BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. 090079-EI

Submitted for filing: August 31, 2009

REBUTTAL TESTIMONY
OF
Masceo S. DesChamps

On behalf of Progress Energy Florida

In re: Petition for rate increase by Progress Energy Florida, Inc.
Docket No. 090079-EI

REBUTTAL TESTIMONY OF
MASCEO S. DESCHAMPS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position.

A. My name is Masceo S. DesChamps. I am the Director of Compensation and Benefits for Progress Energy Service Company, LLC.

Q. Are you the same Masceo S. DesChamps that provided direct testimony in this proceeding?

A. Yes, I am.

Q. Have you reviewed the Intervenor Testimony filed in this Docket?

A. Yes, I have. I have reviewed and I will provide rebuttal testimony to the following intervenor direct testimony: (1) Helmuth Schultz, III ("Schultz") and (2) Martin J. Marz ("Marz"). Specifically, I will rebut the portions of these testimonies related to incentive compensation, payroll levels, and employee benefits.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes. I have supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (MSD-8), Order PSC-92-1197-FOF-EI, *In Re: Petition for a rate increase by Florida Power Corporation* (Oct. 22, 1992);

- Exhibit No. ___ (MSD-9), Order PSC-02-0787-FOF-EI, *In re: Request for rate increase by Gulf Power Company* (June 2, 2002);
- Exhibit No. ___ (MSD-10), which contains the results of a July 2009 survey conducted by the Company;
- Exhibit No. ___ (MSD-11), Watson Wyatt survey results press release;
- Exhibit No. ___ (MSD-12), which is a composite exhibit of the summary of the findings from the Company's 2008 and 2009 job value studies;
- Exhibit No. ___ (MSD-13), June 2009 Top 5 Proxy Analysis completed by Hewitt Associates LLC; and
- Exhibit No. __ (MSD-14), Average Healthcare Costs Per Member (including dependents) – Progress Energy vs. Fortune 500.

All of these exhibits are true and accurate.

II. INCENTIVE COMPENSATION.

Q. Please generally explain the importance of the incentive compensation piece of the total compensation package that Progress Energy Florida offers to its employees.

A. As I explained in my direct testimony, Progress Energy Florida ("PEF") is committed to providing a competitive total rewards package that enables the Company to attract, retain and reward employees who work to high standards. Its compensation program is market-based at the 50th percentile within national, regional, and local comparative markets and aligns with a pay-for-performance philosophy. Incentive compensation is an integral part of the total compensation package. When the Company benchmarks jobs with similar peer utilities, it benchmarks the value of the total compensation package. Similarly, when the Company benchmarks its employee benefits, it is a comparison of the total benefits program.

Q. Please briefly describe the components of the Company's various incentive compensation plans.

A. The Company has four different incentive compensation plans. As a part of total compensation, the Company sponsors the Employee Cash Incentive Plan (ECIP) for all non-management and non-supervisory employees. The ECIP is an annual short-term cash incentive plan that rewards eligible employees with cash bonuses when strategic company and business goals are achieved. The plan is designed to ensure a close link between pay and performance and to share the company's financial success with the employees who make it happen. Each year senior management establishes an Earnings Per Share (EPS) range and ten strategic goals by business unit, such as safety, budget adherence, electric service reliability, plant production and efficiency, and other similar goals.

The EPS component applies equally for all employees and is statused on a quarterly basis. The ten operational goals have equal weighting and are also monitored on a quarterly basis. The plan is designed to pay at higher levels for superior operational performance. There is also a component to allow for CEO Discretion which may be used to help offset extenuating factors such as weather or general economic conditions that may affect operational goal or EPS achievement, or recognize positive overall company financial and operational achievements. Although the ECIP is based on total company and business unit performance, employees receive awards <u>only</u> when individual performance meets certain expectations.

The Management Incentive Compensation Plan (MICP) and Executive Incentive Plan (EIP) were designed to work together to ensure that the Company's annual incentive program would be compliant with section 162 (m) of the Internal Revenue Code. The EIP, an umbrella plan, is for the Company's senior executive officers and is intended to enable the Company to preserve the tax deductibility of incentive awards. The MICP provides annual incentive opportunities to executives, managers, and supervisors to promote the achievement of annual performance objectives. MICP performance targets are designed to appropriately motivate the participants to achieve the desired corporate financial and operational objectives.

The Company also sponsors a long-term incentive plan to provide equity awards to managers and executives. These awards are intended to focus managers and executives on sustained achievement of financial and operational goals.

The purpose of the annual and long-term incentive plans is to provide competitive incentive compensation in attracting, retaining, and rewarding managers and executives when warranted by individual and company performance. The incentive plans' target award opportunities approximate the 50th percentile of the peer group for all of the companies' incentive compensation plans.

Q. What do witnesses Schultz and Marz claim with respect to the Company's requested incentive compensation?

A. Schultz and Marz both testify that the Company's incentive compensation plans do not benefit the customers. Specifically, they claim that the incentive compensation plans with goals linked to the financial performance of the Company should be paid for by shareholders and not customers. Schultz further challenges the inclusion of incentive compensation given the economy. Finally, Schultz suggests that incentive compensation is not a significant factor in attracting and retaining employees. As I discuss below, none of these arguments have merit. Thus, the Company's request for incentive compensation should be approved in its entirety.

Q. How do all the Company's incentive compensation plans benefit customers?

A. Progress Energy's incentive compensation plans are designed to promote and encourage superior performance by its employees. As described above, Progress Energy measures the performance of its employees in a variety of ways, including the performance of the parent company and PEF specific goals such as cost management, operational efficiency, reliability, safety, and customer satisfaction. Contrary to Witnesses Schultz and Marz's testimony that the goals linked to overall Company performance only benefit shareholders, maintaining a financially strong Company also benefits customers. As PEF witnesses Dolan, Toomey, and Sullivan describe in their testimony, a financially strong company can access capital more easily at a lower cost. This reduced cost of capital benefits customers by lowering rates. The fact that the Company's shareholders also benefit from these incentive compensation goals is irrelevant to whether the costs of the incentive compensation plans should be included in base rates. Actions the Company takes to provide reliable and efficient electric service to its customers benefit the shareholders, by allowing the shareholders to earn a return on their investment in the Company's electric business. Simply because shareholders also benefit does not mean that those costs should not be charged to customers. Because the Company's incentive compensation costs allow PEF to provide efficient and reliable electricity they are properly charged as a cost of providing electric service to customers.

Q. Do Witnesses Schultz and Marz recommend any adjustment to the Company's requested incentive compensation costs?

A. Yes. Witness Schultz recommends that all of the Company's request for incentive compensation expense and $12,094 million of the Company's requested long term incentive compensation expense be excluded from base rates. (Schultz Testimony p. 30) This represents approximately 72% of the Company's long-term incentive compensation request, as reflected on Schedule C-35. Witness Schultz gives no indication how he came to this calculation for the long-term incentive compensation adjustment. Witness Marz recommends that all of the Company's incentive compensation budgeted for executives and senior management, as well as 50% of the incentive compensation for management and non-management employees, be excluded from the Company's rate request. (Marz Testimony p. 22).

Q. Do you agree with these proposed adjustments?

A. No, I do not. Incentive compensation (both annual and long term) is an essential part of the Company's total compensation package, which is necessary to attract and retain qualified employees. If Progress Energy did not provide incentive compensation, it would be forced to increase its base pay to compete with other utilities and industries on a total compensation basis for the workforce it needs to provide the reliable and efficient electric service that its customers have come to expect. And unlike incentive compensation, which provides the Company with flexibility to adjust compensation depending on the achievement of goals, the Company would lose the flexibility to adjust compensation based on performance. As explained above, all aspects of Progress Energy's incentive compensation (both annual and long term) programs provide tangible benefits to the customers.

Q. What about Witnesses Schultz's and Marz's assertions that other jurisdictions disallow incentive compensation?

A. First, I think the most relevant prior orders are from Florida, where this proceeding is pending. Historically, Florida has recognized the value of incentive compensation plans and has approved its inclusion in rates. For example, in Florida Power Corporation's 1992 rate case, the Commission specifically included the utility's request for incentive compensation, stating, "Incentive plans that are tied to the achievement of corporate goals are appropriate and provide an incentive to control costs." (Order PSC 92-1197-FOF-EI, page *117, attached as Exhibit No. ___ (MSD-8) to my rebuttal testimony). In addition, in Gulf Power's 2002 rate case, Witness Schultz testified that Gulf's incentive compensation expenses should be disallowed. The Commission rejected those arguments and approved Gulf's incentive compensation plan, recognizing that Gulf employees were paid based on market value and that as result "customers will receive quality service and low rates." (Order PSC-02-0787-FOF-EI, page *71, attached as Exhibit No. ___ (MSD-9) to my rebuttal testimony).

Witness Marz discusses the Florida Commission's most recent consideration of incentive compensation in the TECO rate case. (Marz Testimony p. 28) In the Tampa Electric proceeding, the PSC excluded only the portion of Tampa Electric's incentive compensation tied to the financial goals of its parent, TECO Energy. While peers in the utility industry, Progress Energy can be distinguished from TECO Energy. For example, TECO Energy has many more non-regulated subsidiaries upon which its financial performance is based. In contrast, Progress Energy, Inc. primarily receives revenue from two electric utility subsidiaries, PEF and Progress Energy Carolinas ("PEC"). Furthermore, many of the incentive compensation goals under discussion are tied specifically to PEF performance, with only the EPS goal tied to the parent, Progress Energy, Inc.

With respect to the orders from other jurisdictions that Witnesses Schultz and Marz cite, there are important distinctions between the utilities involved in those proceedings and PEF. For example, the economic factors that impact compensation levels can vary depending on the geographic location of the utility. So a utility in Vermont, as included in Schultz's testimony (p. 18) may have different compensation requirements to attract and retain employees within its service territory than PEF would have. The size, generation mix and complexity of operations of a utility will also impact the type of employees that utility requires. That is why PEF benchmarks against peer utilities, which are similar in size, generation mix, and strategy.

Q. Are PEF's incentive compensation plans reasonable in light of the economic conditions facing the State of Florida and the country?

A. Yes. Customer demand for superior electric service that relies on high quality employees has not changed. For the 2010 test year and beyond we believe that PEF's incentive compensation costs are reasonable and necessary to continue to retain and recruit quality employees.

Contrary to Witness Schultz's sweeping statement that the Company should not pay any incentive compensation given the economy, the Company cannot take such a narrow, short-sighted view with respect to the economic conditions. PEF competes in Florida and nationally for talented employees, and I am not aware of other utilities eliminating incentive compensation from their total compensation packages. Such incentive compensation costs are necessary so that the Company can continue retaining and attracting quality employees, in the future. The Company takes a more long-term strategic approach to continue to provide the safe and reliable electric service our customers have come to expect.

In addition, the Company has continued to benchmark its compensation plans against its peer utilities to ensure that its budgeted compensation expenses are within the 50^{th} percentile. In a survey conducted by the Company in July, 2009, all of the twenty-one responding utilities provided information regarding aspects of their current short-term management and employee incentive programs, an indication that they are continuing to provide this type of compensation to their employees even with the state of the economy. The survey results are attached to my rebuttal testimony as Exhibit No. __ (MSD-10). In addition, according to the latest update to an ongoing series of surveys by

Watson Wyatt, a leading global consulting firm, the number of employers planning to reverse salary cuts and freezes has increased in the past two months. The survey found that 33 percent of employers that froze salaries plan to unfreeze them within the next six months, up from 17 percent two months ago. Forty-four percent plan to roll back salary cuts in the next six months, compared with 30 percent two months ago. Watson Wyatt's latest bimonthly survey was conducted in August 2009 and includes responses from 175 large employers. The press release describing the results of this survey is attached to my rebuttal testimony as Exhibit No. ___ (MSD-11).

Q. Speaking of the market studies at which Progress Energy targets the 50th percentile, what does Witness Schultz assert with respect to those market studies and how do you respond?

A. Witness Schultz challenges the fact that Progress Energy is actually at the 50th percentile. (Schultz Testimony p. 24). He has two main arguments in support of this testimony. First, he claims that the compensation studies are skewed by a few organizations. (Schultz Testimony p. 25). Second, he asserts that because many of the utilities that participate in these studies do not include incentive compensation in the rates charged to customers, it is inappropriate to compare these utilities to Florida. (Id.) Both these arguments are without merit.

Although we have provided to OPC in discovery each of the compensation studies in which PEF participates, Schultz does not undertake any specific analysis as to our particular studies. Nor does he provide any analysis as to whether a particular peer utility in our study "skewed" the results of the study. He also does not give any analysis as to whether the utilities in our studies are allowed to include incentive compensation in the rates it charges customers. Rather, Schultz makes sweeping generalities with respect to market studies without focusing on the only relevant studies in this proceeding, which are the ones in which Progress Energy participates. More specifically to Schultz's first contention, we use a sample of peer utilities that reflect the most appropriate and comparable employment markets. We continue to evaluate and monitor the peer group to ensure that it remains appropriate for such comparisons, provides representative data, and to avoid the possibility that one or two organizations will skew the results.

Schultz's second assertion, that the utility companies included in the studies do not have all their incentive compensation included in rates, is simply irrelevant to this particular point. With this assertion, Schultz does not challenge the validity of the numbers in these market studies. His real issue is that incentive compensation should not be paid for by the customers. This is the same argument he makes elsewhere, that other jurisdictions have disallowed incentive compensation and thus so should Florida. I respond to that argument elsewhere. But for purposes of evaluating the market studies and the data contained in them, it is irrelevant whether a utility charges its incentive compensation to customers, shareholders, or otherwise. The purpose of these market studies is to compare the total compensation **paid to** employees, not to compare how different jurisdictions treat the recovery of portions of that compensation paid to employees. To be competitive with its peer utilities, Progress Energy must compare its compensation to the total compensation paid by those other utilities.

Q. Does the Company use any other mechanisms by which to confirm that its compensation is within the market?

A. Yes, the Company routinely conducts job value studies to ensure that each particular position is appropriately valued within the market. Progress Energy conducts market and internal reviews on all jobs below vice president in the company on a continuous basis. These reviews happen annually to about a quarter of the job classifications in the company. All jobs are reviewed on approximately a three to four year cycle. The market review entails collecting and validating job content for each classification and benchmarking that content to external survey databases within the appropriate peer group. Similar internal jobs are compared against each other to ensure an appropriate amount of equity exists between like work. The findings of the market and internal equity analysis are validated and approved through a process of review with business units' management. A summary of these findings from 2008 and 2009 is attached as composite Exhibit No. __ (MSD-12) to my rebuttal testimony.

Furthermore, we annually review the market values of the vice president positions by performing an analysis of the survey data on similar positions of our peers. From those analyses, we recommend a market value to the CEO for approval. The executive compensation consultant provides the Organization and Compensation Committee of the Board of Directors ("Committee") with an analysis comparing base salaries, annual incentives, and long-term incentives to compensation opportunities provided to the executive officers of our peers. The Committee reviews these analyses and, with input from the consultant, approves the relevant market values. The results of the most recent analysis completed by Hewitt Associates LLC, the Company's executive compensation consultant, is attached as Exhibit No. ___ (MSD-13) to my rebuttal testimony.

Q. Witness Schultz also claims that incentive pay is not a significant factor in attracting and retaining employees. Do you agree with his opinion?

A. No, I do not. Witness Schultz relies on the results of a Towers Perrin survey that ranks the top drivers an employee uses to choose an employer. Because that survey shows the ranking of drivers like competitive base pay, competitive health care benefits, and competitive retirement benefits, but not incentive compensation, Schultz challenges whether incentive pay is even an important factor in the decision that an employee makes when choosing an employer. (Schultz Testimony pp. 25-26) Again, Witness Schultz does not acknowledge that incentive compensation is just one part of Progress Energy's total compensation package. The entire package must be competitive, because current and potential employees look at the entire compensation package when evaluating and comparing jobs. If PEF did not offer incentive pay, it would have to increase base pay to compete for skilled employees on a total compensation basis with its peer utility groups.

