 232, and 242). To maintain or improve its credit rating, any utility, including PEF, must take this guidance into account. In this regard, PEF has taken steps to improve its balance sheet and financial metrics. PEF eliminated dividend payments from PEF to the parent for four of the past five years and increased the level of equity invested in PEF, even as PEF has maintained stable base rates under its settlement agreement during a period of increasing capital investment and declining economic conditions. (Tr. 1277-79; 4252; 4257-58; Hearing Ex. 39). Continued recognition of the S&P imputed debt with respect to PEF's capacity payment obligations under its PPAs in PEF's capital structure is an additional step to improve PEF's financial metrics.

Interveners further rely on the decision by this Commission in the Tampa Electric Company ("TECO") base rate proceeding issued after PEF's base rate proceeding was initiated denying TECO's request for an imputed equity adjustment to account for the impact of S&P's imputed debt adjustment for TECO. Order No. PSC-09-0283-FOF-EI, Docket No. 080317-EI, (Apr. 30, 2009). That decision was based on the record evidence before the Commission in that proceeding. (Id. at p. 36). The record evidence in this proceeding demonstrates a substantially more significant imputed debt adjustment ($711 million) at a time when PEF has incurred and is incurring substantially greater costs for capital investments in its infrastructure during recessionary conditions with declining sales, including the Bartow power plant, the steam generator replacement at its existing nuclear power plant, and substantial investments in it transmission system. (Tr. 320-21; 518; 568; Tr. 4251, L. 8-25, Tr. 4252, L. 1-25, Tr. 4253, L. 1-7). Additionally, PEF is in the process of building new nuclear power plants to meet PEF's customers' needs for base load generation from a clean, low fuel cost source of generation. (Tr. 125). All this has put greater pressure on the Company's financial metrics to the point S&P has warned that "if credit protection measures do not improve over the near term such that adjusted [Funds from Operation (FFO)] to interest coverage exceeds 3.6x and adjusted FFO to total debt exceeds 16%, *the outlook will be revised to negative and ratings may be lowered.*" (Tr. 1250, L. 17-22; Hearing Ex. 96) (emphasis added). These circumstances warrant approval of PEF's requested capital structure including the equity adjustment to account for S&P's imputed debt adjustment for its PPAs to recognize the cost of the financial reality PEF faces in light of the capital investments that have been and must be made to continue to provide PEF customers with safe, reliable, and efficient electric service.[22]

[22] While not binding on this Commission, the Commission has recognized proforma adjustments to PEF's capital structure for ratemaking purposes in approving prior settlements. See Order No. PSC-05-0945-S-EI, Docket No. 050078-EI, (Sept. 28, 2005); Order No. PSC-97-0840-S-EI, Docket No. 970261-EI, (July 14, 1997). Other jurisdictions have acknowledged adjustments to utility financial capital structures to account for off-balance sheet obligations including debt-equivalent associated with leases and purchased power obligations. See, for example, *Application of Wisc. Power & Light Co. for Authority to Change Retail Electric Rates & Natural Gas Rates*, 2007 Wisc. PUC LEXIS 27, *64-65 (Jan. 19, 2007); *Joint Application of Wisc. Electric Power Co. & Wisc. Gas LLC, both d/b/a We Energies, for Wisc. Electric Power Co. to Increase Its Electric, Natural Gas, & Steam Rates & for Wisc. Gas LLC to Increase Its Natural Gas Rates*, 2008 Wisc. PUC LEXIS 34, *95-96 (Jan. 17, 2008) ("We Energies"); *Application of Northern States Power Co., d/b/a Xcel Energy, for Authority to Adjust Electric & Natural Gas Rates*, 2006 Wisc. PUC LEXIS 4 (Jan. 15, 2006); *Application of Wisc. Public Service Corp. for Authority to*

2. There should be no parent-debt tax adjustment for PEF under Rule 25-14.004, F.A.C.

Commission Staff included an issue whether a parent debt tax adjustment should be made for PEF under Rule 25-14.004, F.A.C. No intervener witness filed any testimony and no intervener presented any evidence on this issue. Based on the only record evidence on this issue, submitted by PEF, no such adjustment should be made.

Rule 25-14.004, entitled "Effect of Parent Debt on Federal Corporation Income Tax," states that the "income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary." Rule 25-14.004, F.A.C. The rule applies when an actual parent-subsidiary relationship exists and a consolidated income tax return is filed. (Id.) The presumption that a parent's investment in a subsidiary was made in the same ratios that exist in the parent's capital structure, however is rebuttable. (Id.); See In re: Petition of Southern States Utilities, Inc. for a rate increase in Duval County, 1990 Fla. PUC LEXIS 407, *36, Order No. 22871-B (Oct. 1, 1990) (holding the rule does not apply in this case because the parent company invests only equity in its subsidiaries, therefore a parent debt adjustment is inappropriate for this proceeding).

The evidence demonstrates that no parent debt was used to make equity contributions to PEF. No equity contributions were made to PEF until 2009, and all contributions made and expected to be made by Progress Energy to PEF in 2009 and 2010 will be from funds generated from common equity issuances at Progress Energy. (Hearing Ex. 39). In fact, equity issued in

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Adjust Electric & Natural Gas Rates, 2005 Wis. PUC LEXIS 829 (Dec. 22, 2005). California has also recognized that the debt equivalency of the S&P methodology may be a risk factor in computing a utility's capital structure or cost of equity. *See Order Instituting Rulemaking to Promote Policy & Program Coordination and Integration in Electric Utility Resource Planning*, 2004 Cal. PUC LEXIS 598, (April 1, 2004); *Order Instituting Rulemaking to Integrate Procurement Policies & Consider Long-Term Procurement Plans*, 2007 Cal. PUC LEXIS 606 (Feb. 16, 2006). But see *Application of Southern Ca. Edison Co. (U338E) for Authorized Cost of Capital for Utility Operations for 2008 & Related Matters*, 2007 PUC LEXIS 593 (May 8, 2007). As a result, regulatory commissions have recognized that the imputed debt associated with carrying purchase power obligations can have a real economic cost that affects the utility's credit ratings.

2008, 2009, and 2010 at the parent Progress Energy will be greater than contributions made to PEF in 2009 and 2010. (Id.). There is no other evidence; hence, the parent debt tax adjustment under Rule 25-14.004 should not be made.

3. **The Interveners' proposal for a $35 million rate reduction reduces PEF's financial metrics below the rating agency metrics for the Company's targeted credit rating resulting in a weaker balance sheet and weaker PEF credit ratings.**

Interveners propose a $35 million rate reduction that includes a proposal to reduce depreciation expense by $161 million annually for four years, reduce O&M expenses, and authorize a mere 9.75 percent cost of equity. (Tr. 1969; Hearing Ex. 170, Sch. A-1). Intervener witnesses acknowledge their proposal to reduce depreciation expense by reducing depreciation book reserves reduces PEF's cash flow and, therefore, impacts PEF's credit ratings. (Tr. 2166; Tr. 2233). Dr. Woolridge, OPC's ROE expert, also testified that he was asked to determine the overall fair rate of return or cost of capital for PEF. (Tr. 2944, L. 19-22). He admitted that a fair rate of return should be sufficient to assure confidence in the financial integrity of the utility so as to maintain credit and attract capital. (Tr. 3040, L. 10-14). He further agreed that the *fundamental value of a company*, including a regulated public utility, is *determined by the cash flow it generates* over time for its owners *and the minimum acceptable rate of return required by capital investors*. (Tr. 3065, L. 4-19). Yet, none of the interveners and their witnesses addressed the impact of their $35 million rate reduction proposals on PEF's cash flow and its ability to raise needed capital from bondholders and equity investors.

OPC witness Woolridge agreed that, if accepted, the proposed $35 million rate reduction will reduce PEF's cash flows. (Tr. 3065, L. 24-25, Tr. 3066, L. 1-6). But Dr. Woolridge did not look at the impact of the reduction in cash flows, including the impact of the proposed reduction in depreciation expense by $161 million annually, in his analysis of the fair return required to maintain credit and attract capital for PEF. (Tr. 3066, L. 7-9, Tr. 3067, L. 16-24). He agreed this reduction in cash flows would be perceived by investors and would be built into the Company's stock price. (Tr. 3068, L. 15-25). But he still failed to take into account the impact of the interveners' proposed $35 million rate reduction in recommending a 9.75 percent ROE as the fair return to maintain credit and attract capital. (Tr. 3069, L. 1-8). The Interveners' failure to assess the impact of their proposals on PEF's cash flow and credit ratings, despite admitting that the fundamental value of PEF is determined by its cash flow and minimum required return to attract capital, undermines the credibility of their proposed $35 million rate reduction.

PEF did evaluate the impact of the interveners' proposals on PEF. First, intervener witness Lawton agreed the proposed annual $161 million reduction in depreciation expense will result in lower cash flow from operations for PEF and that cash flow from operations is a key component of the Company's credit rating. (Tr. 2233; Tr. 4140, L. 6-13). He concluded, however, that, although the Company's cash flows decline, they remained above industry averages and maintained PEF's financial integrity. (Tr. 2233). Mr. Lawton erroneously failed to apply the specific target credit metric ranges and adjustments for PEF, failed to apply the book capital structure for the entire company used by the rating agencies, failed to use total debt (both long-term and short-term debt) in his assessment, and grossly understated the interest expense. (Tr. 4140-4141). As a result of the errors, Mr. Lawton's conclusion that PEF's financial integrity is not impacted by the declining cash flows from operations caused by the reduced depreciation expense proposal is also erroneous. Simply put, the drastic reduction in depreciation expense the interveners propose will result in a significant reduction in cash flow from operations which will result in higher financing needs, higher leverage and cost of capital, and greater stress on the Company's credit ratings. (Tr. 4141, L. 16-22).

Intervener witness Lawton admittedly looked only at the impact of the proposed reduction in depreciation expense on cash flow and the Company's financial metrics. That was his sole purpose for testifying in this proceeding. (Tr. 2229; 2234). Yet, even though the interveners understood the importance of this single impact on cash flow and the Company's financial metrics enough to provide testimony on this issue, they did not have Mr. Lawton (or anyone else) analyze the total impact of all their proposed adjustments resulting in a recommended $35 million rate reduction on cash flow and the Company's financial integrity. (Tr. 4142, L. 1-8).

PEF's Treasurer, Mr. Sullivan, provided the S&P and Moody's financial credit metrics and the guidelines for PEF's targeted mid single A credit rating. (Tr. 1232-1235; Tr. 4143, L. 1-6). Mr. Sullivan further reported that Moody's would consider a downgrade "if there is an adverse change in the regulatory environment in Florida which could limit full and timely recovery of costs" and, among other factors, "if financial metrics do not recover from 2008 levels and [Cash from Operations ("CFO")] before working capital plus interest to interest remains below 4.0x and CFO before working capital to debt remains below 20% for a sustained period." (Tr. 4143, L. 7-16; Hearing Ex. 237). PEF calculated the key 2010 cash flow metrics using both S&P's and Moody's methodologies based on PEF's proposed rate increase and the interveners' proposed $35 million rate decrease. (Tr. 4143, L. 16-17, Tr. 4144, L. 1-2, Hearing Ex. 238). The calculations clearly show that PEF does not meet the S&P and Moody's guidelines for a mid-single A credit rating if the interveners' recommended $35 million rate reduction is accepted. For example, if that proposal is accepted, CFO before working capital plus interest to interest is 3.8x and CFO before working capital to debt is 16.3 percent, well below the Moody's guidelines and therefore, likely to result in a downgrade from Moody's. (Tr. 4144, L. 2-6; Hearing Ex. 238). The interveners' proposed $35 million rate reduction will result in reduced cash flows, weaker credit ratings, a weaker balance sheet, and a likely credit rating downgrade with reverberations throughout the capital markets, resulting in higher costs of capital, and ultimately increases in rates for customers. (Tr. 4144, L. 10-11, Tr. 4145, L. 3-7; Tr. 4256, L. 9-25, Tr. 4257, L. 1-12).

D. Reconciliation of Rate Base and Capital Structure (Issue 43).

PEF reconciled rate base to capital structure by first making specific adjustments where appropriate. For common equity, PEF made a specific adjustment for imputed equity and a specific adjustment to reflect the removal on non-utility property. (Hearing Ex. 47, MFR Schedules D-1a and D-1b; Tr. 1667-68; 1669). PEF made a specific adjustment to short-term debt to properly reflect the daily weighted average balance. (Id.) PEF also made a specific adjustment to deferred income taxes related to nuclear decommissioning and to CWIP generated by the Levy nuclear project and collected through the nuclear cost recovery clause. (Id.; Tr. 1669). After these specific adjustments, all other adjustments were made pro rata across all sources of capital.

The only evidence in the record concerning the appropriate method of reconciling rate base to capital structure is found in the testimony of Mr. Toomey and in Exhibit 42. As that exhibit demonstrates, a significant portion of PEF's non-specific (pro-rata) adjustments reflect the removal of clause-related plant and AFUDC-eligible CWIP from PEF's retail rate base. (Hearing Ex. 42 at 1630). The items are removed from rate base because they earn their own rate of return outside of base rates, either through a cost-recovery clause or through AFUDC. (Id.) That rate of return is calculated using all sources of capital, including investor-supplied capital, deferred taxes, customer deposits, and investment tax credits. (Id.) Similarly, when these items are removed from rate base, it is appropriate to make the necessary reconciling adjustment to capital structure on a pro rata basis across all sources of capital in order to avoid double-counting the benefit of zero cost deferred taxes and low cost customer deposits. (Id. at 1630-31). Making the adjustment in this manner is the easiest way to avoid violation of the tax normalization rules and to avoid the risk that ratepayers could lose the benefit of accelerated depreciation. (Id. at 1630-31, 1636; see Tr. 1885).

Making the adjustment across all sources of capital also matches the way that PEF funds its rate base and manages its sources of capital. (Id. at 1631). PEF does not segregate its sources of capital, and when funds are utilized by PEF they come from a pool of funds that is generated from all sources of capital, including deferred taxes, customer deposits and income tax credits. (Id. at 1631, 1635, 1637; see Tr. 1885). Given this uncontroverted evidence on the appropriate way to reconcile rate base to capital structure, PEF's reconciliation methodology should be approved.

E. Return on Common Equity.

PEF retained Dr. Vander Weide, Research Professor of Finance and Economics at Duke University, to prepare an independent appraisal of PEF's cost of equity and recommend a rate of return on equity that is fair, that allows PEF to attract capital on reasonable terms, and that allows the company to maintain its financial integrity. (Tr. 1363-1364). These are legal and economic principles explained in the Bluefield and Hope United States Supreme Court cases. See Bluefield Water Works and Improvement Co. v. Public Service Comm'n, 262 U.S. 679, 692 (1923); Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). In these decisions, a fair return on equity allows (1) enough revenue to cover operating expenses and the capital costs (the debt service and stock dividends) of the utility business and (2) a return commensurate with the risk of investing in similar businesses with corresponding risks in order to attract capital and maintain the utility's financial integrity. Id.; (Tr. 1320-1321).

The cost of equity, however, is not fixed by contract (like debt) and therefore is not known but must be estimated. Additionally, to attract equity investors the company must offer the investors an expected future return commensurate with the expected returns on investments of similar risk. (Tr. 1322, L. 1-12). Therefore, to determine the cost of equity the expected future return on equity must be estimated. To estimate the expected future returns, a comparable company approach is used. Under the comparable company approach, a group of companies with similar risk is identified and the cost of equity is estimated for the companies in this proxy group. (Tr. 1322, L. 14-21). The use of a proxy group to estimate the cost of equity is a generally accepted industry standard method to determine the cost of equity.

