BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for increase in rates by Progress Energy Florida, Inc.)))	Docket No. 090079-EI FILED: August 10, 2009

DIRECT TESTIMONY

OF

HELMUTH SCHULTZ III

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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On Behalf of the Office of Public Counsel

Before the

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Docket No. 090079-EI

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz III. My business address is 15728 Farmington Road, Livonia Michigan 48154.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Senior Regulatory Analyst with Larkin & Associates P.L.L.C.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCITES, P.L.L.C.

A. Larkin & Associates, P.L.L.C. performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney generals, etc.). Larkin & Associates, P.L.L.C., has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including water and sewer, gas, electric and telephone utilities.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. Attached as Appendix I, is a summary of my background, experience and qualifications.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin & Associates, P.L.L.C., was retained by the Florida Office of Public Counsel (OPC) to review the rate increase requested by Progress Energy Florida (the Company or PEF). Accordingly, I am appearing on behalf of the citizens of Florida ("Citizens") who are customers of PEF.

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL?

A. Yes. Kim Dismukes, of Acadian Consulting, is presenting testimony on affiliate transactions. Jacob Pous is presenting testimony on the over-recovery of depreciation expense and the associated excess depreciation reserve. Daniel J. Lawton will address the ratemaking policy and financial implications surrounding the Company's over-recoveries of depreciation expense and the associated excess depreciation reserve. Additionally, Dr. J. Randall Wooldridge is presenting testimony on the OPC's recommended rate of return.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE THE GENESIS OF THIS PROCEEDING.

A. On March 20, 2009 Progress Energy Florida filed its Minimum Filing Requirements (MFR's) requesting a revenue increase of $499.997 million. Corrections have been made since the filing however the amount of increase has not been revised by the Company. We analyzed the Company's filing, issued discovery and evaluated the responses to PEF's discovery responses, including the Commission Staff (Staff). Based on the analysis performed and the recommendations of the OPC's other consultants it was determined that the Company's request for an increase of $499.997 million is excessive and should be denied. The Company should not be allowed an increase and instead rates should be reduced by at least $35.038 million. The results of the OPC witnesses findings are summarized on Exhibit HWS-1, Schedule A-1. Rate base and rate base adjustments are detailed on the B schedules and adjustments to operating and maintenance costs are detailed on my C schedules. The proposed capital structure is presented on Schedule D.

Q. PLEASE EXPLAIN WHY THE COMPANY'S REQUEST IS OVERSTATED?

A. The Company has proposed increases in costs that factor in inflation, an increase in the employee complement, business as usual pay increases, bonuses, a significant increase in operations and maintenance expenses, increased depreciation expenses that are not justifiable, as explained by Mr. Lawton and Mr. Pous, and an excessive rate of return as explained in detail by Dr. Woolridge. Given the current state of the economy and the difficulty that customers are experiencing the excesses requested are definitely inappropriate. Since the fall of 2008, companies and governmental agencies have been cutting costs, freezing and/or limiting pay increases and cutting benefits. Yet the Company has taken the approach that a similar belt tightening effort is not required largely because they are a regulated utility in a monopoly that is to some degree more sheltered from the economic conditions than non-regulated businesses.

Q. HOW IS THE COMPANY SHELTERED MORE THAN THE NON-REGULATED COMPANY?

A. The Company is a monopoly and its customers do not have the choice of looking elsewhere for lower cost energy. When costs go up, the customers are limited in how much they can reduce their demand for energy. When rates are set without regard to the state of the economy and the impact it has on the captive customer base, then those customers have only two choices; (1) pay the rate or (2) stop using electricity. The second choice is not much of an alternative. Non-regulated companies compete and if they do not cut costs, the cost increases will drive up prices to a level that will motivate the customer to either shop elsewhere or simply do without the unregulated company's product. In my opinion this filing does not reflect an attempt by the Company to minimize costs and to take into consideration the economic impact that its business as usual increases will have on customers. In fact this request compounds the inequity already imposed on customers because the Company is being compensated for costs for plant that is not even used and useful, which is in direct contradiction to the traditional general theory of ratemaking.

III. NUCLEAR FUEL BALANCE

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S REQUEST FOR AN INCREASE IN THE NUCLEAR FUEL INCLUDED IN RATE BASE?

A. The Company's requested Net Nuclear Fuel of $155.017 million is not supported by the Company's witness and/or the filing. According to Company Schedule B-16 the witness responsible for the Nuclear Fuel amount included in rate base is Sasha Weintraub. In reviewing the testimony of Sasha Weintraub I was unable to find any discussion that would explain why the amount included in rate base increased from a net average of $86.294 million in 2008 to $155,017 million in 2010. In my review of the filing, the Company indicated in Supplemental Schedule F-8 that in 2009 the Company would acquire approximately $41 million of nuclear fuel. The Schedule F-8 for 2010 indicated that approximately $29 million of nuclear fuel is expected to be purchased. The sum of the purchases would increase the balance by $70 million but after accounting for the amortization that occurred in 2009 and 2010 there is an unexplained difference.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE NUCLEAR FUEL INCLUDED IN RATE BASE?

A. Yes. As shown on Exhibit HWS-1, Schedule B-3 the Company's requested for Net Nuclear Fuel of $155.017 million should be reduced $32.766 million ($26.752 million jurisdictional) to $122.251 million.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT TO THE NUCLEAR FUEL INCLUDED IN RATE BASE?

A. In 2009 I started with the Company balance for December 2008 and each month I added to that one twelfth of the $41 million of nuclear fuel expected to be purchased and deducted one twelfth of the approximate $21.188 million of amortization included on Company Schedule B-16, Page 2 of 3. In 2010 I continued with the calculated balance as of December 2009 and then each month I added to that one twelfth of the $29 million of nuclear fuel expected to be purchased and deducted one twelfth of the approximate $36.283 million of amortization included on Company Schedule B-16, Page 1 of 3.

Q. WHY SHOULD THE COMMISSION ACCEPT YOUR RECOMMENDED ADJUSTMENT TO THE NUCLEAR FUEL AMOUNT INCLUDED IN RATE BASE?

A. The Company filing should support the amounts requested. The Company failed to even identify the change in the original filing. The amount requested was just included. The only attempt to correct the deficiency was the supplemental filing of Schedule B-5 on March 27, 2009. That supplemental schedule simply stated that in 2009 the balance increased by 50.67% to provide working stock and protection against supply interruption. The $68.723 million ($155.017 million - $86.294 million) increase in rate base is of the magnitude that requires sufficient justification in the filing. The Company is obligated to provide that justification when it files. Because the Company failed to justify the amount requested an adjustment is required. By not sending a signal to the Company for its failure to sufficiently explain the significant increases reflected would be the same as giving the Company a blank check for any increase in rates desired.

IV. STORM RESERVE ACCRUAL AND RESERVE BALANCE

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR AN INCREASE IN THE ANNUAL STORM ACCRUAL?

A. Yes, the Company's witness Peter Toomey recommends an annual accrual of $16 million on a system basis and $14.922 million on a retail basis. The intent is to maintain a reserve of approximately $150 million. The accrual amount and the requested reserve are based on an analysis performed by the Company's witness Steven Harris.

Q. ARE THERE CONCERNS WITH THE COMPANY'S REQUEST FOR AN INCREASE IN THE ANNUAL STORM ACCRUAL?

A. Yes. The Company's reserve has increased significantly over the past three plus years due to the collection of a surcharge from customers and also due to the low level of charges against the reserve. The Company's witness Mr. Toomey has stated the annual accrual of $16 million is "equivalent to the expected average recoverable storm loss" from Mr. Harris' study. There are concerns with the focus of the study, the assumptions made, recent history and the conclusions that resulted from the study. There is also a concern with what may not have been factored and/or identified in the study and Company testimony.

Q. WHAT IS THE CONCERN WITH THE FOCUS OF THE STUDY?

A. Mr. Harris's testimony indicates that a focus was placed on four alternative reserve accruals, none of which made any assumption on what would happen if a lower annual accrual were made. This fact was confirmed in the response to OPC Interrogatory No. 365. That suggests that it was pre-determined that the only way to adjust the accrual was to increase it.

Next there was a focus on the historical storms, with an emphasis made on a 1921 storm that hit Pinellas County. Because of the magnitude of that storm it was estimated that the damage could reach $250 million. The worst case scenario is presented with no emphasis on other storms of similar magnitude or even the mentioning of the statistical probability that a comparable storm to the 1921 storm could strike that area. I believe that historical storm information is relevant but storm information should be specific to the PEF service territory. And while Pinellas County is the Company's most densely populated service territory, there are significantly larger geographical areas served by the Company with a statistically higher probability of landfall, where a major storm strike might not produce damage that would exceed the existing storm reserve.

Q. WHAT ARE YOUR CONCERNS WITH THE ASSUMPTIONS INCORPORATED IN THE STUDY?

A. Mr. Harris's testimony states that the study determined an average annual loss of $20.2 million. This assumption is a significant driver in the determination of the estimated reserve results. According to the study (Page 1-1) the loss was computed using the results of thousands of random variable storms. As indicated earlier, the use of storm data that may be applicable to areas outside of the PEF service territory could skew the results. There is also the concern that the study provides no indication as to what factors were used to determine an average annual loss rate of $20.2 million. The fact is that since 1994, with the exception of 2004 and 2005, the Company has only charged anywhere from $0 to $9.9 million to the reserve in any one year or an average of $3 million.

Based on Mr. Harris' testimony at page 11, the analysis took into consideration the 1921 storm and the fact that if that storm occurred there would be an estimated $250 million of damages to the current system. The reserve is not intended to recover costs for a storm of that significance because storms of that magnitude are not common and are unlikely to occur.

Q. WHY HAVE YOU EXCLUDED 2004 AND 2005 FROM THE AVERAGE YOU CALCULATED?

A. The year 2004 was an extraordinary year for hurricane costs and those costs are not costs that were charged against the reserve. In the Storm Cost Recovery proceeding (Docket No. 041272-EI) the decision stated that "PEF contends that the costs of severe storms like the 2004 hurricanes are too volatile, irregular in their occurrence, and unpredictable to be addressed in base rates." Yet, the Company has made its recommendations based on a study that did factor in the impact from those storms. This is despite the fact the Commission in its storm cost recovery decision stated that the 2004 hurricane season was "unprecedented and extraordinary in nature" and the incremental costs of the 2004 hurricanes do not constitute a base rate item.

The 2005 charges, if any, were not included here because the Company did not provide information for 2005 as they were requested to in OPC Interrogatory No. 109. Rather than assuming that the cost was zero for 2005 and thus arbitrarily reducing the average I elected to exclude 2005 from the computation.

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S CONCLUSION EXPRESSED REGARDING THE STUDY?

A. Mr. Toomey states in his testimony that, based on the updated study, the Company increased the annual accrual to $16 million on a system basis. The proposed accrual produces an expected reserve balance in five years of $152.5 million. The fact is the study indicates that based on a $16 million accrual there is a 90% chance that the reserve balance could be within the range of negative $53 million and a positive $231 million. A range of $284 million is significant, especially in today's economic climate. As indicated earlier the $16 million was a predetermined number intended to increase a already sufficient reserve balance, that is significant, given the recent history of storm costs charged against the reserve and taking into consideration that the 2004 and the 1921 storm factored into the study are storms that are not likely to occur and should not have been factored into the storm reserve determination.

Q. WHAT ARE YOUR CONCERNS WITH WHAT WAS NOT FACTORED INTO AND/OR IDENTIFIED IN THE STUDY OR COMPANY TESTIMONY?

A. The Company filing included a request that its storm hardening costs be charged against the reserve. While there is no indication that the study itself factored this request into the results, there is concern that the Company in its fixation on the $150 million reserve and the $16 million accrual had factored this in the determination that the $16 million and $150 million were reasonable numbers.

Based on the response to OPC Interrogatory No. 361 the study did not factor in to the model the impact that the recent storm hardening efforts directed by the Florida Public Service Commission would have on future storm costs. This should be considered a weakness in the development of a reserve cost estimate because the intent of the storm hardening efforts is to minimize damage and cost as the result of the storms. The response went on to state "Further, given that these recent additions and changes have been in place only a few years, it is anticipated that it will be a number of years before they would significantly impact the modeled study results." This assertion, if true, would raise some major concern as to whether the study data is appropriate. Significant dollars have been spent, both recently and over the lengthy history of the Company, to upgrade and improve the reliability of the system. The 1921 storm damage would likely be significantly different today given the improvements to the system over the years especially in recent years.

Mr. Harris on page 10 of his testimony links the $150 million reserve to the 1921 storm. Here Mr. Harris states that "with a $16 million accrual, the resulting reserve level of $152 million would be sufficient to cover storm damage of approximately a one in 35 year storm season." He then states "Thus, a $16 million annual accrual results in a storm reserve balance that will be adequate to cover losses during most, but not all, storm seasons." There are problems with this testimony based on the study results. First, in response to OPC Interrogatory No. 359 the only major storms that Mr. Harris could identify the level of impact on the Company in the last 35 years were the four hurricanes in 2004, and as indicated above all parties agreed those storms should not be factored into determining the reserve level.

On page 11 of his testimony Mr. Harris discusses the 1921 storm that affected PEF's service territory. In response to OPC Interrogatory No. 362, Mr. Harris states that no storms of similar strength and point of landfall have impacted the Company since 1921. He does again reference the 2004 storms as having similar strength and he indicates that the damage was significantly less. Again based on that information I would question the appropriateness of including that storm in the study.

Next, there is a concern that Mr. Harris' testimony on page 11 as referenced above suggests that he is concurring with the Company. Yet on page 10 he states that it was not his role to recommend an annual level of accrual or target reserve level. The testimony on page 10 as well as the Company's position is considered even more questionable when you read the disclaimer to the study on Exhibit No.__(SPH-1), page 4 which states that the study provides no guaranty of any kind, that the limited nature of data causes a level of uncertainty and that there is a "significant amount of uncertainty" in the storm severity and locations; asset vulnerabilities, replacement costs and other computational parameters. Simply put, anything can happen and the results could be significantly different from what is reflected in the study.

Finally, a major missing factor in testimony and in Mr. Harris' study is an explanation as to why a $150 million reserve would be better than $125 million or a $100 million reserve. The Company was requested in OPC Interrogatory No. 364 to explain why the $150 million would be better and the response was that the $150 million presents a lower probability that the reserve will be exhausted over a five year period, decreasing the likelihood of having to petition the PSC for an additional storm surcharge. This is not justification for a $16 million accrual or a reserve of $150 million. The surcharge may only be necessary when unusual storms occur such as those that occurred in 2004. Based on the study--that I question the reasonableness of--there is a 2.7% probability that the $150 million reserve could be exhausted by a storm and there is a 4.48% probability that a $100 million reserve would be exhausted by a storm. Ratepayers should not be required to continue to fund a reserve that is excessive especially in today's economic climate. Ratepayers should not be required to increase the funding so that maybe in 5 years the reserve could be as high as $231 million as indicated on page 24 of 31 of Exhibit No.__(SPH-1).

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO THE COMPANY'S RESERVE ACCRUAL AND RESERVE REFLECTED IN THE FILING?

A. The Company's accrual should be reduced to zero because the reserve is sufficient at this time to cover storm costs that are likely to occur based on recent history. This recommendation reduces O&M expense $14.922 million and increases working capital and rate base $27.160 million as shown on Exhibit HWS-1, Schedule B-4.