Q. Does Witness Schultz challenge the goals upon which the Company's incentive compensation plans are based?

A. Yes, he claims that various operational goals are set at inappropriate levels. Other Company witnesses will address how these operational goals are set and why they are appropriate. Witness Schultz also points to the fact that incentive awards were made to 99.7% of employees, as evidence of the fact that the goals are set too low. (Schultz

Testimony p. 29) This is an inaccurate characterization of this percentage figure. 99.7% of all employees received some amount of incentive payment, but that does not mean that every person received the target amount for which they were eligible under their incentive compensation plans. Employees received a payment commensurate with their individual and business unit performance.

II. EMPLOYEE BENEFITS.

Q. What does Witness Schultz assert with respect to the Company's employee benefits costs?

A. Witness Schultz recommends an adjustment to the Company's requested average benefit per employee expense by reducing the number of employee positions. His arguments regarding the number of employee positions included in the Company's filing will be addressed in the rebuttal testimony of Mr. Peter Toomey. Witness Schultz also makes an adjustment based on changes to the Company's MFR C-35. (Schultz Testimony pp. 31-32) Then Witness Schultz makes some observations about the Company's health care costs and retirement plans, yet he does not make any specific adjustments. He recommends that the Commission somehow take these additional expenses into account when reviewing the Company's overall compensation request. (Schultz Testimony pp. 32-33)

Q. So with respect to the Company's health care costs, does Witness Schultz do any specific analysis of the requested costs?

A. No, he does not. He states that the healthcare increase "appears excessive" and "could be attributed" to the fact that employee share of the cost has not been as high as the projected healthcare cost increase. Schultz then cites the fact that employee contributions increased by 3%, while healthcare costs have been increasing 10-12% annually. (Schultz Testimony p. 32). Schultz has taken data from our interrogatory response out of context. The 3% figure is for Bargaining Unit Plans only and only reflects the increase from 2008 to 2009. Schultz does not acknowledge that PGN's benefit strategy, which includes the introduction of consumer-driven health plans, has limited its health care cost increases per employee to well below the national average over the past several years. Although PGN's cost increases have fluctuated from year to year, it still remains below the national average, as reflected in Exhibit No. ___ (MSD-14) attached to my rebuttal testimony. Furthermore, Schultz does not analyze what employee contributions should be, nor does he assess whether increasing employee contributions would limit the Company's healthcare cost increases.

Schultz's reference to health care costs increasing 10 -12 % annually is based on the company's budget projections. Those projections are based in part on national trends. In contrast, employee contributions are set based upon review of prior year's experience as compared to projections for the next year. To the extent the prior year's actual claims experience is less than the budget projection, employee contributions will not relate directly to the corresponding budget projection. In addition, the company must consider its need to remain competitive with other utilities and other large employers when setting employee rates.

Q. Likewise, with respect to Witness Schultz's testimony regarding the Company's retirement plans, does he do any specific analysis as to the costs for those plans?

A. No. Schultz makes statements about the Company's "generous benefit package" and claims that many of PEF's customers do not enjoy similar benefits. Yet, Progress Energy's benefits packages are part of a carefully designed and benchmarked total compensation package. Not only is Progress competing against other utilities for highly skilled employees, Progress also competes against other non-regulated companies for many of those employees. For example, while an employee may be able to make a higher salary in a non-regulated company, they may give up some of that salary for a more robust pension plan or better health benefits. Again, it is important to remember that Progress Energy approaches compensation and benefits on the basis of a total rewards package. That complete package is carefully designed to be competitive while remaining at the 50th percentile of peer utilities. If a significant piece of the package, such as pension or incentive compensation is eliminated, other portions of the total rewards package may require increases. The Commission recognized the value of a total compensation approach in Gulf's 2002 rate case proceeding which I reference above. (See Exhibit No. ___ (MSD-9), pages *68-72). Accordingly, the Company's total compensation package, and all the expenses included in this rate case for the package, should be approved as reasonable.

Q. Does this conclude your testimony?

A. Yes.

In Re: Petition for a **rate** increase by **Florida Power Corporation**

DOCKET NO. 910890-EI; ORDER NO. PSC-92-1197-FOF-EI

Florida Public Service Commission

1992 Fla. PUC LEXIS 1546; 138 P.U.R.4th 472

92 FPSC 10:408

October 22, 1992

[*1]

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PANEL:

The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; SUSAN F. CLARK; J. TERRY DEASON; BETTY EASLEY; LUIS J. LAUREDO

OPINION: Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on May 5, 1992, in Tallahassee, Florida; on May 13, 1992, in Ocoee, Florida; on May 14, 1992, in Clearwater, Florida; on May 14, 1992, in St. Petersburg, [*3] Florida; and July 9 through July 24, 1992, in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

ORDER GRANTING CERTAIN INCREASES

BY THE COMMISSION:

On January 31, 1992, **Florida Power Corporation** (FPC) filed a petition requesting a **rate** increase, with supporting testimony and minimum filing requirements (MFRs). In its petition the company requested a total permanent **rate** increase of $ 145,853,000 based on projected test years of 1992 and 1993. This request was later reduced to $ 131,948,000 as a result of several audit findings and FPC's decision not to request an increase due to the purchase of the Sebring Utilities distribution system. FPC also requested a $ 9,990,000 reward for excellent performance, and that the proposed increase be implemented in several steps. The requested **rate** increase was based on a 13.60% return on common equity.

FPC filed supplemental MFRs after its initial MFRs were determined to be deficient by the Director of the Division of Electric and Gas of the Florida Public Service Commission. On April 14, 1992, we issued Order No. PSC-92-0208-FOF-EI, suspending the rate schedules filed by FPC, [*4] and authorizing FPC to increase its rates on an interim basis to generate additional annual revenues of $ 31,208,000. On June 19, 1992, a prehearing conference was conducted in this docket. Hearings were held on FPC's petition for a permanent rate increase July 9 through 10, July 13 through 17, July 20 and July 22 through 24, 1992.

I. SUMMARY OF DECISION

We authorize an increase to **Florida Power Corporation** in gross annual revenues of $ 57,986,000 beginning November, 1992; an additional $ 9,660,000 increase beginning April, 1993; and a final increase of $ 18,111,000 beginning November, 1993, for a total increase of $ 85,757,000. **Rate** changes shall become effective with the company's first billing cycle of each month for which permanent new **rates** have been approved.

We have set the rate of return on common equity capital at 12%.

We deny Florida Power Corporation's request for a $ 9,990,000 regard for excellent performance.

II. TEST PERIOD

A. 1992 And 1993 Test Years

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. Based on the filing date of FPC's request for a rate [*5] increase the first year that the new rates will be in effect is approximately from November 1, 1992 to October 31, 1993. Therefore, we should be evaluating the financial operations of FPC for the twelve months from November 1, 1992 to October 31, 1993.

There are primarily two options for evaluating FPC's expected financial operations. The first option is to use a historical test year and make proforma adjustments to it. The second is to use a projected test year. Both of these options have strengths and weaknesses.

The historical test year has the advantage of using actual data for much of rate base, NOI and capital structure; however, the proforma adjustments usually do not represent all the changes which occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

The main advantage of a projected test year is that it includes all information related to rate base, NOI and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the company's ability to forecast. [*6] Many companies are not able to forecast accurately enough to use the forecast for setting rates.

FPC requested the use of two fully projected test years, calendar years 1992 and 1993. It selected the period in which new rates will become effective. The parties agree that, with adjustments, the 1992 test year is appropriate. At issue is the use of the 1993 forecast year. FPC believes that its forecast of financial operations for the years that new rates will be in effect is complete and accurate and provides a valid basis on which to set rates prospectively. The use of dual test periods is authorized by Section 366.076(2), Florida Statutes, and Rule 25-6.0425, Florida Administrative Code, and is consistent with Commission practice. See Order No. 13537, issued July 24, 1984 in Docket No. 830465-EI (FPL rate case). OPC and Occidental believe that the forecast is inaccurate and unreliable and that the authorization of dual test periods would set a dangerous precedent. In its brief, FPC pointed out that the precedent for dual test years was set eight years ago and has not produced the dire consequences [*7] predicted by the intervenor witnesses. In addition, we monitor utility earnings through surveillance reports and could require FPC to file MFRs should it exceed its allowed return.

The parties and the staff have conducted extensive discovery on FPC's forecast. We believe that FPC's forecast, as adjusted herein, is accurate enough to use as a basis for setting rates.

B. Forecast

We reviewed the company's original forecasts of customers and KWH by revenue class and system KW for 1992 and 1993 (Exhibit 147), the revised forecast (Exhibit 148), and the relationship of the original to the revised documents. We also reviewed Public Counsel's filing on the forecast. We have voted for using a revised forecast which reduces the 1992 forecast KWH by 3.59 percent and the 1993 forecast KWH by 2.25 percent.

The May 1992 forecast variance (Exhibit 37) showed actual year-to-date KWH sales to be 5.8% below the original KWH forecast.

Nothing we heard at the hearing persuaded us that the originally filed forecast is the better one to use. Instead, we believe that economic conditions warrant our reliance on the revised forecast. (Tr. 1843-1844, 1859-1860) In addition, reliance on the actual [*8] and more recent data that is available is generally better than a projection. (Tr. 1835, 1843) We have confidence in the integrity of the company's methodology in preparing the forecast and the record demonstrates the company's forecast process is inherently unbiased. (Tr. 1829, 1833, 1841)

The Commission has the discretion to use the original forecast, the revised forecast, forecasts by other parties, or some numbers in-between so long as the determination is based on the record. Gulf Power v. Florida Public Service Commission, 453 So.2d 799 (Fla. 1984).

C. Forecasted Inflation Rates

FPC originally forecast, inflation of 3.7% for 1992 and 3.8% for 1993, as measured by one Consumer Price Index. These forecasts were taken from the DRI Forecast for the US Economy of May 1991 (LF Exhibit 190). This compares to the June 1992 inflation forecast from DRI of 3.3% for 1992 and 3.5% for 1993 (LF Exhibit 190). In the hearing, whose witness, Mr. Kollen, recommended an inflation forecast of 3.1% for 1992, and 3.3% for 1993. (Tr. 2759)

The inflation forecast is used for rate making purposes to determine the appropriate amount of test year expenses. [*9] While we recognize that inflationary expectations have declined by one half of one percent for both 1992 and 1993 since FPC prepared their forecast in May 1991, we believe that FPC's inflation forecasts are appropriate for rate making purposes.

III. ACCOUNTING TREATMENT

A. FAS 87

Statement of Financial Accounting Standard No. (FAS) 87, titled Employer's Accounting for Pensions, which has been in effect since 1987, provides a method to record pension expense on an accrual basis. Although FPC has been using FAS No. 87, it has been making a regulatory adjustment under FAS No. 71, titled Accounting for the Effects of Certain Types of Regulation, to net the expense to zero. However, for the purposes of this proceeding, FPC filed its pension expense based upon a calculation in accordance with FAS No. 87. The company argued that accrual accounting more closely matches the cost of the benefit with the period in which the service is provided. Accordingly, the company stated its desire to move from cash accounting to accrual accounting. The intervenors argued that FAS No. 87 should not be used to determine the appropriate level of FPC's pension expense.

The purpose of FAS [*10] No. 87 is to accrue pension expense over the time employees earn benefits. While FPC will not make a cash contribution until 1993, the benefits earned by today's employees should be paid by today's ratepayers. Therefore, we shall use FAS No. 87 for ratemaking purposes. We approve FPC's request to set its pension expense at a level equal to the expense calculated for accounting purposes under the provisions of FAS No. 87.

B. FAS 106

The basic concept underlying FAS No. 106, titled Employers' Accounting for Postretirement Benefits Other Than Pensions, is the concept of accrual verses cash basis accounting to record other postretirement benefits (OPEB). FPC has requested that we begin using the accrual method for ratemaking purposes. Because accrual accounting matches the cost of employees' services to the period in which the employees provide the services, we agree. If we were to continue the pay-as-you-go method, future customers would pay for costs related to past years. Ultimately, the costs of retirement benefits under FAS No. 106 will not vary from costs under pay-as-you-go accounting, but the timing of the recognition of these costs will be different. The accrual [*11] accounting prescribed by FAS No. 106 appropriately recognizes the cost of retirement benefits. In fact, we have previously approved the concept of using FAS No. 106 for ratemaking purposes by Order No. PSC-92-0708-FOF-TL, issued July 24, 1992, in Docket No. 910980-TL, the recent rate case for United Telephone Company of Florida. In that order, we noted that we can still make adjustments to the cost of retirement benefits within the framework of FAS No. 106.

OPC, FIPUG, and Occidental testified that FAS No. 106 is unsuitable for ratemaking purposes. OPC argued that FPC could restructure its benefits plan, which would lower its FAS No. 106 cost after the rate case. However, FPC has already updated its FAS No. 106 cost to a lower amount based on its most recent collective bargaining agreement. In addition, FPC is constrained from making substantial changes from year to year due to a binding union contract, possible employee relations problems that could result from such changes, and labor market competitiveness. To the extent FPC continues cost containment measures, those measures will be reflected in FAS No. 106 costs and this effect can be monitored by our staff with the existing [*12] surveillance methodology.

OPC and FIPUG testified that the calculation of FAS No. 106 cost is unreliable and speculative. They argued that the FAS No. 106 amount is sensitive to changes in the assumptions used in its calculation, particularly the health care cost trend rate, and that the calculations reflect neither cost containment measures FPC may adopt in the future nor the possibility of government intervention in the health care area. FPC testified that the assumptions represent the best estimate of a particular future event and that the assumptions and measurements used in reporting FAS No. 106 costs are reviewed by independent auditors. FAS No. 106 contains a self-correcting methodology that encompasses changes in assumptions, experience being different from what the company assumed, and benefits plan amendments. Although changes in the FAS No. 106 costs would be accounted for with this methodology, they could not be recognized until the company's next rate case. However, such changes would affect earnings and this effect would be monitored with our present surveillance methodology. The uncertainty surrounding FAS No. 106 costs is no different from the uncertainty involved [*13] with the cost of equity, depreciation expense, nuclear decommissioning expense, fossil fuel dismantlement, or any other costs based upon estimates that we consider for ratemaking purposes.

OPC argued that if we approve FAS No. 106, we should establish a mechanism to annually refund to ratepayers any overrecovery of OPEB costs. FPC recommended that we adopt a dollar tracking procedure to account for any differences that may develop between the FAS No. 106 expense included in rates and subsequent changes to the amount of FAS No. 106 expense. However, we believe that requiring surveillance reports and requiring companies to file MFRs every four years will adequately monitor the effects of changes in FAS No. 106 costs.

OPC and FIPUG testified that using FAS No. 106 for ratemaking purposes can create an intergenerational inequity since the amortization of the transition obligation is a part of FAS No. 106 expense. The transition obligation is, essentially, the unrecognized amount of the postretirement benefit obligation as of the date a company initially applies FAS No. 106. The transition obligation represents the present value of benefits to be paid in the future and the amortization [*14] of the transition obligation allocates the present value of those future benefits to a 20 year period in the future. Under pay-as-you-go accounting, there will always be a mismatch between in time an employee earns postretirement benefits and the time the company recognizes the cost of those benefits. Even with the amortization of the transition obligation, FAS No. 106 is closer to achieving intergenerational equity than the pay-as-you-go method.

Occidental testified that accounting requirements should not drive the ratemaking process and that utility accounting follows the rate actions of a regulator. While generally accepted accounting principles need not be used for ratemaking purposes, in this instance accrual accounting provides more relevant and useful information than cash basis accounting. To the extent that regulatory accounting and generally accepted accounting principles are the same, the accounting and auditing functions could be simplified. Following generally accepted accounting principles can be appropriate for ratemaking purposes.

FIPUG and Occidental testified that FAS No. 71 can be used to defer the difference between FAS No. 106 costs and pay-as-you-go costs. [*15] FPC testified that the Securities and Exchange Commission has taken the position that continued pay-as-you-go accounting is unacceptable. FPC argued that generally accepted accounting principles are the basis for determining cost of service and that continuing the pay-as-you-go method represents a significant departure from cost-based regulation. This, in turn, raises questions about the applicability of FAS No. 71.30

OPC argued that the transition obligation should remain on a pay-as-you-go basis, stating that it would be unwise for the Commission to change its policy "midstream." However, the calculation of the FAS No. 106 expense includes the amortization of the transition obligation. As stated above, FAS No. 106 is appropriate for ratemaking purposes.