There are also generally accepted methods for estimating the cost of common equity. These are the Discounted Cash Flow ("DCF"), risk premium, and Capital Asset Pricing Method ("CAPM"). (Tr. 1333, L. 18-23).[23] These generally accepted ROE estimation methods are applied to the comparable company proxy group. The application of these estimation methods were explained in detail in Dr. Vander Weide's direct testimony and the results were provided in Table 5 of his direct testimony. (Tr. 1334-1359). The average of all cost of equity methods resulted in an 11.5 percent cost of equity estimate. (Tr. 1359, L. 4-12). This cost of equity estimate was adjusted to reflect the higher financial risk associated with PEF's ratemaking capital structure. PEF's recommended book capital structure contains 50 percent common equity while the average market value capital structure of the comparable company proxy group contains 58 percent equity. (Tr. 1360, L. 16-20). From an investors' viewpoint, PEF's ratemaking capital structure embodies greater financial risk that the average market value capital structure of the proxy company group. Accordingly, an adjustment must be made to PEF's weighted average cost of capital ("WACC") to yield the same WACC as the proxy group and,

[23] Interveners questioned the accuracy of the generally accepted cost of equity estimating methods but they failed to identify any method that was more accurate and their own ROE witness employed several of the same methods (DCF and CAPM) to estimate the cost of equity. (Tr. 2972-73). Similarly, several interveners in cross examination suggested that the cost recovery mechanisms in Florida should be taken into account in the ROE analysis because the cost recovery lessens PEF's risk. (Tr. 292-95; 1437). However, neither ROE witness took the cost recovery mechanisms into account, except to note that investors are generally aware of them and therefore they are implicitly included in the market analysis. In other words, because the market is efficient, the resulting ROEs for comparable companies will necessarily include the impact that cost recovery mechanisms may have on the company. (Tr. 1451).

hence, the same comparable risk necessary to attract capital investment for PEF and the proxy group of companies. (Tr. 1361, Hearing Ex. 105).[24] As a result of this adjustment, the recommended fair rate of return on common equity is 12.54 percent. (Tr. 1362, L. 1-4).

Interveners cannot and did not dispute the basic legal and economic principles behind the determination of the cost of equity for PEF. Interveners' sole ROE witness, Dr. Woolridge, agreed that a regulated public utility is entitled to an opportunity to earn a fair and reasonable rate of return on its invested capital. (Tr. 3040, L. 5-9). Dr. Woolridge further agreed that a fair and reasonable rate of return should be sufficient to assure confidence in the financial integrity of the utility to maintain credit and attract capital. (Tr. 3040, L. 10-14). He further agreed with the Bluefield proposition that a public utility is entitled to earn a return on the investment in utility property equal to that return made at the same time in the same general part of the country on investments in other businesses with similar risks. (Tr. 3040, L. 20-25, Tr. 3041, L. 1-5). As a result, Dr. Woolridge also developed a comparable proxy group of companies and then applied

[24] Interveners did not challenge Dr. Vander Weide's testimony that the financial risk of his proxy companies is measured by their market value capital structures while PEF's financial risk is measured by its book value capital structure used for purposes of setting rates. (Tr. 3031; Tr. 2416, L. 19-23, Tr. 2417, l. 1-2). This is the fundamental basis for Dr. Vander Weide's market value capital structure adjustment to PEF's cost of equity estimate. (Tr. 2416, L. 7-17). Instead, they contend this adjustment is unjustified based on erroneous assertions regarding market to book ratios, the simple fact that the Company's leverage does not change and financial publications report capital structures based on book values, and their claim the adjustment is unsupported by any prior authority. (Tr. 3031; Tr. 2416, L. 19-23, Tr. 2417, L. 1-2). None of these arguments challenge the fundamental premise that investors measure financial risk based on market value capital structures. That testimony is undisputed. Further, other regulatory commissions have used market value capital structures in the telecommunications industry. (Tr. 2419, note 17). See *Memorandum Opinion and Order, Petition of AT&T Communications of Virginia Inc., pursuant to Section 252(e)(5) of the Communications Act for Preemption of the Jurisdiction of the Virginia Corporation Commission Regarding Interconnection Disputes with Verizon Virginia, Inc.*, 18 FCC Rcd 17722, ¶ 94, at ¶¶ 103-104, (2003) (the FCC Wireline Competition Bureau accepted Verizon's proposal that the appropriate capital structure component of the [WACC] should be based on the market values of debt and equity, stating, "we give no weight to the portion of AT&T/WorldCom's proposal that is based on incumbent LECs' book value capital structure."); *In the matter, on the Commission's own motion, to review the total element long run incremental costs and the total service long run incremental costs for Verizon North Inc., and Contel of the South, Inc., D/B/A Verizon North Systems, to provide telecommunications services*, Case No. U-15210, at 17, Michigan Public Service Commission (March 18, 2009). ("The Commission is not persuaded that Verizon's capital structure should be based on book value. The Commission agrees with the Staff and adopts Verizon's proposed capital structure of 75% equity and 25% debt.").

the generally accepted ROE estimation methods (the DCF and CAPM) to that comparable proxy group of companies to estimate PEF's rate of return. (Tr. 2955-56). Dr. Woolridge's recommended ROE for PEF, however, was 9.75 percent. (Tr. 2998, L. 15).

The evidence demonstrates that Dr. Vander Weide's recommended ROE of 12.54 percent is the fair and reasonable cost of equity under the generally accepted industry standards for estimating the cost of capital that is necessary to maintain PEF's credit and financial integrity and attract capital. The only other evidence offered under the generally accepted industry standards to estimate the ROE -- Dr. Woolridge's recommended 9.75 percent ROE -- grossly underestimates the fair and reasonable ROE for PEF. Dr. Woolridge (1) uses a proxy group that is not comparable to PEF, (2) uses an inappropriate DCF and CAPM method and calculation, (3) fails to use the "high end" of the total range of the estimated cost of equity to account for the admittedly continuing volatility and uncertainty in the market, and (4) inappropriately fails to account for any flotation costs to finance equity investments in PEF's estimated ROE. When these flaws are corrected, the estimated fair and reasonable ROE is again in the range recommended by Dr. Vander Weide for the Company. (Tr. 2368; Tr. 2369, L. 1-7).

Dr. Woolridge agreed the utilities in his proxy group are supposed to reflect the risk of investing in PEF. (Tr. 3041, L. 6-9). Yet, his proxy group selection criteria focused on small cap utilities in areas far from where PEF operates with few similarities in operations and risk to PEF. To illustrate, his proxy utility group criteria excluded every Florida investor-owned utility in Florida and every operating utility in the southeast except for PEF. (Tr. 3041-3042). His proxy utility group included, however, Central Vermont, a utility with net plant investment approximately equal to PEF's investment in PEF's single steam generator project and less than half PEF's investment in the Bartow combined cycle power plant, that is one-tenth the size of PEF in terms of net investment and customers with a below investment grade credit rating. (Tr.

3042-3045, Tr. 3046, L. 1-6). His proxy group also included other small cap utilities with markedly fewer customers and net investment than PEF, hydroelectric plant operators, transmission and distribution only utilities, and no utility (other than PEF) that is planning on building nuclear power plants. (Tr. 3048-3052). The fact that Dr. Woolridge's proxy utility group is not comparable to PEF is further demonstrated by the fact that Dr. Woolridge obtained a higher ROE of 10.5 percent when he applied even his erroneous ROE calculations to Dr. Vander Weide's proxy utility group. (Tr. 2983). The proxy utility group used by Dr. Woolridge should be rejected and the proxy utility group used by Dr. Vander Weide accepted by the Commission.[25]

The use of inappropriate ROE estimates and calculations by the interveners' witness Dr. Woolridge further underestimates the required ROE for PEF. Dr. Woolridge's ROE estimates include the following errors:

(1). Dr. Woolridge uses an annual DCF model. An annual DCF model assumes dividends are paid only once at the end of the year. Dr. Woolridge's and Dr. Vander Weide's proxy utility companies, however, all pay dividends quarterly. As a result, Dr. Woolridge should have used a quarterly DCF model. (Tr. 2421, L. 5-10) Use of the annual DCF model instead of the quarterly DCF model underestimates the required ROE. (Tr. 2362; 2421).

(2). The annual DCF model, if used, requires that the first dividend is equal to the current annualized dividend multiplied by one plus the growth rate. Dr. Woolridge multiplied the current annualized dividend by the factor one plus one-half times the growth rate. This incorrect procedure underestimates PEF's cost of equity. (Tr. 2978, L. 6; Tr. 2363; Tr. 2421, L. 11-18).

(3). The DCF model requires an estimate of future growth. Dr. Woolridge, however, uses historical and internal growth data and not analyst forecasts to estimate future growth. Historical growth rates are inherently inferior to analyst forecasts because analyst forecasts incorporate historical growth and further include expectations about the future. Despite Dr. Woolridge's erroneous attacks on the accuracy of analyst forecasts, there is no doubt that investors use analyst forecasts in making stock buy and sell decisions. (Tr. 2978-79; 2369-81, Tr. 2364, L. 10-18). As a result, projected growth rates by analysts more accurately reflect the actual investment decisions made by investors and should be used.

[25] Dr. Vander Weide demonstrates that Dr. Woolridge's criteria for his proxy utility group is not comparable in risk to PEF and actually excluded utilities in Dr. Vander Weide's proxy utility group that are comparable in risk to PEF. (Tr. 2351-2360).

Internal growth estimates require an estimate of the expected rate of return on equity in the calculation to determine the estimated cost of equity. For regulated utilities such as PEF the allowed rate of return on equity is set equal to the cost of equity, hence, the internal growth estimate calculation is circular. (Tr. 2365, L. 5-17). This calculation, when applied to regulated utilities like PEF, produces absurd results. To illustrate, Dr. Woolridge recommends a ROE for PEF of 9.75 percent when his own internal growth estimate of the ROE required for his proxy group is in the range of 11 percent to 11.3 percent. (Tr. 2365, L. 19-22, Tr. 2366, L. 1-9; Tr. 3062, L. 5-25, Tr. 3063, L. 1-23). Dr. Woolridge even agreed that an investor in electric utility stocks can look at his estimated internal required ROE for his proxy utility group and understand the investor can invest in the proxy utility group and get a higher mean and median return of 11 percent to 11.3 percent than what he recommended for PEF. (Tr. 3064, L. 4-12).

(4). Dr. Woolridge's CAPM estimate demonstrates that the CAPM method can underestimate the required ROE for a public utility like PEF. Dr. Woolridge obtained a CAPM result of 7.6 percent for his proxy group and 7.7 percent for Dr. Vander Weide's proxy group, a result that was equal to the current average yield on certain utility bonds. (Tr. 2382, L. 12-22). Since investment in equity is significantly more risky than an investment in bonds, Dr. Woolridge's CAPM estimate grossly underestimates the ROE for PEF. (Id.) Dr. Woolridge recognizes this CAPM result is unreasonably low because he excludes these results when he selects his estimated reasonable range of ROE of 9.5 percent to 10 percent. (Tr. 2998; Tr. 2383, L. 1-14).

(5). Dr. Woolridge fails to include flotation costs in his analysis. He erroneously claims there is no evidence flotation costs are incurred and they are unnecessary to avoid dilution of existing shareholders as long as the stock price is above book value. (Tr. 3014-16; Tr. 2412, L. 1-21). Dr. Vander Weide did present evidence that all companies, including Progress Energy, incur flotation costs when they issue new equity securities and that flotation costs represent approximately five percent of the company's pre-issue stock price. (Tr. 1342-44; Hearing Ex. 108; Tr. 2412, L. 8-14). Further, flotation costs are appropriately included not to avoid dilution but because they are a cost of equity issuance and therefore must be recovered to allow the company to earn a fair rate of return on its investment. (Tr. 1342-43; Tr. 2412, L. 16-21). Additionally, the Commission has traditionally recognized a reasonable adjustment for flotation costs in the determination of the required ROE and such adjustments have typically been on the order of 25 to 50 basis points. Order No. PSC-09-0283-FOF-EI, Docket No. 080317-EI, at 44 (Apr. 30, 2009).

If the annual DCF model is corrected and applied to both proxy groups, the average DCF result is in the range 12.2 percent to 12.5 percent. (Tr. 2368, L. 4-17, Hearing Ex. 247) If flotation costs in the range of 25 to 50 basis points are included as this Commission typically does the range of the required ROE for the two proxy groups is a low of 12.45 percent to a high of 13 percent. (Id.) This demonstrates that PEF's estimate of a 12.54 percent ROE based on Dr. Vander Weide's application of the generally accepted cost of equity methods to an appropriate proxy utility group is a reasonable, required ROE for PEF.

Dr. Woolridge's estimated ROE for PEF of 9.75 percent is no different than his estimated ROE for TECO about ten months ago. (Tr. 3064, L. 13-24). The Commission rejected his recommended ROE for TECO based on the evidence there and the Commission should similarly reject the same recommendation for PEF based on the evidence in this proceeding. In fact, based on Dr. Woolridge's own underlying data -- the July 2009 AUS Utility Report (Tr. 3056-3057, Exhibit 306) -- his recommended ROE was the third lowest ROE among the allowed ROEs and 100 basis points below the average allowed ROE of 10.75 percent for electric utilities. (Tr. 3057, L. 17-24; Tr. 3060, L. 18-22). Thus, based on his own data, if his recommended 9.75 percent ROE for PEF was adopted, an investor could invest in 21 other electric utility companies, or the entire group of electric utility companies in his data, and have the opportunity to earn a higher return than an investment in PEF. (Hearing Ex. 306; Tr. 3058, L. 5-20; Tr. 3059-3060).[26] This is not a reasonable ROE for PEF and it therefore should be rejected.

Interveners did not even take Dr. Woolridge's recommended 9.75 percent ROE seriously. They repeatedly questioned PEF witnesses regarding the alleged reasonableness of the average awarded ROEs in 2009 of 10.5 percent in an exhibit they introduced -- not the reasonableness of Dr. Woolridge's estimated 9.75 percent ROE for PEF. (Hearing Ex. 264; Tr. 182-187; 226; 1788-91; 2505-2507). But the average awarded ROEs for electric utilities to date in 2009 is no

[26] Dr. Woolridge's recommended ROE of 9.75 percent for PEF was also below the average allowed ROE of 10.71 percent for electric and gas companies, the average allowed ROE of 10.67 percent for natural gas companies, the average allowed ROE of 11.79 percent for telephone companies, and the average allowed ROE of 9.91 percent for water companies. (Hearing Ex. 306; Tr. 3060-3061). Thus, an investor could invest in the collective group of any of these companies, including the water companies, and have the opportunity to earn a higher return than an investment in PEF if Dr. Woolridge's estimated ROE for PEF was adopted by the Commission.

more relevant to the determination of the required ROE for PEF than Dr. Woolridge's grossly inadequate 9.75 percent ROE estimate. As Dr. Vander Weide explained, "it's circular to look at returns that are authorized in other proceedings, … because of the differences in times at which evidence is provided, the differences in circumstances of utilities in different proceedings in different states, and the economic characteristics of the individual utility, that the best evidence is to provide cost of equity estimates from the models that I've used." (Tr. 1379, L. 8-25, Tr. 1380, L. 1-2).[27] The Commission in the past has taken the position that prior ROE awards and prior or current earned ROEs are no substitute for a determination on the evidence presented of the future return required to attract investor capital. In United Telephone Company v. Mayo, 345 So. 2d 648, (Fla. 1977), respondents the Commission and OPC argued that the Court should reject the utility's argument that the "equality of regulatory treatment" under Bluefield and Hope required identity of treatment because a "given return on common equity which has been properly determined for one company in no way mandates a similar allowance for a completely different company" and that this was not part of the utility's case. (Id. at 654)[28] Likewise, the Commission has rejected reliance on past earned returns on equity for similar reasons, finding that it involves circular reasoning and does not reflect market opportunity costs. In re: Petition of the Winter Park Telephone Company for readjustment of its rates and charges, Order No. 8330, Docket No. 770491-TP, 1978 Fla. PUC LEXIS 514 (June 2, 1978). The Commission noted that, "[w]hile market data may be manipulated to give distorted results, an evaluation of

[27] As Dr. Vander Weide further noted, by requesting that the Commission take into account what ROEs other regulatory commissions have awarded utilities the interveners are asking this Commission to do something those other commissions did not do. If every state commission looked at the allowed return authorized in other states to set the ROE for utilities in the state the allowed ROE would never change and, even from the exhibit interveners introduced, other states do not do that because they do award different ROEs. (Hearing Ex. 306; Tr. 1382, L. 1-11).