Q. WOULD YOU EXPLAIN WHY YOUR ADJUSTMENT IS APPROPRIATE?

A. The Company has established a sufficient reserve to cover major storms in the future. As discussed earlier the calculated average cost of storms charged against the reserve excluding the unusual 2004 storm costs and any cost incurred in 2005 results is $3 million over a 13 year period. As shown on Exhibit HWS-1, Schedule B-4 , by charging the most recent three year average (2008 storm costs recorded in 2009 are reflected in 2008) of $6.590 million against the reserve without any additional accrual results in a December 31, 2010 reserve balance of $128,651,299. Using Table 3-1 in the study performed by Mr. Harris shows the probability that storm costs in a single year would eclipse the reserve to be approximately 3.4%. That's compared to the 2.7% relied on by the Company in establishing the $150 million reserve. After five years without any accrual and assuming an annual expense of $6.590 million the reserve would be $102,291,706. Again using Table 3-1 in the study performed by Mr. Harris the probability that storm costs in a single year would eclipse the reserve would be approximately 4.4%. The low probability that a more than major storm would occur and eclipse the reserve balance justifies the elimination of an accrual for the near future. Ratepayer contributions have essentially established an adequate and sufficient reserve as it exists today. Given the low level of recent charges against the reserve, ratepayers should not be required to contribute more to increase that reserve balance based on the excessive annual $20 million charge assumption used in the study and taking into consideration the overall impact the rate request will have on ratepayers in today's economy.

V. ARO ADJUSTMENT-WORKING CAPITAL

Q. DID YOU REVIEW THE COMPANY'S PROPOSED ARO ADJUSTMENT TO WORKING CAPITAL?

A. Yes. The Company increased the working capital requirement by $446.569 million ($371.128 million jurisdictional) and reduced plant in service $48.532 million for a total net increase to rate base of $398.038 million. This adjustment according to Schedule B-2, page 2, is "To remove recoverable Asset Retirement Obligations". There are multiple concerns with the proposed adjustment.

Q. WHAT ARE THE CONCERNS WITH THE COMPANY'S PROPOSED ARO ADJUSTMENT?

A. First, I could not find any detailed explanation in testimony or in the filing that would explain this adjustment beyond the statement on Company Schedule B-2. That is not appropriate given the significance of the amount in question.

Second, the Florida rules (25-14.014 Accounting for Asset Retirement Obligations Under SFAS 143) state that the implementation of the accounting shall be revenue neutral in the rate making process. The increase in the revenue requirement suggests the adjustment is not revenue neutral.

Next, the Company's financial statements state, that when the ARO requirement was adopted there was no impact on the income statement. That would mean that the entry or entries were all balance sheet related. The footnotes also stated that an amount equivalent to the liability recorded was added to the asset cost and was to be depreciated over the useful life of the asset. If the asset amount is not removed from rate base as the liability was then the ratemaking process is not revenue neutral as required by Florida rules. The entry made by the Company in this docket removes the liability from working capital and does not have an equivalent entry made to plant, accumulated depreciation and/or the deferred assets included in working capital. The entry appears to be a one sided entry. That clearly is not appropriate.

Finally, in the rate case with TECO, in Docket No. 080317-EI, the working capital calculation reflected a $27.111 million ARO obligation and no adjustment was made by TECO to remove the $27.111 million from working capital. That suggests that the adjustment proposed by PEF may be wrong.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO REVERSE THE COMPANY'S ADJUSTMENT TO WORKING CAPITAL?

A. Not at this time. Because of the significance of the adjustment, I propose to defer any determination on my part to allow the Company to provide justification for their making the adjustment.

VI. COMPENSATION AND INCENTIVE PAY

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S REQUEST FOR PAYROLL IN THE FILING?

A. The total payroll requested is $489,779,401 and the amount included in expense is approximately $354,600,286. The Company's request for compensation request is excessive and inappropriate. As shown on Exhibit HWS-1 Schedule C-3, Page 1 of 2, I am recommending a reduction of $53,831,980 ($47,540,636 on a jurisdictional basis) be made to compensation expense.

Q. WHY ARE YOU RECOMMENDING THIS ADJUSTMENT TO THE COMPANY'S REQUEST FOR PAYROLL IN THE FILING?

A. The Company's request totally ignores the state of the economy and the impact that the request will have on the citizens of Florida who are served by the Company. The request includes business as usual pay increases, an increase in payroll for employees that have not been hired yet and an increase in incentive compensation, when the current amount of incentive compensation is not justified.

Q. WHY ARE YOU APPROXIMATING THE PAYROLL EXPENSE IN THE FILING?

A. The Company's filing does not identify the amount of overtime included in the Company's request. The Company MFR Schedule C-35 entitled "Payroll & Fringe Benefit Increases Compared to CPI" does not reflect any overtime compensation. The Company has elected to bury the overtime costs in various other MFR schedules. This is contradictory to the purpose of the MFRs. The total amount of overtime in the projected test year was identified in the response to OPC Interrogatory No. 127. The portion expensed was estimated based on the expense ratio for the payroll costs as shown on MFR Schedule C-35 and the response to OPC Interrogatory No. 128 that identified the portion of payroll from MFR Schedule C-35 that was expensed in the projected test year.

Q. WHAT IS THE PROBLEM WITH THE BUSINESS AS USUAL PAY INCREASES?

A. The Company's response to OPC Interrogatory No. 124 indicates the budgeted increase for non-bargaining positions was 3.75% in 2009 and 2010. For bargaining positions the increases are budgeted at 3% for 2009 and 2010. In a follow up request the Company stated in response to OPC Interrogatories No. 301 and 302 that the increases identified in the response to OPC Interrogatory No. 124 is only the merit increase and that the budgeted labor as shown on MFR Schedule C-35 also includes promotions, off-cycle salary adjustments, market based adjustments and contractual step ups. As shown on Exhibit HWS-1 Schedule C-3 the average base pay reflected in the filing for a PEF employee increased 9.4% from 2008 to 2010. That is an increase of 4.7% per year. Simply put, that significant increase reflected in the projected test year compensation is a business as usual increase. The business as usual increase ignores the current economic climate and it ignores measures taken by other companies, both regulated and unregulated in curbing the amount of compensation and maintaining and/or cutting costs.

Late in 2008 and in early 2009 a number of companies were identified in the media that were either freezing compensation and/or cutting compensation in lieu of reducing employees. A study by Mercer dated June 17, 2009 indicated that 69% of companies surveyed had 2009 budgeted aggregate base pay equal to or below the 2008 budget. PEF is obviously not included in the 69%.

Q. ARE YOU AWARE OF UTLITIES EITHER FREEZING COMPENSATION OR TAKING MEASURES TO AVOID ADDED HARDSHIP TO CUSTOMERS?

A. Yes. In a current rate filing in Vermont, Green Mountain Power has limited the increases in compensation to the contractual rate for bargaining employees and frozen wages for non-bargaining. Potomac Electric Power Company in it's current filing in Case 1076 has foregone any wage increase for non-bargaining employees in its request and has requested only a portion of the bargaining employees increase. People's Gas System in Docket No. 080318-GU eliminated the executive increase and reduced the employees' compensation increases.

Q. DID YOU INQUIRE AS TO WHETHER THE COMPANY HAD CONSIDERED THE CURRENT STATE OF THE ECONOMY?

A. Yes. In the response to OPC Interrogatory No. 303 the Company stated "During each budgeting process historical trends and economic conditions at that time are evaluated. The 3.75% budget for 2010 reflects recent historical trends of year-over-year increases and the current economic conditions by holding the increase from 2007 to 2008 flat for the three year period 2008-2010." I would interpret that response to the Company saying that economic conditions are such that an increase above the 2008 increase of 3.75% is not warranted. The response is insensitive to the ratepayers given the current state of the economy. When the economy was doing well back in 2006 and 2007 the increase was budgeted at 3.5%. As economic conditions deteriorated the budgeted percentage was increased to 3.75% in 2008. This action counters claims by the Company that they have tried to minimize costs and the request for an increase in rates charged to the customers of PEF.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PERCENTAGE INCREASE THAT IS PASSED ON TO RATEPAYERS IN RATES?

A. Yes. Even though I believe that any pay increases granted should be excluded from rates at this time I do not believe that the Commission would approve such a recommendation. Therefore, I am recommending that the annual average increase be limited to 2.35% or one-half of the Company's 4.7% calculated increase in base pay. As shown on Exhibit HWS-1 Schedule C-3, Page 2 of 2 the reduction to an annual increase of 2.35% reduces the proposed average base salary from $75,170 to $71,979 and that reduces payroll expense by $12,209,439.

Q. DO YOU HAVE ANY FURTHER JUSTIFICATION FOR RECOMMENDING AN ADJUSTMENT TO THE PERCENTAGE INCREASE THAT IS PASSED ON TO RATEPAYERS IN RATES?

A. Yes. In the revised response to OPC Interrogatory No. 124 the Company provided the actual 2009 increase for non-bargaining positions. The increase is 2% for management and 3% for non-management employees. Despite the Company's assertion in the response to OPC Interrogatory No. 303 that the increases budgeted and included in this rate request are reasonable in today's economy there appears to be a different strategy when it comes to actual operations.

Q. WHAT ARE YOUR CONCERNS WITH RESPECT TO THE NUMBER OF EMPLOYEES INCLUDED IN THE COMPANY'S REQUEST?

A. The Company is requesting that the number of employees allowed in rates through capitalized and expensed labor be increased a net 370 positions from 4,929 Full Time Equivalents (FTEs) in 2008 to 5,299 FTEs in the 2010 projected test year. The increase again ignores the impact that will be reflected on customer bills in an economy that is already difficult. The request assumes that positions budgeted for will be filled and it assumes that future vacancies will not occur. The increase is not appropriate. As I indicated earlier a Mercer survey indicated that 2009 budgeted base pay would be equal to or less than the 2008 budget for 69% of the companies surveyed. For that to be accomplished for PEF there can be no pay increase and no additional employees added unless pay cuts are implemented. The record is clear that PEF is not reducing payroll, therefore the Company's plan to increase pay and add employees ignores the economic events that other companies and ratepayers are forced to recognize.

A second concern is that even though the Company budget is established based on current employees and proposed additions, the Company's human resource department does not maintain budgeted employee level detail. Month to month changes can be tracked but a comparison to budget can not be provided to evaluate how the Company projections are performing.

Q. HAVE CHANGES OCCURRED WITH THE NUMBER OF EMPLOYEES SINCE 2008?

A. Yes. Based on the response to OPC Interrogatory No. 297, the Company had 4,929 employees as of December 31, 2008 and 4,911 as of March 31, 2009. The decrease of 18 employees is evidence that the fact of vacancies cannot be ignored and raises concerns whether the increase projected is reasonable.

Q. DID YOU INQUIRE AS TO WHERE IN THE FILING THE COMPANY JUSTIFIED THE INCREASE AND THE CURRENT STATUS OF THE ADDED POSITIONS?

A. Yes. The response to OPC Interrogatory No. 299 indicates that in fact, 497 positions are proposed to be added and that 127 positions will be eliminated for a net increase of 370 positions. The Company response eliminates 416 positions from the explanation requirement by indicating that the 387 positions are "Clause Positions" and 29 positions are "Allocated Headcounts". Apparently the Company believes these positions do not require justification. The response continues by stating that after making the two adjustments there only 81 of the net addition of 370 positions that represent true position increases affecting base rates. The 81 positions consist of 36 new positions and 45 vacancies. Only 10 of the new positions have been filled and only 20 of the vacancies have been filled. However, based on the employee count as of March 31, 2009, more vacancies have occurred. The response also indicates that only 33 of the 36 new positions were identified and/or referenced in

Company testimony. That means that along with no justification being provide for the so called "Clause Positions" and the "Allocated Headcounts", the filing has failed to provide any justification for the other 48 positions (81-33) included in the Company's request.

Q. ARE YOU RECOMMENDING THAT AN ADJUSTMET BE MADE TO THE ALLOWANCE FOR THE NUMBER OF EMPLOYEES INCLUDED IN THE FILING?

A. Yes. Based on the response to OPC Interrogatory No. 299 I am recommending that the allowance for 51 unfilled positions the Company classifies as true position increases be removed and the allowance for 29 service company positions be removed for a total adjustment of 80 positions. As shown on Exhibit HWS-1 Schedule C-3, Page 2 of 2, using my adjusted average base salary of $71,979 the payroll expense would be reduced $4,156,891.

Q. HAVE YOU TESTED YOUR ESTIMATE FOR REASONABLENESS?

A. Yes, I have. As I discussed earlier, in addition to not providing justification for the positions, the Company has ignored vacancies by assuming that vacant positions as of December 2008 would be filled. Since the Company would not provide monthly budgeted employee counts I interpolated the increase projected by the Company assuming a level increase from one month to the next. Using the March 2009 actual employee count of 4,911, I estimated a vacancy rate of 1.94%. Applying the 1.94% to the 5,299 projected positions, results in 103 vacant positions. Based on that result my adjustment related to funding these proposed 80 positions is conservative.

Q. WHAT IS YOUR CONCERN WITH INCLUDING INCENTIVE COMPENSATION IN THE COMPANY'S REQUEST?

A. Incentive compensation is compensation in addition to base pay that can only be justified if the performance of employees results in improved customer service, customer reliability and improved financial results. With those improvements there is a benefit to both ratepayers and shareholders. The cost for incentives should follow the benefit. Therefore, if the improvement in operations can be shown in service, reliability and earnings then it would be appropriate for shareholders and ratepayers to share the cost of that improved performance. If service and reliability does not improve, but profits do, then the shareholders are receiving a greater benefit and they should be responsible for the cost. It is not appropriate to assume that incentive compensation is a required part of a compensation package that makes it a cost that should automatically be passed through to ratepayers.

Next, taking into consideration the current state of the economy, the inclusion of the payment for incentive compensation in rates is even more inappropriate. The Company is requesting that an increased level of incentive compensation be included in rates as if the economy has not had a downturn. This is hypocritical when you take into consideration the fact that the pension costs requested by the Company reflect the downturn in the economy, yet base compensation increases and incentive compensation are treated as business as usual. To ask ratepayers who may be unemployed and/or who have had to make other concessions because of reduced or frozen compensation is not appropriate.

Q. DID YOU ASK THE COMPANY WHETHER THEY WOULD CONSIDER REMOVING THE INCENTIVE COMPENSATION FROM THE COMPANY'S REQUEST?

A. Yes. In OPC Interrogatory No. 376 the Company was asked if they would be willing to remove the cost of incentive compensation from the current request based on the current economic conditions and the Company's efforts to manage its cost. The response stated "No, the Company is not willing to remove these costs from the current rate request. These compensation structures are standard practice in the electric power industry and other industries. They are a necessary cost of doing business and are essential in attracting, retaining and properly motivating the highly skilled workforce needed to efficiently manage and operate today's electric utility. Customers benefit in that these employees are essential for the efficient and reliable service that customers have come to expect." This is a typical response that, along with the use of another misnomer, has in the past, convinced the Commission Staff and the Commission that incentive compensation is required to be included in rates. The reality is that while many companies do pay incentive compensation there are a number of jurisdictions that either do not allow and/or limit the amount of incentive compensation in rates.

Q. WHAT IS THE OTHER MISNOMER THAT YOU REFERED TO THAT YOU BELIEVE IS MISLEADING?

A. Typically a Company will state that the payment of incentive compensation is required to attract, retain and motivate and it follows a pay-for-performance philosophy. That is supplemented with reference to the compensation program being market-based at the 50^{th} percentile of national and regional markets. The

Company's witness, Masceo DesChamps, essentially states this very position on pages 5 and 6 of his pre-filed testimony. I have been analyzing rate requests for more than 30 years and after incentive compensation came into play that is the most frequent argument that I have heard. In my experience, I have found very few companies that will state they are anywhere but in the 50^{th} percentile. My opinion, based on the numerous studies reviewed is that the compensation level referred to in the studies as being the 50^{th} percentile is skewed by a limited few organizations. But to reiterate the one fact that is missed by commissions when they accept the-attract and-retain argument, along with the 50^{th} percentile argument, is that the utility companies that are in those studies do not have all of the incentive compensation included in rates. Therefore, to allow the incentive compensation in rates in its entirety based on an inappropriate comparison puts Florida ratepayers at a disadvantage when compared to ratepayers in other jurisdictions.