Finally, OPC argued that interest expense on OPEB costs that have already been recognized should be excluded from the FAS No. 106 expense calculation. OPC stated that if the company funded its OPEB plan, the plan assets would earn profits that would offset interest. However, funding of OPEBs could be more costly due to the lack of a comprehensive funding method, and interest cost is inherent with the present value concepts [*16] behind FAS No. 106. OPC also argued that the discount rate should be the Commission's allowed return on equity. For reasons that will be discussed later, we disagree.

We approve FPC's request to move from a cash basis to an accrual basis when accounting for post-retirement benefits other than pensions for ratemaking purposes. The allowed OPEB expense should be calculated according to FAS No. 106 beginning in November of 1992.

IV. RATE BASE

To establish FPC's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the company is entitled to earn a reasonable return. A utility's rate base is comprised of various components, including 1) plant-in-service, 2) depreciation reserve, 3) construction work in progress (CWIP) (where appropriate), 4) property held for future use, 5) net nuclear fuel, and 6) working capital.

FPC requested a rate base of $ 3,006,775,000 ($ 3,318,818,000 system) for the 1992 current test year and $ 3,211,239,000 ($ 3,592,614,000 system) for the 1993 projected test year. Evidence developed during the course of the proceedings has led us to reduce that amount to $ 2,950,832,000 for 1992 and $ [*17] 3,179,393,000 for 1993. We therefore approve the rate base summarized in the following tables.

1992 Rate Base

Jurisdictional

(000's)

	FPC	Adjustments	Commission Approved
Pl.-in-Serv.	4,245,287	(21,904)	4,223,383
Acc. Deprec.	(1,483,255)	11,509	(1,471,746)
Net P.I.S.	2,762,032	(10,395)	2,751,637
CWIP	124,340	(32,288)	92,052
PHFU	9,559	(7,185)	2,374
Nuc. Fuel	58,351	(15)	58,336

	FPC	Adjustments	Commission Approved
Net Plant	2,954,282	(49,883)	2,904,399
Work. Cap.	52,493	(6,060)	46,433
Total	$ 3,006,775	$ (55,943)	$ 2,950,832

1993 Rate Base

Jurisdictional

(000's)

	FPC	Adjustments	Commission Approved
Pl.-in-Serv.	4,617,090	(23,584)	4,593,506
Acc. Deprec.	(1,628,030)	18,483	(1,609,547)
Net P.I.S.	2,989,060	(5,101)	2,983,959
CWIP	110,667	(27,746)	82,921
PHFU	9,436	(7,073)	2,363
Nuc. Fuel	50,487	(17)	50,470
Net Plant	3,159,650	(39,937)	3,119,713
Work. Cap.	51,589	8,091	59,680
Total	$ 3,211,239	$ (31,846)	$ 3,179,393

A. Plant-In-Service

The amount of plant-in-service proposed by FPC was $ 4,245,287,000 ($ 4,715,371,000 system) for the 1992 current test year and $ 4,617,090,000 [*18] ($ 5,175,330,000 system) for the 1993 projected test year. We have made certain adjustments, described below, which reduce plant-in-service to $ 4,223,383,000 for 1992 and $ 4,593,506,000 for 1993.

1. Aircraft

a. FPC's ownership of aircraft

FPC owns three aircraft which are also used by FPC's affiliates. None of FPC's investment in this flight equipment is allocated to any of its affiliates, nor is any related depreciation expense recovered from any of its affiliates. However, FPC does allocate to its affiliate other major costs of operating the aircraft such as fuel, salaries, and hangar fees. The affiliates' initial charge for use of the aircraft is generally based on 70% of commercial coach fare. Any remaining expenses not recovered from this initial charge are allocated based on usage.

Because FPC's affiliates' use of the aircraft is substantial, FPC and its affiliates should share the investment for the flight equipment as well as share the related depreciation. Accordingly, the investment and depreciation figures filed by FPC shall be reduced by 50%. The adjusted figures are as follows:

1992

	System	Factor	Jurisdictional
Flight equipment	3,465,000	.941986	3,263,981
Accumulated Depreciation	(288,000)	.938045	(270,157)
Depreciation expense [*19]	237,000	.938045	222,317

1993

	System	Factor	Jurisdictional
Flight equipment	3,465,000	.942785	3,266,750
Accumulated Depreciation	(525,000)	.938942	(492,945)
Depreciation expense	238,000	.938942	223,468

b. Rescinded purchase of airplane

In December 1990, FPC purchased a Piper Cheyenne from Florida Progress. In August 1991, the purchase was rescinded and plant-in-service and accumulated depreciation were adjusted, as though the purchase never occurred. Consequently, the Piper Cheyenne and related accumulated depreciation were on FPC's books during a portion of the interim test period and were included in the MFRs.

The company made pro forma adjustments to remove the airplane's effect on rate base, reducing plant-in-service $ 833,000 and reducing accumulated depreciation $ 68,000. However, these pro forma adjustments were calculated incorrectly because they treated the Piper Cheyenne as if it had been on the books for thirteen months, instead of nine months. Plant-in-service shall be increased $ 265,000 ($ 278,000 system) and accumulated depreciation shall be increased $ 38,000 ($ 40,000 system) in the 1991 interim test period to adjust for these overstatements. Because the [*20] 1992 and 1993 pro forma adjustments correctly remove the effects of the rescinded aircraft purchase, no adjustments are necessary for these test years.

2. Crystal River 3

FPC purchased Sebring Utilities Commission's 3.5 megawatt share of Crystal River 3. When compared to FPC's avoided cost, the purchase results in a savings of $ 893,000 over the remaining life of Crystal River 3; therefore, we find the purchase to be cost-effective. Accordingly, the acquisition and inclusion of $ 2,310,000 ($ 2,500,000 system) for Sebring's ownership share of Crystal River 3 is an appropriate addition to rate base for the 1992 current test year.

3. Lake Tarpon Substation

FPC expanded the Lake Tarpon substation to protect existing equipment that was operating at or near its existing emergency rating. An outage of the existing transformer would jeopardize reliable service. The substation upgrade was needed despite the fact that it will serve as the terminal point for the Lake Tarpon-Kathleen 500kv line. Because the substation expansion will maintain system reliability, the installation of the terminal point for the Lake Tarpon-Kathleen 500kv transmission line is a cost-effective [*21] addition. Accordingly, $ 10,838,960 ($ 14,381,000 system) was appropriately included in the 1992 current test year for capital additions at the Lake Tarpon Substation.

4. Sebring Utilities' Distribution System

The parties stipulated that the Sebring acquisition would not be included in this rate proceeding. Accordingly, for the 1992 and 1993 test years, the following reductions were made to remove the Sebring electric distribution system acquisition from rate base and net operating income:

	1992		1993	
	System	Juris. *	System	Juris. *
Plant In Service	15,924,000	18,640,000	17,150,000	20,317,000
Less:Acc.Dep.	5,787,000	6,910,000	6,783,000	8,011,000
CWIP	0	91,000	0	76,000
Working Capital	2,863,000	2,436,000	2,863,000	2,719,000
PHFU	0	9,000	0	11,000
Nuclear Fuel-Net	0	15,000	0	17,000
Regulatory Prac.	0	25,000	0	24,000
Total	$ 13,000,000	$ 14,306,000	$ 13,230,000	$ 15,153,000
Op. Revenues	6,927,000	6,927,000	7,158,000	7,158,000
Other Op. Revs.	640,000	540,000	736,000	613,000
Total Op.Revs.	$ 7,567,000	$ 7,467,000	$ 7,894,000	$ 7,771,000

	1992 System	1992 Juris. *	1993 System	1993 Juris. *
O&M	6,723,000	6,011,000	6,964,000	6,203,000
Deprec. & Amort.	677,000	800,000	705,000	848,000
Taxes Other	21,000	253,000	229,000	275,000
Rev. Taxes	4,000	4,000	4,000	4,000
Income Tx.-Fed.	(286,000)	(132,000)	(266,000)	(120,000)
Income Tx.-St.	(47,000)	(22,000)	(41,000)	(20,000)
Deferred Tax	146,000	122,000	131,000	104,000
ITC-Net	0	(7,000)	0	(8,000)
Regulatory Prac.	0	1,000	0	1,000
Total Op. Exp.	$ 7,438,000	$ 7,030,000	$ 7,726,000	$ 7,287,000

[*22]

* The jurisdictional amounts include the difference due to the change in the allocation factor. This additional amount represents the impact on the jurisdictional amounts resulting from the removal of Sebring sales from the system.

B. Accumulated Depreciation

Florida Power requested $ 1,483,255,000 ($ 1,673,510,000 system) for the 1992 current test year and $ 1,628,030,000 ($ 1,837,549,000 system) for the 1993 projected test year for accumulated depreciation. FPC used zero net salvage in forecasting the depreciation reserve for the 1992 and 1993 test years, which is unrealistic. The currently prescribed net salvage value is a more viable method. Using our currently prescribed net salvage value with numbers submitted by FPC, we find that the depreciation reserve shall be reduced $ 5,596,000 ($ 6,321,000, system) for 1992 and $ 10,581,000 ($ 11,958,000, system) for 1993. With the net result of the adjustments discussed below, we find the appropriate amount of accumulated depreciation to be $ 1,471,746,000 for 1992 and $ 1,609,547,000 for 1993.

1. Nuclear Decommissions Expense

We approve the stipulation by the parties that the adjustments made to accumulated depreciation [*23] based on the company's nuclear decommissioning study shall be reversed in accordance with our decision in Docket No. 910081-EI regarding FPC's nuclear decommissioning study. Accumulated depreciation shall be reduced $ 2,221,000 ($ 2,052,000, system) for 1992 and $ 6,662,000 ($ 6,139,000, system) for 1993. This adjustment is included in the line item adjustment removing the entire nuclear decommissioning reserve from rate base, and has a zero effect. However it is necessary to reduce depreciation expense by $ 4,103,000 in 1992 and by $ 4,092,000 in 1993.

2. Fossil Fuel Dismantlement Reserve

FPC requested an adjustment to the 1992 and 1993 accumulated depreciation to reflect the effect of implementation of a levelized fossil fuel dismantlement expense. We find that FPC's requested adjustment is not appropriate. FPC's 1992 adjustment shall be increased by $ 991,687 ($ 1,193,460 system), and its 1993 adjustment shall be increased by $ 933,872 ($ 1,194,960 system). As discussed below, we shall increase the dismantlement expense which shall also serve as a rate base reduction. An increase in the dismantlement expense reduces rate base because of the corresponding increase [*24] in the depreciation reserve. Because we increase FPC's yearly fossil fuel dismantlement accrual below, we must adjust the associated reserve.

3. Reserve Transfer Reversal

Our decision in Docket No. 920096-EI, Order No. PSC-92-0680-FOF-EI, dated July 21, 1992, denied FPC's petition to reverse the transfer of reserves. Therefore, all figures associated with this adjustment should be reversed. The accumulated depreciation should be increased by $ 6,877,000 for 1992 and $ 6,468,000 for 1993. Construction work in progress should be increased by $ 507,000 for 1992 and $ 492,000 for 1993. Working capital should be decreased by $ 582,000 for 1992 and decreased by $ 2,503,000 for 1993.

When we net these adjustments, rate base is reduced by $ 6,952,000 in 1992, and $ 8,479,000 in 1993. In addition, O&M expense is increased by $ 1,157,000 and depreciation expense is decreased by $ 3,850,000 for a net decrease of $ 2,693,000 to net operating income in 1992. For 1993, O&M expense is increased by $ 1,132,000 and depreciation expense is decreased by $ 2,987,000 for a net decrease of $ 1,855,000 to NOI.

C. Construction Work In Progress

The company has requested the amounts [*25] $ 124,340,000 ($ 139,203,000 system) for the 1992 current test year and $ 110,667,000 ($ 123,348,000 system) for the 1993 projected test year for construction work in progress (CWIP) to be included in rate base. However, we find that adjustments should be made to the balances for 1991, 1992, and 1993.

For the 1991 interim test year, CWIP should be reduced by $ 2,314,122 ($ 2,452,067 system) for construction projects which were included in Account 107.20, CWIP Not Eligible for allowance for funds used during construction (AFUDC), but which accrued AFUDC. CWIP should be increased by $ 1,069,179 ($ 1,131,851 system) for construction work orders which did not accrue AFUDC and were not included in CWIP. This results in a net decrease of $ 1,244,943.

OPC testified that one project in the 1992 test year was classified as Rate Base CWIP even though it accrued AFUDC. We agree; therefore, 1992 CWIP should be reduced by $ 1,254,066 ($ 1,405,000 system).

OPC also testified that actual CWIP for the months of December 1991 through March 1992 was approximately 25% lower than the balances projected by the company. FPC stated that OPC omitted from actual CWIP that portion of CWIP that is considered [*26] completed but not classified to electric plant in service. Because Account 106 is for projects that are classified in service, these amounts are plant in service and not CWIP. Because FPC overprojected the beginning months of the two year forecasts, which should be the easiest to accurately project, and it also forecasted by historical trend, it is appropriate to apply these early variances to the future projections. Therefore, the CWIP allowed in rate base should be reduced by 25% for both the 1992 and 1993 test years.

CWIP for 1992 shall be reduced by $ 1,254,066 ($ 1,405,000 system) for an AFUDC eligible project that was included in rate base. Also, the 1992 and 1993 test year jurisdictional CWIP allowed in rate base shall be reduced by a 25% overprojection factor, which is $ 30,684,000 for 1992 and $ 27,640,000 for 1993. The appropriate amount of CWIP for the 1992 test year is $ 92,052,000 and for the 1993 test year is $ 82,921,000.

D. Property Held For Future Use

In the past, Commission rate case decisions have reflected the importance of retaining certain properties held for future use in view of Florida's projected growth rate, the burden on the utilities to meet [*27] this growth rate, and the expense that might be incurred if the properties were sold and had to be replaced in the future at a greater cost. In this instance, except for the inclusion of Avon Park Unit 2, the parties agree that the level of Property Held for Future Use is appropriate.

Florida Power requested $ 9,559,000 ($ 11,145,000 system) for the 1992 current test year and $ 9,436,000 ($ 11,145,000 system) for the 1993 projected test year for property Held for Future Use. Because we have removed Avon Park Unit 2 from property held from future use, the appropriate jurisdictional level of property held for future use is $ 2,374,000 for 1992 and $ 2,363,000 for 1993.

1. Avon Park Unit 2

In FPC's 1984 rate case, the Commission ordered seventeen of FPC's units to be placed in extended cold shutdown, and that they be excluded from rate base, but allowed to accrue a carrying charge equivalent to the AFUDC rate until such time as they were returned to commercial service. For the 1992 test year, FPC projects that the only unit of the original seventeen still in extended cold shutdown will be Avon Park Unit 2. The company included this unit in Property Held for Future Use. [*28]

FPC has entered into a contract with Eco Peat to lease Avon Park Unit 2 for 32 years beginning in 1994 if Eco Peat meets its performance and construction dates. At present, Eco Peat appears to be on target to meet its schedule. Eco Peat plans to convert Unit 2 to a 40 megawatt electric generating facility fired by peat or other permitted fuels. The lease revenues from Unit 2 range from $ 500,000 to $ 1,200,000 per year plus bonus payments, if the tenant exceeds certain profitability thresholds. The net book value of the unit is about $ 1,028,000 in system figures.

Occidental recommended that Unit 2 be excluded from rate base. Occidental argued that the unit is not presently used and useful and may never be used and useful for retail ratepayers. While it is true that the unit is not used and useful at the present time, to exclude it from rate base entirely would deny the company the opportunity to recover its investment.

OPC argued that the unit should be included in rate base and revenues be recorded above the line. We disagree. Because there is a possibility that the lease may not become operational in 1994, ratepayers would have to pay a return on a unit that was not in [*29] service and from which no lease revenue would be recognized.