[28] The Court held that the Commission did not act unlawfully in refusing to honor the "comparable earnings approach" advanced by the petitioner utility because it refused the petitioner the opportunity to alter its theory. (Id. at 655). Tellingly, the interveners' reliance on the comparable ROEs awarded by other Commissions is also not part of any intervener witnesses testimony, including the interveners' ROE witness, Dr. Woolridge.

market data is essential in an equity cost determination. Market data reveals information about investor expectations of future earnings. The cost of equity capital is the return the investor demands at present to entice him to invest in equity capital – not the return that he actually earned in the past under different circumstances." (Id. at *42). Here, as demonstrated above, the record evidence of the investors' expected return to invest in PEF is 12.54 percent.[29]

VI. PEF's O&M Expenses are Reasonable and Supported by Evidence.

Intervener witnesses have raised several issues with respect to PEF's O&M expenses, recommending various adjustments or disallowances to PEF's various expenses.[30] As shown below, each of these recommended adjustments is unfounded and should be denied.

A. The Commission Should Approve the Company's Generation O&M Expenses. (Issues 49, 62, 69, 83-84, 87)

The Company presented the testimony of Mr. David Sorrick in support of its generation O&M costs. Mr. Sorrick is the Vice President of Power Generation for Florida, and he has more than 20 years of power plant experience, specifically with the Progress Energy generation fleet. (Tr. 369-370) For the test year 2010, the Company needs $134 million in capital[31] and $175

[29] Interveners also questioned PEF regarding the Commission's recent award of an 11.25 percent ROE for TECO. They challenged any reference to the TECO award despite the undisputed evidence that both TECO and PEF share equal risk from the point of view of the equity investor based on the application of the generally accepted standard cost of equity estimation models at the same time, meaning if the ROE estimate for TECO was performed at the same time the estimate was performed for PEF the result would have been the same for TECO that it is for PEF. (Tr. 1412, L. 19-25, Tr. 1413, L. 1-4). Interveners cannot have it both ways. They cannot argue that this Commission cannot award PEF the same or higher required ROE awarded TECO while at the same time arguing the Commission should award PEF an ROE consistent with their exhibit of the average ROE awarded by other regulatory commissions so far in 2009 in other jurisdictions under other circumstances and evidence.

[30] One overarching argument interveners make with respect to the Company's planned projects is that the legislative and policy goals, which some of these projects are designed to meet, are simply aspirations rather than real requirements. (Tr. 139-151). However, as Mr. Dolan explained, the money the Company has requested in this rate proceeding is necessary to meet the needs of its business, and the benefit of achieving these future policies and goals is secondary. (Tr. 200). Additionally, it is prudent and reasonable for PEF to prepare for the future and anticipate the current and future policies of the state and federal government. It is bad regulatory policy for this Commission to discourage such a proactive approach. No one can say that utilities should not take known future and planned policies into account when doing long-term strategic planning.

[31] No intervener challenged the Company's capital expenses for generation, transmission, or distribution.

million in O&M expenses to maintain and operate its existing generation fleet so that the Company's fleet can continue providing safe and reliable power generation to its customers. (Tr. 372). PEF's generation fleet consists of 12 fossil steam units, 5 combined cycle units (not including the new Bartow units), 1 cogeneration unit, and 46 simple cycle combustion turbine units. (Tr. 373). These units can produce up to 9,400 MWs of safe, reliable power. (Id.)

The cost to maintain and operate this generating fleet has increased since the Company's last rate case in 2005, because PEF has added several new generating units since that time. This includes Hines Units 3 and 4, as well as the Bartow Combined Cycle plant.[32] (Tr. 373-375). Fleet growth increases the cost to operate and maintain the units because there are additional labor, material, and permit costs for the additional units, and there are additional costs related to maintenance of the new units. (Tr. 375-376).

Intervener Witnesses Schultz and Marz have three criticisms with respect to the Company's generation O&M expenses, each of which is without merit: (1) the maintenance costs appear excessive; (2) the cost of maintenance work at Crystal River Unit 4 ("CR4") should be spread over some period of time; and (3) the costs are not supported by adequate documentation. (Tr. 1949-1952; Tr. 2304-2308).

Interveners' first criticism of the Company's generation O&M expenses is based on the fact that certain historical year expenses appear lower than the requested 2010 expenses. (Tr. 2831). While the 2009 and 2010 budgeted and projected O&M costs for generation maintenance are somewhat higher than prior years, the future budgets are based on the actual operations of the units over the last few years, as well as the projected operation in 2009 and 2010. (Tr. 2771). Given the size of PEF's generation fleet, it is not uncommon for major maintenance costs to

[32] The benefits and costs of the Bartow Repowering Project were explained in detail in Kevin Murray's testimony, filed in Docket 090144-EI and consolidated with this proceeding. (Tr. 517-26). The parties entered a Category 2 stipulation that there should be no adjustments to the requested rate base for the Bartow project.

fluctuate year to year. (Id.) The number of units in the fleet, the operational characteristics of each unit, and the position of each unit in its maintenance cycle all impact the maintenance needs for a particular year. (Tr. 2772). Unlike Mr. Schultz's and Mr. Marz's sole reliance on numbers to justify their recommended adjustments to the maintenance costs for PEF's generating fleet, Mr. Sorrick, the person held accountable for these units on a day-to-day basis, presented testimony and data to support the real maintenance needs for these units based on his actual experience with the units. (Tr. 2772).

Specifically, preventative maintenance on generating units is essential to prevent equipment degradation and unplanned outages. (Tr. 2772; Tr. 416-17; 484-85). As Mr. Sorrick explained, much of the equipment in these generating units operates in a harsh environment, subjected to very high temperatures. (Tr. 2773). The equipment will only work properly if other mechanisms, such as cooling and internal coating, are in place to prevent damage. (Tr. 2774). Ongoing maintenance is essential to prevent failure of the parts. Maintenance also serves to reduce the overall operational cost, because it is generally much less expensive to repair a part than it is to replace one. (Tr. 2774).

Interveners' second argument, that the cost of the CR4 maintenance should be spread over a period of time (five or nine years), is likewise without merit for many of the same reasons explained above. While PEF tries to levelize its maintenance expenses from year to year, given the size and complexity of the generating fleet, it is often impossible to do so. (Tr. 2776-2777). Again, the age of the unit, how often the unit is run, and other factors will impact the timing and type of maintenance for that unit. Accordingly, it is arbitrary and unfair to decrease the maintenance expense for 2010 solely because there is one major maintenance project in that year for 2010.[33] Furthermore, the CR4 major maintenance will be done in the Spring of 2010 to take advantage of an already-planned outage to install clean air equipment at the plant. (Tr. 2777). PEF's customers benefit from this combined outage, because it shortens the length of time that this baseload generating unit would otherwise be offline, thus providing fuel savings. (Tr. 2778). Customers also benefit because CR4 will perform better after the major maintenance has been completed. (Id.) The Company should not be punished for its efficient scheduling of maintenance. In any event, as explained by Mr. Sorrick when responding to questions posed by counsel for OPC, in 2011 and 2012, the preliminary budget numbers show that the Company expects to spend about $177 million and $180 million, respectively, for power generation O&M. (Tr. 448-49). Thus, contrary to interveners' assertions, the O&M needs for the 2010 test year of $175 million are not inappropriately high or overstated.

Finally, Intervener Witness Schultz claims that the Company has not supported certain of its requested O&M costs with appropriate documentation. This argument is without merit and should be rejected. Mr. Schultz appears to suggest that the projected costs should be supported by the same level of detail and documentation that is available for actual, incurred costs. Obviously, detailed invoices and charge slips, available to support actual costs, will not be available for a projected cost. In any event, the Company did present support for its projected costs.

Specifically, with respect to the Long Term Service Agreement ("LTSA") for the Bartow plant, PEF explained the costs in MFR C-41, Mr. Sorrick's direct testimony, and provided the relevant portions of the LTSA, which is a confidential contract. (Tr. 394; Tr. 2785; Tr. 2827-28). Regarding the other maintenance estimates, PEF provided supporting documentation to explain the components of the expense. (Tr. 2786). In addition, as explained by Mr. Sorrick, those

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[33] Interveners agree to pay part of the maintenance cost for this outage. (Tr. 2306; 1951). They clearly do not dispute the prudence of this outage, they just do not want to pay for the entire cost.

estimates were based on PEF's years of experience in maintaining its generating fleet.[34] (Tr. 2786-2787). In some instances, PEF has learned that it can perform the maintenance at a lower cost than a third party vendor, so there would be no invoice or estimate for that work either. (Tr. 2786). Counsel for OPC, in his questions of Mr. Sorrick, implied that the Commission should not accept these estimates because they were not validated by any documents or estimates, much like what someone would receive when she took her car into the shop for a repair. (Tr. 2829). However, as Mr. Sorrick testified, the more applicable analogy is that PEF owns a fleet of cars and it uses the same shop to do the same repairs year after year. (Tr. 2829). So there is no need for a detailed estimate to support the reasonableness of the estimate in that example. Therefore, the Commission can and should rely on the expertise, documentation, and sworn testimony offered by Mr. Sorrick in his support of these required maintenance expenses.

In sum, PEF's requested O&M expenses for its power operations are reasonable and prudent. Any adjustment to the Company's request is unwarranted and could result in higher costs, both in replacement fuel and equipment repairs. (Tr. 2788). Decreased maintenance, especially proactive maintenance, will also result in lower generation fleet reliability and increase the long-term cost of maintaining the fleet. (Id.) The Intervener witnesses ignore the physical realities of the complex units for which Mr. Sorrick is responsible, and decreasing maintenance of these units can be catastrophic to the equipment involved and extremely expensive to fix. (Id.) Therefore, the Commission should approve the Company's requested generation O&M expenses of $175 million.

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[34] Mr. Sorrick explained it best when he said: "And it just doesn't make sense to us to necessarily go out for a formal quote for hundreds of lines of maintenance when we have a good understanding of what that cost is. It's almost like saying how long is it going to take to drive from, from St. Petersburg to Tallahassee? Well, by experience we know it takes four to four and a half hours. We don't necessarily need to go out and ask a lot of people to confirm that." (Tr. 453, L. 3-11).

B. The Commission Should Approve the Company's Transmission O&M Expenses. (Issues 49, 62, 70, 83-84, 87)

To support and explain PEF's requested transmission costs, PEF presented Mr. Dale Oliver, the Vice President of the Transmission Planning and Operations Department ("TPOD"). (Tr. 552). Mr. Oliver has more than 20 years of engineering experience, and has been involved with PEF's specific transmission system since January 2001, when he joined the Company. (Tr. 552-553). PEF's transmission system includes approximately 5,000 circuit miles of transmission lines, as well as transmission substations, towers, poles, and related equipment across 20,000 square miles.[35] (Tr. 555). To continue to build and maintain these transmission facilities, the Company needs $185.2 million in capital expenditures and approximately $45.3 million for O&M expenses. (Tr. 554).

Specifically, PEF requires these additional dollars to comply with various state and federal regulatory requirements and to meet increasing demand on the transmission system, all while continuing to provide the high transmission reliability that PEF's customers have come to expect. (Tr. 554-555). On the federal level, the North American Reliability Council ("NERC") adopted more stringent transmission reliability standards, and the Company must incur more costs to meet these higher standards. (Tr. 564). In addition, the Federal Energy Regulatory Commission ("FERC") issued orders directing the operation and regulation of electric utility transmission systems, which require more transparency and coordination with other utilities that access the transmission system. (Id.) The Florida Reliability Coordinating Council ("FRCC") has also taken a greater role in transmission planning at the regional level, which has translated into more capital projects and more focus on the reliability of PEF's 69 kV transmission lines.

[35] Interveners questioned why the additional maintenance and capital expenditures were needed given the lower customer growth. As Mr. Oliver explained, however, the Company must plan for demand, not energy sales. Because PEF just hit a new winter peak in February of 2009, the Company must plan transmission to meet that peak, irrespective of reduced customer sales. (Tr. 607-609).

(Tr. 564-565). At the state level, the Company must comply with new storm hardening rules, including wood pole inspections and increased vegetation maintenance. (Tr. 566-567). All these additional regulations mean higher transmission costs for the Company.

Intervener witnesses recommend substantial adjustments to the Company's requested Transmission O&M dollars. Specifically, Witness Schultz argues that the $6.9 million increase for compliance with FERC 890 is not adequately supported by the Company. (Tr. 1945; Tr. 1947). Mr. Schultz also asserts that the line bonding and grounding costs were not explained by the Company and should be reduced to reflect that they occur every other year. (Tr. 1946). Finally, Witnesses Schultz and Marz claim that the Company's requested dollars for vegetation maintenance in the test year are too high compared to the actual costs from prior years. (Tr. 1945-1946; Tr. 2303-2304). These disallowances are not justified, and the Company's request should be approved in whole as explained below.

Witness Schultz's first argument with respect to transmission O&M expenses regarding the costs for compliance with FERC 890 is without merit. FERC 890 requires the Company to provide credits to transmission customers under the Open Access Transmission Tariff (OATT) for customer owned integrated transmission facilities. (Tr. 2880). This is a recurring, incremental expense over which the Company has no control. (Id.) Expenses for customer credits are first budgeted in 2010, because the only customers who could be eligible for such credits have contracts that expire in late 2009. (Id.) These expenses have been explained and supported by Mr. Oliver's testimony and are thus appropriate for inclusion in the 2010 test year.

Likewise, Mr. Schultz's argument regarding line bonding and grounding should be disregarded. Contrary to Mr. Schultz's assumption that line bonding and grounding occurs every other year, it actually is maintenance work performed on an annual basis. (Tr. 2881). Mr. Schultz again makes this erroneous assumption about the frequency of these costs by looking solely at budget numbers, without understanding the true reasons why the activities are performed. Line bonding and grounding are routine maintenance activities charged to FERC Account 571 – Transmission Overhead Lines Maintenance. (Id.) Due to the high volume of lightning strikes in PEF's service territory, increased line bonding and grounding is the most effective way to improve transmission reliability. (Id.) PEF implemented higher standards for line bonding and grounding, which are considered an industry best practice. (Tr. 2882). However, because the work is labor-intensive and time-consuming, PEF needs this money now and in future years to complete the work on all its transmission lines. (Id.) The Company therefore needs these dollars to complete this important work to maintain transmission reliability.

The final argument intervener witnesses make regarding transmission O&M expenses is that the Company's vegetation management expenses are higher compared to prior years. This is not a valid reason for adjusting the Company's requested expenses. As explained by Mr. Dale Oliver, the additional dollars are needed to comply with NERC Standard FAC-003-01. (Tr. 2882). Contrary to interveners' assertions, this NERC standard did not just simply adopt existing guidelines with which the Company already complied. Rather, it imposed new and different requirements. (Tr. 637-38). The NERC Standard also imposed a $1 million a day penalty for non-compliance with vegetation management standards on lines greater than 200 kV. Accordingly, the Company shifted priorities in line clearing from the non-NERC lines (less than 200 kV) to those higher voltage lines falling within the NERC Standard. (Tr. 2883). The Company cleared lower voltage lines only to the extent necessary to maintain safe, reliable operation, but those lines were not cleared to the full extent they would have otherwise been without the NERC Standard. (Id.; Tr. 586-88). Thus, the dollars for vegetation management are needed to clear the lower voltage lines, while also continuing to maintain the NERC Standards for the lines above 200 kV. (Id.) The expected expenses for vegetation management have also increased because the Company has added miles of transmission lines to its system. This vegetation management will be needed in 2010 and in future years[36] to maintain the safe, reliable electric service PEF's customers have come to expect.