There is also some question as to whether it is true that incentive pay is as significant a factor in attracting and retaining competent employees is as factual as the Company would lead you to believe. In response to OPC Interrogatory No. 284, the Company provided the top five drivers an employee uses to choose an employer based on a Towers Perrin survey. They are as follows:

1) Competitive Base Pay
2) Competitive Health care Benefits
3) Vacation/Paid Time Off
4) Competitive Retirement Benefits
5) Career Advancement Opportunities

Missing from the list is incentive compensation that is really added compensation. In fact in reviewing the response to OPC POD No.222, it was noted that incentive compensation was not included in any of the top 10 attraction drivers.

Q. ARE YOU SURE THAT THE COMPARATIVE COMPENSATION HAS NOT BEEN ADJUSTED FOR THE INCENTIVE COMPENSATION NOT ALLOWED IN OTHER JURISDICTIONS?

A. Yes. Based on my review of compensation studies over the past 30 years I have never found any study that indicated that the various companies' compensation levels within the studies have been adjusted to reflect the disallowance of compensation by a regulator. The Company confirmed this in the response to OPC Interrogatory No. 283.

Q. DOES THE COMPANY VIEW INCENTIVE COMPENSATION AS ADDED COMPENSATION?

A. The answer to this question is it all depends on who the Company is discussing the topic of incentive compensation with. In response to OPC Interrogatory No. 344 the Company stated that "Incentive compensation should not be viewed as an amount that is "added" to base salary, but rather as one variable component of a competitive total compensation program." In the Company Employee Cash Incentive Plan (ECIP) (Company response to OPC POD 31, page 156) a frequently asked questions is "How will the ECIP affect my annual base pay?". The response is clear "The ECIP is separate from, and <u>in addition to</u>, your base pay. Any award you receive will not affect either your base pay or future salary adjustments to your pay." (emphasis added).

Q. ARE THERE CONCERNS WITH THE PLAN ITSELF?

A. Yes, the incentive compensation plans are directed at improving the financial performance of the Company. PEF's emphasis, therefore, is the shareholders interest. The Management Incentive Compensation Plan (MICP) states first and foremost that the purpose of the plan "is to promote the financial interests of the Company". It continues with the rhetoric regarding attracting and retaining employees and motivating with goals through the payment of cash incentives. Therein lies more of the problem, the incentive compensation plan is based on goals that do not require above average performance.

Q. WHAT ARE YOUR CONCERNS WITH THE GOALS?

A. The plans emphasis is on financial performance of the Company which is directed toward shareholders. Companies argue that if there is financial success that ratepayers benefit. That assertion is not necessarily true. The financial success may be attributed to cost reductions in customer service areas. To add further concern, the results can be adjusted based on the CEO's discretion.

Next there are the operational goals which may not be real goals. For example:

- The Corporate Services 2006 employee incentive goal of less than 1.25 recordable injuries was not achieved and in 2007 the goal was relaxed to less than 1.37 recordable injuries. Not only was this goal change not appropriate, I observed that in 2006 of the ten operating goals listed for Corporate Services the OSHA goal was listed twice with a second goal level. This duplication was noticed elsewhere.

- Another example is the Sarbanes-Oxley "goal" of no material weakness of the internal controls for a number of groups. The employees' base pay has to have some performance requirements tied to it and one would expect that maintaining proper internal controls would be expected of all employees. To establish a goal for achieving a task that should be an expected duty falling under base pay compensation is redundant and inappropriate.
- The Transmission goal in 2006 for System Average Interruption Index (SAIDI) was less than or equal to 9.3 was not achieved, in 2007 the goal was changed to 9.48, lowering the performance requirement, and despite being achieved in 2007, the goal for 2008 was set at 10.2, again lowering the performance requirement. Compounding the problem is that the SAIDI goal was listed twice at different levels.
- In Power Operations, Company witness David Sorrick states that it is PGF's goal to have zero accidents yet the incentive compensation goal allows for accidents.
- A further illustration is where then there are the goals that are accomplished in one year and the next year the goal is the same. As an example, the response to OPC Interrogatory No. 255 shows that even though the environmental goal of greater than or equal to 4 was achieved in 2005, 2006, 2007 and 2008, the goal in 2009 remains at 4.

The term incentive means to stimulate. There is no stimulation if goals are not increased. Failure to raise the bar to promote improvement means that the plan can be little more than designed to provide added compensation at the expense of ratepayers. The Company payout for incentive compensation is further evidence that the plan is simply additional compensation that is expected by employees and not driven by an incentive to improve performance that will benefit ratepayers.

Q. HOW DO THE INCENTIVE PAYMENTS PROVIDE EVIDENCE THAT THE PLAN IS NOT DESIGNED TO IMPROVE PERFORMANCE?

A. The response to OPC Interrogatory No. 131 shows that in 2006 99.6% of eligible employees were awarded an incentive payment. In each of the years 2007 and 2008 the awards were made to 99.7% of the eligible employees. With approximately 5,000 employees I find it very hard to believe that performance was so high among the employees that almost everyone earned a payment. This is further evidence that this is just added compensation and not truly incentive pay.

Q. IS THERE CONCERN THAT THE FOCUS IS NOT ON RATEPAYERS IN DETERMINING WHETHER AN INCENTIVE PAYMENT SHOULD BE MADE?

A. A review of the plans and the changes in the plans that occurred failed to identify a reference to ratepayers. As indicated earlier the purpose is to promote the financial interest of the Company and share achievement with employees. Absent actual documented proof that the plan provides improved performance to ratepayers, there is no justification for ratepayers to bear any portion of the incentive compensation costs. Other jurisdictions have recognized this fact and have either totally disallowed incentive compensation or they have limited the recovery in rates. Florida should be no different.

Q. COULD YOU IDENTIFY SOME OTHER JURISDICTIONS THAT HAVE DISALLOWED INCENTIVE COMPENSATION IN TOTAL OR IN PART?

A. In New York the decision in Consolidated Edison Company, Case 07-E-0523 the Commission disallowed the cash incentive compensation, commonly referred to as variable pay and the stock based plan costs. Even though the Company argued that both incentive plans should be allowed, using the standard argument that it is necessary to attract and retain employees and it compensates for achievement of good service, reliability and safety, the Commission did not find the request justified. In a recent filing in Washington D.C., Potomac Electric Power Company removed its incentive compensation from its request because it was in accordance with a previous decision. In Vermont, Green Mountain Power in Docket No. 5983 had incentive compensation totally disallowed because the goals did not provide an incentive that would require an improvement above goals that were previously achieved. Currently in Vermont it is common practice that portions of incentive compensation is automatically excluded when a filing is submitted by the company. In Connecticut the Department has determined that various levels of incentive compensation should be excluded from rates. In Arizona cash based incentive costs are shared between ratepayers and shareholders and stock based incentive compensation is generally excluded in its entirety.

Q. WHAT ARE YOU RECOMMENDING BE DISALLOWED IN THIS RATE FILING?

A. The Company's request for $25,371,639 of incentive compensation expense and approximately $12,094,011 of long term incentive compensation expense should be disallowed in its entirety. The disallowance is based on the Company's failure to establish a plan that is designed to provide a tangible and/or quantifiable benefit to ratepayers. As stated earlier, the design and the goals are a simple formula for paying added compensation. If PEF's management believes that attaining goals that do not encourage improvement is sufficient for payment of added compensation to its employees, then shareholders, not its ratepayers, should pay for the related compensation.

Another reason the incentive compensation should be disallowed is it is not justifiable for the Commission to allow in rates this added compensation with dubious demonstrable benefits which will increase rates to customers who are already struggling to meet their own financial obligations in today's economy. People on fixed incomes, people who have lost their jobs and people who have made sacrifices so they can keep their jobs should not in good conscience be required to fund a better way of life for a Company that is insensitive to the current economic impact imposed on its customers just because the monopolistic environment in which it exists allows it to do so.

VII. EMPLOYEE BENEFITS

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO EMPLOYEE BENEFIT EXPENSE?

A. Yes. At a minimum, an adjustment is required based on the recommended adjustment to the Company's employee complement. Based on a discrepancy between the initial filing and the revised filing another adjustment is required to account for a change reflected to MFR Schedule C-35. As shown on Exhibit HWS-1 Schedule C-4, I first reduced the $138,288,606 of expense reflected in the filing by

$9,376,809 for the change in total fringe benefits reflected in the revised MFR Schedule C-35. I determined the adjustment by multiplying the expense ratio for fringe benefits provided in response to OPC Interrogatory No. 128 by the total fringe benefit cost on Revised MFR Schedule C-35.

My next adjustment simply took the average benefit expense per employee by my recommended reduction of 80 positions in the employee complement. The result is an adjustment of $1,946,206.

Q. WHY DID YOU STATE THAT THE RECOMMENDED ADJUSTMENT IS "AT A MINIMUM"?

A. The Company's fringe benefit costs are projected to increase $79,676,684 (83.1%) from $95,825,556 in the 2008 base year to $175,502,240 in the projected test year 2010. The increase is driven by the $67,472,819 increase in pension costs and a $7,071,527 (26.3%) increase in medical costs. The pension increase is attributed to the significant downturn in the economy. The healthcare increase appears excessive and could be attributed to the fact that employee sharing has not kept pace with the cost increases the Company has projected. For example, in response to OPC Interrogatory No. 349 the employee contribution increased by 3% while according to the response to the response to OPC Interrogatory No. 136, health care costs are increasing at 10%-12% annually.

The Company has a wide array of benefits that include two retirement plans. The pension plan and the employee savings plan. Having two retirement plans is a luxury that I am confident most PEF ratepayers cannot enjoy. In addition there is a generous health care plan (i.e. general health plan, health savings plan pre tax, dental and vision), various miscellaneous benefits (including added bonuses) and retiree benefits. Again the ratepayers that are paying for this generous benefit package may themselves be uninsured and/or may not have any retirement plan. The Commission when evaluating the overall compensation request made by PEF should factor this fact into its decision process especially in today's economic climate.

VIII. RATECASE EXPENSE

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S REQUEST FOR RATE CASE EXPENSE?

A. The Company's request is excessive, the amortization period is not acceptable and the rate base treatment is not consistent with rate making principles. As shown on Exhibit HWS-1 Schedule C-5, the Company's expense request should be reduced $989,618 and the amount included in rate base should be reduced $969,531.

Q. WHY IS THE TOTAL AMOUNT REQUESTED CONSIDERED EXCESSIVE?

A. The Company's request does not reflect the contractual terms of the consultants and lawyers. The consultant's costs are overstated by approximately $70,090 and the lawyer's fees exceed the contract amounts by $697,500, for a total overstatement of $767,590.

Q. WHY IS THE AMORTIZATION PERIOD NOT ACCEPTABLE?

A. The Company has requested an amortization period of two years based on what Mr. Toomey says is a "long-standing Commission practice". When asked about the long-standing Commission practice the Company stated in response to OPC Interrogatory No. 381 that it was relying on the January 1999 <u>DIGEST OF COMMISSION REGULATORY PRACTICES AS EXPRESSED IN RATE MAKING PROCEEDINGS AND CURRENT DECISIONS</u> which referenced a 1982 decision. That ignores the period between rate cases in more recent years and it ignores recent rulings in other cases. Because of the time between rate cases and taking into consideration that lengthening the amortization period will help reduce the immediate impact on rate payers, a five year amortization period is recommended.

Q. WHAT IS THE RATE BASE TREATMENT REQUESTED THAT IS INCONSISTENT WITH RATEMAKING PRINCIPLES?

A. The Company has requested the full amount be included in rate base without factoring in amortization in the rate year and ignoring the fact that rate base is an average not a beginning of the year amount. Allowing the Company treatment would result in a double charge to ratepayers and ignores the fact that amortization in the rate year occurred. An adjustment to the average rate base amount in 2010 is appropriate.

<u>IX. TRANSMISSION O&M EXPENSE</u>

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR TRANSMISSION O&M EXPENSE?

A. To some degree I was able to analyze portions of the request based on the limited specifics included in testimony and budget information supplied. There is a general concern with the significant increase in the budgeted dollars. Based on the

Company's MFR C-4 the costs for transmission O&M between 2005 and 2008 ranged from $31.3 million in 2005 to $35.2 million in 2008. The 2009 budgeted cost is $35.1 million. In 2010, the projected test year, the costs spikes upward by $10.3 million for a total of $45.3 million. The Company's testimony identifies $6.9 million of added costs for FERC Order 890. Budget information shows an increase of $1 million for a line bonding and grounding program, and there is an increase of $2.7 million for vegetative management. All of these cost increases are of concern.

The FERC Order 890 cost estimate is not based on any historical costs. There is no explanation in the Company testimony and/or filing for the bonding and grounding program. Based on the explanation for 2009 benchmark comparison, it appears that the bonding and grounding is not a cost incurred on an annual basis. The vegetative management increase appears to coincide with the fact that the Company is in for a rate increase and ignores any potential cost savings resulting from this activity.

Q. WHY DO YOU BELIEVE THE VEGETATIVE MANAGEMENT INCREASE IS DRIVEN BY THE RATE REQUEST?

A. The storm hardening initiative has been in effect since 2006. According to the response to OPC Interrogatory No. 238 the Company spent $6.3 million in 2006, $6.9 million in 2007, $5.9 million in 2008 and have budgeted $6.6 million for 2009. The projected test year 2010 is set at $9.3 million. The Company's requested increase is excessive when compared to the historical spending and the 2009 budget. If the Company was required by the Commission to perform an increased level of trimming that increase should have been reflected in the 2009 budget. Without reflecting an increase in the 2009 budget there is concern that need for an increase in trimming does not exist. The cost increase in 2010 is not justified.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR VEGETATIVE MANAGEMENT EXPENSE INCLUDED IN THE TRANSMISSION O&M EXPENSE?

A. Yes, an adjustment of $1,717,043 is recommended on a jurisdictional basis as shown on Exhibit HWS-1 Schedule C-6. The adjustment assumes that vegetative maintenance will continue at the level the Company deemed appropriate over the period 2006-2009. The increase requested is not justified given the Company's historical spending level. The only justification provided for the increase is on MFR Schedule C-41; Page 8 where the Company simply states it is required to comply with FERC and Commission standards. The Company has not indicated that the historic spending and the budgeted 2009 spending level was insufficient to maintain compliance, so there is no justification for the increase.

Q. ARE YOU RECOMMENDING ANY ADDITIONAL ADJUSTMENTS TO THE COMPANY'S REQUESTED TRANSMISSION O&M EXPENSE?

A. Yes, an adjustment of $338,145 ($500,000 x .67629) is recommended on a jurisdictional basis to reflect a more normalized level of expense for line bonding and grounding. The $1 million included in the projected test year is reduced to reflect the average of an every other year expense. It is not appropriate to overload the projected test year to increase rates.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE FERC 890 COSTS INCLUDED IN THE TRANSMISSION O&M EXPENSE?

A. A specific adjustment is not being recommended but I will discuss how I took the Company's failure to adequately support the request for the FERC 890 cost elsewhere in my testimony.

X. DISTRIBUTION O&M EXPENSE

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR DISTRIBUTION O&M EXPENSE?

A. As with the transmission O&M request there was a limited amount of specifics included in testimony and budget information supplied. Company witness Jackie Joyner stated that the Company was requesting $145 million for distribution O&M expense in the projected test year 2010. The only specific discussion regarding O&M expense is the mentioning that PEF will spend $3.2 million for pole inspections and $34.4 million for vegetation management. The benchmark comparison on MFR Schedule C-41 adds little valuable information in identifying any other changes or programs. On MFR Schedule C-41 there are three costs described that net to a $400,000 increase. In 2008 there were $120.6 million in costs charged to Distribution O&M and as indicated the Company is seeking $145 million in the 2010 projected test year. Vegetation management accounts for $15.9 million of the $24.4 million increase. The pole inspection costs for 2010 are $.8 million more than 2008. Therefore approximately $7.7 million of the increase is essentially unexplained.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S DISTRIBUTION O&M EXPENSE REQUEST?