We considered the option of placing Unit 2 in plant in service and imputing revenues for 1993. However, there is a chance that the lease may not become operational, and it is difficult to calculate revenues that will be imputed since we do not have an executed lease setting specific lease payments. Instead, we shall exclude the unit from rate base, but allow it to accrue a carrying charge at the AFUDC rate until such time as the unit is returned to commercial service, or the lease becomes operational. When the lease becomes effective, the unit shall be recorded in plant-in-service and lease revenues shall be recorded above the line.

For the 1992 and 1993 test years, the following reductions shall be made to remove Avon Park Unit 2 from plant held for future use:

(000)

	1992		1993	
	Juris.	System	Juris.	System
PHFU	$ 7,176	$ 8,178	$ 7,062	$ 8,178
Acc.Dep/Amort.	(6,276)	(6,797)	(6,259)	(6,797)
Fossil Dsmtlmt.	(326)	(353)	(541)	(588)
Working Capital	473	508	472	508

(000)

1992		1993	
Juris.	System	Juris.	System
$ 1,047	$ 1,536	$ 734	$ 1,301

E. Working Capital

FPC requested $ 52,493,000 ($ 65,536,000 system) [*30] for the 1992 current test year and $ 51,589,000 ($ 67,405,000 system) for the 1993 projected test year for working capital. However, the appropriate jurisdictional amounts for 1992 and 1993 are $ 46,433,000 and $ 59,680,000. This is a calculation based on the resolution of all other working capital issues.

1. Methodology

Occidental argued that we should direct FPC to calculate working capital based upon a lead/lag methodology in its next base rate filing in lieu of its current methodology. We disagree. It would be inappropriate to single out FPC from the other regulated utilities in Florida to make a change that would be better handled in a generic proceeding.

2. Property Insurance Reserve

FPC currently maintains a funded Property Insurance Reserve to cover losses inflicted by major storms. FPC's base rates were last adjusted in Docket No. 870220-EI. Since that time, the company has been accruing $ 1,104,000 annually in its reserve. In this case, in accordance with Rule 25-6.0143, Florida Administrative Code, the company has requested an increase to the scope of its current storm damage reserve to include not only tropical [*31] storms and hurricanes, but other destructive acts of nature as well. We find that it would be appropriate for FPC to expand the scope of its reserve to cover other destructive acts of nature.

In addition, the company requested a cap of $ 5 million for its reserve, which is the amount of its Property Insurance deductibles. The company reduced its requested accrual to $ 314,000 annually to attain this cap. However, if FPC exceeds the $ 5 million cap before its next rate case, it shall continue to accrue its reserve. Because of the catastrophic damage caused by Hurricane Andrew, which took place after the proceeding in this case, we shall review the adequacy of the reserve in FPC's next rate case.

Also, FPC shall establish an unfunded reserve effective January 1, 1993. This unfunded reserve shall be established in accordance with the provisions of Rule 25-6.0143, Florida Administrative Code. Because an unfunded reserve will reduce rate base, an unfunded reserve will ultimately result in lower revenue requirements. The funded reserve must be discontinued December 31, 1992.

All future charges shall be made against the funded reserve [*32] until it is extinguished. Also, all investments should be liquidated upon maturity, or sooner, if economically feasible, with the net proceeds recorded in the general cash account. In addition to enabling the company to go to an unfunded reserve as soon as practical, this should give FPC the necessary flexibility to manage its portfolio. FPC shall record any gains associated with the sale of investments in a deferred account until its next rate case, during which the disposition of these gains will be determined.

FPC shall accrue $ 100,000 annually in the unfunded reserve. This annual accrual will result in a December 31, 1993, balance of $ 100,000 or $ 50,000 on average in the Unfunded Property Insurance Reserve. Accordingly, working capital shall be reduced $ 46,465 ($ 50,000 system). FPC's requested Property Insurance Reserve of $ 3,732,000 ($ 4,010,000 system) for the 1992 current test year is appropriate.

3. Contract Retainage

Although the company made an error in the 1991 interim test year by removing the wrong amount from working capital for contract retainage, the amount removed in 1992 and 1993 is correct. Therefore, no adjustments shall be made to the 1992 [*33] and 1993 working capital allowance for contract retainage.

4. Fuel and Conservation Expenses

It has long been our policy to include net fuel and conservation overrecoveries in working capital. This reduces working capital and consequently rate base. However, FPC excluded from working capital the net overrecovery of fuel and conservation expenses in its 1992 test year and the net under recovery in the 1993 test year.

FPC receives interest on underrecoveries and pays interest on overrecoveries through the Fuel and Conservation Clause Adjustment. This acts as an **incentive** for the company to make its projections as accurately as possible. If overrecoveries were excluded from working capital, rate base would be increased and ratepayers would have to provide the interest to pay themselves.

FPC disagrees with our practice of including overrecoveries in working capital, because in a projected test year, the company matches the current month fuel/conservation revenues with the appropriate expenses through the corporate model. FPC testified that any overrecovery is eliminated by year end by understating the monthly revenues to be collected during the year. The company argued [*34] that customer accounts receivable are not overstated by the accumulated net overrecovery of fuel/conservation expenses, but are really understated because the monthly fuel/conservation revenues have been modeled to be less than the applicable expense in order to eliminate the accumulated net overrecovery.

At no time did the company argue that the overrecovery did not exist, nor did the company dispute the amount of the overrecovery. Both the accounts receivable and the overrecovery are 13-month average amounts. Even though these accounts were adjusted throughout the year, and an overrecovery no longer existed at year's end, there would still be a 13-month average amount that should be included in rate base. To exclude the overrecovery from working capital would mean that ratepayers would be paying FPC a return on the amount of the overrecovery for years after the refund to customers had, in fact, taken place. In addition, the amount paid to the company by ratepayers would exceed many times the one-time refund with interest the company is required to pay.

Based on the above, the net fuel/conservation overrecovery shall be included in rate base and working capital shall be reduced [*35] by $ 8,434,000 ($ 4,651,000 system) for the 1992 test year. No adjustment is necessary for 1993 because the company properly excluded its projected net underrecovery of $ 2,328,000 ($ 6,244,000 system) from working capital.

5. Accrued Utility Revenues

Accrued utility revenue is unrecorded revenue applicable to unread meters. Since meters are read on a cycle basis, at the end of any given accounting period, there are certain meters which have not been read for as many as 30 days. The KWHs recorded on these unread meters represent service actually rendered to customers. Unbilled revenues are booked by utilities in order to preserve the matching principle - matching revenues with expenses for services rendered. Our practice has been to include accrued utility revenues in working capital.

Occidental argued that accrued utility revenue should be excluded from working capital because it is an asset created by accounting that has no associated carrying cost. The intervenor stated that there is no carrying cost because unlike accounts receivable, which have already been billed, these have not been billed. In addition, the amount at issue is the ongoing balance from the initial [*36] recognition of accrued utility revenues, not year-to-year changes in that balance. We have repeatedly considered and rejected repeatedly this position in the past.

The company included accrued utility revenues in working capital. FPC records unbilled revenue as other operating revenues and as such reduces the gross cost to be recovered from the customer. Accrued utility revenues, which are offset to the unbilled revenue, compensate for the timing difference between revenue recognition and cash receipt to the company. Therefore, to remove accrued utility revenues from rate base without removing unbilled revenues from net operating income would result in a severe mismatch between the income statement and balance sheet.

Accrued utility revenue is a proper component of working capital. Accordingly, no adjustments shall be made, and accrued utility revenues shall be included in working capital.

6. FAS No. 106 Net Assets

Occidental argued that when FPC accounted for the implementation of FAS No. 106, the result was a net increase to working capital of $ 22.8 million. FPC testified that implementation of FAS No. 106 would cause a net reduction to working capital.

We find that [*37] the implementation of FAS No. 106 results in an increase in the liability side of the working capital calculation which causes a reduction to working capital. FPC updated its FAS No. 106 costs due to a new collective bargaining agreement and a new discount rate, and we have adjusted the discount rate, as discussed below. The effect of these changes is the reduction of FAS No. 106 costs, the reduction of liability associated with FAS No. 106, and the increase of working capital. To reflect these changes, we reduced the FAS No. 106 liability by $ 3,168,207 ($ 3,388,095 system) for 1992 and by $ 10,565,031 ($ 11,288,633 system) for 1993. Because the implementation of FAS No. 106 results in a net liability that reduces working capital for 1992 and 1993, no adjustments should be made to working capital for 1992 and 1993 to exclude FAS No. 106 net assets.

7. Vacation Pay Accrual Asset

Occidental argued that the vacation pay accrual asset should be a liability rather than an asset that should be excluded form working capital. FPC stated that the vacation pay accrual asset represents the amount of vacation earned but not taken that is estimated to be capitalized. The company charges [*38] O&M and the vacation pay accrual asset, and credits the accrued vacation pay liability for vacation pay when earned. The vacation pay accrual asset compensates for the timing difference between vacation earned and vacation taken for payroll that will be charged to construction. No adjustments shall be made to working capital for 1992 and 1993 to exclude the vacation pay accrual asset.

8. Interest on Tax Deficiency

FPC has proved that its ratepayers will benefit in 1992 and 1993 from its tax administration policies, which give rise to this interest expense. The 1992 and 1993 working capital allowances properly include the deferred debit and accrued tax liability related to the interest expense on tax deficiencies, which shall be included in the 1992 and 1993 test year O&M expenses as discussed below in greater detail. The 1992 and 1993 working capital allowances shall not be adjusted to exclude interest on tax deficiencies, as this would result in a mismatch between the income statement and the balance sheet.

9. Light Oil Inventory

We reduced the 1992 test year light oil inventory by $ 574,522 ($ 637,120 system). No adjustment is made to the fuel inventory for the [*39] 1993 test year.

The Commission's guidelines used to justify Florida Power's fuel inventory levels were approved in Order No. 12645. These guidelines allow for a 30-day level of light oil inventory at peaker units when measured at a high rate of burn and for a 45-day level of inventory at steam units when measured at the average rate of burn.

According to FPC's witness, D. D. Williams, FPC's 1992 fuel inventory target level for light oil inventory is 383,000 barrels (Exhibit No. 149). FPC's methodology for calculating its light oil inventory for 1992 has included a full year of fuel inventory for the DeBary Peakers, which will go in service in November, 1992. (Tr. 1889)

We determined that the fuel inventory for the DeBary plant should be adjusted to reflect only those two months that the plant is scheduled to be in service.

FPC is entitled to recover the full amount of their requested fuel inventory for 1993 (Exhibit 150). In 1993, the DeBary plant will be in service for the entire year.

10. Prepaid Interest

The parties stipulated that an adjustment should be made to the working capital allowance to exclude prepaid interest for the 1991 interim test year, the 1992 current [*40] test year, and the 1993 projected test year.

Working capital shall be reduced as follows to exclude prepaid interest:

	Jurisdictional	System
1991 Interim Test Year	$ 186,000	$ 196,000
1992 Current Test Year	229,000	246,000
1993 Projected Test Year	330,000	355,000

In addition, for the 1991 interim test year, temporary cash investments shall be reduced $ 2,559,000 ($ 2,692,000) system.

V. COST OF CAPITAL

A. Cost Of Common Equity Capital

To arrive at a fair overall rate of return, it is necessary that we utilize our judgment to establish an allowable rate of return on common equity capital.

Three witnesses presented testimony concerning the fair rate of return on common equity for FPC. Witness Carl H. Seligson, testifying on behalf of FPC, recommends an ROE of 14.15%. (Tr. 162) Witness Mark A. Cicchetti, testifying on behalf of the OPC, recommends an ROE of 10.80%. (Tr. 306) Witness Richard A. Baudino, testifying on behalf of Occidental, recommends an ROE of 10.65%. (Tr. 466)

Witness Carl H. Seligson, testifying on behalf of FPC, relied on a risk premium approach based on the logic of the Capital Asset Pricing Model (CAPM) in arriving at [*41] his estimate of a fair ROE for FPC. (Tr. 159, 258-259) The risk premium approach attempts to estimate the ROE by recognizing the higher return investors require on equity securities than on debt securities. (Tr. 160)

Witness Mark A. Cicchetti, testifying on behalf of the OPC, utilized two methodologies in arriving at his estimate of a fair ROE for FPC. He first performed a Discounted Cash Flow (DCF) analysis on an index of high quality electric utility companies. Also performed a risk premium analysis on the same index of companies. (Tr. 296)

Witness Richard A. Baudino, testifying on behalf of Occidental, utilized two methodologies in arriving at his estimate of a fair ROE for FPC. He first performed a DCF analysis on a group of comparable electric companies and on FPC's parent, Florida Progress Corporation. He also performed a "Revised" risk premium analysis based on the analysis done by witness Seligson. (Tr. 442)

Based upon the evidence in the record and a detailed review of the cost of equity capital methodologies presented, we have determined that the cost of common equity capital for FPC is 12% with a range of plus or minus 100 basis points (for ratemaking purposes). [*42] We believe that a return of 12% would continue to provide the company with comfortable coverage ratios that, along with its strong qualitative factors, maintain the company's present credit rating. In addition, this ROE is reasonable given the current market conditions and the relatively low risk associated with this high quality, well managed electric utility.

B. Weighted Average Cost Of Capital

Based upon the proper components, amounts, and cost rates associated with the capital structures for the test years ending December 31, 1992 and December 31, 1993, we find that the weighted average cost of capital is 8.39% and 8.37%, respectively.

The company per book amounts were taken directly from FPC's MFR filing. [Exhibit 5, Sch. D-1, p. 1, 1992 and 1993] Specific adjustments were made to the Investment Tax Credit and Deferred Tax balances. After all specific adjustments were made, a pro rata adjustment was made across all other sources of capital to reconcile the capital structure with the rate base.

We agreed with and used the respective cost rates provided by FPC with the exception of the cost rates for common equity, long-term debt, and short-term debt. We used the [*43] ROE of 12.0% instead of the ROE recommended by the company of 13.6%, the ROE recommended by OPC of 10.8%, or the ROE recommended by Occidental of 10.65%.

We also adjusted the cost rates the company projected for the issuance of long-term and short-term debt during the 1992 and 1993 test years. The company projected that it would issue $ 150 million of first mortgage bonds at 9.70%, $ 100 million of medium term notes at 9.00%, and $ 50 million of pollution control revenue bonds at 8.00% during 1992. The company also projected that it would issue $ 100 million of first mortgage bonds at 9.7% in 1993. [Exhibit 5, Schedule D-10a, 1992 and 1993]

Company witness Bongers testified that in the KPMG Peat Marwick audit of FPC, the audit staff came to the conclusion that the interest rate assumptions made by the company concerning its long-term debt were too high relative to the level of interest rates currently prevailing. He stated that KPMG Peat Marwick believed a rate of 8.5% was more reasonable than the 9.7% projected by the company. (Tr. 2208) Company witness Seligson testified that FPC could issue first mortgage bonds at 8.25% or more based on the U.S. long-term bond trading at [*44] a yield of 7.40%. (Tr. 138-139) Although he stated that he did not believe the 8.25% rate was wrong, he did state that since the time of his prefiled direct testimony the spread between the rate FPC could probably issue first mortgage bonds and the yield on long-term treasury bonds had narrowed to 70 to 75 basis points. (Tr. 166-167) Based on witness Bongers testimony, we used the rate of 8.5% instead of 9.7% for the first mortgage bonds the company projects to issue in 1992 and 1993.

Company witness Seligson testified that FPC could issue medium-term notes at a rate of 7.25% or less. He also noted that Southern California Edison (SCE), a AA-rated electric utility that OPC witness Cicchetti used in his index of comparable-risk companies and that FPC cited in its legal brief as comparable to FPC as discussed in Issue No. 29, recently issued medium term notes at a rate of 6.22%. We used the rate of 7.25% which is conservatively between the 9.0% used by the company in its MFR filing and the 6.22% recently incurred by SCE for the medium term notes the company projects to issue in 1992.