In sum, the Company has supported its 2010 transmission expenses. They are reasonable and prudent and based on real needs to maintain the 5,000 miles of transmission lines that carry power across PEF's service territory. Without the requested expenses, the reliability of the Company's transmission system may suffer and customers will be without the excellent service they have come to expect.

C. The Commission Should Approve the Company's Distribution O&M Expenses. (Issues 49, 62, 71, 84-84, 87)

To support its needed distribution costs, the Company provided the testimony of Mr. Jackie Joyner, the Vice President of Distribution – Florida. In this role, Mr. Joyner directs and manages the development of PEF's distribution strategic programs and compliance policies for various distribution areas. (Tr. 652). In the distribution area, the Company needs $236 million for distribution capital investments and $145 million in distribution O&M expenses in the 2010 test year. (Tr. 655). These dollars are needed to distribute electric power to PEF's customers in a safe, reliable manner, as well as to comply with Commission reliability initiatives. PEF's distribution system delivers electricity to the Company's 1.6 million customers via approximately 18,000 circuit miles of overhead primary voltage distribution conductors, approximately 13,000 miles of underground primary voltage distribution cable, distribution substations, and related poles, transformers, cables, wires, and other equipment. (Tr. 655).

[36] Contrary to interveners' suggestions that the Company will cut or reduce vegetation management costs in the future, the only evidence in the record is that the Company will spend this money in 2010 and beyond. In fact, in response to questions from FIPUG's counsel as to whether vegetation dollars had ever been cut to increase cash flow, Mr. Oliver testified, "It has not happened on my watch here." (Tr. 633-34).

Specifically, PEF needs additional capital and O&M dollars because it is serving more customers with a larger distribution system than it did in 2005. (Tr. 662). The additional demand that more customers place on the system requires that the Company continue to invest in capacity expansion to avoid losses and outages. (Tr. 663). In addition, the system has aged since the Company's last rate case, thus requiring more maintenance costs to upkeep the equipment. (Id.) Finally, the Commission's storm hardening initiatives, which include aggressive wood pole inspection and vegetation management requirements, translates into additional investment in capital and O&M. (Tr. 668-670).

Despite these real needs to increase distribution spending, intervener witnesses recommend large cuts in the Company's request. Intervener witness Schultz argues that the Company has a $7.7 million variance that it did not explain or account for. (Tr. 1947). In addition, both Mr. Marz and Mr. Schultz challenge the expense for 2010 for distribution vegetation management and arbitrarily recommend adjustments based on the historical cost levels without considering the reality of maintaining and operating a distribution system. (Tr. 2304; Tr. 1948). As explained further below, both of these arguments are without merit and must be rejected.

Mr. Schultz's first assertion, that the Company has not supported $7.7 million in distribution O&M expense variance, is without merit. Mr. Joyner, in his testimony and on MFR C-41, provided a detailed explanation of all the distribution costs and variances. Specifically, as required by the Commission, on MFR C-41 the Company multiplied the total 2006 distribution O&M expenses by a compound multiplier, which was based on the percentage change in PEF's customers and change in CPI over the time period from 2006 to 2010. (Tr. 3084-3085). Making this calculation resulted in a distribution expense for 2010 of $130.6 million, which was then compared to the Company's requested 2010 costs of $145 million. (Id.) The resulting variance of $14.3 million was explained in detail on MFR C-41, and is comprised of variances in Vegetation Management, Environmental Operational Cost Efficiencies & Reorganization, and FERC Account Reclassifications. (Tr. 3085, Hearing Ex. 47, MFR C-41, pages 157-158; Tr. 691-95). Contrary to Mr. Schultz's assertions, there is more than adequate support and explanation of all the variances for distribution expense.

Intervener witnesses Marz and Schultz both argue for reductions in the Company's projected 2010 costs for vegetation management. Marz contends that because the storm hardening initiatives were already in place in 2006, there should be no increase in vegetation management and storm hardening costs for 2010. PEF, however, has spent more money since 2005 on these areas, directly because of the storm hardening initiatives. In 2005 and before, PEF spent approximately $14 million a year in these areas, while from 2006-2009, it spent (or projects to spend) about $19 million a year. (Tr. 3087). So, over the period of PEF's last rate case settlement, PEF spent about $21 million more on tree trimming than what was provided under the 2005 rate case settlement. (Tr. 3088). What both Mr. Marz and Mr. Schultz fail to understand, however, is that in 2010 the Company's vegetation management plan includes trimming to keep pace with a 3-year backbone cycle and to complete the fifth year of a 5-year lateral cycle. (Tr. 3089). Feeder backbones serve the most amount of customers and are usually easily accessible for pruning. Feeder laterals extend from backbones, serve fewer customers, and are typically less accessible than backbones. (Id.) The 3/5 trimming schedule is required as part of the Commission's storm hardening initiative. PEF, by increasing the amount of dollars incurred for tree trimming from 2006-2009, was able to actually reduce the level of expense that otherwise would have been needed to complete the necessary trimming in 2010. (Id.) PEF was also able to provide more "bang for the buck" by focusing on those backbone lines that provide more reliability to more customers than the lateral lines. (Hearing Ex. 47, MFR C-41, page 10 of

18; Tr. 717-18). Contrary to Mr. Schultz's argument that PEF failed to trim trees from 2006-2008 and increased the number of miles to be trimmed in 2010, PEF is on track to meet its required 3/5 schedule. (Tr. 3088). Again, without the additional money PEF spent from 2006-2009, it would be requesting even more money in 2010 to comply with the Commission's storm hardening initiatives. (Tr. 756). PEF acted in an efficient manner in deciding how to most effectively trim trees from the various lines and still comply with the Commission initiatives. PEF's customers benefited from this efficient trimming schedule by decreased outages and improved reliability. Again, PEF should not be punished for working efficiently to maintain safe and reliable distribution service.

Projected 2010 vegetation management costs have also increased significantly compared to 2006 costs because of substantial increases in fuel and labor. However, PEF has taken measures to offset these rising costs. For example, the Company has dedicated additional resources to the field to ensure quality work at the lowest possible cost. (Tr. 3091). PEF has also increased the level of system data, which reduces cost by allowing the Company to choose the most effective way to prune a particular area (for example, by machine or by hand). (Tr. 3092).

PEF needs the requested vegetation management expenses to comply with regulatory requirements set by the Commission. Despite interveners' arguments that PEF has heavy loaded the test year with non-recurring expenses,[37] PEF has demonstrated that it requires these expenses in 2010 to comply with the regulations and has shown that rather than "heavy loading" its test year, PEF has actually reduced 2010 O&M expenses from the level that they would have

[37] Interveners implied through questions of Mr. Joyner that Commission would not know whether all the money is spent on vegetation management in 2010 and beyond. (Tr. 715-16; 699-701). Mr. Joyner's testimony is the only evidence on this point, however, and he testified that he needs this money in 2010 and if he does not spend it to do the trimming, he could violate the storm hardening initiatives which he has no plans of doing. (Id.; 3110-11).

otherwise been. (Tr. 684-85). If the Commission disallows these expenses, PEF's ability to provide safe and reliable electric service may be hampered.

D. The Company's Requested Incentive Compensation and Payroll Expenses are Necessary to Attract and Retain Skilled Employees and Should be Approved by the Commission. (Issues 49, 62-67, 83-84, 87)

The Company must attract and retain highly skilled employees to provide safe, reliable, and efficient electric service to its customers. (Tr. 805). Because PEF competes in the market against both other utility companies, as well as non-utility companies, PEF benchmarks against the market to ensure that its total compensation is competitive. PEF, however, does not strive to be the highest-paying employer in the market. By contrast, the Company's compensation philosophy is to set its total compensation levels at the 50th percentile of the market. (Tr. 805). For the test year 2010, PEF estimates overall payroll expense (including incentive compensation) of $448,918,732, per the MFR C-35, revised June 6, 2009. (Hearing Ex. 47, MFR C-35).

Interveners raise four main points with respect to the Company's requested level of payroll expense: (1) the Company has not justified the increased head count for the 2010 test year; (2) incentive compensation goals linked to Company financial performance only benefit shareholders and thus that portion of incentive compensation expense should not be recovered from customers; (3) the economic conditions require that incentive compensation and base pay increases be reduced; and (4) many of the Company's operational goals are not appropriately set. (Tr. 1926-41; 2309-16). These arguments are without merit.

Headcount

Mr. Schultz recommends that 80 positions be removed from PEF's employee count for 2010. As explained by PEF's operational witnesses for generation, transmission, and distribution, however, Mr. Schultz's recommendation is unsupported by record evidence. These 80 positions represent: (1) 26 (of the 36 new positions) not yet filled as of 6/22/09, (2) 25 vacant positions not filled as of 6/22/09, and (3) an allocation of 29 Service Company Full Time Equivalents ("FTEs") as provided in PEF's response to OPC Interrogatory 299. (Hearing Ex. 45).

Mr. Schultz does not refute PEF's need for any of the 36 "new" positions. Rather, he recommends taking away the 26 positions that were unfilled as of 6/22/09, simply because they have not been filled yet. (Tr. 1931-32). This recommendation is not based on any analysis. His proposed reduction instead improperly assumes that the Company does not plan to fill these positions. Mr. Schultz, however, has no evidence that PEF is not going to fill these positions other than the fact that they are currently vacant. In fact, some of these new positions are not scheduled to be filled until 2010 and therefore would not logically be filled in the first half of 2009. The Company needs these employees and will fill these positions during the remainder of 2009 and 2010.

Similarly, Mr. Schultz does not challenge the Company's need for the 25 vacant positions which have not been filled as of 6/22/09. Mr. Schultz does not and cannot provide any evidence that the Company will not fill these positions, other than the fact that the particular positions were vacant as of a particular date. Of these 25 positions, 15 are in the Transmission Operations and Planning area. The Company plans to fill these positions to address the increased scope of transmission work required by NERC standards as Mr. Oliver discusses in his testimony. (Tr. 563-65). Again, the Company needs to fill these vacancies to continue to provide its customers with safe and reliable electric service. There is no principled basis to remove these positions from the Company's request.

Finally, Mr. Shultz recommends removing the 29 Service Company allocated full time employees because they were not explained. These allocated positions were in fact explained in PEF's response to OPC's Interrogatory 299. (Hearing Ex. 45). The increase in the allocation ratio to PEF is driven by an increase in PEF base payroll costs compared to PEC as a result of the many projects which were explained by PEF's operational witnesses for generation, transmission, and distribution.

Incentive Compensation

Interveners' argument regarding incentive compensation essentially boils down to whether shareholders or customers should pay for the incentive compensation. (Tr. 1933; 2314-15). Specifically, witnesses Mr. Schultz and Mr. Marz assert that any incentive compensation based on financial earnings goals only benefit shareholders. (Id.) Similarly, counsel for OPC argued that incentive compensation is like charitable contributions, which are recorded below the line and benefit both shareholders and customers. (Tr. 2523). However, this Commission has already recognized the importance of incentive compensation plans, by including it in customer rates in Florida Power Corporation's ("FPC's") 1992 rate case proceeding. (Hearing Ex. 209). The Commission stated: "Incentive plans that are tied to the achievement of corporate goals are appropriate and provide an incentive to control costs." Id. at *176. The Commission also rejected arguments to reduce incentive compensation expense in Gulf Power's 2002 rate case, finding that, because Gulf employees were "paid based on market value, customers will receive quality service and low rates." (Hearing Ex. 210 at *71).

Goals linked to Company performance do benefit customers because a financially strong company can access capital more easily at a lower cost. (Tr. 3245; 1652; 1233-34; 119-120). It is irrelevant whether shareholders also benefit from a particular goal. For example, shareholders benefit, along with customers, from a highly reliable electric system because providing reliable electricity allows shareholders to earn a return on their investment. (Tr. 3245-46). No one can argue, however, that only shareholders should pay for the costs associated with providing that reliable electric service, simply because they benefit along with customers. Likewise, incentive compensation, even that portion of compensation linked to financial goals, benefits the customers and thus the customers should bear that cost along with the other costs of providing service.

Customers also benefit from all incentive compensation because it enables PEF to attract and retain highly skilled and effective employees. (Tr. 3246-47). As explained by Mr. DesChamps, the Company focuses on the total compensation amount when setting compensation and benchmarking against peer employers. (Tr. 3251). Adjustments cannot be made to a portion of that total compensation, like incentive compensation, without impacting the overall competitiveness of the compensation package. When employees choose an employer, they base their decision on total compensation levels, including benefits. (Tr. 3256). Employees may give up higher base pay at one company in exchange for a lower base pay and the opportunity to do good work and be rewarded with incentive compensation at another company. Indeed, the Commission, in its recent TECO rate case order, recognized that lowering or eliminating incentive compensation would result in TECO employees being paid below market based on their total compensation, which would in turn adversely affect TECO's ability to compete in the market for highly skilled employees. Order No. PSC-09-0283-FOF-EI at *59.

In addition, structuring the total compensation based in part on pay for performance (incentive compensation) provides the Company flexibility to adjust the compensation level as warranted by each employee's performance. (Tr. 3242-3244; Tr. 3385-3386). This adds value to customers by providing an incentive to perform good work and may result in lower cost in terms of overall payroll expense.

Interveners pointed to the recent TECO rate case order as precedent for disallowing incentive compensation based on goals related to the financial success of the parent corporation. (Tr. 2316; 3312-16). The TECO order, however, is not directly applicable in this circumstance because the holding companies, TECO Energy and Progress Energy, Inc., have vastly different operating characteristics. Notably, as admitted by OPC witness Ms. Dismukes, Progress Energy, Inc. has divested itself of the great majority of its non-regulated businesses. (Tr. 2249-2250). Indeed, Mr. Sullivan, PEF's Treasurer, testified that the Company has returned to a "back to basics focus on core electric utility operations." (Tr. 4257-58). By contrast, TECO Energy has a higher percentage of non-regulated subsidiaries than Progress Energy, Inc. (Tr. 3248). Indeed, the Commission, when explaining the disallowance of incentive compensation, indicated "that the incentive compensation should be directly tied to the results of TECO and not to the *diversified interest* of its parent company TECO Energy." Order No. PSC-09-0283-FOF-EI at *59 (emphasis added). However, unlike TECO Energy, Progress Energy, Inc. is not diversified and is focused on the electric utility business. Accordingly, any financial goals related to Progress Energy, Inc. are more directly related to the financial performance of PEF. This distinguishes the TECO order from the instant case.

<u>Compensation and the Economy</u>

Interveners' next argument with respect to incentive compensation and base pay increases is related to the state of the economy. (Tr. 2524-2525; Tr. 3291-92; Tr. 170-175). While PEF is cognizant and empathetic of the economic conditions facing both PEF and its customers, it must also plan for the long-term future of the Company. As Mr. Dolan testified, PEF has been providing electric service for over one hundred years, and it plans to continue to do so for many more years. (Tr. 2525-27). Part of the key to the Company's success has been steady and moderate growth, in good times (like during the economic boom of the 1990s) and in bad times (such as now). (Tr. 2525-27; 220-221). The Company cannot afford to take a short-sighted view of the economy and eliminate incentive compensation pay or freeze salaries, because it must compete in the national market for the skilled employees it needs to provide electric service. (Tr. 3249). PEF takes a more long-term, strategic approach to attracting and retaining its employees, an approach that has benefited PEF's customers in both good and bad economic times. (Id.) In addition, the Company continuously benchmarks its total compensation plans, which include base pay and incentive compensation, to ensure it remains within the 50th percentile of its peer utilities. (Tr. 3242-3243, 3249). PEF uses various survey and market benchmarking tools to make these comparisons with other companies.[38] (Tr. 3250-3253). According to recent survey data, companies have not eliminated incentive compensation and have started to reverse previous salary freezing decisions made as a result of the economy. (Tr. 3249-50). Thus, PEF cannot and should not take any short-sighted measures to reduce total compensation, because it risks losing its skilled employees.