A. Yes, a reduction of $8,924,197 is recommended on a jurisdictional basis, as shown on Exhibit HWS-1 Schedule C-7, for Distribution Vegetation Management. The adjustment factors in the trimming of the 18,341 primary conductor miles over a five year period using the Company $5,538 cost per mile and adds an estimated $5 million for trimming and treatment of the remaining 7,297 miles that consists of secondary conductors.

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S VEGETATION MANAGEMENT REQUEST?

A. The Company trimmed 3,419 miles in 2006, 4,303 miles in 2007 and 3,297 miles in 2008. Based on the response to OPC Interrogatory No. 272 the Company's projected expense for 2010 is based on trimming 5,080 miles. The significant increase suggests that the Company did not trim the required miles in the years 2006-2008 and is attempting to make up for the shortfall in the year rates are being set. Based on the response to OPC Interrogatory No. 270 the Company's 2009 budget is comparable to the amount expended in 2007. The significant increase in 2010 over 2009 further suggests that costs are being deferred to the projected test year. Limiting maintenance in previous years, for whatever reason, is not justification for passing the catch up costs on to ratepayers. The amount allowed in rates should be based on the annual requirement to trim the primary conductor miles of line. Furthermore, it would be inappropriate to defer costs properly attributable to 2009 since that period is covered by a revenue sharing mechanism that assumes that earnings are fairly presented for surveillance purposes.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE UNEXPLAINED COSTS INCLUDED IN THE DISTRIBUTION O&M EXPENSE REQUEST?

A. No specific adjustment is being recommended for the unexplained O&M expense but I will discuss this concern elsewhere in my testimony.

XI. POWER OPERATIONS O&M EXPENSE

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S POWER OPERATIONS O&M EXPENSE REQUEST?

A. The request appears excessive. As with the transmission and distribution submissions there was a limited amount of specifics regarding what the Company was including in the request. Beginning on page 24, Company witness, David Sorrick provides an explanation of the $53.1 million benchmark variance. The Company's request for Power Operations O&M expense is $175 million after excluding the payroll taxes, employee benefits and injuries and damages budgeted by the Power Operations cost center. The real budget total is $201 million. A very generic explanation of why the benchmark variance is $53.1 million does not constitute adequate justification for the $175 million identified by the Company's witness.

Q. WHY DO YOU BELIEVE THE COMPANY'S POWER OPERATIONS O&M EXPENSE REQUEST IS EXCESSIVE?

A. The Company's $175 million request has increased significantly when compared to the 2008 costs of approximately $138 million and the 2007 costs of approximately $127 million as shown on Company MFR Schedule C-6. Company testimony attempts to justify the increase by describing the various improvements in operations and efficiencies achieved. The problem is that the testimony does not provide an adequate explanation and it does not justify the cost increase requested. For example on page 15 of his pre-filed testimony Mr. Sorrick discusses the improvement in Equivalent Forced Outage Rates (EFOR) for unit CR2. A review of the response to OPC Interrogatory No. 248 indicates that in 2008 CR1, CR4 and CR5 EFOR increased. There are other increases also. In reviewing the response to OPC Interrogatory No. 247 it was observed that unit availability declined for a majority of the units in 2008. There is also discussion about costs savings and efficiencies but no indication as to how and/or whether any savings are reflected.

Q. ARE YOU RECOMMENDING SPECIFIC ADJUSTMENTS TO THE POWER OPERATIONS O&M EXPENSE REQUEST?

A. Yes. There is one specific adjustment and later in my testimony I will include some discussion regarding Power Operations in a proposed overall adjustment to the Company's request. As shown on Exhibit HWS-1 Schedule C-8 the Company's Power Operations Maintenance Expense should be reduced $17,741,309 on a jurisdictional basis.

Q. COULD YOU EXPLAIN HOW YOU DETERMINED THE ADJUSTMENT TO THE POWER OPERATIONS O&M EXPENSE REQUEST?

A First, the maintenance expense for power generation is projected to increase from $76.5 million in 2008 to $109.2 in 2010. After excluding company labor from the request, the maintenance is projected to increase $19 million (35.2%) from $54 million in 2008 to $73 million in 2010. Maintenance can fluctuate from year to year and basing the rate request on one high year is inappropriate. Therefore, some adjustment was required to smooth out the cost being passed onto ratepayers. The Company's 2010 projected cost was adjusted for certain increases to smooth out the 2010 maintenance overload.

One cost driver of the increase is the adding of major Clean Air equipment at Crystal River Unit 4. Based on the response to OPC Interrogatories No. 260 and 263 there are two concerns with the $15.1 million of added cost in this project. The first concern is this type of work is typically performed every 9 years. The second concern is the cost increase appears to include $5.3 million for a precipitator and if that response is correct, this a capital cost not an expense. Because the cost is not typical maintenance and will not be recurring, the cost for rate making purposes should be spread over at least 5 years. Spreading the $15.1 million over 5 years reduces the 2010 cost by $12 million.

Second, the Company was requested in OPC's Production of Document Request No. 213 to provide <u>all supporting documentation</u> that the company has for the $4.6 million cost estimate for 2010 under the Long Term Service Agreement discussed by Mr. Sorrick on page 26, of his pre-filed testimony. (emphasis added) The Company response was, to see the response to OPC POD Question #1, MFR Schedule C-41, page 3 of 18. The MFR as indicated earlier provides a generic explanation for the increase over the benchmark and the explanation for the $4.6 million consisted of a paragraph that concludes by stating "We estimate the costs of that maintenance work covered by the LTSA to be approximately $4.6 million for the completion of two combustion inspections and two Balance of Plant outages." Another request was made for a more detailed explanation of the cost estimate in OPC Interrogatory No. 261. The response indicated that the inspection requirement included for the two units occurs every 12,500 hours. Assuming the unit operates 24-7 that would equate to an inspection every 6 years. Supporting documentation for a cost estimate is not a paragraph that says "we estimate the cost to be this". Because the Company failed to provide supporting documentation for the requested expense the cost estimate of $4.6 million should be disallowed. However because this is also an infrequent cost I am recommending that only half of the cost be allowed in rates. This reduces the maintenance expense by $2.3 million.

Finally the Company was asked about the $14.7 million increase for existing fleet maintenance. OPC Interrogatory No. 264 asked the Company to identify the supporting documentation for the $14.7 million cost estimate and the response simply referred to the benchmark comparison explanation. Once again documentation for costs is not a paragraph but an invoice or cost quote. The response also provided a summary listing of the cost estimate. This estimate only provides further verification that what has occurred in the 2010 projections is an overloading of maintenance expense. The fact that 2010 is the projected test year for setting rates is not coincidental. The $14.7 million should be reduced $7.35 million to smooth out the costs for maintenance being charged to ratepayers. Without this smoothing, rates could be set artificially high and in future year's shareholders will benefit from the over-collection.

<u>XII. DIRECTORS AND OFFICERS LIABILITY INSURANCE</u>

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. Yes. The Company has included $2.2 million of expense in account 925 for Directors and Officer's liability insurance (DOL) based on the response to OPC Interrogatory No. 310. The response to OPC POD No. 272 indicates that the budget includes $2,750,650 allocated to PEF. This expense is for $300 million of coverage. This expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. The question is whether this cost that the Company has elected to incur as a business expense is for the benefit of shareholders and/or ratepayers. The question also is whether the cost for $300 million of coverage is necessary and whether the cost for that level of coverage is appropriate to pass on to ratepayers.

Q. DID YOU JUST RECENTLY ADDRESS THIS ISSUE IN THE TAMPA ELECTRIC CASE AND THE PEOPLES GAS CASE?

A. Yes and in both cases the Commission allowed the cost to be included in customer's rates. The justification for allowing the cost was the cost was determined to be a legitimate business expense. In fact in the Agenda Conference for Peoples Gas Company, on May 5, 2009, at least one Commissioner opined that the decision to allow the cost should be applied consistently to all utilities electric, gas and water and sewer on the basis that the cost is a legitimate business expense.

Q. BASED ON THAT STATEMENT AND THE DECISIONS WHY ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE COST ASSOCIATED WITH DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. The Florida Commission has in the past disallowed DOL insurance costs and I respectfully disagree with the staff's recommendation and the Commission's conclusion on this issue in recent cases. The issue is more than whether the cost is a legitimate business expense. The issue is whether the cost is one that is beneficial to ratepayers and that should be borne by ratepayers as opposed to shareholders. Contributions and lobbying are deemed legitimate business expenses but they are not deemed appropriate costs to be passed on to ratepayers. In fact other regulatory agencies have also determined that the cost for DOL insurance to be a legitimate business expense but that the cost should not be borne totally be ratepayers. I believe that because the Staff concluded that the cost, in their opinion, is a legitimate business expense should not be the ultimate deciding factor as to whether the cost is appropriate to be borne by ratepayers. As a witness that is representing the ratepayers of Florida it is my responsibility to recommend to the Commission that ratepayers should not be required to pay for costs, that are solely for the benefit of the shareholders of the Company, especially when the cost have been disallowed from rates in other jurisdictions.

Q. COULD YOU PROVIDE SOME ADDITIONAL INFORMATION AS TO WHY OTHER JURISDICTIONS HAVE NOT REQUIRED RATEPAYERS TO BEAR THE COST ENTIRE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. Yes. In Connecticut there has been multiple decision where the amount allowed to be recovered from ratepayers has been limited. For example in Docket No. 07-07-01 the Department limited the recovery by Connecticut Light and Power for DOL insurance cost from ratepayers to 30% because it was determined that ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. On February 4, 2009 the Department determined that United Illuminating Company could only recover 25% of the cost of DOL insurance from ratepayers. In New York in Case 07-E-0523 the Commission did not disallow the cost recovery of DOL insurance based on the judges recommendation even though the a disallowance of such cost could be made based on Commission policy. The issue was raised again when Consolidated Edison Company filed in Case 08-E-0539. In the final decision the Commission ruled that $300 million of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100 million excess and then disallowed 50% of the premium associated with the $200 million that was determined to be reasonable. In the discussion the Commission notes that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place while customers have no influence. The decision continued by stating "We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders." (Page 91 of the decision)

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE INCLUDED IN THE COMPANY'S REQUEST?

A. I am recommending total disallowance of the $2,750,650 ($2,412,100 jurisdictional) because the cost provides a direct benefit and protection to shareholders. In each of the cases cited above the company argued that the cost is a necessary and prudent cost that is required to attract and retain competent directors and officers. There are regulatory decisions that have indicated that although DOL insurance is a necessary cost of doing business, the ratepayers should not be required to pay the full cost of coverage because the insurance primarily benefits shareholders. In ratemaking the cost should follow the benefit and the benefit of this insurance clearly inures first and foremost to shareholders. In fact, shareholders will likely be the one that makes a claim against the policy. I have never heard of a claim being filed by ratepayers against a D&O insurance policy.

Q. WHY ARE YOU PROPOSING THE ENTIRE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE BE DISALLOWED AS OPPOSED TO A SHARING AS EXHIBITED IN THE CASES YOU IDENTIFIED?

A. I am recommending total disallowance for the same reason the Company is requesting that all the costs be allowed in rates. It is my belief that the entire cost is for the protection of shareholders. A common argument for the insurance is that it is required to attract and retain competent directors and officers chosen by shareholders. That argument may justify shareholders purchasing the insurance because they are the ones who hold the officers and directors accountable. There is no argument that would justify ratepayers bearing any of the cost. It is not my position that the Company should not have the insurance coverage, I just believe that the burden should follow the benefit and in this case the benefit is to shareholders. That being said I would not object to some form of sharing if some benefit to ratepayers could be shown.

XIII. INJURIES & DAMAGES EXPENSE ADJUSTMENT

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO INJURIES & DAMAGES EXPENSE?

A. The Company's request in the filing is not supported by the record. The original filing as shown on MFR Schedule B-21, Page 1 of 4, showed there was no expense in the projected rate year for injuries and damages. The witness for Schedule B-21, Mr. Toomey does not discuss injuries and damages. As shown on Exhibit HWS-1 Schedule C-9, I am recommending an adjustment of $5,449,303 or $4,778,603 on a jurisdictional basis.

Q. IF THERE WAS NO EXPENSE IN THE PROJECTED TEST YEAR WHY WOULD YOU PROPOSE AN ADJUSTMENT TO INJURIES & DAMAGES EXPENSE?

A. There was an expense in the projected test year 2010. The Company was requested to verify whether the MFR was correct and if the MFR was not correct the Company was requested to provide the costs included in the projected test year 2010 by budget center. The response to OPC Interrogatory No. 342 indicated the MFR was not correct and that there was $2,694,313 in various budget centers and $1.7 million in the legal department's budget. However, it turns out that this information was also incorrect.

Q. HOW DID YOU DETERMINE THAT THE RESPONSE TO OPC INTERROGATORY NO. 342 WAS NOT CORRECT?

A. The Company was requested in OPC Interrogatory No. 386 to explain what the costs that were identified as either "Other" or "Purch" with the classification of "Salaries and Wages" were that were included in the budget provided in response to OPC POD No. 37. The response indicated that the "Salaries and Wages" identification was incorrect and should have been labeled "A&G Office Supplies & Expense". In addition the response indicated that the nuclear budget had misclassified $450,000 that should have been included in "A&G Injuries & Damages". That would mean that there was at least $4,844,313 ($2,694,313 +1,700,000 + 450,000) included in the 2010 projected year. My analysis of the budgeted costs actually revealed $5,020,063. As shown on Exhibit HWS-1 Schedule C-9, the legal budget included $1,825,000 plus another $50,750 not the $1,700,000 indicated by the Company. The $1,825,000 was verified in the response to OPC POD No. 274. As will be discussed elsewhere the Company budgeting is a concern and the costs included in that budget are of even greater concern since the Company apparently has problems identifying costs and has errors in the process itself.

Q. WHY WOULD YOU ELIMINATE THE ENTIRE AMOUNT REQUESTED FOR INJURIES AND DAMAGES IN THE PROJECTED TEST YEAR 2010?

A. The Company failed to provide any justification for any cost for 2010. This is important considering the fact that it appears that the 2008 did not have any expense. The Company provided the 2008 budgeted and actual cost for 2008 in response to OPC Interrogatory No. 389 and as shown on Exhibit HWS-1 Schedule C-9, there was a negative expense in 2008. It would not be appropriate for the Company to be allowed an expense in the projected test year when there was no expense in the base year 2008. This is especially true when there was initially an indication that zero expense was included in the projected year and when there is no testimony or justification for any amount in the projected test year 2010.

XIV. BUDGET ANALYSIS

Q. DID YOU REVIEW BUDGET DETAIL USED BY THE COMPANY IN THE DEVELOPEMNT OF PROJECTED TEST YEAR COSTS FOR 2010?

A. There was a review of budget information supplied in various responses to OPC discovery and there was a sample review performed in an attempt to determine what support existed for the Company projections. Based on my review I have some grave concerns about the costs included in the Company's rate request.

Q. WHAT CONCERNS HAVE YOU IDENTIFED?

A. Initially the Company was requested in OPC POD No. 15 to provide the 2009 and 2010 budget in the most detailed format available. The response included 46 documents and on each document were numbers that do not provide any added information beyond what was already reflected in the filing. If you could identify a number that was in the filing you still were unable to determine what the factors were that made up the number. I have attached one of the documents as Exhibit HWS-2 as an example. In an attempt to derive some use from the documents provided the Company was requested in OPC Interrogatory No. 315 to provide a mapping that would allow for the tracking of the budget information supplied to the MFRs. The response did not provide any additional assistance.

The Company did provide in response to OPC POD No. 37 a more detailed budget that did have some information that was useful. As discussed above, the report provided did allow me to identify the problem with the Company's MFR for injuries and damages and served as source for identifying the concerns that I have with the budget. The report is by budget center and identifies cost by type and account. In my review I selected twenty-eight line items totaling $62.5 million for further review. With the exception of OPC POD Nos. 272-274, my request clearly stated "Provide the supporting detail for the budgeted costs and documentation for the budgeted costs". Of the nineteen line items that documentation was requested only two had what would be considered documentation. Detail of what was included in the line item amounts was provided for fourteen of the nineteen line items. There was not sufficient detail or documentation for five of the line items. If detail was provided it had numbers on it that could not be tied to the line item is was supposed to detail. The concern is, the information supplied was detail that provided in some cases more information as to what the different cost components were but there was no supporting documentation for the numbers on the detail page.