Company witness Greene testified that in 1991 FPC refinanced its 10.0% and 10.25% pollution control [*45] revenue bonds at a rate of 7.2%. (Tr. 635) He also testified that more recently the company established the interest rate on its annual tender pollution control bonds at 6.625%. (Tr. 760) Company witnes Bongers testified that this new rate would result in further refinancing of tender pollution control bonds in early 1992. (Tr. 2190-2191) We used the rate of 7.2% which is conservatively between the 8.0% used by the company in its MFR filing and the 6.625% that has recently been established for its annual tender pollution control bonds for the pollution control revenue bonds the company projects to issue in 1992.

Although the company did not issue the bonds and notes as projected in its MFR filing, witness Greene did testify that the company still planned to issue this debt during its projected 1992 and 1993 test years. (Tr. 758-760) In addition, the embedded cost of fixed rate long-term debt the company used to calculate its recommended overall cost of capital reflects the cost rates for these debt issues. The adjustments we made had the effect of reducing the company's embedded cost of fixed rate long-term debt in 1992 and 1993 from 8.53% to 8.24% and from 8.63% to 8.26%, [*46] respectively.

Also reflected in the company's overall cost of capital calculation is an assumption of short-term borrowing at rates of 7.4% in 1992 and 7.5% in 1993. Occidental witness Baudino testified that these rates are excessive and do not correspond with current market rates for commercial paper and short-term loans from banks. He stated that based on the Federal Discount Rate of 3.5%, commercial paper rates are at most only 4.0%. He also stated that it would be prudent for FPC to use the most cost effective short-term financing available, i.e., commercial paper. (Tr. 484-485) Since the time of his prefiled testimony, the Federal Reserve lowered the Discount Rate again. (Tr. 171) Although the cost of commercial paper dropped with the decline in the Discount Rate, we used the rate of 4.0% instead of 7.4% or 7.5% for the short-term debt the company projects to issue in 1992 and 1993.

Schedules 2 and 9 show the components, amounts, cost rates, and weighted average cost of capital associated with the respective test year capital structures.

C. Investment Tax Credits

Florida Power's requested balances of accumulated deferred investment tax credits in the amount of [*47] $ 106,584,000 for the 1992 current test year and $ 102,088,000 for the 1993 projected test year are not appropriate. We find that ITCs should be $ 106,121,000 for the 1992 test year and $ 101,666,000 for the 1993 projected test year.

The parties to this docket stipulated to exclude the company's projected acquisition of the Sebring Transmission and Distribution System (Sebring T & D) from consideration in this proceeding. Consequently, we find that the company's Sebring T & D pro forma adjustments to the 1992 and 1993 Rate Base and NOI should be reversed. On MFR Schedule D-1, the company made specific adjustments totalling $ 463,000 for 1992 and $ 422,000 for 1993. These adjustments increased its per books ITCs and were identified as adjustments for the Sebring acquisition. Thus, reversing these adjustments to exclude Sebring requires adjustments of $ 463,000 for 1992 and $ 422,000 for 1993, reducing the ITC balance as filed. The result of these adjustments decreases 1992 ITCs from $ 106,584,000 as filed to $ 106,121,000 and decreases 1993 ITCs from $ 102,088,000 as filed to $ 101,666,000.

D. Accumulated Deferred Taxes

Florida Power's requested balances of accumulated [*48] deferred taxes in the amount of $ 388,551,000 for the 1992 current test year and $ 391,231,000 for the 1993 projected test year are not appropriate. Accumulated Deferred Taxes should be $ 388,370,000 for the 1992 current test year and $ 395,325,000 for 1993 projected test year.

Our adjustments to the 1992 current test year and the 1993 projected test year result from three factors: the reversal of the company's pro forma adjustments for the Sebring Transmission and Distribution (Sebring T & D) acquisition; the effect of adjustments to rate base; and the effect of adjustments to operating expenses.

E. FAS 109 Accounting For Income Tax

We do not believe the effect of implementing FAS No. 109, Accounting for Income Tax, in early 1993 should be reflected in setting current rates.

Our current review of the regulatory implications of implementing FAS No. 109 has not been concluded. We believe that its implementation should be revenue neutral; whether or not this is borne out by our review, its effect shall be excluded from consideration in this proceeding.

FPC's calculation of current and deferred income taxes was based on the company's operating and construction forecasts [*49] and the statutory tax rates in effect for both the federal and state jurisdictions. The method of calculating deferred income taxes followed the guidelines established in Accounting Principles Bulletin, Opinion No. 11, 'Accounting for Income Taxes.' (Tr. 2252)

FAS No. 109 changes the method of accounting for income taxes. It was issued in February 1992, which is subsequent to the date Florida Power's MFRs were filed. Implementation of FAS No. 109 is mandatory for financial reporting for years beginning after December 15, 1992. Consequently, the company will be required to implement the accounting during the 1993 projected test year.

The most significant difference between APB 11 and FAS No. 109 is the shift from an income statement to a balance sheet approach which involves the definition and evaluation of accumulated deferred tax balances. Under APB No. 11, the deferred taxes are recorded at the statutory tax rates in effect when recorded and reverse at that same rate even if the tax rate changes. Under FAS No. 109, the accumulated deferred tax balances would be reevaluated if the tax rate changes. For example, if the deferred taxes are recorded at 48% and the statutory [*50] tax rate changes to 34%, the accumulated deferred tax balance would be written down to reflect the 14% decrease. FAS No. 109, takes a liability approach. Under FAS No. 109 deferred taxes will still exist, but will be valued at the rate at which they expected to be paid back.

In a nonregulated environment, companies that have fluctuation under GAAP would credit an income account or retained earnings for the difference between the statutory rate previously used and the new rate. However, in a regulated environment, the differences should be reflected through the use of regulatory asset or regulatory liability accounts. This treatment results in an equitable treatment of tax rate changes. The ratepayers will benefit and the stockholders will not realize a "windfall" from a decrease in tax rates which results in a write down of deferred tax balances.

Witness Scardino testified that the adoption of FAS No. 109 will be revenue neutral and have no effect on the ratemaking process if the regulatory assets and liabilities resulting from the implementation of the standard are treated in the same manner as accumulated deferred income taxes in the capital structure. (Tr. 2558) This was [*51] not contested by any party at the hearing. Mr. Scardino agreed that implementation of FAS No. 109 in this proceeding may be premature, in view of the Commission's currently ongoing review of the matter. (Tr. 2561)

Our current review of FAS No. 109 has not been concluded. We believe that its implementation should be revenue neutral. We therefore find that its effect should be excluded from consideration in this proceeding.

VI. NET OPERATING INCOME

Having established the company's rate base and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income (NOI) applicable to the test periods. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

VII. OPERATING REVENUES

The company has proposed operating revenues of $ 958,462,000 ($ 1,047,013,000 system) for the 1992 current test year and $ 997,294,000 ($ 1,096,519 system) for the 1993 projected test year. Evidence developed during these proceedings has led us to decrease this amount. As discussed earlier, the company agreed that 1992 Operating Revenues should be reduced by $ 7,467,000 ($ 7,567,000 system) and 1993 Operating [*52] Revenues by $ 7,771,000 ($ 7,894,000 system), associated with the removal of the Sebring Distribution System. In addition, these revenues have been further reduced by $ 24,280,000 for 1992 and $ 15,515,000 for 1993 to be consistent with our decision concerning FPC's forecasts of customers and kWh by revenue class. These adjustments result in total operating revenues of $ 926,715,000 for 1992 and $ 974,008,000 for 1993.

VIII. OPERATING AND MAINTENANCE EXPENSE

Florida Power requested $ 409,492,000 ($ 445,335,000 system) for the 1992 current test year and $ 435,083,000 ($ 479,570,000 system) for the 1993 projected test year for Operating and Maintenance Expense. Evidence developed during these proceedings has led us to decrease this amount to $ 389,322,000 for 1992 and $ 415,222,000 for 1993.

A. Rescinded Purchase of Airplane

As discussed above, FPC purchased a Piper Cheyenne from Florida Progress that was later rescinded. The utility's books were adjusted as though the purchase had never occurred. From the net operating income standpoint, the 1991 aircraft depreciation was charged to a clearing account, which was cleared monthly to various expenses and construction [*53] work in progress (CWIP). In August

1991, the company reversed the $ 84,554 of depreciation taken on the airplane. This reversal, which was also booked to the clearing account, removed the CWIP and NOI effect from the interim test period.

The company made a pro forma adjustment to remove $ 65,000 from interim O&M expenses. However, as noted above, the book adjustment made by the company in August 1991 had already removed the effect of depreciation, which was ultimately charged to the company's expense and CWIP accounts. Consequently, the adjustment filed by FPC is inappropriate and results in an understatement of O&M expenses. Accordingly, we shall adjust the 1991 Interim Test Year to reverse Florida Power's O&M pro forma adjustment by increasing O&M Expense for 1991 by $ 65,000 ($ 65,000 system). The pro forma adjustments made to both the 1992 and 1993 test years correctly removed the effects of the rescinded aircraft purchase. Accordingly, no adjustments are needed for these test years.

B. Advertising Expense

FPC projected total advertising expense of $ 3,075,000 ($ 3,090,000 system) for 1992 and $ 3,321,000 ($ 3,338,000 system) for 1993. The company made adjustments [*54] in each year to remove the balances of Accounts 913 and 930, leaving only the balances of Account 909, Informational and Instructional Advertising Expenses. FPC agreed that the "Real People" advertisements in Account 909 should be removed, which totaled $ 10,317 in 1991.

The company's Christmas 1990 Spot and the PBS-WEDU ads do not provide specific information for customers; they are merely image enhancing. Therefore, the cost of these two ads, totalling $ 95,579, shall be removed from Account 909.30. Other advertisements discussed during the course of the hearing may also be image-enhancing; however, they were insignificant in amount. Our analysis indicates that the 1991 advertising expense shall be reduced by $ 95,579.

OPC argued that there should be an adjustment to the 1992 test year to remove the costs of advertisements which promote the company and the use of electricity. OPC also argued that there should be an adjustment related to FPC's strategic plan. We find that OPC did not provide sufficient evidence to make these adjustments.

Because we do not have a detailed list of FPC's projected ads for 1992 and 1993, a method is needed to calculate the appropriate deductions [*55] for these two years. A comparison of the company's actual to budgeted expenses indicates that the advertising account was significantly under budget in 1987, 1989, 1990, and 1991; 1992 shows the largest budget increase since 1987. Because the company has consistently overbudgeted the advertising account, an adjustment greater than the inflation rate is necessary. We followed OPC's method of calculating adjustments to Account 909.30, and find that the total amount listed for FPC's ads for 1991 shall be reduced by $ 387,000 for 1992 and $ 414,000 for 1993.

The company's $ 13,879 in 1991 expenses related to nuclear advertiisng shall be allowed in this instance.

We have made adjustments decreasing the level of advertising expense $ 420,000 for 1992 and $ 450,000 for 1993. Accordingly, the appropriate amount of advertising expense for 1992 is $ 2,655,000 and for 1993 is $ 2,871,000.

C. Lobbying Expenses

FPC recorded all lobbying expenses below-the-line, even those expenses associated with the company's Tallahassee and Washington offices.

The company made an adjustment to transfer $ 114,000 above-the-line in 1992 and $ 120,000 in 1993 for Jim Stanfield, FPC's Tallahassee [*56] based employee. This adjustment was made pursuant to Staff Advisory Bulletin No. 36, which states that all lobbying expenses shall be recorded below-the-line, including liaison related expenses. However, when preparing a rate case, the company may make an adjustment to transfer these expenses above-the-line; the company must then justify any amounts charged to jurisdictional expenses. Because rent expenses, utilities, and secretarial expenses were excluded, we find that the company adequately justified the liaison expenses related to Mr. Stanfield. FPC's adjustment, which includes only a portion of the liaison's related expenses, is reasonable and consistent with the last Gulf Power rate case. Accordingly, we shall make no adjustments to the lobbying expenses filed by FPC.

D. Industry Association Dues

FPC budgeted Industry Association Dues of $ 6,751,000 ($ 7,142,000 system) for the 1991 interim test year, $ 7,044,000 ($ 7,373,000 system) for the 1992 current test year, and $ 7,406,000 ($ 7,765,000 system) for the 1993 projected test year. The company removed $ 25,000 from the 1991 test year, $ 21,000 from the 1992 test year, and $ 25,000 from the 1993 test year system [*57] amounts by a pro forma adjustment to cost of service. Evidence developed during these proceedings has led us to make the following adjustments.

FPC acknowledges that one third of the EEI administrative dues attributed to lobbying expenses for the 1991 test year should be removed, which would result in a system decrease of $ 135,000 for the interim period. Concerning the 1992 test year, OPC argued that the NARUC Audit Report of EEI Expenditures using 1988 data should be used to determine the overall percentage by which EEI expenditures should be disallowed.

Based on the recommendation of the NARUC Staff Subcommittee on Accounts, and to remain consistent with our previous decisions, all of the EEI Media Communications Fund dues shall be disallowed. This results in a $ 180,000 reduction to the 1992 test year and a $ 189,576 reduction to the 1993 test year. One third of the EEI administrative dues was already removed by the company for the 1992 and 1993 test years.

Because FPC has not actively participated in the U.S. World Energy organization, the dues for this organization shall be disallowed for the 1992 and 1993 years. Accordingly, $ 1000 shall be disallowed from the 1992 [*58] test year and $ 1053 shall be disallowed from the 1993 test year.

Prior to 1987, the U.S. Council for Energy Awareness was called the Atomic Industrial Forum. Because the dues for this organization have been disallowed by us in the past due to this organization's pro-nuclear lobbying, we shall not allow the dues here. Accordingly, the 1992 test year shall be decreased by $ 342,000, and the 1993 test year shall be decreased by $ 360,000.

In the past, we have disallowed dues for membership in the American Nuclear Energy Council and the EEI Utility Nuclear Waste and Transportation Program, both lobbying organizations. However, because of the importance of the nuclear waste issue, and the lobbying activity of these two organizations toward achieving a nuclear waste repository, we shall make an exception here. The membership dues associated with these organizations shall be allowed in this instance.

In addition, we shall allow the inclusion of membership dues for the Earth Energy Association and the Electric Transportation Coalition, both lobbying organizations. The Earth Energy Association promotes the use of geothermal systems. The Electric Transportation Coalition lobbies [*59] to improve air quality and to contribute to environmental benefits of the nation. Because FPC's customers receive conservation benefits from FPC's membership in these organizations, these membership dues are justified.

Based on the above adjustments, we shall disallow $ 726,936 ($ 769,000 system) for the 1991 interim test year, $ 499,674 ($ 523,000 system) for the 1992 test year, and $ 525,544 ($ 551,000 system) for the 1993 test year. The resulting totals of $ 6,000,764 ($ 6,348,000 system) for the 1991 interim test year, $ 6,524,427 ($ 6,829,000 system) for the 1992 test year, and $ 6,856,868 ($ 7,189,000 system) for the 1993 test year shall be allowed.

E. Growth In Salaries And Wages

Florida Power requested the O&M expense level for Salaries and Employee Benefits to be $ 163,960,000 ($ 176,135,000 system) and $ 56,408,000 ($ 60,300,000 system) for the current 1992 test year, and $ 171,939,000 ($ 184,948,000 system) and $ 89,001,000 ($ 95,058,000 system) for the 1993 projected test year. Based on evidence presented at the hearing, salaries and wages shall be reduced by $ 745,530 ($ 797,244 system) in 1992 and by $ 783,086 ($ 836,759 system) in 1993. Fringe benefits [*60] shall be reduced by $ 184,796 ($ 197,614 system) in 1992 and by $ 288,671 ($ 308,457 system) in 1993.

FPC budgeted 269 new positions in 1992, whereas it had budgeted only 77 new employees in 1990 and 71 in 1991. By March of 1992, the company had hired only 41 new employees for the year.

OPC argued that the company's 1992 budgeted payroll is excessive, because the budget is based on the number of authorized positions, and not the number of positions that are actually filled. OPC also argued that FPC's projection of 269 new positions for 1992 is excessive. Occidental argued that the company's projected number of employees significantly exceeded its average actual growth rates and should be reduced.