Operational Goals

Finally, Mr. Schultz challenged certain of PEF's operational goals as not being "real" because they are not, in his opinion, appropriately set to incent PEF's employees. Mr. Schultz further claimed that because incentive compensation was paid to 99.7% of employees, the goals are too easy to meet. Contrary to Mr. Schultz's arguments, all of the Company's goals for its incentive compensation program are designed to meet the Company's SMART objective (specific, measurable, achievable, realistic, and timely) while still providing an incentive for excellent performance. (Tr. 2766). Employees are not incentivized to do good work if they know that the goals are set so high that no one, or very few people, could ever achieve them.

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[38] Several interveners objected to the inclusion in evidence of the Company's third party market surveys and studies. (Tr. 844-51; Tr. 933-34). The exhibits were entered into evidence over those objections. Mr. DesChamps, PEF's Director of Compensation and Benefits, testified that his group regularly uses this data to set the appropriate compensation levels for all job levels, from executives down to non-management employees. (Tr. 805). While interveners complained that there was no way to test the validity of the data, the fact remains that this data is what the Company uses to benchmark its compensation and compete in the market for job talent. Interveners did not present any witnesses to challenge the validity of the market studies, nor did any intervener witness testify that any of PEF's compensation was above or below market. While Mr. Schultz generally testified that all market studies are skewed by one or two outliers, he presented no evidence to support this assertion, nor did he provide any specific analysis as to the market studies that PEF uses. (Tr. 1935).

PEF's incentive goals are appropriately set to achieve the desired performance from its employees. Mr. Schultz also misinterprets the significance of the 99.7% figure – this means that 99.7% of employees received *some* level of incentive compensation, not necessarily the most incentive compensation they were eligible to receive. (Tr. 3254). As Mr. DesChamps explained, when incentive compensation is paid, the more goals that are achieved, the more compensation is paid. Likewise, when fewer goals are met, the Company pays less incentive compensation. The awards under the incentive compensation plan are not arbitrary, and it should be of no surprise that almost all of PEF's employees meet some of their goals each year and receive some portion of their incentive compensation. (TR. 3385). In fact, that is the very purpose of what incentive compensation is designed to do—make the amount of compensation an employee receives contingent on his or her performance.

Similarly, PEF's operational goals are not based on work that employees should do as part of earning their base pay. Contrary to interveners' arguments that employees are expected to fulfill the goals set just to receive increases to base pay or keep their jobs (Tr. 2806-2807), PEF's goals are designed to motivate excellent performance from its employees. Again, it is to the Company's, and customers', benefit to allow the Company to pay for performance. Without incentive compensation, or "at risk" dollars, there is no incentive for employees to perform above what they would otherwise do just to keep their jobs. (Tr. 3385-3386).

With respect to the specific operational goals that Mr. Schultz challenged, each of those goals is appropriately set. Mr. Sorrick provided testimony regarding the safety and environmental goals specific to generation. Mr. Schultz challenged the generation safety goal, because the goal allows for accidents, while Mr. Sorrick indicated in his direct testimony that the Company strives for a zero-accident workplace. (Tr. 1938). It is true that PEF always strives to have no accidents in the workplace, as any organization should attempt to accomplish for its employees. (Tr. 2767). For the purpose of designing an incentive compensation goal, however, PEF targets a level to drive the actual safety performance of the work crews to top decile performance when compared to PEF's peer group utilities. (Id.) Despite everyone's best efforts, accidents will happen. This makes it inappropriate to set a safety goal at zero accidents. By setting the safety goal in the manner PEF does, employees are incented to work towards making a safer work environment. (Id.)

Mr. Schultz also claimed that the generation environmental compliance goal was set the same for 2009, even after the goal was achieved in 2008. (Tr. 1938). He argued that goals must be continually improved to truly incentivize. However, PEF's environmental goals are set at levels much higher than mere compliance levels with environmental regulations. (Tr. 2769; 2800-01). Mr. Schultz in essence wants to punish PEF for its excellent environmental performance, which is akin to punishing a student who earned a 98% A+ grade instead of a 100% A+. (Id.) In the case of environmental goals, as explained by Mr. Sorrick, achieving perfection (which is what Mr. Schultz's proposal would result in) would impose additional costs on PEF's customers with no real benefit to the system. (Tr. 2770).

Mr. Schultz also challenged the appropriateness of the Company's SAIDI[39] goals for transmission reliability by claiming that the goal level decreased from year to year and thus could not encourage employees to continuously perform better. First, Mr. Schultz used the wrong data to compare the goals from 2006 to 2007, because the 2006 goal was based on a combined PEF and PEC SAIDI number, while the 2007 goal separated out PEF. (Tr. 2878). This is an apples to oranges comparison and thus an inappropriate method of comparing the level of goals between 2006 and 2007. Further, the SAIDI goals are carefully established by analyzing a number of factors that affect transmission reliability, including historical

[39] SAIDI means "System Average Interruption Duration Index." SAIDI tracks the average duration of a transmission-related outage. (Tr. 557).

performance of the system, number of customers added, size of the transmission system (more lines mean more outages), and weather trending factors. (Id.) The SAIDI goals are also checked by PEF's internal auditing process to ensure they are sufficiently challenging and aggressive. (Id.) The fact is that the Company cannot and should not set the SAIDI goals by simply making it more challenging each year by some numerical percentage, as Mr. Schultz seems to suggest. Such an approach would result in goals that ignore the realities of the system and could actually de-incentivize employees by making goals virtually un-achievable and uneconomic. PEF's SAIDI goals are appropriate and well reasoned, a fact that is evidenced by PEF's excellent and consistent improvement in circuit SAIDI from 2003 to 2007. (Tr. 2879).

E. Storm Reserve Accrual (Issue 33)

PEF has requested an increase in the annual accrual to its Storm Damage Reserve from $6 million to $16 million (system) or $14.9 million (jurisdictional). PEF requests a target reserve level of $152.5 million, which is the expected reserve balance at the end of 5 years. (Tr. 1663-64). PEF also proposes to discontinue the accrual of interest on the storm reserve balance and to remove the storm reserve balance from rate base. (Tr. 1664). This reduction in rate base serves to lower the Company's overall revenue requirement. (Tr. 1664-65).

In establishing the requested annual accrual, PEF relied on a December, 2008 study entitled Hurricane Loss and Reserve Performance Analyses (the "Study") performed for PEF by ABS Consulting, Inc. (Tr. 1663-64; Hearing Ex. 85). The Study estimated that PEF's expected annual storm loss is $20.2 million. (Tr. 1008). Of this amount, approximately $16.4 million represents the O&M costs that can be charged against Storm Reserve pursuant to the Commission's storm reserve rule. (Tr. 1009-10). Thus, PEF's proposed $16 million annual accrual is roughly equivalent to the expected annual recoverable storm loss. (Tr. 1664).

The reserve performance analysis portion of the Study shows that with a starting balance of $133 million and a $16 million annual accrual, the expected reserve balance at the end of 5 years is $152.5 million. It also shows that there is a 10% probability that the reserve will have a negative balance at some time during the next 5 years. (Tr. 1006; Hearing Ex. 85 at 5). If accruals are continued at the current $6 million annual level, there is a 14% chance that the reserve will be insolvent at some point during the next 5 years. (Tr. 1010, Hearing Ex. 85 at 5). The Study assumes that PEF continues to credit interest on the reserve balance at the rate of 3.45%. (Tr. 1089; Hearing Ex. 85 at 23). If PEF's proposal to discontinue crediting interest on the reserve is approved,[40] the expected balance at the end of 5 years will be lower, and the likelihood of a negative balance during the 5 year period will be greater. (Tr. 1011).

OPC witness Mr. Schultz and FIPUG witness Mr. Marz both recommend that the Commission should discontinue annual accruals to the storm reserve. Mr. Schultz contends that the reserve is sufficient to cover storm costs that are likely to occur based on recent history. (Tr. 1923). Mr. Marz asserts that the reserve balance is sufficient to continue to provide coverage for eight years based on the level of expected annual losses, and is sufficient for 30 years if losses remain at the levels experienced from 2006-2008. (Tr. 2320, 2324). Both witnesses make the fundamental error of selectively choosing the storm history that they consider. Mr. Schultz arbitrarily excludes storm damage from the 2004 hurricane season, while Mr. Marz arbitrarily begins his analysis after that season. (Tr. 1019). It is not meaningful or appropriate to selectively exclude any possible damage events when analyzing potential storm loss. (Tr. 1019, 1030). The

[40] Based on questions of Mr. Toomey, Staff may recommend that the Commission require PEF to continue to accrue interest expense on the storm reserve balance, thereby requiring an adjustment to the Company's request. If this occurs, PEF would need to continue to remove the storm reserve balance from rate base, and the adjustment reflected on MFR B-1, line 7, of $154,429,000 accomplishes this. Therefore, this adjustment would continue to be made; however, the adjustment on line 32 of $159,106,000 would be removed. The effect of removing the adjustment on line 32 would be to increase rate base by $159,106,000. Because the figures presented on MFR B-1 are retail numbers, rather than system numbers, no further adjustment to account for the jurisdictional factor would be necessary. (Tr. 1889-90).

most reliable methodology for estimating storm losses is to use the longest, most complete historical record available. (Tr. 1019). This is the methodology used in the Study, which used 100 years of storm history and employed one of only four models approved for projecting hurricane loss costs by the Florida Commission on Hurricane Loss Projection Methodology. (Tr. 1006-1007).

The Interveners' recommendation to eliminate the storm reserve accrual is inconsistent with the concept of self-insurance that the Commission adopted in 1994 when commercial insurance for T&D assets at reasonable prices became unavailable in the wake of Hurricane Andrew. (Tr. 1023). The concept of self-insurance using a reserve with accruals is to allow the accumulation of funds during periods of favorable storm experience that will be available for infrequent future hurricane losses. Although PEF has been allowed to accrue $6 million annually since 1994, after ten years of favorable storm history, the accumulated reserve of approximately $47 million in 2004 was exceeded by damage of over $285 million from the 2004 and 2005 storm seasons. (Tr. 1024). In fact, three of the four 2004 storms individually caused total costs ($146 million, $128.6 million, and $86.2 million), that exceeded the then-balance of the storm reserve. This substantial damage occurred even though the storms made landfall outside PEF's territory and the Company's assets in Orange County experienced sustained wind speeds corresponding only to Category 1 or tropical storm wind speeds. (Tr. 1017; Hearing Ex. 38, Interrogatory No. 359).

PEF's exposure to storm damage has increased substantially since the $6 million annual accrual was approved by the Commission in 1994, with the value of its T&D assets increasing by more than a factor of three since that time. (Tr. 1024). Given the concentration of approximately $1.5 billion of T&D assets in Pinellas County, a single Category 3 storm making landfall near

Pinellas County would exceed the current balance of PEF's storm reserve and a Category 4 storm would result in restoration costs greater than half a billion dollars. (Tr. 1029).

Mr. Marz suggests that the current storm reserve is sufficient to cover all Category One and Two storms and states that PEF is seeking to establish the reserve at a level to cover all storm damage. (Tr. 2022-23). This reflects a misinterpretation of the figures at pages 19 and 20 of the Study. (Hearing Ex. 85). The figures reflect the *average* damage from storms making landfall within each 10-mile segment of the coast; some storms result in lesser damage and some in greater damage than the average. Contrary to Mr. Marz' contention, damage from a single Category 2 storm could exceed $140 million. (Tr. 1020). The insufficiency of the reserve to cover all storm damage is illustrated by the figures on pages 21 and 22 of Exhibit 85, which show that the *average* damage from Category 3 and 4 storms at some landfall locations is substantially in excess of the current or target reserve balance.

The Interveners argue that because the Study does not take into account the effect of recent storm hardening efforts, it is not a reliable basis to support an increased storm accrual. Mr. Harris conceded that the damage calculations in the Study are based on historical data about the effect of past storms. Because there have been no significant storms since the hardening efforts began, the data used in the model does not quantify the effect of these efforts. (Tr. 1046, 1059). However, the hardening efforts are at an early stage, and the embedded T&D assets have been designed to a number of different standards. (Tr. 1032, 1040). In addition, much of the storm damage to T&D assets comes from factors other than direct wind, and includes damage from debris fields, disassembled buildings, and vegetation. (Tr. 1034). Although it does not attempt to predict the effect of the storm hardening efforts to date, the model used in the Study nevertheless provides the best estimate of storm risk that exists today, as it will be a number of years before the changes would significantly impact the modeled study results. (Hearing Ex. 38, Interrogatory No. 361). PEF is required by Rule 25-6.0143(l) to file an updated storm damage study at least every 5 years. As actual data becomes available on the effect of storm hardening efforts, this data will be reflected in future studies. If such studies show a substantial reduction in expected annual loss, the Commission can revisit the appropriate reserve accrual at that time.

Finally, the Interveners argue that because storm costs can be recovered after-the-fact through a surcharge or other mechanism, there is no need to continue to fund a storm reserve. If this position were adopted, it would constitute a departure from the concept of self-insurance, in which customers pay a relatively stable "premium" through rates in order to avoid a substantial assessment in the aftermath of a storm, at a time when they may be least able to afford it. The proposed increase in the accrual from $6 million to $16 million per year is in line with the increase in the value of PEF's T&D assets since the current accrual level was originally set 15 years ago. (Tr. 1024, see Tr. 1859). Consistent with Commission policy, such an accrual is an appropriate mechanism to provide for the cost of some but not all storms.

F. The Company's Needs Nuclear Fuel Inventory to Protect Against Supply Interruption and Provide Protection Against Price Volatility. (Issue 32)

The Company maintains an inventory of various components of nuclear fuel to ensure fuel supply for the CR3 refueling outages and to help protect customers from price volatility. (Tr. 3628-29) PEF presented the testimony of Mr. Joseph Donahue, the former[41] Vice President of Nuclear Engineering and Services to support and explain the need for the nuclear fuel inventory. (Tr. 3621). CR3 is on a twenty-four month refueling cycle, so that every other year approximately one-half of the nuclear fuel assemblies are replaced. (Tr. 3628). Nuclear generation is the lowest cost fuel on the Company's system, so it is imperative for PEF to have the nuclear fuel it needs to complete the refueling outage during the timeframe of the particular

[41] When Mr. Donahue filed his rebuttal testimony on August 31, 2009, he was the VP of Nuclear Engineering and Services. However, in the second week of September, his title changed to VP of Nuclear Oversight. (Tr. 3621).

outage. (Id.) Given recent market occurrences with respect to mines being unavailable or back-logged and increased demand for nuclear fuel because of additional nuclear units coming online, PEF decided that it was in its customers' best interests to maintain a strategic inventory to mitigate these risks and ensure an available supply of nuclear fuel for CR3. (Tr. 3649-52). PEF, in its MFR schedules, presented the detailed cost information to support its requested nuclear fuel balance of $155.017 million. (Hearing Ex. 47, MFR schedule B-16 and F-8).

Intervener witness Mr. Schultz disputes the Company's requested nuclear fuel balance solely because he claims that the Company did not include the requisite level of detail to support the requested balance. (Tr. 1914-16). PEF, however, did present the necessary information in its MFRs. (Hearing Ex. 47, MFR schedule B-16; Tr. 3638-39). PEF further presented the rebuttal testimony of Mr. Donahue to explain the proposed increase in nuclear fuel inventory. (Tr. 3623-34). PEF, therefore, has fully supported its requested nuclear fuel balance.