Q. WHAT WAS DIFFERENT WITH THE REQUESTS OPC POD NOS. 272-274?

A. The request stated "Provide the supporting documentation and/or detail for the budgeted costs". The "and/or" may have been interpreted to mean that either was sufficient. Such a reading would be contrary to the instructions accompanying the discovery. The Company provided detail for each of the nine line items identified. What could be considered as further detail or documentation was provide for one line item that allowed me to see how a cost was determined. Here again detail did in some case provided additional information but without supporting documentation for the cost, the numbers are just numbers on a piece of paper.

Q. WHAT IS SUPPORTING DOCUMENTATION?

A. Supporting documentation would be a quote, an invoice or an estimate from a third party that could justify a cost estimate included in the budget. Some costs like injuries and damages or labor for a certain type of project could be supported with actual historical cost detail. Numbers on a piece of paper is not supporting documentation. If an auditor or the IRS would ask for supporting documentation for a $1,200,000 line item in A&G Office Supplies and Expense they would not accept a piece of paper that says "Corporate Managed Account".

Q. WHAT DOES THE COMPANY CONSIDER SUPPORTING DOCUMENTATION TO BE?

A. I cannot answer that. The response to OPC Interrogatory No. 394 state that "PEF considers documentation to have the meaning given to it by applicable orders, rules, and statutes in Florida". The Company response did not provide any specific cite that could be relied on. Just like the costs there is no support provided for the Company response.

Q. ARE THERE CONCERNS WITH THE DETAIL INFORMATION SUPPLIED?

A. Yes. Even though there may have been a detailed listing of various costs included in the cost estimate, the detail did not provide any real information. For example, the response to OPC POD No. 272 provided four pages of "detail" for the $1,780,000 of

General Advertising Expense included in the budget. The detail simply labeled the cost as "other" and as "Utility Advertising". That really is not very informative. No indication is provided showing the type of advertising or the media used for the advertising. Another example is the response to OPC POD No. 267. The detail for the $1,789,440 is reference to a contract for $1,611,778 plus burdens of $177,662. The word contract is not support in anyway for costs, it is simply a word and a number. A third example, are the costs detailed in the response to OPC POD No. 268. There is $315,521 for which no detail was provided and then there are two combustion inspections each with an expense of $1.6 million. The concern is the detail indicates that the total project cost for each inspection is $2.158 million, with $558,000 being capitalized. There is a concern that the amount being capitalized is understated and there is also a concern that the documentation that was supplied indicates the expense is high. The documentation supplied for these two line items is the only real documentation supplied, it is confidential, and it is less than the projected expense. That fact raises my concern even more with the cost estimate for which no supporting cost documentation was supplied.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR ANY OF THE COSTS YOU ATTEMPTED TO REVIEW?

A. Yes. As shown on Exhibit HWS-1 Schedule C-10, I am recommending a specific adjustment of $2,688,677 ($2,331,755 on a jurisdictional basis) for cost included in A&G Office Supplies and Expense that are not appropriate costs to be included in rates especially in today's economy. With respect to the Company's failure to provide sufficient supporting documentation for the remaining costs I have factored that into my Productivity discussion and adjustment as will be discussed next.

Q. WHAT ARE THE COSTS THAT YOU ARE RECOMMENDING AN ADJUSTMENT FOR BECAUSE YOU BELIEVE THEY ARE NOT APPROPRIATE?

A. On Exhibit HWS-1 Schedule C-10, lines 1 and 2, I adjusted out $2,688,677 of costs. The first adjustment of $1,488,677 consists of $1,268,677 for events such as the Tampa Bay Lightning for $59,900, the Tampa Bay Buccaneers for $139,527, the Orlando Magic for $20,000 and more. The two listings of events and costs are included as Exhibit HWS-3. The remaining $220,000 is for service awards. Typically the Commission would allow the payment of service awards if the amount were determined to be reasonable but I believe at this time this cost should not be passed on to ratepayers.

The second adjustment is $1,200,000 for what is described as "Corporate Managed Account". This appears to be a large petty cash account for the president's budget center. The Company did not provide any supporting documentation for this expense as requested therefore the cost is not justified and should be excluded from rates.

Q. ARE YOU SURE THAT THE COMPANY DID NOT REMOVE THE COSTS IN QUESTION FROM ITS RATE REQUEST?

A. There is no evidence that the cost have been removed. The costs were budgeted in account 921 "A&G Office Supplies and Expense". In response to OPC Interrogatory No. 391 the Company supplied a reconciliation that links the budget costs reviewed to MFR Schedule C-1 and in turn to MFR Schedule C-2. The only adjustments O&M Expense reflected that remove budgeted costs are the aircraft adjustment and the advertising. The costs are not aircraft costs and the advertising adjustment of $3.388 million relates to labor costs in account 920 and advertising costs in account 9301.

XV. O&M EXPENSE PRODUCTIVITY ADJUSTMENT

Q. ARE YOU RECOMMENDING A PRODUCTIVTY ADJUSTMENT TO THE COMPANY'S O&M EXPENSE REQUEST?

A. Yes. The Company's request is excessive because it reflects an overloading of unsupported costs into the test year, and it does not reflect the cost savings that should be generated from any increase in maintenance and improvements in operations. In addition the Company can be expected to undertake every effort after rates are established to minimize its future costs so the corporate strategy can be achieved.

Q. IS THE COST SAVINGS AND UNSUPPORTED COSTS THE CONCERNS YOU HAD IDENTIFIED EARLIER AND YOU INDICATED WOULD BE DISCUSSED AT LATER TIME?

A. That is correct. The unsupported FERC 890 cost request of $6.9 million, the unidentified distribution increase of $7.7 million are examples and the budgeted costs that were not supported with documentation as requested. The Company's testimony identifies a number of improvements without any explanation as to where the cost savings are reflected. For example, the testimony of David Sorrick, at page 15, indicates that there will be cost savings from the Hines Power Block 4 Combustion Optimization Package in the future and, on page 16, the Anclote Cooling Tower project is expected to reduce maintenance cost in the future. There has to be some benefit to ratepayers from the significant increase in spending being requested that will offset the cost. If that cost savings is not reflected then there is the risk that it will flow through to shareholders absent a regular earnings adjustment filing by the Company. If rates are set based on the significant spending without recognition of the benefits that are forthcoming, when the cost savings occur there is no way for ratepayers to receive that benefit.

Q. WHAT IS THE CORPORATE STRATEGY TO WHICH YOU REFERRED?

A. In response to OPC Production of Documents No. 5, the Company provided a copy of the 2009 Progress Energy Florida Strategic Plan. An important point in the strategy commitment is the following statement "The overall mission of Progress Energy is to reward its investors by providing above-average total shareholder returns over a continuous timeframe." This thought process is further emphasized in the financial objectives that include "Annual EPS growth (4-5%)", continue dividend growth and an annual TSR of 8-10%. Part of the strategy is discussed on page 12 in the customer price analysis where it is indicated that the base rate filing in 2009 will add significantly to the 2010 price. There is also a reference to pursuing wholesale customers and consider the opportunities to expand generation, transmission, distribution and/or customer service to support other utilities in Florida. And then there is the commitment to annual productivity gains of at least 3%-5%. This emphasis on productivity gains is mentioned on pages 7 and 27. The strategy mentioned is noteworthy given the current rate request because it focuses on shareholders and is not concerned with the fact that the plan mentions that a weakness is customer rates generally are higher than peers.

Q. WHAT IS YOUR INTERPRETATION OF THE CORPORATE STRATEGY YOU JUST DISCUSSED?

A. The Company is requesting a $500 million rate increase. The increase reflects significant cost increases over historical cost levels that appear to have been controlled in the past by the Company. The significant increase requested includes costs such as payroll increases and incentives that many other companies are freezing, reducing or in the case of utilities minimizing the amounts requested in rates. PEF has not followed what many other companies are doing. The overall mission as clearly stated by PEF is to provide "above-average total shareholder returns". This mission is not only insensitive to ratepayers during theses difficult economic times but it also reflects a mentality that through regulation this company is free to ignore the economic realities of the day. It is clear that the focus is an increasing return for shareholders at the expense of ratepayers. Even though the plan identifies an objective of customer satisfaction and affordable rates, the rate request suggests that PEF has a different interpretation of what affordable rates are based on customer concerns presented in public hearings.

Q. ARE YOU QUESTIONING THE COMPANY'S EFFORT TO MINIMIZE RATEPAYER COSTS YET ACHIEVE THE MISSION TO REWARD SHAREHOLDERS WITH ABOVE-AVERAGE RETURNS?

A. Yes. As indicated earlier the Company goal is to award shareholders with above-average shareholder returns. There is no goal to minimize the rate request and that is substantiated with the business as usual pay increases, increased incentive compensation and the other significant cost increases that are recorded above the line. Mr. Toomey states, on page 13, of his testimony that the Company understands the tough realities of the current economic conditions and I believe the Company does but from a shareholders perspective. This is substantiated by the increases requested for above the line test year costs while 2010 budgeted shareholder costs have declined. In response to OPC Interrogatory No. 309 the Company stated that the declining economic condition was the reason that donations and civic expenses were less in the 2010 budget than in 2008. A budget reduction of approximately 20% of below the line costs for civic functions and donations is an important fact when you take into consideration the increase in above the line costs. Business as usual for above the line costs and belt tightening for shareholder costs in my opinion is evidence that the focus is on shareholder returns.

Q. HOW CAN THE CORPORATE STRATEGY ACHIEVE THE MISSION TO REWARD SHAREHOLDERS WITH ABOVE-AVERAGE RETURNS?

A. As stated above the Company has requested a $500 million rate increase. The increase is based on significant projected increases in cost estimates. The corporate strategy to achieve productivity gains of at least 3%-5% is the second step to achieving the success desired. If rates are increased based on the significant cost increase requested and then afterwards the productivity gains are achieved, the benefit will flow solely through to shareholders. This is not the time to be seeking excess earnings at the expense of ratepayers. This is the time to tighten the belt, contain costs and make concessions that will help ratepayers deal with today's economic downturn. This filing does not do this.

Q. WHAT ARE YOU RECOMMENDING FOR A PRODUCTIVITY ADJUSTMENT?

A. As shown on Exhibit HWS-1, Schedule C-11, the adjustment I am recommending is a reduction to O&M expense of $13.034 million. My adjustment takes the Company's requested 2010 O&M Expense net of labor and assumes a 3% productivity factor. The 3% is the low end of the Company strategy.

Q. IS THIS TYPE OF ADJUSTMENT APPROPRIATE FOR THE COMMISSION TO MAKE?

A. Most certainly. The Commission has to determine a fair cost of service that will produce a reasonable opportunity for the Company to achieve a reasonable rate of return. The Company has set a productivity goal of 3%-5% that means there is a good possibility of achievement of that goal and it would be inappropriate to ignore that fact. In New York, when Consolidated Edison Company files for a rate increase it incorporates a 1% productivity adjustment to payroll as previously directed by the commission. In the decision in Case 08-E-0539 the Commission determined that because of the increased investment in plant (similar to PEF's reflecting an increase in plant investment) there would be an increase in productivity and ruled that the productivity adjustment should be 2% instead of 1%. After evaluating the issues, the Commission made an additional adjustment reducing O&M cost by $60 million. This adjustment factored in the downturn in the economy and the impact the company's request would have on ratepayers. In the decision the company was ordered to implement austerity programs to constrain costs and tighten belts to limit discretionary spending. The adjustment I am recommending is reasonable and pales in comparison to the adjustment ordered by the New York Commission.

XVI. OTHER OPC WITNESS ADJUSTMENTS

Q. HAVE YOU REFLECTED ADJUSTMENTS PROPOSED BY OTHER OPC WITNESSES IN YOUR EXHIBITS?

A. Yes. The impact of adjustments to the reserve for accumulated depreciation and the change in depreciation expense has been reflected on Exhibit HWS-1, Schedule B-5. The impact on deferred income taxes was calculated by me based on the average change to the reserve for accumulated depreciation.

On Exhibit HWS-1, Schedule D, Page 2, I have reflected the capital structure ratios and the weighted cost rates as recommended by Dr. J Randall Woolridge. On Exhibit HWS-1, Schedule D, Page 1, I have reflected a revised capital structure that changes the capital structure ratios after reflecting the change in deferred income taxes that resulted from the adjustment proposed by OPC witness Jacob Pous.

On Exhibit HWS-1, Schedule B-2 and Schedule C-2, I have reflected the adjustments proposed by Ms. Kimberly Dismukes.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. 090079-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony of Helmuth W. Schultz III, CPA has been furnished by U.S. Mail and * hand delivery on this 10th day of August 2009, to the following parties:

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EXHIBITS OF HELMUTH SCHULTZ, III

APPENDIX A
QUALIFICATIONS OF HELMUTH W. SCHULTZ, III

Mr. Schultz received a Bachelor of Science in Accounting from Ferris State College in 1975. He maintains extensive continuing professional education in accounting, auditing, and taxation. Mr. Schultz is a member of the Michigan Association of Certified Public Accountants

Mr. Schultz was employed with the firm of Larkin, Chapski & Co., C.P.A.s, as a Junior Accountant, in 1975. He was promoted to Senior Accountant in 1976. As such, he assisted in the supervision and performance of audits and accounting duties of various types of businesses. He has assisted in the implementation and revision of accounting systems for various businesses, including manufacturing, service and sales companies, credit unions and railroads.

In 1978, Mr. Schultz became the audit manager for Larkin, Chapski & Co. His duties included supervision of all audit work done by the firm. Mr. Schultz also represents clients before various state and IRS auditors. He has advised clients on the sale of their businesses and has analyzed the profitability of product lines and made recommendations based upon his analysis. Mr. Schultz has supervised the audit procedures performed in connection with a wide variety of inventories, including railroads, a publications distributor and warehouser for Ford and GM, and various retail establishments.

Mr. Schultz has performed work in the field of utility regulation on behalf of public service commission staffs, state attorney generals and consumer groups concerning regulatory matters before regulatory agencies in Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Kentucky, Kansas, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, Rhode Island, Texas, Utah, Vermont and Virginia. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on numerous occasions.