Although FPC budgeted 269 new positions for 1992, no more than 89 are included in this rate case filing. Of those 89, a portion are budgeted to capital projects and are not included in O&M. 59 new employees are projected for 1993. From 1987 to 1991, the company has had an average annual increase of 63 new employees.

The 89 employees included in this rate case filing represent a significant increase over the average. Because 89 positions for 1992 appears to be excessive, we shall [*61] adjust this projection to equal the 1987-1991 average by decreasing the 1992 number of new employees to 63. Salaries, wages, and fringe benefits shall also be reduced accordingly.

OPC argued that the company's projected wage increase was too high, and that the budgeted merit increase should be limited to 4%, based on the actual increase granted to the bargaining unit. Occidental testified that assumed growth in salaries and wages should be limited to inflation. FPC argued that OPC's position was mistaken, because exempt and office and technical employee compensation is market based and not tied to the increases negotiated in FPC's bargaining unit agreements.

No record evidence was presented that convinced us that FPC's projected wage increase is not appropriate. However, because we removed 26 employees from FPC's projection of new employees for 1992, salaries and wages shall be reduced by $ 745,530 ($ 797,244 system) for 1992 and by $ 783,086 ($ 836,759 system) for 1993; and fringe benefits shall be reduced by $ 184,796 ($ 197,614 system) for 1992 and by $ 288,671 ($ 308,457 system) for 1993.

F. OPEB Expense

FPC requested Other Post Employment Benefits (OPEB) Expense [*62] levels in the amount of $ 24,215,000 ($ 25,887,000 system) for the 1992 current test year and $ 26,117,000 ($ 27,894,000 system) for the 1993 projected test year. These levels should be adjusted to reflect FAS No. 106 accounting, FPC's updates to its FAS No. 106 costs, and a discount rate of 8.25%. After these adjustments, the appropriate levels of OPEB expense are $ 17,658,368 ($ 18,883,935 system) for 1992 and $ 18,804,655 ($ 20,092,590 system) for 1993.

As discussed above, we have decided to use FAS No. 106 for ratemaking purposes. FPC updated its estimates of the FAS No. 106 costs presented in its MFRs to reflect a new collective bargaining agreement and a change in the discount rate from 8.75% to 7.75%. We shall use this current information in our decision on OPEB expense. Based upon this current information, we reduced the amount of O&M expenses, the amount of CWIP, and the liability associated with FAS No. 106 (which increases working capital) for the 1992 and 1993 test years. These adjustments reflect the removal of the Sebring system.

While we accept the information concerning the new collective bargaining agreement, we believe that the 7.75% discount rate is too [*63] low. OPC argued that non-regulated companies have used 9.00% as the discount rate for 1992, and the higher the discount rate, the lower the expense. According to OPC, the discount rate should be our allowed return on equity.

FPC's selection of 8.75% was based on the then existing 8.50% pension discount rate. At the time the company developed its discount rate in September of 1991, a rough range of discount rates was from 7.50% to 9.00%.

FAS No. 106 directs that the discount rate should be based on "high-quality fixed-income investments currently available whose cash flows match the timing and amount of expected benefit payments." Accordingly, the return on equity is disqualified as a suitable discount rate. Because FPC's current discount rate of 7.75% is very close to the current Treasury Bond yield of 7.60%, it reflects a rate of the highest quality. FPC argued that because FPC has an AA bond rating, it must issue new first mortgage bonds at 70-75 basis points above the Treasury Bond yield, or 8.30-8.35%. AA bonds are high-quality fixed-income investments, and an 8.25% discount rate is in line with or slightly lower than current yields on AA rated bonds. We have chosen 8.25% [*64] as FPC's appropriate discount rate.

A 1% increase in the discount rate causes an 11% decrease in the FAS No. 106 expense. Accordingly, the discount rate shall be increased by .50%, which results in a 5.50% decrease in the FAS No. 106 expense for 1992 and 1993. This adjustment also decreases the FAS No. 106 amount capitalized as CWIP as well as decreasing the FAS No. 106 liability by 5.50%, as discussed above. The combined adjustment to reduce the expense for both the update and the change in the discount rate for 1992 is $ 5,196,528 ($ 5,557,190 system) and for 1993 it is $ 5,874,536 ($ 6,276,885 system). The adjustment to reduce CWIP, for both the update and the change in the discount rate is $ 454,181 ($ 456,555 system) for 1992 and $ 478,603 ($ 481,105 system) for 1993. As we have previously dismissed an adjustment to working capital shall also be made to reduce the FAS 106 liability by $ 3,168,000 in 1992 and by $ 10,565,000 in 1993.

G. Pension Expense

Florida Power requested Pension Expense in the amount of $ 4,270,000 ($ 4,561,000 system) for the 1992 current test year and $ 6,257,000 ($ 6,683,000 system) for the 1993 projected test year. However, we have made [*65] adjustments to the company's request as discussed below. Net pension expense shall be reduced by $ 2,653,000 for the 1992 test period and $ 2,464,000 for the 1993 test period. Pension liability shall be decreased by $ 1,672,000 for 1992 and by $ 4,876,000 for 1993. CWIP shall be reduced by $ 232,000 for 1992 and by $ 31,000 for 1993.

Although the intervenors argued that we should make adjustments to pension expense based on cash basis accounting, we have decided to use FAS No. 87 to determine pension expense, as discussed above. Even though FPC filed its pension expense projects pursuant to the provisions of FAS No. 87, we shall make several adjustments to the company's request.

As discussed above, FPC updated its filing to reflect the results of bargaining unit negotiations and a reduction in the discount rate, which resulted in the company's net pension expense request decreasing from $ 3,386,000 to $ 2,199,000 for 1992 and from $ 5,034,000 to $ 4,337,000 for 1993. While we do not take issue with using the terms of the bargaining unit negotiations, we believe that the new discount rate used by the company is too low.

FPC originally filed a discount rate of 8.5%, and subsequently [*66] dropped its estimate to 7.25%. Because only 5 months lapsed between the company's original filing and its update, the drop appears to be excessive. The company testified that a 50 basis point shift in the discount rate would have a $ 1.2 million dollar impact on Florida Progress, FPC's parent.

FAS No. 87's definition of the discount rate is identical to the definition of the discount rate under FAS No. 106, as discussed above. The relationship between the discount rates used for FAS No. 87 and FAS No. 106 should remain somewhat constant for the timeframe of the test period.

FPC testified that the Pension Benefit Guaranty Corporation (PBGC) publishes a rate that can be used to discount pension liabilities. The PBGC interest rates have dropped from 7.25% in January 1991 to 6.5% in June, 1992, a drop of 75 basis points. However, the company dropped its discount by 125 basis points for the same time frame. The company's drop was too dramatic. Accordingly, the discount rate used for pensions shall be increased from 7.25% to 8.00%. This adjustment will decrease pension expense by $ 1,573,342 ($ 1,682,000 system) for 1992 and by $ 1,574,857 ($ 1,682,000 system) for 1993.

The [*67] professional expense included in pension expense was calculated using 1991 as a base period and was calculated as a percentage of the asset value of the pension fund. In 1991, the professional fees were .71% of the asset value. If a five year average from 1987 through 1991 is used, the percentage is .63%. Because this average is more reflective of typical professional fees, professional fees shall be reduced by $ 291,812 ($ 312,199 system) for 1992 and $ 295,945 ($ 316,620 system) for 1993 using the five-year average.

These adjustments result in a net reduction to pension expense of $ 2,653,000 ($ 2,653,000 system) for 1992 and $ 2,464,000 ($ 2,632,000 system) for 1993. The corresponding working capital adjustments are an increase to working capital in 1992 of $ 1,672,000 ($ 1,787,000 system) and in 1993 of $ 4,876,000 ($ 5,210,000 system). CWIP shall be decreased by $ 232,000 ($ 233,000 system) in 1992 and by $ 31,000 ($ 31,000 system) in 1993.

H. Pension Expense Amortization

In prior years, FPC's $ 3.7 million regulatory asset related to pension expense has been deferred. In this proceeding, FPC requested that we include net amortization associated with the pension [*68] regulatory asset in the amount of $ 916,000 for 1992 and $ 927,000 for 1993. For reasons discussed below, FPC shall not recover amortization expense of this asset.

FPC first recorded pension expense in 1987 for financial statement purposes using FAS No. 87. The company used FAS No. 71 to record as a regulatory liability or asset, the difference between the pension expense allowed rates, and the amount recorded for financial statement purposes. It was not until 1991 that FPC had a positive pension expense under FAS No. 87. For 1992, FPC forecasted a positive pension expense which would result in a net regulatory asset. It is this forecasted asset that FPC wants to amortize over three years.

We believe the regulatory asset and its amortization should be disallowed for ratemaking purposes. First, in order to record an asset or a liability under FAS No. 71, there must be an indication from us that the asset or liability will be recoverable. In this case, there was no such indication. It was inappropriate for FPC to use FAS No. 71 without our prior approval.

Second, we do not believe pension expense should be "tracked." Pension expense will be run through earnings and will [*69] fluctuate. Earnings should be reviewed in aggregate with no true-up provision for certain expenses. If a true-up is allowed for one expense, it can easily be argued that all the expenses should be trued-up. Other expenses also change, but the change itself does not justify deferring the expenses. Utilities are given an opportunity to recover their costs, not a guarantee. If costs change, the entire cost to serve must be reevaluated. Individual changes in costs should not be deferred for future recovery in another rate case.

The net amortization associated with the pension regulatory asset resulting from disallowance is $ 916,000 ($ 979,000 system) for 1992 and $ 927,000 ($ 992,000 system) for 1993. Accordingly, $ 752,000 ($ 804,000 system) for 1992 and $ 2,696,000 ($ 2,881,000 system) for 1993 shall be removed from rate base. $ 80,000 ($ 80,000 system) for 1992 and $ 12,000 ($ 12,000 system) for 1993 of CWIP shall also be removed from rate base.

I. Outside Services Expense

Public Counsel argued that all one-time outside professional services should be disallowed. While one-time services may not recur each year, they may be replaced with other new services, thus continuing [*70] the annual cycle of expense. However, only a reasonable level of non-recurring expense should be allowed in O&M expenses. Because there is no record basis to support what a reasonable level of one-time services might be, we shall make no adjustment.

Public Counsel further argued that all outside services related to FPC's strategic plan should be disallowed. OPC stated that although FPC's desire to become more environmentally aware is a laudable pursuit, it is unrelated to the provision of electric utility service. In addition, FPC has not performed a cost benefit analysis to determine the overall effect on ratepayers.

In 1992, FPC budgeted $ 200,000 for land identification, $ 100,000 for water conservation, $ 90,000 for solid waste, $ 100,000 for computer program development, and $ 150,000 for air quality. These expenses will allow the company to contract with specialized environmental consultants to cope with evolving regulatory requirements and to meet its goal to exercise good environmental stewardship. While not all such expenditures will be allowed, we find these expenses to be reasonable. Accordingly, FPC's request for $ 640,000 for studies, recommendations, and modeling [*71] shall be allowed. The appropriate amount of outside services expense is $ 12,106,515 ($ 13,088,960 system) for 1992 and $ 12,555,047 ($ 13,586,498 system) for 1993.

J. Medical/Life Accrual

Florida Power maintains an unfunded medical/life reserve for active and retired employees in compliance with Rule 25-6.0143, Florida Administrative Code, and the Uniform System of Accounts as prescribed by us. The amount accrued is based on the pay-as-you-go basis. The company has maintained this reserve since 1984. FPC is self-insured and uses the reserve to pay claims. The medical portion of the reserve is managed by Blue Cross and Blue Shield.

Occidental argued that FPC should amortize the reserve balance over five years as a negative expense. The intervenor proposed no other specific adjustment to the company's expense.

Because we find that FPC should continue to use the reserve concept for its self-insurance program, no specific adjustments shall be made to medical/life expense other than the adjustments to fringe benefits discussed above. Accordingly, FPC's 1992 and 1993 test year accrual for medical/life reserve-active employees [*72] and retirees is appropriate.

K. Storm Damage Accrual

FPC requested an accrual of $ 1,104,000 for 1992 and $ 314,000 in 1993 in order to attain the $ 5 million deductible on its property insurance policy. The company requested to cease accruals once the cap is reached. According to the company, the $ 314,000 expense would continue to be included in rates even though an expense would no longer be incurred.

Occidental testified that the expense accrual is an accounting derived cost due to its discretionary amortization of reserve deficiency. Occidental argued that the $ 1.636 million reserve deficiency as of December 31, 1991, should be amortized over five years or $ 327,000 annually. If we were to follow Occidental's suggestion, this would result in a $ 777,000 reduction to the company's proposed expense for 1992.

Contrary to Occidental's belief, the company does not have significant control over its reserve related expense accruals. Rule 25-6.0143(4)(a), Florida Administrative Code, states that ". . . [t]he provision level and accrual rate for each account . . . shall be evaluated at the time of a rate proceeding and adjusted [*73] as necessary. However, a utility may petition the Commission for a change in the provision level and accrual outside a rate proceeding."

The company's requested accrual of $ 1,104,000 for 1992 is appropriate. This accrual should eliminate any concerns regarding retroactive adjustments to the 1992 funded reserve.

However, FPC's requested accrual for 1993 shall be reduced by $ 196,962 ($ 214,000 system), to result in an accrual of $ 100,000. The $ 5 million cap will not be in place. Under this method, the company will continue to incur the expense while the expense is included in the cost of service, and FPC will also attain its $ 5 million deductible. The accrual and provision level shall be evaluated in the company's next rate case, or sooner upon petition of the company.

Because we have decided that FPC shall discontinue its funded reserve, O&M expenses shall be credited with the earnings on the funded reserve until the funded reserve is extinguished. This should avoid increasing the funded reserve beyond a reasonable level, and should enable the funded reserve to be extinguished more quickly. Accordingly, O&M expenses shall be reduced $ 69,152 ($ 75,134 system) for the [*74] 1993 pre-tax earnings credited by FPC to the funded reserve.

L. Claims Reserve Accrual

Florida Power maintains an unfunded injuries and damages and Worker's Compensation reserve in accordance with Rule 25-6.0143, Florida Administrative Code, and the Uniform System of Accounts as prescribed by us. The account was established to meet FPC's probable liability for deaths or injuries to employees or others not covered by insurance.

During 1991, FPC expensed $ 4.081 million, and projected $ 4.208 for 1992 and $ 4.568 million for 1993. The company determines the desired balance for the reserve by matching current year charges and accounting accruals and by maintaining an adequate balance to cover unforeseen incidents. The company has projected an increase to the reserve from $ 4.009 million for the 1991 interim test year to $ 4.340 million for the 1993 projected test year.

The company projected the worker's compensation expense to decrease $ 200,00 from 1991 to 1993, and injuries and damage to increase $ 487,000 over the same period, for a net increase of $ 287,000. FPC calculated an A&G benchmark variance of $ 6.864 million for [*75] the period 1987 through 1992. Part of the justification for this variance was a decrease of $ 3.873 million for injuries and damages expense during this time frame. The company stated that claims have decreased since the mid 1980's because of efforts to educate the public on the hazards of electrical contact with overhead lines. Worker's compensation claims have decreased since the end of 1987 probably because of the implementation of self insured programs and several cost containment procedures.

Occidental testified that the 1992 projected charges are twice as high as FPC's 1991 actual costs, and nearly $ .8 million in excess of the 1991 accrual. The intervenor also argued that the company's request does not reflect amortization for the perceived reserve deficiency. Occidental testified that the 1992 requested accrual should be reduced by $ 1.011 million, and the 1993 projected test year the 1993 accrual should also be reduced by $ 1.011 million.

Although Occidental proposed a $ 1.011 million reduction to expense, no corresponding adjustment increasing working capital was proposed. Also, Occidental argued that injuries and damage should be decreased $ 1.011 million when in [*76] fact these expenses increased $ 150,000 from 1992 to 1993.

We find that the company's requested accrual for the claims reserve is appropriate. Accordingly, no adjustment shall be made to the injuries and damage and worker's compensation expense or reserve.