No Intervener witness challenged the propriety or need to maintain nuclear fuel inventory. Counsel for FIPUG seemed to suggest that the Company does not need nuclear fuel inventory because there has never been an interruption in fuel supply to CR3 or any of PEC's Carolina nuclear plants. (Tr. 3655; 3659-60). There are other nuclear operators, however, who have had to enter the spot market to purchase uranium because of supply interruptions. (Tr. 3655). Purchasing uranium on the spot market (assuming it is available) could result in higher prices than if a supply inventory is maintained. (Tr. 3656). In any event, PEF does not and should not wait to actually have a fuel supply interruption before taking proactive measures to address the issue. PEF has prudently monitored the market for signs like the supply interruptions due to mine closings and the increased demand from new units, and it is taking action to ensure that nuclear fuel will be available at the time it is needed at the lowest possible cost. (Tr. 3658). A fuel supply interruption could, in the best case scenario, lead to higher prices on the spot market. In the worst case, if the fuel is not available on the spot market, then PEF could have to shut CR3 down. (Tr. 3659).

To conclude, the Company needs the requested nuclear fuel inventory to ensure that the necessary fuel is available during each refueling outage at CR3. Based on the market conditions affecting supply and demand of certain components of nuclear fuel, the Company has decided to maintain this strategic inventory. The cost impacts of not having sufficient nuclear fuel at CR3 are too great to deny the Company the cost of this strategic nuclear fuel inventory. The Commission should therefore approve the Company's request with no adjustments.

G. The Commission should Approve the Company's Requested Pension Expense because the Amount is Appropriate and Supported by Record Evidence. (Issues 49, 62)

After the extraordinary events of the 2008 economic market, the Company's pension expense greatly increased to $30.9 million because the value of its pension assets fell as compared to its pension obligation. (Tr. 1728; Hearing Ex. 47, MFR C-17). This is a real expense for the Company and an expense that is entirely out of the Company's control. Intervener counsel, through cross-examination, implied that because the Company had not done an updated analysis of the pension expense to take into account the improved stock market conditions, the amount of pension expense included in the MFRs should be adjusted to reflect the improvement. (Tr. 1728-32; Tr. 1820-28). However, such cherry picking with respect to the information to be updated is inappropriate and denies PEF due process. Specifically, because PEF has not been allowed to present evidence updating certain information regarding its sales forecast, other parties should not be allowed to argue for adjustments based on new, selective information since the filing of the case. (Tr. 12-13; 1895-96). Thus the only evidence that the Commission can properly consider on this topic is that which existed at the time of the filing of PEF's rate case, including the actuarial analysis attached to Mr. Deschamps' testimony and the supporting MFR schedules. (Hearing Ex. 68; Hearing Ex. 47, MFR C-17). There is no other evidence in the record as to the appropriate level of pension expense. No other witness has provided any contrary actuarial analysis to support an alternate pension expense for the Company's 2010 test year. It would be pure speculation for the Commission to reduce the Company's pension expense simply based on an alleged and hypothetical turn-around in the economy.

In any event, even if this Commission were to consider changed conditions with respect to the economy, there is still no evidence that it would have any impact on the requested expense. First, even assuming a stock market rebound, the stock market fall in 2008 continues to impact the future value of the pension fund because, as Mr. Toomey explained, there was less money in the fund in 2008 that would be earning money in the fund. (Tr. 1733-34). The Company had projected $80 to $90 million in assets in the pension fund in 2008, but instead experienced a $320 million loss in the overall value of the pension fund. (Tr. 1821). In addition, there is $34 million of deferred pension expense from 2009. Therefore, the stock market would first need to recover the $34 million to offset the deferred expense and then the stock market would need to recover to the point that the pension fund value was re-built up to the value it held before 2008. Only after the stock market recovered to that extent would customers be at risk of paying for additional pension expense that the Company did not incur. (Tr. 1826).

Likewise, the only evidence in the record with respect to the assumed return for the pension expense supports the Company's calculations, as set forth in the actuarial studies attached to Mr. DesChamps' testimony and the MFR schedules. (Hearing Ex. 68; Hearing Ex. 47, MFR C-17). The assumed overall return for the pension fund is 8.75%, which is a blended percentage based on various stocks and bond investments. (Tr. 1821; Hearing Ex. 42, Interr. No. 171). The interveners' attempts to compare the Company's requested ROE of 12.54% to this expected return of 8.75% are inappropriate and irrelevant to the amount of pension expense. (Tr. 1750-51; 1827-28). The pension fund assumes investment in a wide variety of stock and bonds, so the 8.75% is a weighted average on the assumed returns of a variety of investments. (Tr. 1828). If the pension fund only invested in common utility stock, the comparison between the requested 12.54% ROE and the 8.75% pension return may be helpful. However, since the Company prudently invests in several different stocks and bonds, such a comparison is not apples to apples. (Id.)

In sum, the Company's requested pension expense for the 2010 test year is a legitimate business expense. No intervener witness presented testimony challenging the level of pension expense. The record evidence supports a finding that the pension expense be included in rates for 2010.

H. The Commission Should Reject the Interveners' Proposal regarding Non-Regulated Operations because PEF has Properly Allocated Costs and the Commission Does Not Have the Legal Authority to Grant the Proposal. (Issues 24, 85)

As OPC Witness Ms. Dismukes admits in her testimony, PEF has divested the great majority of its non-regulated utility businesses since 2005. (Tr. 2249). Indeed, the Company's main subsidiaries are the regulated electric utilities PEF and Progress Energy Carolinas ("PEC"), as well as Progress Energy Services Company, LLC, which provides administrative support to the two utilities. (Tr. 2249, Tr. 947-948). Accordingly, in 2008, approximately 0.1% of Progress Energy, Inc.'s revenues came from nonregulated businesses. (Tr. 2249).

Although Ms. Dismukes spends several pages of her testimony describing the nature of affiliate transactions, and though she reviewed various interrogatory responses and documents produced by PEF through discovery related to affiliate transactions and allocations, Ms. Dismukes does not make any recommendations with respect to PEF's affiliate transactions. (Tr. 2245-50). In fact, she correctly points out that less than one percent of Progress Energy, Inc.'s revenues are generated from non-regulated businesses. Thus, while Ms. Dismukes discusses this issue generally, she did not find any improper affiliate allocations with respect to PEF. (Tr. 2245-2248).

Further, Ms. Dismukes spends a significant portion of her testimony discussing non-regulated operations despite the fact that those expenses are not part of PEF's base rate request. By their nature, non-regulated activities and their associated expense are recorded "below-the-line" and do not impact the company's revenue requirement request. Indeed, Rule 25-6.1351(2)(g), F.A.C. defines nonregulated operations as "services or products that are not subject to price regulation by the Commission or not included for ratemaking purposes and not reported in surveillance."

Despite the clear guidance from the Commission rule regarding the nature of non-regulated activities, Ms. Dismukes recommends that the Commission move all the revenues, expenses, and investment associated with these non-regulated operations *above* the line for ratemaking purposes. (Tr. 2262). The Commission must reject this recommendation, because it does not have legal authority to regulate non-regulated operations. A search of Commission orders revealed no authority for Ms. Dismukes' recommendation.[42] In any event, even if the Commission could implement Ms. Dismukes' recommendation, there would still be no basis to do so. Contrary to Ms. Dismukes' argument that the Company has not shown that costs are properly allocated, governance costs for non-regulated operations are properly assigned to the non-regulated operations as explained by Mr. Toomey and in PEF's responses to OPC

[42] In fact, the Commission only moves revenues above the line where there is a complete lack of documentation that the expenses associated with that revenue are excluded from the costs charged to the utility. See, e.g. In re: Application for increase in wastewater rates in Monroe County by K W Resort Utilities Corp., 2009 Fla. PUC Lexis 42, Order No. PSC-09-0057-FOF-SU (Jan. 27, 2009) (Commission moved revenues from cleaning County lift stations above the line because the utility did not provide any documentation regarding the cost of cleaning the lift stations, nor did it provide any proof that those costs were recorded below the line). In this case, Ms. Dismukes admits that the Company has allocated costs below the line to the non-regulated operations (Tr. 2259). Therefore, unlike the KW Resort order, there is no justification for the Commission to move any of the non-regulated operations revenues above the line.

Interrogatory 402 and OPC Request for Production number 250. (Tr. 1805-06; Hearing Exs. 45 and 282). Therefore, the Commission should reject Ms. Dismukes' recommendation because the Commission has no legal authority to implement it, and because the Company has properly shown that it appropriately allocates costs to the non-regulated operations.

I. The Company has Appropriately Supported its Adjustments for Asset Retirement Obligations. (Issue 36)

Mr. Schultz claims that the Company proposes to increase rate base by $398.038 million to adjust for Asset Retirement Obligation ("ARO") and that the Company has not provided sufficient justification to support this adjustment. (Tr. 1924-26). He also claims that Rule 25-14.014 states that the implementation of Financial Accounting Standard No. 143 should be revenue neutral in the rate making process, and he suggests that PEF has increased revenue requirements through this adjustment and therefore, the adjustment is not revenue neutral. (Tr. 1925). Schultz's arguments in this regard are misplaced for the reasons stated below.

The Financial Accounting Standards Board issued Statement No. 143 in June 2001. The statement requires the accrual of legal obligations associated with the retirement of tangible, long-lived assets. In 2003, the Florida Public Service Commission issued Rule 25-14.014, Accounting for Asset Retirement Obligations, under SFAS 143. The provisions of this rule require that SFAS 143 be implemented in a manner that the assets, liabilities and expenses created by SFAS 143 are revenue neutral in the rate making process. See Rule 25-14.014, F.A.C.

For financial accounting purposes, PEF is required to state its financial statements in accordance with the provisions of SFAS 143. For regulatory reporting purposes, in accordance with the provisions of this rule, PEF is required to neutralize the effect of SFAS 143. The adjustments that Mr. Schultz references were made simply to remove from rate base the cumulative effect of the entries for SFAS 143 as required by the rule.

Further, MFR B-1, Line 3, Column J, reflects an adjustment to rate base for the ARO amount in question. (Hearing Ex. 47). What Schultz fails to recognize, however, is that this adjustment has been made to remove the effects of FAS 143 per the requirements of Rule 25-14.014 because the account balances related to FAS 143 are included as a net reduction to the System per Books numbers on MFR B-1, Line 1, Column J. (Id.)

Additionally, the net ARO liability that is adjusted out of rate base is a funded liability. The offsetting assets that fund this liability are the accounts for the nuclear decommissioning trust fund located in the Other Special Funds (128) adjustment located on line 13 of MFR Schedule B-1, page 1 of 3, as explained in PEF's response to Staff's Interrogatory Number 323. (Id.; Hearing Ex. 42). This further proves that the entries to record FAS 143 have had a neutral effect on rate base, and Mr. Schultz's criticisms of this item are unfounded.

J. Director's and Officer's Liability Insurance is a Legitimate Business Expense and Should be Included in the Company's Rates. (Issue 59)

Mr. Schultz also recommends total disallowance for the Company's requested $2.7 million expense for directors and officers ("D&O") liability insurance. (Tr. 1953-57). His argument is that D&O liability insurance does not benefit ratepayers, so shareholders should have to pay for it. Mr. Schultz, however, is incorrect. This Commission, in the recent Tampa Electric and Peoples Gas rate case proceeding, has already decided that D&O liability insurance is a legitimate business expense this is appropriately included in customer's rates. See Order No. Order No. PSC-09-0283-FOF-EI. The Commission has also already decided that D&O liability insurance is a necessary and reasonable expense for the Company to do business. Thus, the Commission has already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for the Commission to depart from its previous findings in this case.

K. The Injuries and Damages Expense is a Legitimate Business Expense and Should be Included in the Company's Rates. (Issue 60)

Mr. Schultz further proposes that the entire amount requested for injuries and damages should be eliminated. (Tr. 1957-59). This expense, however, has been recognized as a legitimate business expense in the Company's rates in the past and, most recently, this Commission recognized this was a legitimate business expense in the rate proceeding for Tampa Electric Company. See Order No. PSC-09-0283-FOF-EI, p. 63. There is no justification for the elimination of this expense in its entirety from the Company's revenue requirements and Mr. Schultz provides none.

FERC account 925 on MFR C-4 page 44 of 48 reflects an expense of $8,882,000 for injuries and expenses. This amount ties to the Company's books and records, and the MFRs for 2008 actuals in this docket were audited by the Florida Public Service Commission auditors who reconciled the amounts on the MFRs to the Company's actual book and records. (Hearing Ex. 208). The Company's actual 2008 expense has been verified, and PEF has based its 2010 budget for this expense on its actual historical expenses. PEF is, therefore, entitled to recover this legitimate business expense.

L. PEF's Wholesale Allocation with respect to the City of Tallahassee is Appropriate.

Ms. Dismukes challenged the Company's wholesale allocation to the City of Tallahassee and recommended that $6,278,578 of administrative and general expenses be removed from the retail jurisdiction and assigned to the wholesale sale to the City of Tallahassee. This recommendation is erroneous. First, the Company did properly allocate A&G costs through the City of Tallahassee wholesale contract. This is reflected in the development of the labor allocator in the Jurisdictional Cost of Service Study. (Hearing Ex. 47, MFR Schedule E-1). In addition, Ms. Dismukes' recommendation is wrong as demonstrated by a simple calculation. According to Exhibit 152, total system A&G expenses are $269,669,716. Dividing this figure by total system energy of 48,574,264 MWh[43] yields a system average A&G cost of $5.55 per MWh. In contrast, Ms. Dismukes would assign $6,278,578 of A&G costs to the sale of 102,119 MWh to the City of Tallahassee, or an average cost of $61.48 per MWh. The assignment to the City of Tallahassee on a MWh basis of more than 11 times the system average A&G expense is absurd on its face. The Commission should therefore reject Ms. Dismukes' recommendation outright.

VII. Miscellaneous Issues.

A. Effective Date of New Rates (Issue 115).

The effective date of new rates is determined by PEF's settlement agreement approved by the Commission. Order No. PSC-05-0945-S-EI, Docket No. 050078-EI, (Sept. 28, 2005) (the "Agreement"). Under the Agreement, existing base rates continued "for the term of this Agreement," the term continued "through the last billing cycle in December of 2009," and any increase in base rates "would not take effect prior to the first billing cycle for January 2010," (subject to enumerated exceptions). Id. at Attachment A, ¶¶ 1, 2, 4. Existing base rates clearly continue only for that consumption covered by the "last billing cycle in December of 2009" and new rates can take effect for that consumption covered in "the first billing cycle for January 2010." That is exactly what PEF proposes and interveners, in their recent filings with the Commission, acknowledge is the case.

B. Interim Rates (Issue 116).

Interveners' positions indicate their view that interim rates were not lawfully granted and/or are barred by PEF's Agreement. These purely legal issues were decided by the Commission in Order No. PSC-09-0413-PCO-EI, therefore, interveners' positions reflect untimely and improper re-argument. Rule 25-22.0376, F.A.C.

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[43] This consists of total energy of 48,472,145 MWh exclusive of the sale to the City of Tallahassee, plus 102,119 MWh for the City of Tallahassee, as shown on page 55 of the Jurisdictional Separation Study.

Further, the calculation of any potential refund is governed by Section 366.071(4), which requires the application of the "newly authorized rate of return" that is "found fair and reasonable on a prospective basis." Based on the evidence of the fair and reasonable rate of return in this proceeding there should be no refund. §366.071(4), Fla. Stat.; Order No. PSC-08-0696-PCO-GU, Docket No. 080318 (Oct. 20, 2008) (calculating any refund to the range of the newly authorized rate of return and removing adjustments made in the rate case test period that do not relate to the period of interim rates).