<u>Partial list of utility cases participated in</u>:

U-5331	Consumers Power Co. Michigan Public Service Commission
Docket No. 770491-TP	Winter Park Telephone Co. Florida Public Service Commission

Case Nos. U-5125 and U-5125(R)	Michigan Bell Telephone Co. Michigan Public Service Commission
Case No. 77-554-EL-AIR	Ohio Edison Company Public Utility Commission of Ohio
Case No. 79-231-EL-FAC	Cleveland Electric Illuminating Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Refunds Michigan Public Service Commission
Docket No. 820294-TP	Southern Bell Telephone and Telegraph Co. Florida Public Service Commission
Case No. 8738	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
82-165-EL-EFC	Toledo Edison Company Public Utility Commission of Ohio
Case No. 82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
Docket No. 830012-EU	Tampa Electric Company, Florida Public Service Commission
Case No. ER-83-206	Arkansas Power & Light Company, Missouri Public Service Commission
Case No. U-4758	The Detroit Edison Company - (Refunds), Michigan Public Service Commission
Case No. 8836	Kentucky American Water Company, Kentucky Public Service Commission
Case No. 8839	Western Kentucky Gas Company, Kentucky Public Service Commission

Case No. U-7650	Consumers Power Company - Partial and Immediate Michigan Public Service Commission
Case No. U-7650	Consumers Power Company - Final Michigan Public Service Commission
U-4620	Mississippi Power & Light Company Mississippi Public Service Commission
Docket No. R-850021	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. R-860378	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. 87-01-03	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 87-01-02	Southern New England Telephone State of Connecticut Department of Public Utility Control
Docket No. 3673-U	Georgia Power Company Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Alaska Public Utilities Commission
Docket No. 8363	El Paso Electric Company The Public Utility Commission of Texas
Docket No. 881167-EI	Gulf Power Company Florida Public Service Commission
Docket No. R-891364	Philadelphia Electric Company Pennsylvania Office of the Consumer Advocate

Docket No. 89-08-11	The United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. 9165	El Paso Electric Company The Public Utility Commission of Texas
Case No. U-9372	Consumers Power Company Before the Michigan Public Service Commission
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
ER89110912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Case No. 90-041	Union Light, Heat and Power Company Kentucky Public Service Commission
Docket No. R-901595	Equitable Gas Company Pennsylvania Consumer Counsel
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company Delaware Public Service Commission
Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission
Case No. PUE900034	Commonwealth Gas Services, Inc. Virginia Public Service Commission
Docket No. 90-1037* (DEAA Phase)	Nevada Power Company - Fuel Public Service Commission of Nevada

Docket No. 5491**	Central Vermont Public Service Corporation Vermont Department of Public Service
Docket No. U-1551-89-102	Southwest Gas Corporation - Fuel Before the Arizona Corporation Commission
	Southwest Gas Corporation - Audit of Gas Procurement Practices and Purchased Gas Costs
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 5532	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 910890-EI	Florida Power Corporation Florida Public Service Commission
Docket No. 920324-EI	Tampa Electric Company Florida Public Service Commission
Docket No. 92-06-05	United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. C-913540	Philadelphia Electric Co. Before the Pennsylvania Public Utility Commission
Docket No. 92-47	The Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control

Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation (Supplemental) State of Connecticut Department of Public Utility Control
Docket No. 93-08-06	SNET America, Inc. State of Connecticut Department of Public Utility Control
Docket No. 93-057-01**	Mountain Fuel Supply Company Before the Public Service Commission of Utah
Docket No. 94-105-EL-EFC	Dayton Power & Light Company Before the Public Utilities Commission of Ohio
Case No. 399-94-297**	Montana-Dakota Utilities Before the North Dakota Public Service Commission
Docket No. G008/C-91-942	Minnegasco Minnesota Department of Public Service
Docket No. R-00932670	Pennsylvania American Water Company Before the Pennsylvania Public Utility Commission
Docket No. 12700	El Paso Electric Company Public Utility Commission of Texas
Case No. 94-E-0334	Consolidated Edison Company Before the New York Department of Public Service
Docket No. 2216	Narragansett Bay Commission On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission

Docket No. 2216	Narragansett Bay Commission - Surrebuttal On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Case No. PU-314-94-688	U.S. West Application for Transfer of Local Exchanges Before the North Dakota Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 96-01-26**	Bridgeport Hydraulic Company State of Connecticut Department of Public Utility Control
Docket Nos. 5841/ 5859	Citizens Utilities Company Before Vermont Public Service Board
Docket No. 5983	Green Mountain Power Corporation Before Vermont Public Service Board
Case No. PUE960296**	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission

Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission
Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-01-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-04-18	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 99-09-03	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 980007-0013-003	Intercoastal Utilities, Inc. St. John County - Florida
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 6332 **	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. G-01551A-00-0309	Southwest Gas Corporation Before the Arizona Corporation Commission

Docket No. 6460**	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 01-05-19 Phase I	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 010949-EI	Gulf Power Company Before the Florida Office of the Public Counsel
Docket No. 2001-0007-0023	Intercoastal Utilities, Inc. St. Johns County - Florida
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket Nos. R. 01-09-001 I. 01-09-002	Verizon California Incorporated Before the California Public Utilities Commission
Docket No. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 5841/5859	Citizens Utilities Company Before the Vermont Public Service Board
Docket No. 6120/6460	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 020384-GU	Tampa Electric Company d/b/a/ Peoples Gas System Before the Florida Public Service Commission

Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 6914	Shoreham Telephone Company Before the Vermont Public Service Board
Docket No. 04-06-01	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket Nos. 6946/6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42**	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 050045-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 050078-EI**	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-03-17	The Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 05-06-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Docket NO. 7120 **	Vermont Electric Cooperative Before the Vermont Public Service Board
Docket No. 7191 **	Central Vermont Public Service Corporation Before the Vermont Public Service Board

Docket No. 06-035-21 **	PacifiCorp Before the Public Service Commission of Utah
Docket No. 7160	Vermont Gas Systems Before the Vermont Public Service Board
Docket No. 6850/6853 **	Vermont Electric Cooperative/Citizens Communications Company Before the Vermont Public Service Board
Docket No. 06-03-04** Phase 1	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Application 06-05-025	Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company Before the California Public Utilities Commission
Docket No. 06-12-02PH01**	Yankee Gas Company State of Connecticut Department of Public Utility Control
Case 06-G-1332**	Consolidated Edison Company of New York, Inc. Before the NYS Public Service Commission
Case 07-E-0523	Consolidated Edison Company of New York, Inc. Before the NYS Public Service Commission
Docket No. 07-07-01	Connecticut Light & Power Company Connecticut Department of Public Utility Control
Docket No. 07-035-93	Rocky Mountain Power Company Before the Public Service Commission of Utah
Docket No. 07-057-13	Questar Before the Public Service Commission of Utah
Docket No. 08-07-04	United Illuminating Company Connecticut Department of Public Utility Control

Case 08-E-0539	Consolidated Edison Company of New York, Inc. Before the NYS Public Service Commission
Docket No. 080317-EI	Tampa Electric Company Before the Florida Public Service Commission
Docket No. 7488**	Vermont Electric Cooperative, Inc. Before the Vermont Public Service Board
Docket No. 080318-GU	Peoples Gas System Before the Florida Public Service Commission
Docket No. 08-12-07***	Southern Connecticut Gas Company Connecticut Department of Utility Control
Docket No. 08-12-06***	Connecticut National Gas Company Connecticut Department of Utility Control

* Certain issues stipulated, portion of testimony withdrawn.
** Case settled.
*** Assisted in case and hearings, no testimony presented

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010
(000's)

Docket No. 090079-EI
Exhibit HWS-1
Schedule A-1
Page 1 of 1

Revenue Requirement

Line No.	Description	Per Company Amount	Per Citizens Amount	Reference
1	Adjusted Rate Base	6,238,617	6,348,626	Schedule B-1
2	Required Rate Of Return	9.21%	7.48%	Schedule D
3	Income Requirement	574,577	474,898	L.1 x L.2
4	Adjusted Net Operating Income	268,546	496,344	Schedule C-1
5	Income Deficiency (Sufficiency)	306,031	(21,446)	L.3-L.4
6	Earned Rate of Return	4.30%	7.82%	L.4/L.1
7	Gross Revenue Conversion Factor	1.6338	1.6338	
8	Revenue Deficiency (Sufficiency)	499,997	(35,038)	L.5 x L.7

Source: The Company amounts are from MFR Schedule A-1.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Adjusted Rate Base (000's)

Docket No. 090079-EI
Exhibit HWS-1
Schedule B-1
Page 1 of 1

Line No.	Description	Per Company Amount	Citizens Adjustments	Per Citizens Amount	Reference
	Utility Plant				
1	Electric Plant	10,381,341	(2,312)	10,379,029	
2	Accumulated Depreciation	(4,437,117)	112,883	(4,324,234)	
3	Construction Work In Progress	151,145		151,145	
4	Plant Held for Future Use	25,723		25,723	
5	Nuclear Fuel	126,566	(26,752)	99,814	
6	Total	6,247,658		6,331,476	
7	Working Capital Allownace	(9,041)	26,190	17,149	
8	Total Rate Base	6,238,617		6,348,626	

Source: Company amounts are from Company Schedule B-1, Page 1 of 3, Revised June 5, 2009.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Docket No. 090079-EI
Exhibit HWS-1
Schedule B-2
Page 1 of 1

Rate Base Adjustments

Line No.	Description		Per Citizens Amount	Reference
1	Plant		(2,312,387)	a
2	Accumulated Depreciation	113,445,500		B-5
3	Accumulated Depreciation	(562,236)		a
4	Total Accumulated Depreciation		112,883,264	
5	Nuclear Fuel		(26,752,411)	B-3
6	Working Capital - Rate Case		(969,531)	C-5
7	Working Capital - Storm Reserve		27,159,752	B-4
8			0	
9	Working Capital Adjustment		26,190,221	

Source: (a) Adjustment proposed by Kimberly Dismukes.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Docket No. 090079-EI
Exhibit HWS-1
Schedule B-3
Page 1 of 1

Rate Base Adjustment - Nuclear Fuel

Line No.	Month	2008	2009	2010	Reference
	Per Company				
1	December	78,852	106,080	159,832	a
2	January	77,189	103,777	156,436	a
3	February	75,175	104,270	160,328	a
4	March	74,633	102,878	156,856	a
5	April	72,528	101,828	153,497	a
6	May	70,574	128,750	157,743	a
7	June	94,762	133,790	154,384	a
8	July	92,570	140,164	150,913	a
9	August	90,721	137,821	154,951	a
10	September	95,282	143,245	152,152	a
11	October	94,351	158,599	155,951	a
12	November	99,098	158,599	152,591	a
13	December	106,080	159,832	149,585	a
14	Average	86,293	129,203	155,017	a
	Per Citizens				
15	December	78,852	106,080	125,892	
16	January	77,189	107,731	125,285	
17	February	75,175	109,382	124,678	
18	March	74,633	111,033	124,071	
19	April	72,528	112,684	123,464	
20	May	70,574	114,335	122,857	
21	June	94,762	115,986	122,251	
22	July	92,570	117,637	121,644	
23	August	90,721	119,288	121,037	
24	September	95,282	120,939	120,430	
25	October	94,351	122,590	119,823	
26	November	99,098	124,241	119,216	
27	December	106,080	125,892	118,609	
28	Average	86,293	115,986	122,251	
29	Nuclear Fuel Adjustment			(32,766)	L.28-L.14
30	Nuclear Fuel Adjustment Jurisdictional @.81646			(26,752)	

Source: (a) Company Schedule B-16

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Docket No. 090079-EI
Exhibit HWS-1
Schedule B-4
Page 1 of 1

Storm Reserve Analysis

Line No.		Beginning Balance	Accrual	Storm Charges	Net Collected	Interest	Ending Balance	Reference
	Actual							
1	2006	5,566,000	5,566,000	(6,578,163)	0	0	4,553,837	a
2	2007	4,553,837	5,566,000	(3,321,660)	55,840,459	814,343	63,452,979	a
3	2008	63,452,979	5,566,000	0	65,718,698	4,200,235	138,937,912	a
4	03/31/09	138,937,912	1,391,500	0	253	606,904	140,936,569	a
5	2009	140,936,569	4,174,500	(9,869,872)	0	0	135,241,197	b
6	2010	135,241,197	0	(6,589,898)	0	0	128,651,299	Testimony
7	2011	128,651,299	0	(6,589,898)	0	0	122,061,400	Testimony
8	2012	122,061,400	0	(6,589,898)	0	0	115,471,502	Testimony
9	Three Year Average of Charges			6,589,898				(Line 1-5)/3
10	Accrual Per Citizens			0				
11	Accrual Per Company			14,922,000				c
12	Expense Adjustment Recommended			(14,922,000)				
13	2010 Average Balance Per Citizens						131,946,248	
14	2010 Average Balance Per Company						159,106,000	d
15	Working Capital Increase						27,159,752	
16	1994			1				e
17	1995			5,044				e
18	1996			7				e
19	1997			1,159				e
20	1998			0				e
21	1999			4,506				e
22	2000			2,102				e
23	2001			5,896				e
24	2002			0				e
25	2003			715				e
26	2004	Not Included						
27	2005	Not Included						
28	2006			6,578				a
29	2007			3,322				a
30	2008*			9,870				b
31	13 Year Average			3,015				

Source: (a) Company response to OPC-153.
(b) Company response to OPC-355.
(c) Company Schedule B-21, Page 1.
(d) Company Schedule B-17, Page 3.
(e) Company response to OPC-2 (Docket No.050078-EI).

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Depreciation Adjustment

Docket No. 090079-EI
Exhibit HWS-1
Schedule B-5

Line No.	Description	Rate Base Jurisdictional	O&M Jurisdictional	Reference
1	Amortization of Reserve	73,006,500	(146,013,000)	a
2	Depreciation Expense	40,439,000	(80,878,000)	a
3	Total Reserve Adjustment	113,445,500		b
4	Total Depreciation Expense		(226,891,000)	a
5	ADIT Adjustment	(43,761,602)		

Source: (a) Per OPC witness Jacob Pous
(b) The ADIT is 38.575% of Line 3.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010
(000's)
Adjusted Net Operating Income

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-1
Page 1 of 1

Line No.	Description	Per Company Amount	Citizens Adjustments	Per Citizens Amount	Reference
1	Operating Revenues	1,517,918	8,646	1,526,564	a
	Operating Expenses				
2	Fuel & Net Interchange	8,125		8,125	
3	Operation & Maintenance	713,371	(132,331)	581,040	a
4	Depreciation & Amortization	357,869	(226,960)	130,909	a
5	Taxes Other Than Income	129,587	(21)	129,566	a
6	Interest Synchronization	0	(1,780)	(1,780)	a
7	Current/Deferred Income Taxes	44,490	141,940	186,430	a
8	Investment Tax Credits	(1,547)		(1,547)	
9	Gain On Sale Of Property	(2,523)		(2,523)	
10	Total Operating Expenses	1,249,372	(219,153)	1,030,219	
11	Operating Income	268,546	227,798	496,344	

Source: Company amounts are from Company Schedule C-1, Page 1 of 3, Revised June 5, 2009.
(a) Schedule C-2.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Net Operating Income Adjustments

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-2
Page 1 of 1

Line No.	Description	Per Citizens Amount	Reference
1	Operating Revenues	$8,645,724	a
	O&M Expenses		
2	Storm Reserve Accrual	(14,922,000)	Schedule B-4
3	Payroll	(47,540,636)	Schedule C-3
	Employee Benefits		
4	- Employee Expense Factor Adjustment	(9,376,809)	Schedule C-4
5	- Employee Complement Adjustment	(1,946,206)	Schedule C-4
6	Rate Case Expense	(989,618)	Schedule C-5
7	Transmission Vegetative Maintenance	(1,717,043)	Schedule C-6
8	Transmission Bonding & Grounding	(338,145)	Testimony
9	Distribution Vegetative Maintenance	(8,924,197)	Schedule C-7
10	Power Operations Maintenance	(17,741,309)	Schedule C-8
11	Directors & Officers Liability	(2,412,100)	Testimony
12	Injuries & Damages	(4,778,603)	Schedule C-9
13	A&G Office Supplies & Expense	(2,331,755)	Schedule C-10
14	A&G Adjustment to Wholesale Sales	(6,278,578)	a
15	Productivity Adjustment	(13,033,908)	Schedule C-11
16	Total O&M Expense	(132,330,907)	
17	Depreciation Expense	(226,891,000)	Schedule B-5
18	Depreciation Expense	(68,887)	a
19	Total Depreciation Expense Adjustment	(226,959,887)	
20	Taxes Other Than Income	(21,000)	a
21	Interest Synchronization Tax Adjustment	(1,780,419)	Schedule C-12
22	Income Tax Adjustment	141,939,613	Schedule C-13

Source: (a) Adjustment proposed by Kimberly Dismukes.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Payroll Adjustment

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-3
Page 1 of 2

Line No.	Description	Base Year	Per Company Projected Test Year	Projected Expense	Company Reference
1	Base Payroll	338,678,217	398,328,277	287,551,512	a,d
2	Incentive Compensation	31,192,187	33,886,020	25,371,639	a,c
3	Long Term Incentive Comp	12,319,236	16,704,435	12,094,011	a,d
4	Sub Total Payroll	382,189,640	448,918,732	325,017,162	a,c
5	Overtime	43,088,714	40,860,669	29,583,124	b,d
6	Total Payroll	425,278,354	489,779,401	354,600,286	L.5+L.6
7	Average Regular FTEs	4,929	5,299		a
8	Gross Average Salary	77,547	84,726		a
9	Average Base Salary	68,711	75,170		
10	Percentage Increase		9.40%		