M. *Interest On Tax Deficiencies*

Florida Power requested consideration of interest on tax deficiencies in its cost of service. Because the company's last full revenue requirements proceeding was stipulated, we have never explicitly addressed the propriety of interest expense on tax deficiencies as an element of Florida Power's cost of service. Since 1987, the company has recorded the accrual and amortization from interest on tax deficiencies on its books and records as well as on its monthly surveillance report filed with us.

This interest expense arises from the accrual and amortization of interest for actual and potential tax deficiencies. Actual tax deficiencies result at the conclusion of an Internal Revenue Service or Department of Revenue audit and have been either assessed or proposed and agreed to by the company. Potential deficiencies result from carryover items from previous audits and disclosure items. [*77] The tax treatment for carryover items extends beyond the tax year in which they arise. These items come about because of the time lapse between when the tax return is filed and when a final agreement is reached on the appropriate tax treatment. Disclosure items relate to income/deduction/capitalization tax positions where the company considers the tax law unclear or where the company has intentionally taken a controversial position. They may or may not be allowed. However, because the company has disclosed its position, it can avoid understatement penalties.

The company has recorded these interest costs as deferred debits and accrued liabilities as they become known and estimated. It has requested regulatory recognition of the amortization of this interest expense over a three-year period as an O&M expense.

OPC argued that interest on tax deficiencies should not be included in O&M expense. Public counsel does not believe that it is appropriate to require ratepayers to pay for an estimated cost that is calculated based on a potential tax deficiency, especially since it is a potential, and not a known deficiency. An interest accrual of this type and magnitude only acts as [*78] a signal to the IRS that the company has taken a position on a tax issue that even the company itself considers questionable.

As discussed above, the interest accrual relates to both actual and potential deficiencies: carryovers and disclosures. OPC addresses only the potential deficiencies. Although the potential tax deficiencies may not be known at the time the related interest is accrued, we believe that the company has shown that both the liability and the related interest are highly probable and may be reasonably estimated. In addition, the IRS is already aware of any carryover items from prior audit cycles and it becomes aware of other potential items through the disclosure process. Interest on tax deficiencies gives neither the IRS nor auditors any signals. Tax law often provides little or no guidance with respect to the proper treatment of an item, and there may be varying interpretations. When that is the case, the company has stated that it will interpret the law to protect its customers' interests.

Occidental also argued that interest expense on tax deficiencies should be disallowed. The intervenor stated that the interest expense should not be recovered from ratepayers [*79] because it is similar to the costs of any other penalties or fines assessed by government agencies. Occidental further stated that because the utility is prohibited from reducing rate base (or return) by any portion of the allowable credit, the utililty reaps the benefit of interest free capital. According to Occidental we would be prohibited from passing this benefit on to the ratepayers because of the danger that FPC may loose all ITC tax benefits.

We reject Occidental's argument that interest on tax deficiencies is similar to the costs of any other penalty or fine assessed by government agencies. The IRS assesses interest expense for the use of money, and for no other reason. Interest on tax assessments, unlike penalties and fines, is fully deductible for tax purposes. Although most, if not all, penalties and fines can be abated for reasonable cause, interest expense cannot. If a tax assessment is made, the taxpayers have had use of the money for some period of time.

Regarding Occidental's argument that the ratepayer never received the interest or return benefit of the disallowed ITC utilization, the intervenor admitted that even though the return benefit may not be passed [*80] on to ratepayers, the amortization of the ITCs may be utilized to reduce the cost of service income tax expense. Furthermore, Occidental did not address the savings realized by the ratepayers from the use of zero cost of capital for the increased balance of deferred taxes.

In addressing interest on tax deficiencies, there are two things that we must consider. The first consideration is whether or not the company has demonstrated that its aggressive tax strategy (which results in tax deficiencies and the ensuing interest) has benefitted the ratepayer such that the interest should be considered a cost of service component for 1992 and 1993. If the interest is considered a cost of service component, the second consideration is whether or not the requested three-year amortization period reasonable.

FPC argued that when the company is required to pay interest on a deficiency, it is because the company has withheld cash payments from a taxing authority and has used the cash to displace external capital financing. To the extent that other capital financing has been displaced, the cost of capital displaced presents a savings to the customers of the company.

The company prepared a [*81] cost/benefit analysis for the years 1982 through 1985, the latest closed years during which it had been assessed interest on deficiencies. FPC's conservative estimate of the gross benefits received from its aggressive tax preparation for the tax years 1982-1985 was $ 19,839,000. Its conservative estimate of net benefits was $ 17,798,000.

We believe that FPC's analysis was reasonable, and that the company has demonstrated that its tax strategies have benefitted the ratepayers through avoided cost-based external financing. This is consistent with our prior treatment of other utilities. Accordingly, we find that FPC's interest on tax deficiencies shall be appropriately included as a component of cost of service.

That brings us to the question of amortization. We have decided to use a three year amortization period because that seems to be the midpoint of amortization periods that we have used for FPC.

Based on the above, we find that FPC's requested interest on tax deficiencies of $ 2,141,000 ($ 2,378,000 system) for 1992 and $ 1,167,000 ($ 1,308,000 system) for 1993 shall be included in O&M expense.

N. Bad Debt Expense

Florida Power projected $ 2,521,000 ($ 2,521,000 [*82] system) for 1992 and $ 2,722,000 ($ 2,722,000 system) for 1993 for bad debt expense. Because this projection included Sebring Utilities, bad debt expense was reduced $ 21,000 for 1992 and $ 22,000 for 1993 because Sebring was stipulated out of the case. This results in bad debt expense of $ 2,500,000 ($ 2,500,000 system) for the 1992 current test year and $ 2,700,000 ($ 2,700,000 system) for the 1993 projected test year.

The net write-offs as a percentage of sales are 0.14% for 1992 and 1993. Because this percentage equates to a three-year average of net write-offs as a percent of sales, it is consistent with our test that determines the reasonableness of bad debt expense. Accordingly, FPC's request for bad debt expense for 1992 and 1993 is reasonable, and no adjustments are necessary.

O. Rate Case Expense

Florida Power projected rate case expense of $ 424,200. Because actual expenses were $ 583,626 as of July 31, 1992, FPC revised its rate case expense projection to $ 596,726. The revision is $ 172,526 higher than FPC originally requested and is detailed below:

	Total Forecasted Expenses	Budget MFR C24	Variance
Outside Services	405,860	325,000	80,860
Legal Services	20,488	25,000	(4,512)
Meals and Travel	101,381	52,200	49,181
Paid Overtime	17,628	20,000	(2,372)
Other Expenses			

	Total Forecasted Expenses	Budget MFR C24	Variance
Duplicating	8,453		8,453
Mats. & Supp.	3,513		3,513
Postage & Fedx.	6,224		6,224
Public Notif.	24,849		24,849
Xerox Rental	5,424		5,424
Misc.	2,906	2,000	906
TOTAL	$ 596,726	$ 424,200	$ 172,526

[*83]

OPC argued that rate case expense should be reduced by fifty percent to recognize excess expense associated with the 1993 test year and because the company's request for a performance reward was unjustified. There appears to be no record basis for Public Counsel's argument. In fact, a fifty percent disallowance is unreasonably high, especially since most of the work was necessary for the 1992 test year as well. Outside services, legal services, and paid overtime could possibly decrease, but meals and travel and "other expenses" would change very little.

The actual expense incurred for the 1987 rate case was $ 400,254. In our opinion, the rate case expenses for this case appears reasonable. $ 583,626 of the $ 596,726 represents actual expenses, with $ 13,100 in additional expenses forecasted through the end of the case. Although we have declined to allow revised rate case expense in the past, there have been instances where we have allowed a utility to revise its rate case expense, where the revision was based on the most recent information available. Because we have used the most recent information available to decide other issues, we feel it is appropriate to do the same [*84] here. Accordingly, $ 596,726 in rate case expense is appropriate.

At issue is the amortization period over which the expense will be spread. In the last major electric utility rate case, we ordered Gulf Power Company to amortize rate case expense over a 4 year period (Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI). Although we did approve a five year amortization period for Florida Public Utilities - Fernandina Beach Division (Order No. 22224, issued November 27, 1989, in Docket No. 881056-EI).

FPC requested a 2 year amortization period because we approved a 2 year amortization period in FPC's 1984 and 1987 rate cases. FPC also made an assumption in its current Five Year Business Plan that the company would file its next rate case in 1994. However, it has been 8 years since FPC's last rate case where a rate increase was granted, and 5 years since its last rate case. Pursuant to Chapter 366, Florida Statutes, FPC must file Modified Minimum Filing Requirements (MMFRs) in 1996. Based on these facts and the arguments presented above, we believe the amortization period should be greater than 2 years but less than 5 years. We find that rate case expense shall [*85] be amortized over 4 years beginning November 1, 1992. If FPC files for another rate increase in less than 4 years, and there is an unamortized balance left on the books as a result of this proceeding, the recovery can be considered at that time.

The appropriate amount of rate case expense is $ 596,726, and it shall be amortized over 4 years beginning November 1, 1992. Because the appropriate amount of rate case expense for 1992 and 1993 is $ 149,182, there shall be a reduction to expenses of $ 62,918 for each test year.

P. Membership Dues

The company included in operation and maintenance express membership dues in the Chamber of Commerce and the committee of 100. The parties stipulated that expenses should be reduced $ 71,654 ($ 75,000 system) and $ 75,827 ($ 79,500 system) for 1992 and 1993 respectively to remove these membership dues.

This adjustment is consistent with past Commission practices.

Q. Tree-trimming Expenses

FPC's requested level of tree-trimming expense of $ 8,855,559 ($ 8,879,000 system) for 1992 is not appropriate. We find that $ 7,301,000 ($ 7,320,000 system) for 1993 is appropriate.

FPC's tree-trimming expenses for the past five years were [*86] as follows:

1987	$ 6,396,000
1988	$ 5,808,000
1989	$ 6,902,000
1990	$ 6,207,000
1991	$ 6,323,912

According to FPC Witness Scardino, actual 1990 and 1991 tree-trimming expenses were under budget because work was deferred to 1992. Increased expenditures for 1992 were required to "catch-up" with deferred work. Mr. Scardino agreed that the $ 7.3 million projected for 1993 would be more indicative of ongoing operations in 1992. He also agreed that the amount of $ 7,320,000 should be the proper level of tree trimming expense for both 1992 and 1993 text years. We find that $ 7.3 million be the appropriate level of tree trimming expense for both the 1992 and 1993 test years. We make the following adjustment for 1992:

$ 8,879,000	(FPC's requested 1992 tree trimming expense)
($ 7,320,000)	(Indicative of ongoing operations for 1992)
$ 1,559,000	1992 adjustment (system)
X .99736	Jurisdictional Separation Factor
$ 1,554,884	1992 adjustment (Jurisdictional)

Therefore, expenses for the 1992 current test year shall be reduced by $ 1,554,884 ($ 1,559,000 system). This adjustment reduces FPC's tree trimming expenses for 1992 to $ 7,301,000 ($ 7,320,000 system) [*87] to reflect ongoing operations. We make no adjustment for the 1993 test year.

R. O&M Benchmark

During the course of the proceedings, an issue arose concerning whether the O&M benchmark should be applied to the company as a whole, or to FPC's individual functional units. As discussed below, we find that the O&M benchmark shall be applied to FPC's individual functional units. However, in so doing we are not precluded from examining the O&M expenditures of the company as a whole.

In making this determination, it is important to keep in mind that the benchmark is simply a tool or an indicator. The benchmark is a test, not a reward or penalty mechanism. It is not a floor or a ceiling. Certain expenses may not grow at the benchmark level, while others may exceed the benchmark level. In neither case are we precluded from looking closely at O&M expenditures. The benchmark forces the company to justify any inability it experiences in holding expenses within the rate of inflation and customer growth. It would be an improper use of the benchmark to offset positive variances of one functional group with negative variances of another functional group. The company can not justify [*88] being above the benchmark in one area by simply stating that it is below the benchmark in another area.

S. Consumer Price Index Factors

The appropriate Consumer Price Index (CPI) factors to use in determining test year expense is 3.7% for 1992 and 3.8% for 1993. The company requested these factors in its initial filing, relying on the May 1991 DRI/McGraw-Hill Forecast for the U.S. Economy. During the company's next full requirements rate case, we shall require FPC to true-up the forecasted CPI to the actual data.

During the hearing, an updated June 1992 DRI CPI forecast was introduced. This updated forecast indicated a 3.3% CPI Factor for 1992 and a 3.5% CPI Factor for 1993. OPC argued that we should use the updated CPI forecast to determine test year expenses. Occidental argued that we should use a 3.1% CPI factor for 1992 and a 3.3% factor for 1993. However, if we were to use a lower CPI for O&M expenses in the 1992 and 1993 test years, the benchmark variances for the functional areas would increase. Traditionally, the MFR's filed by the company incorporate a true-up of the CPI and Customer Growth multipliers from those forecasted in the company's last rate case. [*89] The initial and supplemental MFR's filed be FPC trued-up the CPI and Customer Growth compound multipliers for the periods 1987-1992 and 1984-1987. These true-ups incorporated the company's last two rate cases. We shall apply these adjustments to the allowed level of O&M to calculate the base year O&M benchmark levels for the current rate case.

T. Nuclear O&M

The Federal Government has continuously required increased expenditures to insure the safety of nuclear facilities. Costs incurred for nuclear power safety vary so much from CPI that we believe the O&M benchmark is not a useful tool to evaluate nuclear O&M expenses. This does not mean that the utilities will be given a "carte blanche" on nuclear related expenditures. We will continue to analyze the prudence of nuclear expenditures, to determine whether those expenditures are justified. We have done so in this case, and we find that variances over the benchmark have been justified by the company.

In order to study the appropriateness of a nuclear operating and maintenance expense benchmark, our staff shall conduct a workshop. This workshop shall focus on the way we should look at nuclear O&M expenses. Our staff [*90] shall attempt to develop an appropriate test to analyze nuclear expense.

Florida Power's requested level of Nuclear O&M in the amount of $ 92,037,897 ($ 97,819,000 system) for the 1992 current test year and $ 95,763,861 ($ 101,779,000 system) for the 1993 projected test is appropriate. We find that FPC has justified its nuclear related expenditures in the following areas:

1. Increased Personnel

We accept the company's justification of $ 1,373,188 ($ 1,463,000 system) for 1992 and $ 1,369,596 ($ 1,463,000 system) for 1993. We find that FPC has justified $ 3,010,880 ($ 3,200,000 system) of expenses associated with Increased Personnel in excess of the 1992 Nuclear O&M benchmark for the 1984 through 1987 time period.

2. B&W Owner's Group

The B&W Owner's Group allows plant owners to share the costs of regulatory programs and modifications, which keeps each utility from having to spend the full amount needed to respond to any such issue on its own. A nonparticipating utility would not be as likely to avoid as many of the NRC compliance costs as participating utilities. This owners group is recognized by the NRC as the focal point for specific regulatory issues generic [*91] to the B&W plant design. Because of FPC's membership in the group, the company is expected to avoid expenditures of approximately $ 1.6 million to $ 4.1 million. We find that for the 1987 through 1992 time period, Florida Power has justified $ 408,351 ($ 434,000 system) of expenses associated with the B&W Owner's Group that are in excess of the 1992 Nuclear O&M benchmark.

3. Motor Valve Testing System

Because the company has justified the variances associated with the motor valve testing system, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $ 135,490 ($ 144,000 system) of expenses associated with the Motor Operated Valve Testing System that were in excess of the 1992 Nuclear O&M benchmark.

4. Long Term Maintenance Plan

Because the company has justified the variances associated with the long term maintenance plan, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $ 2,861,277 ($ 3,041,000 system) of expenses associated with the Long Term Maintenance Plan which are in excess of the 1992 Nuclear O&M benchmark. [*92]

5. Operator Training Simulator

Because the company has justified the variances associated with the operator training simulator, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $ 478,918 ($ 509,000 system) of expenses associated with the Operator Training Simulator which are in excess of the 1992 Nuclear O&M benchmark.