C. Deferred 2009 Pension Expense (Issues 119-121).

These issues are legal issues related to the Commission's PAA Order in Docket Number 090145-EI, Order Number PSC-09-0484-PAA-EI. Although the interveners filed a protest to this order, none of the interveners submitted any evidence or raised any factual issue in this proceeding with respect to these issues. Thus, the Commission's legal ruling on these issues, as reflected in Order Number PSC-09-0484-PAA-EI, binds the Commission in this proceeding. Any attempt by the interveners to re-argue the Commission's legal ruling would amount to an improper motion for reconsideration and thus should be rejected.

D. Rate Case Expense (Issues 35 and 73).

The Company has proposed a two-year amortization period for its rate case expenses. (Tr. 1663) The amortization period for rate case expenses attempts to reflect the time period in which a utility is expected to be involved in rate cases. The two-year period is appropriate for PEF given the period of rapid capital investment and expansion which the Company is entering and which no intervener disputes. This rapid capital expansion is similar to the early 1990s, when it was common for the Commission to approve two-year amortization periods. See, e.g. Order No. 11307, Docket No. 820007-EU (Nov. 10, 1982). Interveners argued that a four-year amortization period was more appropriate, relying on the Commission's TECO order as support.

(Tr. 1943-44; Tr. 1799-1800) PEF, however, is different from TECO in terms of length of time between rate cases. TECO had not been in a rate case proceeding for more than a decade. Order No. PSC-09-0283-FOF-EI. By contrast, PEF has only had four years between rate cases (due to settlements) and is entering a period of rapid capital investment, thus increasing the likelihood of more frequent rate cases.

Regarding the amount of rate case expenses, while Mr. Schultz challenged the amount of the expense, PEF ultimately submitted discovery proving that he was relying on information that had not been updated. (Hearing Ex. 45, Staff Interr. 267) This discovery response also demonstrates that PEF's rate case expense was supported, justified, and (where estimating was required) reasonable estimating tools were used. (Id.) Accordingly, the Commission should approve the Company's requested rate case expenses, amortized over two years, with no adjustments.

VIII. Interveners' additional arguments challenging PEF's requested rate relief based on the alleged failure to meet the burden of proof and the claim rate relief should be denied solely based on economic conditions are without merit. (Issues 115A and 115B)

Interveners argued at various times during the hearing that PEF had not met its burden of proof and that economic conditions somehow justify a reduction in rates even if the costs are reasonable and necessary to allow PEF the opportunity to earn a reasonable return on its investment. Both arguments attempt to divert the Commission's attention from the evidence supporting PEF's rate request and both are without merit or legal support.

First, PEF supported its requested rate increase with its petition, testimony, MFRs, exhibits, and discovery with respect to all costs supporting its requested rate relief. Thus, the Company has met its burden of proof in all aspects of this rate case.[44] Interveners' argument that

[44] Interveners' claims that PEF did not provide sufficient information and documents to support its request ring hollow given the voluminous amount of information provided interveners in the course of the 6

PEF failed to meet this burden is contrary to the Commission's statutes, rules, and practice. The applicable Commission statute and rule set forth a number of *minimum* requirements (the MFRs) that the Company must file with its case. See Section 366.06, Fla. Stat. and Rule 25-6.043, F.A.C. The purpose of the MFRs is to set forth the minimum requirements that the utility must meet to move forward with the rate proceeding. Indeed, the Commission Staff is required by statute to review the utility's MFRs and determine if the MFRs are complete. See Section 366.06(3), Fla. Stat. In this case, after Staff noted minor deficiencies with PEF's MFRs, PEF corrected them and then Staff accepted the MFRs as complete. See Document No. 04064-09, Letter from Staff dated April 30, 2009. No party challenged the Staff's acceptance of the MFRs as complete.

After the initial filing, the Order Establishing Procedure allows for approximately six months of discovery, enabling all parties to request further information regarding the Company's filing. Indeed, the parties took full advantage of that discovery period -- PEF responded to 1,593 interrogatories[45] and 525 requests for production of documents, produced thousands of pages of documents, and made seven (7) witnesses available for hours of deposition prior to the final hearing. OPC (and the other interveners) should not be heard to complain now about a process that is established by Commission statute, rule, and Order for base rate proceedings that they did not object to and that they took full advantage of during the entire course of the base rate proceeding.[46] This non-substantive argument demonstrates that interveners do not have any meaningful issues with PEF's costs supporting PEF's rate increase.

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months of discovery in this proceeding described below. Further, their claims conveniently ignore the fact that testimony from PEF's own witnesses is evidence and provides more than adequate support for the requested costs.

[45] This number includes sub-parts. PEF notes that both Staff and OPC exceeded the interrogatory limit set forth in the Order Establishing Procedure, but PEF did not object to the discovery and provided responses to all these interrogatories.

[46] Notably, none of the interveners moved to dismiss PEF's petition or to strike any testimony or evidence based on a claim that PEF failed to meet any burden of proof.

Interveners also argue that, even if the Company establishes by the evidence that its costs are reasonable and therefore support the requested rate increase, the Commission, nevertheless, should deny the requested increase in whole or in part because of the state of the economy. This is not the law. There is no affordability test for setting rates under Chapter 366. The Florida Legislature, in Sections 366.06 and 366.041(1), provides that the Commission shall determine and fix fair, just, reasonable, and compensatory rates, and that "no public utility shall be denied a reasonable rate of return upon its rate base." Sections 366.06, 366.041(1). Rates are fair, just, reasonable, and compensatory when they allow the utility to recover its reasonable costs and a return of and on its capital investment. Indeed, under the Hope[47] and Bluefield[48] Supreme Court cases, PEF is entitled to rates that allow the opportunity to earn a reasonable return on its investment. Failure "to allow the utility the opportunity to earn a fair rate of return would violate the rights to due process, to just compensation for taking of property and the right to possess and protect property." Gulf Power Co. v. Bevis, 289 So. 2d 401, 403, n.1 (1974). This is an essential part of the "regulatory compact" and is an essential part of the exchange for PEF's obligation to serve and the strict regulations under which PEF has agreed to operate, conditions that do not apply to non-regulated corporations that are free to serve who they like, under whatever conditions they like, for whatever price they choose. If PEF demonstrates, as it did, that its requested costs underlying its requested rate increase are reasonable and necessary to provide safe, reliable electric service, the Commission cannot disallow those costs simply because economic conditions have impacted customer ability to pay.[49]

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[47] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).
[48] Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
[49] Interveners' argument, taken to its logical conclusion, would require PEF, and any other utility in Florida, to provide free electricity to its customers if this Commission somehow found that no customer could afford to pay for the service. This is, of course, a result that is not contemplated by the legislature, the U.S. Supreme Court, or the United States and State of Florida Constitutions.

The Commission, in setting the fair, just, reasonable and compensatory rates for the utility, therefore, cannot consider whether customers can afford the rates. Affordability is only relevant by law to the consideration of the appropriate rate structure, i.e. which customer class pays for what percentage of the rates, rather than the *amount* of the total rate allowed. Section 366.06(1), Fla. Stat. (public acceptance of rate structures is only a consideration when the Commission is fixing the rates for each class). Indeed, if the legislature intended the Commission to consider affordability as a factor in setting the amount of rates, it could have provided so in Chapter 366 like it has done in the telecommunications statutes. See Section 364.01 (requiring telecommunication service to be "affordable."). The legislature did not do so in Chapter 366. Accordingly, the Commission has no legal authority to consider customer affordability when setting the amount of rates in this proceeding.[50]

In apparent further support of their proposed adjustments to the Company's rate request based on economic conditions, Interveners rely on a New York Public Service Commission ("NYPSC") order involving Consolidated Edison's rate case proceeding decided under different circumstances and different legislative and regulatory standards. (Hearing Ex. 298). In that proceeding, the NYPSC required Con Edison to make a $60 million "austerity" adjustment to its O&M budget, amounting to 3.6% of its O&M budget. (Hearing Ex. 298, page 343). The NYPSC order, however, is distinguishable on its facts from the instant case. The evidence in that proceeding showed that Consolidated Edison admitted that 8% of its budget was "discretionary." (Hearing Ex. 298, page 339). Thus, even with the austerity adjustment, the utility still had more than 4% of "discretionary" budget remaining. In this case, however, there

[50] In addition, the investment community would clearly react negatively to a decision that departs from the legal and regulatory standards for setting rates. Investors are generally aware of these standards, their historic application in Florida, and they have historically viewed Florida as having constructive regulation. (Hearing Ex. 299) A departure from the law to consider affordability of rates or economic conditions, if the Commission chooses to consider those things in reducing the Company's request, would be viewed negatively by the investment community. (Tr. 4257).

is no evidence that any percentage of PEF's budget is discretionary.[51] In addition, despite the "austerity" adjustment, Consolidated Edison, a transmission and distribution-only utility, was awarded a $721.405 million increase in revenues, which is approximately 88% of the $819.024 million it requested, an ROE increase, and protected from the impact of declining sales on revenues by a revenue decoupling mechanism. (Hearing Ex. 298; Tr. 2741-2743). Applying the same percentage recovery awarded Consolidated Edison to PEF's requested $499 million increase would mean an award of a $439 million rate increase for PEF (with the austerity adjustment being part of the $60 million denied in the rate request). This Order, therefore, does not support the interveners' proposed $35 million rate reduction for PEF, rather, when viewed as a whole it supports a substantial rate increase for PEF.

PEF cannot control the economic environment that faces the Company and its customers. Regardless of the economic conditions, PEF must fulfill its statutory obligation to provide customers with safe, reliable electric service on demand. Section 366.03, Fla. Stat. The Company has determined that it needs $499 million in additional base rate revenues to meet its obligation to serve and continue to provide the level of electric service its customers demand. The Company understands the impact of the current economic conditions on customers and would not request a rate increase if the Company did not need it. This need is demonstrated by the Company's petition, MFRs, testimony, exhibits, and discovery responses and the Company is entitled to the requested rate increase to provide it the opportunity to earn a reasonable return on

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[51] Intervener witness Mr. Schultz did argue for a three percent "productivity adjustment" to PEF's O&M budget based not on some discretionary element of the budget but rather the Company's continuing policy of managing its costs. (Tr. 1964-68). Mr. Schultz's proposed adjustment ignores the undisputed testimony that PEF has in fact achieved reductions to O&M due to improved productivity. The record is replete with instances that PEF made the so-called "productivity adjustment" to its budgets. These adjustments were made before the Company filed its rate case by, for example, laying off employees and implementing "belt-tightening" measures in 2008 and 2009. (Tr. 458; 678; 681-82). However, as pointed out by several of the Company's witnesses, many of these belt-tightening measures, or reductions in O&M expenses, are simply not sustainable over a long period of time, especially in the face of increasing costs. (Tr. 463-64; 2692).

its investment. Accordingly, the Commission should approve the Company's requested base rate increase.

IX. PEF's Cost of Service Methodology and Rate Design Should Be Approved.

The Interveners have raised two major issues, and several minor ones, recommending rejection of PEF's cost of service methodology and changes to various aspects of PEF's proposed rate design. As shown below, PEF's proposed "12 CP and 50% AD" methodology most fairly allocates the company's costs to its customer classes and should be approved. The Commission should also approve PEF's proposal to close its grandfathered interruptible and curtailable rate schedules and transfer customers to the comparable, cost-effective IS-2, IST-2, CS-2 and CST-2 rate schedules.

A. Cost of Service (Issues 88, 89, 90, 91, 92)

The first step in developing retail rates and charges is to perform a jurisdictional separation study to determine the costs involved in providing retail service. (Tr. 1484, 1517). No party challenges PEF's original jurisdictional separation study that was included in Section E of the Company's MFRs and supported by the testimony of Mr. Slusser. (Hearing Ex. 47; Tr. 1486-91; see Prehearing Order, Issue 89). Likewise, no party contests the billing determinants included in the originally filed cost allocation studies. (See Prehearing Order, Issue 88).

1. The 12 CP and 50% AD Methodology Should be Approved

The second step is to allocate the retail costs to the individual rate classes in a way that most accurately reflects the causation of those costs. (Tr. 1517, 1523, 4035). The record demonstrates that PEF's proposed "12 CP and 50% AD" methodology for allocating the fixed costs of production capacity provides the most accurate basis for determining class cost responsibility. The Commission's MFRs require, at a minimum, that a utility provide a cost of service study that allocates production plant using the "12 CP and 1/13th AD" method that allocates about 92% of production capacity costs on the basis of class monthly coincident peak demands and about 8% based on class average hourly energy demands. (Tr. 1495). This 8% energy weighting gives too little recognition to the role that energy plays in generation facility planning. (Tr. 1495). Accordingly, PEF submitted two additional cost studies using a 25% energy weighting and a 50% energy weighting, respectively. (Tr. 1495-96).

The study using a 50% energy weighting most accurately reflects the various classes' cost causation responsibility. While additional generation is typically added to meet peak capacity needs (measured by coincident peak demand), the type of generation added takes into account overall system economics. This requires a trade-off between low capital cost, high operating cost peaking generation that would be added if meeting peak demands were the only consideration, and high capital cost, low operating cost intermediate or base load generation that is added if substantial energy requirements must also be met. The benefit to customers of the utility from investing in higher capital cost units is the fuel savings they realize over the life of the project based on their energy usage. It is therefore appropriate to allocate a significant portion of the Company's production capacity costs on an energy basis in order to reflect that high-energy-use customers obtain the most benefit from the addition of more capital intensive production plant. This is particularly true today, when relatively higher fuel costs and stricter emissions requirements have led to the construction of state-of-the-art generation facilities that have a higher up-front capital cost but provide benefits to customers in the form of fuel cost savings. (Tr. 1497-99, 1576, 1612-15, 4057-58; Hearing Ex. 318 at 75-79). The traditional practice of "just allocating costs based on reliably meeting your peak demand doesn't make sense when the portion of the equation of serving energy has become such a large part of the cost of generation." (Hearing Ex. 318 at 78).

In order to test whether 50% is an appropriate energy weighting, Mr. Slusser compared the cost of meeting peak demand with peaking-only resources versus the cost of meeting that demand with the Company's existing generation fleet. This analysis showed that approximately 50% of the Company's investment was made for the purpose of meeting peak demand, and approximately 50% for other reasons, such as fuel savings benefits. (Tr. 1498-99; Hearing Ex. 113; Hearing Ex. 318 at 77). Thus the 50/50 weighting recommended by Mr. Slusser is a good representation of the dual function that generating resources perform: (1) providing the demand capability to meet the Company's system peak loads and (2) generating the energy needs of its customers throughout all hours of the year. (Tr. 1499). When the same analysis is applied to production capacity costs that are recovered through various cost recovery clauses, it shows that PEF could justify allocating even more than 50% of its production costs on an energy-weighted basis. (Exhibit 41 at Bates 1582-85).

Intervener witnesses oppose the proposed 12 CP and 50% AD methodology and instead generally support the 12 CP and 1/13th AD methodology that the Commission has used in prior years. The interveners failed to support their preferred methodology other than by pointing to its so-called "traditional" status. (Tr. 4036, 4054). As discussed below, the Interveners' specific criticisms of PEF's proposed methodology are not well founded. In fact, FIPUG witness Pollock admitted that FIPUG made many of the same criticisms of the 12 CP and 25% AD method in the recent TECO rate case, in which the Commission approved that methodology over FIPUG's objections. (Tr. 3221-22; see Order No. PSC-09-0283-FOF-EI at 81-85).

Mr. Pollock, citing the Public Utility Commission of Texas, claimed that the amount of a class's average demand is double-counted in PEF's methodology, since average demand is also a component of peak demand. (Tr. 3174-76). However, this Commission previously considered the same contention in the context of the equivalent peaker methodology and concluded that there is no such double counting problem because the average demand and peak demand allocators are applied to two separate pots of dollars. (Tr. 4037-38: see Order No. 15451 at 35).