Line No.	Description	Projected Test Year	Projected Expense
11	Base Payroll	375,656,958	271,185,182
12	Incentive Compensation	0	0
13	Long Term Incentive Comp	0	0
14	Sub Total Payroll	375,656,958	271,185,182
15	Overtime	40,860,669	29,583,124
16	Total Payroll	416,517,627	300,768,306
17	OPC Recommended Payroll Expense Adjustment		(53,831,980)
18	OPC Jurisdictional Payroll Expense Adjustment @ .88313		(47,540,636)

Source: (a) Company Schedule C-35, Revised June 5,2009.
(b) Response to OPC 3-127.
(c) Response to OPC 3-129.
(d) Estimated expense based on other expense factors.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Payroll Adjustment

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-3
Page 2 of 2

Line No.	Description	Base Year	Projected Test Year	Projected Employees	Base Payroll
	Average Base Salary Adjustment				
1	Per OPC	68,711	71,979	5,299	381,415,256
2	Per Company	68,711	75,170	5,299	398,328,277
3	Pay Increase Adjustment				(16,913,021)
4	Expense Ratio				72.19%
5	Expense Adjustment				(12,209,439)
	Employee Complement Adjustmenyt				
6	Per OPC		71,979	5,219	375,656,958
7	Per Company (as adjusted for pay rate)		71,979	5,299	381,415,256
8	Employee Complement Adjustment			(80)	(5,758,298)
9	Expense Ratio				72.19%
10	Expense Adjustment				(4,156,891)

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-3WP

Payroll Adjustment - Employee Count

Line No.	Description	Per Company	Projected Changes	Actual	Vacancy Rate	Reference
1	December 2008	4,929	4,929	4,929		a
2	January 2009		4,955			
3	February 2009		4,982			
4	March 2009		5,008	4,911	1.94%	a
5	April 2009		5,034			
6	May 2009		5,061			
7	June 2009		5,087			
8	July 2009		5,113			
9	August 2009		5,140			
10	September 2009		5,166			
11	October 2009		5,192			
12	November 2009		5,219			
13	December 2009	5,245	5,245			a
14	January 2010		5,250			
15	February 2010		5,254			
16	March 2010		5,259			
17	April 2010		5,263			
18	May 2010		5,268			
19	June 2010		5,272			
20	July 2010		5,277			
21	August 2010		5,281			
22	September 2010		5,286			
23	October 2010		5,290			
24	November 2010		5,295			
25	December 2010	5,299	5,299			a

Source: (a) Response to OPC 297.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Employee Benefit Adjustment

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-4
Page 1 of 1

Line No.	Description	2008	2010	Expense	Reference
1	Gross Payroll	425,278,354	489,779,401	354,600,286	Sch. C-4
2	Payroll Taxes	27,591,698	31,761,735		a
3	Workers Compensation	5,118,851	3,144,313		a
4	Pension Plan Expense	(14,594,190)	52,878,629		a
5	Life Insurance Benefits	1,096,179	1,158,221		a
6	Medical Insurance	29,969,289	37,040,816		a
7	Retiree Health/Life	21,677,092	22,717,974		a
8	LTD Health/Life	717,622	1,159,096		a
9	LTD Salary Continuation	1,036,592	1,359,355		a
10	Employee Educational	642,727	1,102,147		a
11	Performance Awards	5,956,180	4,591,943		a
12	Employee Savings Plan	15,111,915	17,204,244		a
13	Wellness Program	1,501,603	1,383,767		a
14	Total Fringe Benefits	95,825,558	175,502,240	138,288,606	a,b
15	Percentage of Payroll	22.53%	35.83%	39.00%	L.14/L.1
16	Average Regular FTEs	4,929	5,299	5,299	Sch. C-3
17	Average Benefits Per FTE	19,441	33,120	26,097	L.14/L.16
	Per Citizens				
	Change in Benefit Cost Adjustment				
18	Revised Filing June 5, 2009		175,502,240	128,911,797	a
19	As Filed		188,267,953	138,288,606	b
20	Expense Adjustment			(9,376,809)	L.18-L.19
21	Adjusted Average Cost Per Employee			24,328	L.18/L.16
22	Employee Complement Adjustment			(80)	Sch. C-3
23	Employee Benefit Adjustment For Reduction in Employees			(1,946,206)	L.21xL.22

Source: (a) Company June 5, 2009 Revised Schedule C-35.
(b) Company response to OPC-128.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Rate Case Expense Adjustment

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-5
Page 1 of 1

CONFIDENTIAL

Line No.	Description		Per OPC	Per Company	Recommended Adjustment	Actual To Date	Company Reference
1	Consulting			600,000			
2	Legal			2,000,000			
3	ABSG Consulting	#	[redacted]			72,540	a
4	TLG Services, Inc	#	[redacted]			93,100	a
5	AUS Consulting		60,500				a
6	Wm. Slusser *		90,000			81,789	a
7	James Vander Weide*		35,000			28,725	a
8	Burns & McDonnel	#	176,000				a
9	Carlton Fields	#	[redacted]			293,017	a
10	Richard Melson	#	[redacted]			41,307	a
11	Travel & Other		187,000	187,000		46,065	a
12	Total		2,019,410	2,787,000	(767,590)	656,543	
13	Amortization		403,882	1,393,500	(989,618)		
14	End of Year 2009		1,615,528	1,393,500	222,028		
15	Average Balance		1,817,469	2,787,000	(969,531)		

Source: (a) Company response to OPC POD-46.
* Contract not a fixed amount.
** [redacted] Confidential

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Transmission Vegatative Management

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-6
Page 1 of 1

Line No.	Year	Miles Trimmed	Cost Per Mile	Total Cost	Reference
1	2006	966	6,571	6,347,798	a
2	2007	843	8,232	6,939,355	a
3	2008	360	16,436	5,916,832	a
4	Average	723		6,401,328	
5	2009 Budgeted			6,554,550	a
6	2010 Recommended Per Citizen's			6,750,000	
7	2010 Requested			9,300,000	b
8	Citizen's Recommended Adjustment			(2,550,000)	L.6-L.8
9	Jurisdictional Adjustment @ .67335			(1,717,043)	d
	Transmission system includes 4,911 miles that require some level of vegataion management. The Company indicated that 1,410 miles required trimming in 2008 based on cycle.				c

Source: (a) Company response to OPC 238.
(b) Company testimony of Dale Oliver at page 21.
(c) Company response to OPC 239.
(d) Jurisdictional rate from Company Schedule C-4.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Distribution Vegatative Management - Tree Trimming

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-7
Page 1 of 1

Line No.	Year	Miles Pruned	Danger Trees	Total Cost	Reference
1	2006	3,419	Not Tracked	17,960,000	a
2	2007	4,303	6,301	19,928,846	a
3	2008	3,297	4,969	18,530,730	a
4	Average	3,673	5,635	18,806,525	
5	2009 Budgeted			20,773,023	a
6	2010 Recommended Per Citizen's			25,490,600	
7	2010 Requested	5,080		34,433,040	b
8	Citizen's Recommended Adjustment			(8,942,440)	
9	Jurisdictional Adjustment @ .99796			(8,924,197)	d
	The distribution system consists of 48,361 line miles, 22,723 line miles do not require trimming, leaving 25,638 subject to trimming or herbicide treatment. There are 18,341 primary conductor miles requiring trimming.				c

Source: (a) Company response to OPC 270.
(b) Company response to OPC 272.
(c) Company response to OPC 271.
(d) Jurisdictional rate from Company Schedule C-4.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Fossil Plant Maintenance

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-8
Page 1 of 1

Line No.	Year	Total Cost	Labor	Excluding Labor Cost	Change	Reference
1	2006	56,449,269	22,807,307	33,641,962		a,b
2	2007	67,643,769	21,433,250	46,210,519	37.36%	a,b
3	2008	76,463,793	22,441,034	54,022,759	16.91%	a,b
4	Average	66,852,277	22,227,197	44,625,080		
5	2009 Budgeted	80,003,204	28,769,157	51,234,047	-5.16%	a,b
6	2010 Recommended Per Citizen's			51,368,338	0.26%	Testimony
7	2010 Requested	109,165,652	36,147,314	73,018,338	42.52%	a,b
8	Citizen's Recommended Adjustment			(21,650,000)		
9	Jurisdictional Adjustment @ .81946			(17,741,309)		d
	Overhaul Expense					
10	2006	21,870,783				c
11	2007	24,742,347				c
12	2008	20,737,926				c
13	Average	22,450,352				
14	2009 Budgeted	24,988,328				c
15	2010 Requested	53,641,870				c

Source: (a) Total cost is from Company response to OPC 139.
(b) Labor amount is from Company response to OPC 353.
(c) Cost is from Company response to OPC 150.
(d) Jurisdictional rate from Company Schedule C-4.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

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Schedule C-8
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Fossil Plant Maintenance

Line No.	Plant	2005 Cost	2006 Cost	2007 Cost	2008 Cost
	Planned Outages				
1	Anclote #1		1,604,000	1,300,000	
2	Anclote #2		4,646,000		2,641,000
3	Bartow #1	809,000		1,018,000	248,000
4	Bartow #2	992,000	433,000	366,000	142,000
5	Bartow #3	5,794,000		675,000	354,000
6	Bartow #4		6,000	469,000	
7	Bayboro			41,000	
8	DeBary #1-#6				210,000
9	DeBary #7-10	1,045,000	226,000	293,000	
10	Crystal River #1			4,038,000	806,000
11	Crystal River #2		1,130,000	4,911,000	
12	Crystal River #4	4,799,000	518,000	789,000	
13	Crystal River #5		4,953,000	1,338,000	
14	Higgins #1			66,000	
15	Hines Energy #1	1,380,000	1,532,000	2,240,000	784,000
16	Hines Energy #2	722,000	885,000	1,029,000	2,313,000
17	Hines Energy #3		289,000	1,483,000	630,000
18	Hines Energy #4				233,000
19	Intercession City 8-14	1,641,000	364,000	379,000	1,369,000
20	Turner #1-#4		17,000		1,751,000
21	Tiger Bay #1	266,000		663,000	1,528,000
22	University of Florida #1	571,000	477,000	746,000	358,000
23	Suwannee River #1-3		296,000	846,000	499,000
24		18,019,000	17,376,000	22,690,000	13,866,000

Source: Historical is from company response to OPC 256.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Fossil Plant Maintenance

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Line No.	Plant	2005 Cost	2006 Cost	2007 Cost	2008 Cost	2010 Total Cost
	Unplanned Outages					
1	Anclote #1-2					
2	Avon Park	8,000		149,000		
3	Bartow #1-4	14,000				
4	Bayboro		277,000	20,000		
5	DeBary #1-#6					
6	DeBary #7-10	67,000				
7	Crystal River #1,2,4,5					
8	Higgins #1-3	114,000	103,000	181,000	142,000	
9	Hines Energy #1-4				261,000	
10	Intercession City 8-14		234,000			
11	Turner #1-#4	48,000	4,000			
12	Tiger Bay #1	113,000		304,000	1,332,000	
13	University of Florida #1					
14	Suwannee River #1-3					
15	Total Unplanned Outages	364,000	618,000	654,000	1,735,000	
	Maintenance W/O Labor					
16	Anclote		7,393,724	4,423,508	5,466,230	6,883,989
17	Bartow		3,401,311	6,543,121	5,009,213	6,988,556
18	Crystal River		11,511,394	20,085,698	15,704,403	26,815,820
19	Debary		691,400	1,034,299	3,520,461	7,888,991
20	Hines - Tiger Bay					17,214,556
21	University of Florida #1		1,472,720	1,839,102	2,061,679	1,754,744
22	Suwannee River #1-3		779,484	1,384,957	1,078,907	1,577,269
23	Other		1,456,958	2,063,870	5,166,966	2,405,748
24	Combined Cycle Plants		6,934,973	8,828,171	16,004,899	0
25	Combustion Turbines			36,458	10,000	1,439,843
26			33,641,964	46,239,184	54,022,758	72,969,516

Source: Company response to OPC 257.
Maintenance W/O Labor is from Company response to OPC 308.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Injuries & Damages Expense Adjustment

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Exhibit HWS-1
Schedule C-9
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Line No.	Description	Budget 2008	Actual 2008	2010	Adjustment	Reference
1	Nuclear	0	133,248	450,000		a,b
2	Power Operations	200,000	67,175	200,000		a,b
3	Customer & Market Servi	0	3,245	0		a
4	Energy Delivery	2,400,000	(836,077)	2,000,000		a,b
5	Transmission	0	248,116	304,000		a,b
	Service Company					a
6	Chairmen	0	(82,860)	190,313		a,b
7	Corp Insurance	0	1,286,313	842,667		a
8	Corp Insurance	0	75,722	4,794,430		a
9	Corp Services	10,918	0			a
10	Corp Services	0	34,745			a
11	Legal	1,950,000	3,168	1,825,000		a,b
12	Legal	73,035	0	50,750		a
13	Regulated Fuels	175,284	0	0		a
14	Treasury	870,000	0	0		a
15	Treasury	4,843,615	4,516,594	0		a
16	Total	10,522,852	5,449,389	10,657,160		
17	Insurance		(5,878,629)	(5,637,097)		
18	Adjusted Total		(429,240)	5,020,063	(5,449,303)	
19	Jurisdictional Adjustment @ .87692				(4,778,603)	

Source: (a) Company response to OPC POD No. 37 and OPC Interrogatory No. 389.
(b) Compeny Revised response to OPC Interrogatory No. 342.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Budget Analysis

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-10

Line No.	Description	Account	Budget 2010	Comment	Adjustment	OPC Reference
1	A&G Off Supplies & Expense	921	3,105,877	Detail Only	(1,488,677)	POD 259
2	A&G Off Supplies & Expense	921	1,200,000	Detail Only	(1,200,000)	POD 259
3					(2,688,677)	
4	NUC Misc Nuclear Power Exp	524	9,805,056	Detail Only		POD 260
5	NUC Maint of Electric Plant	531	1,775,509	Detail Only		POD 261
6	NUC Maint of Reac Plant Equip	530	500,000	Detail Only		POD 262
7	Misc General Expense	9302	465,206	Detail Only		POD 262
8	FOS Maint of Boiler Plant	512	522,204	Numbers		POD 263
9	FOS Maint of Struct	511	4,816,000	Detail Only		POD 264
10	FOS Maint of Boiler Plant	512	1,075,797	Detail Only		POD 265
11	FOS Maint of Elect Plant	513	483,915	Numbers		POD 266
12	FOS Maint of Elect Plant	513	1,789,440	Detail Only		POD 267
13	FOS Maint of Boiler Plant	512	315,521	None		POD 268
14	CT Maint of Gen and Elect Plant	553	1,600,000	Detail & Doc.		POD 268
15	CT Maint of Gen and Elect Plant	553	1,600,000	Detail & Doc.		POD 268
16	CT Maint of Structures	552	1,040,040	Detail Only		POD 269
17	CT Maint of Structures	552	180,000	Numbers		POD 269
18	CT Maint of Structures	552	1,040,040	Detail Only		POD 269
19	FOS Oper Super and Engineer	500	1,522,100	Reference		POD 270
20	Cust Accts Records & Collec Ex	903	7,311,911	Detail Only		POD 271
21	Gen Advertising Exp	9301	1,780,000	Ltd Detail		POD 272
22	A&G Injuries & Damages	925	190,313	Detail & Doc.		POD 272
23	A&G Injuries & Damages	925	842,667	Detail Only		POD 272
24	A&G Injuries & Damages	925	4,794,430	Detail Only		POD 272
25	A&G Off Supplies & Expense	921	3,634,676	Detail Only		POD 272
26	Salaries & Wages	920	357,887	Detail-Alloc		POD 273
27	Salaries & Wages	920	1,966,564	Detail-Alloc		POD 273
28	A&G Off Supplies & Expense	921	6,967,603	Detail Only		POD 274
29	A&G Injuries & Damages	925	1,825,000	Detail Only		POD 274
30	Total Cost Requested Documentation For		62,507,756			
31	Jurisdictional @ .86725				(2,331,755)	