Mr. Pollock and Mr. Selecky claim that because only kWh usage up to an economic break-even point is a factor in a utility's choice between competing generating alternatives, only demand up to that break-even point should be considered in the allocation of production capacity costs. (Tr. 1627-29, 3172-74). This ignores the fact that fuel cost savings produced by kWh generated after the cost break-even point is just as valuable to customers as the fuel savings generated from kWh generated before the break-even point is reached. (Tr. 4038). This point was vividly illustrated by Mr. Slusser's analogy to a high efficiency air conditioner with a 10-year useful life, but a 4-year economic break-even point. That unit continues to provide savings well beyond the break-even point, and the incremental cost of obtaining the increased efficiency should appropriately be assigned to all usage, not just that in the first four years. (Tr. 4064-66).

In addition, Mr. Slusser's Exhibit 250 demonstrates that the costs that customers bear through an energy-based allocation of the capital costs incurred to provide fuel savings represent only a fraction of the fuel cost savings they enjoy. It also demonstrates that allocating the additional investment costs on the same energy-basis that the fuel savings are realized is an equitable treatment, since it produces the same benefit-to-cost ratio for each customer class. (Tr. 4039, 4124-26).

The 12 CP and 50% AD method thus is the best method to recognize that cost-causation is a function of both peak demand and energy requirements. (Tr. 4035-36; Hearing Ex. 318 at 75-79). The effect of adopting this method, as compared to the 12 CP and $1/13^{th}$ AD method, is to reduce the bill for a 1,000 kWh residential consumer by $1.60 per month. (Tr. 1500, 1607-09; Hearing Ex. 114).

Finally, FIPUG also introduced Exhibit 317 on the cross-examination of Mr. Slusser in an effort to show that applying the 12 CP and 50% AD methodology to both base rates and clause increases would increase the revenues received from the IS class by more than 1.5 times the system average increase. However, Mr. Slusser pointed out that the exhibit excludes fuel clause revenues – which are more than half of the total bill – thus greatly overstating the percentage increases. (Tr. 4075-76). In fact, Column (J) of Mr. Slusser's Exhibit 116 shows that, even with a base rate increase that is 150% of the system average, the IS/CS class is below parity and is not fully covering its cost of service.

2. Miscellaneous Cost of Service Matters

The Commission's practice has been to use the production capacity cost allocation methodology approved in a utility's most recent rate case to allocate any demand related costs in the utility's cost recovery clauses. (Tr. 1501). No party appears to dispute that the Commission should continue this practice, and use the allocation methodology approved in this proceeding in PEF's clause proceedings. (See Prehearing Order Issue 91).

Second, PEF proposes to recognize the Commission's prior practice of limiting the percentage rate increase for any customer class to 150% of the overall percentage increase in the Company's total revenues. (Tr. 1504-05). This practice significantly limits the increases for the CS/IS rate class and the Lighting-Energy rate class and results in the shift of $5,061,000 and $1,117,000 respectively from those classes to the residential and general service non-demand rate classes. (Tr. 1504-05; Hearing Ex. 41 at Bates 1568). FIPUG witness Mr. Pollock's proposal to apply the 150% limitation on a rate schedule basis, rather than a rate class basis, is inconsistent with Commission precedent, which is expressed in terms of a limitation on increases to a "rate class," not a "rate schedule." (Tr. 4046; see Order No. PSC-09-0283-FOF-EI at 87).

Third, PEF proposes to treat the interruptible and curtailable customers as a single rate class for the purpose of setting base rates and billing adjustment charges. (Tr. 1505). These two groups both offer non-firm load capability and load research shows that their 12 CP load factor characteristics are similar. In some years, the CS class will have a more favorable coincident load factor, and in other years the IS class will be more favorable. (Tr. 1583-85; Hearing Ex. 41 at Bates 1571-72). Accordingly, PEF sees no reason to differentiate among these customers for ratemaking purposes, other than for the amount of credit they receive. (Tr. 1509, 1584-85).

Finally, PEF's cost allocation studies recognized that due to changes in the pricing relationship between the general service non-demand and the general service demand rate schedules, some customers will find it advantageous to transfer from the GSD to the GS rate schedule. If the Commission's decisions in this proceeding result in further revisions to the general service rates, the final rate design should take into account any change in billing determinants that will result from general service customers transferring to the most economic rate. (Tr. 1508).

B. Interruptible and Curtailable Rate Schedules (Issues 95, 96, 109, 110)

1. Eliminating Schedules and Transferring Customers.

PEF proposes to eliminate its interruptible and curtailable rate schedules IS-1, IST-1, CS-1 and CST-1 that have been closed to new customers since April 1996 (the "closed CS/IS schedules"). (Tr. 1509-10). In its 1994 demand side management docket (Docket No. 941171-EG), PEF's predecessor, FPC, demonstrated that these interruptible and curtailable rate schedules were not cost-effective as DSM programs. In June 1995, the Commission's final order in the DSM case directed that a separate docket be opened to address the future treatment of these programs. (Order No. PSC-95-0691-FOF-EG at 5-6). In Docket No. 950645-EI, opened pursuant to that order, the Commission in April 1996 found that the existing interruptible and curtailable rates were not cost-effective. It therefore approved a stipulation which closed the schedules to new customers, but allowed existing customers to continue under those schedules until the company's next rate case. (Order No. PSC-96-0589-S-EI). PEF recommended the elimination of the closed CS/IS schedules in its next two rate cases in 2002 and 2005; however, both cases ended in settlements under which the grandfathered customers were allowed to continue to take service under the closed rate schedules. (Tr. 1587-88). The current docket thus is the Commission's first opportunity to take action to eliminate these non-cost-effective rate schedules that have continued in effect on a temporary basis for over 13 years.

PEF proposes to transfer the customers served under these closed CS/IS schedules to the comparable open rate schedules IS-2, IST-2, CS-2 and CST-2 (the "open CS/IS schedules). (Tr. 1509-10). The transferred customers will continue to have the same quality of service, and be subject to the same base rates and recovery clauses, as they would have otherwise. The primary difference is that the transferred customers will be subject to the cost-effective curtailable and interruptible demand credits that apply under the open schedules to which they are transferred.[52] (Tr. 1510).

FIPUG and PCS Phosphate oppose the elimination of the closed CS/IS rate schedules but present no evidence – other than one short statement in witness Pollock's summary – to support the continuation of those schedules. On cross-examination of Mr. Slusser, the attorney for PCS Phosphate repeatedly implied that existing IS-1 interruptible customers might prefer to take firm service rather than be automatically transferred to the IS-2 rate schedule. (See Tr. 1551, 1554-56). PCS Phosphate also implied that it was unfair to require involuntarily transferred

[52] PEF also proposes to modify some of the terms and conditions of the open CS/IS rate schedules in order to accommodate the transferred customers. (Tr. 1510-11). Although the industrial interveners oppose elimination of the closed rate schedules, they support PEF's proposed grandfathering of certain terms and conditions in the event they are required to transfer to the open schedules. (Prehearing Order, Issue 96).

customers to provide 36 months' notice to move to a firm rate schedule from an interruptible schedule they had not chosen. (Tr. 1555-56). However, an attorney's questions are not evidence. No intervener presented evidence that any transferred customers would elect to move off of the IS-2 rate schedule, either now or 36 months in the future.

It is now time to complete the transition and eliminate these non-cost-effective rate schedules. The Interveners have been on notice for over 13 years that these schedules are subject to elimination in a litigated rate case. They must not be allowed to claim surprise or unfair treatment if their grandfathered status is finally terminated. To hold otherwise would mean that these schedules can never be eliminated, since the interveners will have the same "fairness" arguments available to them in the next rate case as they have today.

2. Level and Application of Interruptible Credit

If the closed CS/IS rate schedules are eliminated, then the interveners seek to have the open schedules modified to (a) increase the amount of the interruptible credit, and (b) eliminate the load factor adjustment that is applied to that credit.

These modifications should be rejected. The level of the interruptible and curtailable credits and the associated payment structure are not base rate issues and are not appropriate for resolution in this docket. The value of the Company's ability to interrupt or curtail the demand is reflected in a billing credit, not in base rates. The Commission treats such credits as a demand side management program. This means that the level of the credit must be cost-justified in the same manner as the cost of any other DSM program. It also means that the credit payments are accounted for as DSM costs, and are recovered from all customers through the conservation cost recovery clause. The DSM goals docket or the conservation clause docket is thus the proper forum to address the cost-effective level of the credit and its payment structure. (Tr. 1598-99, 4049, 4121-22).

C. Uniform Percentage Increase Within Commercial and Industrial Classes (Issues 111, 112)

Once the cost responsibility for each class has been determined through a cost of service study, the utility must design rates that recover each class's share of the revenue requirements from the members of that class in a fair and equitable manner. (Tr. 1518). Within the nonresidential rate classes that pay both demand and energy charges, PEF proposes to increase both rate elements on a proportionate basis. (Tr. 1518). This will result in uniform percentage increases for most customers in their respective rate class. (Tr. 4048).

FIPUG's witness Pollock takes issue with this rate design, and recommends that the entire increase for the GSD and CS/IS rate classes be allocated to the demand charge, with no increase to the energy charge. (Tr. 3187-88). Because not all customers in each class possess similar load factors, coincidence factors, and time of use characteristics, the effect of Mr. Pollock's proposal would be to provide an unfair advantage to high load factor customers and to unfairly burden low load factor customers.[53] (Tr. 4047; Hearing Ex. 318 at 41-43).

The primary driver for production and transmission capacity costs is the customer's contribution to the Company's monthly system peak demand, and the driver for distribution primary capacity costs is the customer's contribution to the class's peak demand. (Tr. 4048). For billing purposes, however, the Company measures the customer's maximum demand, whenever it occurs during the month. This billing demand may or may not be coincident with the Company's system peak or with the class's peak. (Tr. 4047). Thus allocating all capacity costs to customers on the basis of their billing demand would ignore differences in their coincidence factors and their cost responsibility. (Tr. 4047).

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[53] It is interesting that Mr. Pollock supports limiting the increase to each rate schedule to no more than 1.5 times the system average rate increase, but within the rate schedules he supports a rate design that would result in lower percentage increases to the high load factor customers that typify FIPUG members and higher increases to other class members.

Load research performed by PEF shows that a customer's contribution to PEF's coincident system peak demand (the production and transmission cost driver) is more highly correlated with the customer's kWh energy usage than with the customer's kW billing demand. Conversely, the customer's contribution to class peak demand (the primary distribution capacity cost driver) is most highly correlated with kW billing demand. Thus it is appropriate for the demand charge to reflect, at a minimum, the cost of distribution capacity and for a portion of production and transmission capacity costs to be recovered on an energy charge basis. PEF's proposal to provide a uniform percentage increase for most customers in each class by proportionately increasing the demand and energy charges reflects the use of the billing parameters that best correlate to functional cost recovery. (Tr. 4048; Hearing Ex. 318 at 41-43).

D. Time of Use Rates (Issue 107)

PEF does not propose to make any changes in this proceeding to the design of its time-of-use (TOU) rates; PEF has designed those rates in the same manner as has been prescribed by the Commission since their inception. (Tr. 1513-14).

Mr. Klepper, on behalf of a coalition of quick serve restaurants calling themselves AFFIRM, has asked the Commission to order PEF to design a new commercial time-of-use rate that better matches the usage characteristics of those customers and to require PEF to develop multi-location rates for use by those customers. (Tr. 2275, 2284-85). Both of these recommendations should be rejected.

First, Mr. Klepper asserts very few commercial customers, if any at all, can obtain a better economic outcome by using PEF's current general service time-of-use rate (GSDT-1) in lieu of its general service demand rate (GSD-1). (Tr. 2279). This assertion is wrong. As shown on Exhibit 253, over 10,000 general service demand customers out of a total of 55,000 have elected service under the TOU rate and have realized an average savings of about 1.0 cents/kWh. (Tr. 4050).

Second, Mr. Klepper suggests that few AFFIRM member customers take service under the GSDT-1 rate. In fact, PEF has been able to identify 151 accounts that appear to be AFFIRM members, and a predominance of those identified customers take service under the GSDT-1 rate. (Tr. 4050; Hearing Ex. 253 at 2). PEF has also been able to identify one competing quick serve restaurant for which the Company has hourly load data from its most recent load research study. With long operating hours and weekend hours that are typical of quick serve restaurants, this customer benefits from the optional GSDT-1 rate schedule. (Tr. 4051-52; Hearing Ex. 254).

Third, Mr. Klepper's request for a multi-location rate option for AFFIRM members overlooks the fact that this type of treatment is currently prohibited by Commission Rule 25-6.102 on conjunctive billing. This rate case is not the proper forum to consider a variance from the provisions of that rule.

As Mr. Slusser explained on cross-examination by Staff, additional load research information, which does not exist today, would be required to develop a new time of use rate. (Tr. 4114, 4120-21). Thus no change to PEF's proposed TOU rate structure should be made in this docket.

E. Miscellaneous Rate Design and Tariff Issues (Issues 98, 99, 100, 101, 114)

PEF has proposed a number of miscellaneous rate design and tariff changes which are briefly discussed below.

First, PEF proposes to include the cost of a customer's transformer in the customer charge for residential service. The customer charge is intended to recover fixed costs that are independent of the level of a customer's usage. The transformer, like the customer meter and service wire tap, is a necessary facility to make the customer electrically active. Thus it is more appropriate to recover the cost of the transformer in the customer charge, rather than through a usage charge. (Tr. 1506). From a customer perspective, the break-even point is 1,118 kWh, meaning that customers with usage of less than 1,118 kWh per month would see a higher bill as a result of the Company's proposed rate design, while customers with higher usage would see a lower bill. (Tr. 1586).

Second, PEF proposes to change its service charges, its charge for Temporary Service, and its Premium Distribution Service Charge to more closely assign costs to the customers who impose such costs. The effect of the proposed changes to service changes is to produce additional revenues of approximately $4.1 million. Revenues from these service charges serve to offset what would otherwise be an increase in the Company's base rate charges.[54] (Tr. 1515). On cross-examination by Staff, Mr. Slusser acknowledged that the cost of initial establishment of service is $179.23. PEF believes that increasing this charge to recover the full cost would unreasonably burden new customers. In order to set a reasonable charge that mitigates the impact on new customers, PEF proposes to increase the charge from $61 to $75. (Tr. 1578-79). For similar reasons, PEF proposes to increase the charge for temporary service from $227 to $250, which is below the actual $303.02 cost of providing that service. (Tr.1580-81). No intervener presented testimony or conducted cross-examination on any of these charges, and the Prehearing Order reflects Staff's position that both the proposed temporary service charge and premium distribution service charge are appropriate.

Finally, PEF proposes to revise its "Leave Service Active" tariff provision to expressly state that this provision is available only to multi-family rental housing facilities on a contiguous

[54] The Florida Retail Federation took a tentative position in the Prehearing Order that PEF's proposed service charges, temporary service charge, and primary distribution charge are not appropriate and should be reset based on the revenue requirement established by the Commission. This position appears to overlook the fact that the effect of these charges is to reduce the amount of the Company's revenue requirements that must be recovered through base rates.

property with a minimum of 10 rental properties and one owner account. (Hearing Ex. 47, MFR E, Rate Schedules, Sheet 6.110 at page 72). The Leave Service Active provisions were added to PEF's tariff in Docket No. 830470-EI in response to a petition by the Pinellas Apartment Association and were intended to provide an option for landlords of multiple units at a single location to assume responsibility for an account without the need for the Company to incur the cost of field work to disconnect and reconnect service at the premises. (Hearing Ex. 41 at Bates 1559-60). The purpose of PEF's proposed revision is to conform the language of the tariff to both the original intent of the provision and the way that the Company is currently interpreting and applying the tariff. (Tr. 1594).

X. Conclusion.

For all the foregoing reasons, and based on the Company's testimony, exhibits, and MFRs, the Commission should approve the Company's requested base rate increase in its entirety.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been served via electronic and U.S. Mail to the following counsel of record as indicated below on this ~~8~~ 16TH day of October, 2009.

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