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

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Exhibit HWS-1
Schedule C-11
Page 1 of 1

Productivity Adjustment

Line No.	Year	2008	2009	2010	Change	Reference
1	Production O&M	259,783	264,219	332,822	28.12%	a
2	Transmission O&M	35,241	35,085	45,336	28.65%	a
3	Distribution O&M	120,595	125,842	144,926	20.18%	a
4	Customer Account	49,944	51,442	54,185	8.49%	a
5	Customer Service & Sales	4,570	3,989	4,100	-10.28%	a
6	Administrative & General	190,977	266,631	286,789	50.17%	a
7	Total O&M	661,110	747,208	868,158	31.32%	
8	Depreciation & Amortization	299,253	302,259	402,973	34.66%	a
9	Taxes Other	114,186	134,218	146,970	28.71%	a
10	Gain On Sale	(2,317)	(2,862)	(2,862)	23.52%	a
11	Income Taxes	198,488	156,829	70,845	-64.31%	a
12	Total	1,270,720	1,337,652	1,486,084		
	Jurisdictional					
13	Production O&M	214,307	204,973	236,832	10.51%	a
14	Transmission O&M	24,943	24,591	30,527	22.39%	a
15	Distribution O&M	120,346	125,595	144,630	20.18%	a
16	Customer Account	48,511	51,027	53,932	11.17%	a
17	Customer Service & Sales	4,570	3,989	4,100	-10.28%	a
18	Administrative & General	171,167	246,456	251,475	46.92%	a
19	Total O&M	583,844	656,631	721,496	23.58%	
20	Depreciation & Amortization	277,577	278,729	357,869	28.93%	a
21	Taxes Other	104,979	123,429	129,587	23.44%	a
22	Gain On Sale	(2,120)	(2,630)	(2,516)	18.68%	a
23	Income Taxes	153,484	99,811	42,943	-72.02%	a
24	Total	1,117,764	1,155,970	1,249,379		
25	Payroll Expense (325,017 x .88313)			287,032		
26	Adjusted O&M			434,464		
27	Productivity Adjustment @ 3%			(13,034)		

Source: (a) Company MFR Schedule C-4.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Interest Synchronization Adjustment (000's)

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Exhibit HWS-1
Schedule C-12
Page 1 of 1

Line No.	Description	Amount	Reference
1	Rate Base Per Citizen's	6,348,626	Schedule B-1
2	Weighted Cost of Debt (plus customer deposits	2.88%	Schedule D
3	Interest Deduction	182,977	L.1 x L.2
4	Interest Deduction in Filing	178,362	a
5	Difference	4,615	L.3 - L.4
6	Composite Tax Rate	38.575%	
7	Increase (Decrease) In Income Tax Expense	(1,780)	L.5 x L.6

Source: (a) Company Schedule C-4, Page 16, Line 9.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010

Income Tax Expense

Docket No. 090079-EI
Exhibit HWS-1
Schedule C-13

Line No.	Description	Amount	Reference
1	Operating Income Adjustments	367,957,518	Schedule C-1
2	Composite Income Tax Rate	38.575%	
3	Increase (Decrease) to Income Tax Expense	141,939,613	L.1 x L.2

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010
(000's)
Overall Cost of Capital As Adjusted

Line No.	Description	Per OPC Capital	Adjusted OPC Capital	Ratio	Cost Rate	Weighted Cost Rate
1	Common Equity	2,948,994	2,948,994	46.94%	9.75%	4.577%
2	Preferred Stock	21,211	21,211	0.34%	4.51%	0.015%
3	Long Term Debt	2,821,103	2,821,103	44.91%	6.05%	2.717%
4	Short Term Debt	106,680	106,680	1.70%	3.06%	0.052%
5	Customer Deposits - Active	119,781	119,781	1.91%	5.95%	0.113%
6	Customer Deposits - Inactive	1,248	1,248	0.02%	0.00%	0.000%
7	FAS 109 DIT-Net	(114,791)	(114,791)	-1.83%	0.00%	0.000%
8	Deferred Taxes	329,399	373,161	5.94%	0.00%	0.000%
9	Tax Credit	4,991	4,991	0.08%	7.84%	0.006%
10		6,238,615	6,282,378	100.00%		7.480%
11	Weighted Cost of Debt (plus customer deposits)					2.88%

Source: Per Citizen's witness Dr. J.R. Woolridge.

PROGRESS ENERGY FLORIDA INC.
Projected Test Year Ended December 31, 2010
(000's)
Overall Cost of Capital

Line No.	Description	Per Company Capital	Per OPC Capital	Ratio	Cost Rate	Weighted Cost Rate
1	Common Equity	3,151,819	2,948,994	47.27%	9.75%	4.609%
2	Preferred Stock	19,881	21,211	0.34%	4.51%	0.015%
3	Long Term Debt	2,637,596	2,821,103	45.22%	6.05%	2.736%
4	Short Term Debt	38,609	106,680	1.71%	3.06%	0.052%
5	Customer Deposits - Active	111,734	119,781	1.92%	5.95%	0.114%
6	Customer Deposits - Inactive	1,129	1,248	0.02%	0.00%	0.000%
7	FAS 109 DIT-Net	(115,057)	(114,791)	-1.84%	0.00%	0.000%
8	Deferred Taxes	389,297	329,399	5.28%	0.00%	0.000%
9	Tax Credit	3,610	4,991	0.08%	7.84%	0.006%
10		6,238,617	6,238,617	100.00%		7.533%
11	Weighted Cost of Debt (plus customer deposits)					2.90%

Source: Per Citizen's witness Dr. J.R. Woolridge.

J9B2 Rate Case	2009 Year	2010 Year
Progress Energy Florida - FERC		
B:[Gross Revenue]	5,551,974,715	5,766,613,634
C:[Fuel Expense]	(2,241,845,741)	(2,322,281,439)
D:[Deferred Fuel]	(125,709,952)	(6,111,236)
E:[Purchased Power]	(805,415,874)	(871,525,000)
F:[ECCR Expense]	(76,756,038)	(85,912,264)
G:[ECRC Expense]	(55,805,683)	(63,370,145)
H:[Nuclear Recovery O&M Expense]	(5,731,475)	(4,924,740)
I:[Nuclear Recovery - Amort Expense]	(161,424,862)	(131,691,871)
J:[Recoverable Security Expense]	(6,682,373)	
K:[Regulatory Assessment Fees]	(2,239,661)	(2,424,954)
L:[Regulatory Assessment Fees - Base Rate]	(1,225,995)	(1,122,974)
M:[Franchise/ Gross Receipts Tax Expense]	(230,633,497)	(236,041,229)
N:[Interest on Levy Joint Owner payment]	16,725,701	
O:[Interest on Def Fuel Balance]	1,872,668	71,881
P:[Gross Margin]	1,857,101,932	2,041,279,664
Q:[]		
R:[Retail Base Revenue]	1,384,591,395	1,387,702,437
S:[Wholesale Base Revenue]	213,303,427	209,390,686
T:[Other Operaing Revenue (incl Transm)]	192,680,876	231,509,302
U:[Less GPIF Amortization/Award]	2,167,933	
V:[Unrecovered Capacity]	45,766,624	32,381,677
W:[Offset for AFUDC Recovery - Levy]	(15,080,399)	
X:[Offset for AFUDC Recovery - CR3 Uprate]	(6,932,003)	
Y:[Fuel Over-Recovery (gen Units)]	1,978,985	899,084
Z:[Regulatory Assessment Fee - Base Rates]	(1,225,995)	(1,122,974)
AA:[CAIR Recovery]	22,803,672	111,740,758
AB:[ECRC Difference]	4,681,041	59,282,587
AC:[ECCR Difference]	1,348,891	3,357,433
AD:[Fuel Difference]	11,017,486	6,138,673
AE:[Gross Margin]	1,857,101,933	2,041,279,664
AF:[Check]	(0)	0
AG:[]		
AH:[]		
AI:[Interchange revenue]	21,038,800	32,157,018
AJ:[Fuel Clause Revenue]	2,449,409,390	2,376,372,766
AK:[Fuel Clause Revenue - Whlsl]	70,255,701	102,658,560
AL:[Base Fuel Revenue]	296,713,464	322,108,072
AM:[GPIF (Amortization)/Award]	(2,167,933)	
AN:[Fossil Fuel Expense]	(2,215,794,154)	(2,276,087,193)
AO:[Amortization of Nuclear Fuel]	(21,187,640)	(39,641,974)
AP:[Spent Fuel]	(4,863,947)	(6,552,272)
AQ:[Deferred Fuel]	(125,709,952)	(6,111,236)
AR:[Retail Fuel Reg Assessment Fee]	(1,739,703)	(1,799,912)
AS:[Purchased Power Energy]	(454,830,221)	(496,137,953)
AT:[Interest in Def Fuel Bal]	1,872,668	71,881
AU:[Net Fuel]	12,996,471	7,037,756
AV:[]		
AW:[Plant recovery per Recov Fuel]	1,978,985	899,084
AX:[Transmission Line Losses - Retail]	4,743,893	4,777,716
AY:[Transmission Line Losses - Wholesale]		
AZ:[Coal Consolidation - Rtn on Inv]	5,621,247	
BA:[Wholesale Interest]	801,354	1,032,781
BB:[Total Expected Fuel Difference]	13,145,479	6,709,581
BC:[Unreconciled Fuel Difference]	(149,008)	328,176
BD:[]		
BE:[ECRC Revenue]	83,350,365	234,562,253
BF:[ECRC Reg Assessment Fee]	(59,969)	(168,763)
BG:[ECRC O&M - Current Month Deferral]	(0)	0
BH:[ECRC O&M - Total Expenses]	(51,489,623)	(59,438,014)
BI:[ECRC O&M - Amort of Prior Period Deferral]	(4,316,060)	(3,932,131)
BJ:[ECRC Net]	27,484,713	171,023,345
BK:[ECRC Return Requirements]	22,803,672	111,740,758
BL:[ECRC Depreciation Exp]	(5,463,850)	(52,380,780)
BM:[ECRC Property Tax Exp]	(2,419,713)	(11,368,254)
BN:[ECRC Property Insurance (included in other O&M	(256,008)	(567,926)
BO:[ECRC Wholesale expense allocation]	(3,458,530)	(5,034,374)
BP:[Total Expected ECRC Difference]	11,205,571	42,389,424
BQ:[Check]	16,279,142	128,633,921
BR:[]		
BS:[ECCR Revenue]	78,161,205	89,334,018
BT:[ECCR Amortization]	(2,687,646)	(3,573,791)
BU:[ECCR Depreciation]	(266,784)	(1,484,373)
BV:[ECCR Reg Assessment Fee]	(56,276)	(64,320)
BW:[ECCR O&M - Current Month Deferral]	3,559,047	0
BX:[ECCR O&M - Amort of Prior Period Deferral]	3,235,874	(299,364)

BY:[ECCR O&M]	(80,596,529)	(80,554,736)
BZ:[ECCR Net]	1,348,891	3,357,433
CA:[ECCR Return Requirements]	1,348,891	3,357,433
CB:[Check]	(0)	0
CC:[]		
CD:[Capacity Clause Revenue]	531,836,596	544,777,293
CE:[Nuclear Security recovery]	(6,682,373)	
CF:[Recover Nuclear COL - Current year]	(54,905,023)	(131,691,871)
CG:[Recover Nuclear COL - Prior years]	(84,507,437)	
CH:[Recover Levy O&M (net of JO)]	(5,045,336)	(4,211,612)
CI:[Recover CR3 Uprate O&M]	(686,140)	(713,127)
CJ:[Levy JO Payment - interest portion]	16,725,701	
CK:[Capacity Reg Assessment Fee]	(383,713)	(391,957)
CL:[Capacity - Current Month Deferral]	1,481,721	0
CM:[Capacity - Prior period amortization]	15,292,976	1,047,932
CN:[Purchased Power Capacity]	(367,360,349)	(376,434,979)
CO:[Net Capacity]	45,766,624	32,381,677
CP:[Capacity Schedule H Sales]	(48,600)	(48,600)
CQ:[Retail Wheeling]	(330,352)	(330,349)
CR:[Wholesale portion of Recoverable Nuc O&M]	(477,432)	(410,231)
CS:[CR3 Uprate Return on DTA]	212,862	648,148
CT:[Levy Return on DTA]	5,739,088	15,818,006
CU:[CR3 Uprate Other]	8,441,830	
CV:[CR3 Uprate Retail AFUDC Revenue]	13,813,675	10,302,132
CW:[Levy Retail AFUDC Revenue]	43,126,955	58,079,008
CX:[Levy Wholesale Joint Owner Interest]	1,393,251	
CY:[Wholesale allocation of capacity costs (Unreco	(26,104,653)	(51,676,437)
CZ:[Total Expected Capacity Clause Difference]	45,766,624	32,381,677
DA:[Check]	0	(0)
DB:[]		
DC:[Tax recovery]	230,633,497	236,041,229
DD:[Tax Expense - Gross Receipts]	(115,078,556)	(117,781,116)
DE:[Tax Expense - Gross Receipts (adjust Retail Reve		
DF:[Tax Expense - Franchise Fees]	(115,554,941)	(118,260,113)
DG:[Tax Net]	(0)	0
DH:[]		

C Charge By ID	Charge To ID	Resource T	Activity ID	Project ID	Account ID	Line Item	FY09	FY10
60121D	60121D	OMC	B1501	20064598	9210000	CORPORATE MANAGED ACCOUNT	$1,200,000.00	$1,200,000.00
60121D	60121D	OMC	B1501	20016025	9210000	PEF PRESIDENT & CEO	$555,000.00	$555,000.00
60121D	60121D	OMC	B1501	20016025	9210000	PEF RAYMOND JAMES SUITE	$3,000.00	$5,000.00
60121D	60121D	OMC	B1501	20016025	9210000	PEF TROPICANA SUITE	$3,000.00	$3,000.00
60121D	60121D	OMC	B1501	20016025	9210000	PEF TRANSITIONS CHAMPIONSHIP	$3,000.00	$3,000.00
60121D	60121D	OMC	B1501	20016025	9210000	PEF PALMER INVITATIONAL	$0.00	$10,000.00
							$564,000.00	$576,000.00

C Charge By ID	Charge To ID	Resource T	Activity ID	Project ID	Account ID	Line item	FY09	FY10
60121D	60121D	OML	B1501	20016025	9210000	PEF PRESIDENT & CEO	$170,000.00	$170,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF TB LIGHTNING	$83,270.00	$59,900.00
60121D	60121D	OML	B1501	20016025	9210000	PEF TB BUCCANEERS	$134,160.00	$139,527.00
60121D	60121D	OML	B1501	20016025	9210000	PEF UF SUITE	$56,000.00	$60,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF ORLANDO MAGIC	$1,000.00	$20,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF 2009 SUPER BOWL	$10,000.00	$0.00
60121D	60121D	OML	B1501	20016025	9210000	PEF TRANSITIONS CHAMPIONSHIP	$44,000.00	$44,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF TRANSITIONS CHAMPION PRO-AM	$34,950.00	$98,250.00
60121D	60121D	OML	B1501	20016025	9210000	PEF UCF	$30,000.00	$30,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF UCF	$2,400.00	$3,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF UCF	$5,000.00	$3,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF GRAND PRIX	$5,000.00	$5,000.00
60121D	60121D	OML	B1501	20016025	9210000	PEF PALMER INVITATIONAL	$20,000.00	$60,000.00
							$595,780.00	$692,677.00 (4)