6. Wage Differential

We find that for the 1984-87 time period, FPC has justified expenses in excess of the Nuclear O&M Benchmark for wage differential in the amount of $ 2,397,972 ($ 2,537,000 system). While we are not disallowing this expense, we are concerned with the comparison used by FPC. This comparison indicated that some FPC employees received annual raises above CPI, which was consistent with selected comparison groups who also received raises exceeding CPI. We believe a more fitting comparison would include an analysis of the employees' entire benefit package, including such items as retirement plans, stock options, health insurance, and vacation time. The analysis should also include a study of the impact the annual wage increase has on employee retention.

Occidental [*93] argued that the company failed to justify its wage expenses because FPC presented no evidence showing an increase in productivity or other benefits. FPC argued that it needed wage increases above CPI to maintain parity with industry peers because the wage program attracts and retains qualified personnel.

FPC also introduced a comparison of budgeted merit increases for office and technical employees and exempt employees. The comparison groups were compared to CPI. FPC's average annual merit increase from 1984 through 1990 was between 6% to 8%.

7. Plant Maintenance

FPC justified expenses in excess of the Nuclear O&M Benchmark of $ 1,660,716 ($ 1,757,000 system) for plant maintenance for the 1984-87 time period because the scope of FPC's existing and new programs required for plant maintenance has increased.

Occidental testified that FPC has initiated or increased spending for numerous nuclear programs which should decrease, not increase plant maintenance expense. FPC argued that improvements in efficiency have resulted from its Pooled

Inventory Management Program, its Fully Integrated Materials Information System, and its Fire Protection Program. We agree.

8. Projects [*94] and Modifications

FPC has justified $ 4,943,396 ($ 5,230,000 system) of expenses in excess of the Nuclear O&M Benchmark for Projects and Modifications for the 1984 through 1987 time frame. Because of NRC regulatory requirements, these expenditures have increased faster than the benchmark.

Occidental argued that FPC identified no projects or modifications incurred in 1984 that were not incurred in 1987. The intervenor argued that if some of these expenses were for new or modified systems to improve the performance of Crystal River 3, there should be a net reduction to O&M expense. Any costs associated with the introduction or modification of these systems should be capitalized.

FPC admitted that expenses for this program include nonrecurring items; however, there will always be nonrecurring items and historic data and current forecasts indicate that similar efforts will recur. NRC regulations account for 75% of the costs of this category. The remainder of costs are attributed to the company's increased emphasis on safety.

9. Configuration Management

FPC has justified expenses of $ 2,146,193 ($ 2,281,000 system) in excess of the Nuclear Production O&M Benchmark [*95] for Configuration Management for the 1987 through 1992 time period. Increased NRC regulatory requirements have caused these expenses to increase faster than the benchmark.

The majority of these costs are for projects to resolve design basis issues and to construct and maintain an online Information System consisting of complex databases which document technical specifications. Occidental argued that this program should result in improved and more efficient maintenance, which should result in long term, if not immediate, reductions in O&M expense.

All capital cost associated with the development of the software have been capitalized; however, maintenance of the information system is on ongoing O&M expense. Although the main justification for the Configuration Management program is safety, the program may also have beneficial effects efficiency and O&M costs.

10. *Maintenance Activity Control System*

FPC has justified expenses of $ 288,856 ($ 307,000 system) in excess of the nuclear production O&M benchmark for its Maintenance Activity Control System for the 1987 through 1992 time period. This program is an enhancement to the control and implementation of the nuclear maintenance [*96] program, which has caused these expenditures to increase faster than the benchmark.

The Maintenance Activity Control System is a computerized work process and control system which allows online planning, review, and approval of maintenance activities. The regulatory environment requires detailed documentation and approval of all maintenance activities.

Occidental testified that these expenditures should result in long term, if not immediate, reductions in O&M expense and that the software development and hardware construction should be capitalized, not expensed. However, the only costs attributable to this system are maintenance costs, and not capital costs.

11. Electrical Calculation Program

FPC has justified expenses of $ 127,962 ($ 136,000 system) in excess of the nuclear production O&M benchmark for its Electrical Calculation Program for the 1987 through 1992 time period. Increased NRC regulatory requirements have caused these expenditures to increase faster than the benchmark.

The NRC has concluded that the analysis performed on early nuclear plant designs did not always adequately demonstrate compliance with the plant design basis. This program is an ongoing effort [*97] to identify areas of potential non-compliance. When deficiencies are identified, the Electrical Calculations program constructs individual modification packages to correct the problem.

12. Planning and Scheduling

FPC has justified expenses of $ 189,121 ($ 201,000 system) in excess of the nuclear benchmark for Planning and Scheduling for the 1987 through 1992 time period. These expenses have been justified because this program will provide greater scheduling accuracy and efficient management of outages and daily maintenance.

Occidental testified that the Planning and Scheduling expenditures should result in long term, if not immediate, reductions in O&M expense. FPC argued that planning precision and schedule accuracy are essential to efficient management of outages and daily maintenance. The impact of this program can be seen in the development of midcycle outage and shorter refueling outages at Crystal River 3. This new outage maintenance approach should reduce forced outages between refueling outages.

13. Valve Reliability Program

Because the company has justified the variances associated with the valve reliability program, we shall not make the adjustments recommended [*98] by our staff. For the 1987 through 1992 time period, Florida Power has justified $ 188,180 ($ 200,000 system) of expenses associated with the valve reliability program that were in excess of the 1992 Nuclear O&M benchmark.

14. Technical Specification Improvement

FPC has justified its expenses of $ 127,021 ($ 135,000 system) that are in excess of the nuclear production O&M benchmark for technical specification improvement for the 1987 through 1992 time period. Expenses in this category exceed the benchmark due to FPC's response to industry and NRC concerns.

This program is a multi-utility/NRC effort. Assembled teams from several utilities are working together to refine and upgrade generic technical specifications for nuclear plants. The upgrade will reduce administrative burdens on operators, increasing their flexibility to properly operate the plant. This will result in improved availability and enhanced safety. This cost will continue over the lifetime of the plant due to continuous revisions of operating specifications.

15. Industry Groups

FPC has justified expenses of $ 125,140 ($ 133,000 system) in excess of the nuclear production O&M benchmark for Industry [*99] Groups for the 1987 through 1992 time period. Membership in these groups allows FPC to take advantage of combined operating experience when addressing regulatory concerns. These efforts are pointed toward achieving consistency and efficient resolutions of generic issues among owners of nuclear plants.

U. Fossil O&M

Florida Power's requested level of Total Fossil O&M in the amount of $ 88,844,000 ($ 101,071,000 system) for the 1992 current test year and $ 100,496,000 ($ 114,336,000 system) for the 1993 projected test year is not appropriate.

The requested level of Fossil O&M should be $ 86,322,000-jurisdictional ($ 98,271,000 system) for the 1992 current test year and $ 97,936,000-jurisdictional ($ 111,513,000 system) for the 1993 projected test year.

This is a mathematical calculation which incorporates all recommended adjustments related to FPC's requested level of Fossil O&M expenses as follows:

1. Scheduled Outage Expenses

We make no adjustment to 1987 or 1992 scheduled outage amounts because the increase in O&M expenditures are a result of increased levels of planned maintenance due to plant aging and increased generation from existing plant. We make an adjustment [*100] of $ 2,560,349 ($ 2,823,126 system) to 1993 scheduled outage amounts to normalize FPC's outage expenses in 1993 and 1994. FPC's requested budgeted outage expenses were lower in 1994 than 1993. The adjustment was calculated by averaging FPC's requested 1993 and 1994 budgeted amounts and subtracting this result from the requested 1993 budgeted amount.

Scheduled Outage expenses for 1992 exceed the benchmark by $ 7.5 million and represent approximately 45% of the total Fossil Production benchmark variance of $ 16.9 million. FPC identified expanded scope and increased costs associated with O&M programs addressing the increasing operating hours of the generating units, plant aging, and increased system demand.

FPC cites the reduced Equivalent Forced Outage Rate (EFOR) as the underlying theme and justification for the O&M variance. In 1988, the EFOR rate was 11.24%; due to the increased O&M expenses FPC has lowered the EFOR to 5.32% in 1992. FPC witness Hancock stated that 1992 fuel costs would have increased $ 23 million if the 1988 EFOR rate was used. However, witness Hancock failed to note FPC's 1987 EFOR of 6.55% was significantly lower than the 11.24% EFOR reported in 1988 which [*101] the company relied upon to estimate fuel savings. We note that it took FPC over three years to reduce the EFOR to the 1987 level during which time replacement fuel costs were higher to the customers.

FPC also cites increased generation as a cause of the increased level of O&M expense. In 1987, generation at the oil and gas units had increased by 52% above the 1984 level, and by 70% in 1992. The increased generation has resulted in the need for an increase in the frequency of scheduled maintenance outages. Boiler outages have also increased from 10 performed in 1984 to 17 scheduled for 1992.

2. Environmental Changes

FPC has provided justification for $ 194,438 ($ 215,850 system) related to its Ongoing Energy Efficiency Program. The program consists of new regulatory scope, falling under the section Regulatory and Governmental Requirements in the 1992 MFR. Schedule C-57a, page 170, states that FPC will

Develop, implement, monitor, and up-grade an ongoing program to incorporate energy efficiency into all generating facilities and facility construction methods. It is important for the company to set an example in energy efficiency. Conservation will result in long-term [*102] avoidance of costs associated with additional generation and will reduce daily operating costs.

FPC's witness for Fossil O&M, Mr. Hancock, testified that the energy efficiency program would result in future cost avoidance. We believe that any energy efficiency program that results in quantifiable avoided costs is prudent. We do not believe it to be imprudent for a utility to implement programs to comply with governmental requirements. FPC has identified an environmental mandate that calls for an energy efficiency program for its facilities. FPC has justified the expenses in excess of the 1992 Fossil O&M benchmark which have been identified in the MFR's.

Occidental's recommendation to disallow expenses related to the Solid Waste Minimization Program ($ 62,700), the Water Conservation Program ($ 139,750), the Crystal River Hazardous Waste ($ 208,894), and Other Hazardous Waste ($ 219,763) is not valid. Occidental's reason for recommending disallowance for these programs is that FPC did not quantify any current or future cost savings which would result from them. We believe that the four programs in question are justified by Schedule C-57a because they address new regulatory [*103] and environmental requirements. FPC should be allowed to recover expenses in excess of the O&M benchmark due to these four programs:

The Solid Waste Minimization program is justified because the Florida Solid Waste Act, implemented in 1988 and expanded in 1992, will continue to make it more expensive to dispose of solid waste and less likely that landfill space will be available (Schedule C-57a, p. 170).

The Water Conservation program is justified because federal and state agencies continue to enact restrictions on water use. In addition, the cost of water is becoming increasingly expensive, so this program is a good business decision as well (Schedule C-57a, p. 170).

The Crystal River Hazardous Waste and Other Hazardous Waste programs are justified because increasing federal, state, and local regulations have caused the list of hazardous wastes to continue to grow. Facing the need to dispose of more waste at higher cost, FPC established a centralized hazardous solid waste disposal site at the Crystal River site. Other Hazardous Waste expenses are incurred by the handling and transport of hazardous waste materials from plant sites to the centralized location [*104] (Schedule C-57a, pp. 172-4).

3. *Increased Painting Costs*

For the 1987 through 1992 and the 1992 through 1993 time periods, Florida Power has justified $ 703,672 ($ 794,840 system) of expense in excess of the 1992 Fossil Production O&M benchmark and $ 183,803 ($ 207,617 system) of expenses in excess of the 1993 Fossil Production O&M benchmark associated with Increased Painting Costs.

In Schedule C-57a of its 1992 MFR (pp. 199-201), FPC provided a table which showed specific detail of the facilities that require painting, the interval between paintings, and the projected cost each time a facility is painted. By estimating an annual cost for painting its facilities, FPC has reasonably levelized future expenses. The majority of the facilities which now have recurring painting costs were not included when the 1987 O&M benchmark was set.

We believe that Occidental's recommendation to disallow painting expenses that exceed the O&M benchmark is not valid. Occidental offered no reason for its position other than a belief that the expenses were not justified. FPC has shown in its MFRs that painting expenses escalated primarily due to the increased scope of facilities that require [*105] periodic painting. We believe that this is reasonable, and we believe that FPC has justified its painting expenses. FPC shall be allowed to recover painting expenses which exceed the O&M benchmark.

4. Aging and Maturation Activities

For the 1987 through 1992 and the 1992 through 1993 time periods, Florida Power has justified $ 1,987,002 ($ 2,244,439 system) of expenses in excess of 1992 Fossil Production O&M benchmark and $ 689,419 ($ 781,300 system) of expenses in excess of the 1993 Fossil Production O&M benchmark associated with Aging and Maturation Activities at Florida Power's coal, oil, and natural gas plants.

This issue received considerable attention at the hearing. FPC Witness Hancock testified that the largest factor influencing outage costs is plant aging. He testified that the average age of FPC's fossil steam plants is 29 years, and that a facility's age affects the amount of maintenance required. Witness Hancock used an automobile as an analogy to a power plant, to describe that an older power plant tends to need more maintenance than a newer one.

In Schedule C-57a of its 1992 MFR, FPC identified several factors related to its coal, oil, and gas plants [*106] which resulted in expenses which exceeded the 1992 Fossil O&M benchmark (pp. 192-5). Some of these expenses include the following:

* replacement of boiler controls and plant computer at Crystal River 2 due to aging of existing equipment no longer supported by the manufacturer

* increasing maintenance and repair expenses related to elevators at Crystal River 1 and 2, whose age is nearly 25 years

* replacement and repair of control systems at the oil and gas plants, whose average is nearly 33 years

* increased repair and replacement of mobile equipment, boiler systems, and structures (Bartow and Higgins)

In Schedule C-57a of its 1993 MFR, FPC identified particular maintenance programs for its coal, oil, and gas plants which they believed would result in fewer forced outages (pp. 127-9). These maintenance programs include ones for large motors, air heaters, and fans. FPC stated that this equipment needs very little maintenance during the first several years, but that as the equipment ages, maintenance becomes necessary more frequently (1993 MFR, Schedule C-57a, pp. 127-8). FPC believes that implementing equipment maintenance programs will help reduce the duration and severity [*107] of forced outages.

We disagree with Occidental's assertion that FPC did not provide evidence to justify its aging and maturation activities above the benchmark. Occidental argues that "many of the systems cited by FPC are related to capital replacements and should be capitalized, not expensed." We find that the majority of FPC's activities, were prudently incurred. Therefore, we will allow all expenses in excess of the 1992 and 1993 Fossil O&M benchmark attributed to aging and maturation activities.

5. Intercession City Peaking Units

For the 1992 through 1993 time period, Florida Power has justified $ 970,245 ($ 1,099,552 system) of expenses associated with the Activation of the New Intercession City Peaking Units in excess of the 1993 Fossil Production O&M benchmark. This issue was stipulated to at the start of the hearing. We approve the stipulation.

6. University of Florida Cogeneration Unit

For the 1992 through 1993 time period, Florida Power has justified $ 2,406,305 ($ 2,727,000 system) of expenses associated with the University of Florida Cogeneration Unit in excess of the 1993 Fossil Production O&M benchmark.

This issue was stipulated at the start of the [*108] hearing. We approve the stipulation.

7. Existing Gas Turbines

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $ 322,431 ($ 344,000 system) associated with Existing Gas Turbines.

The 1987 Fossil O&M benchmark for expenses was set in the 1984 rate case. At that time, FPC did not budget any expenses to mothball 16 gas turbine units which were subsequently placed into extended cold shutdown (ECS) status (Schedule C-57a Supplemental, p. 20). As such, FPC allocated a large portion of its 1987 Fossil O&M budget for planned mothballing costs for the 16 ECS units. The mothballing costs for the 16 ECS units and the maintenance costs for the four remaining units caused FPC to exceed the 1987 Fossil O&M benchmark by $ 322,431 ($ 344,000 system). We believe that these expenses were reasonable.

We disagree with Occidental's argument that FPC's 1987 expense level was overstated because it included nonrecurring mothballing costs. There is no discussion or evidence in the record to support this conclusion. Schedule C-57a (Supplemental) justifies expenses for existing gas turbine maintenance. Therefore, we will allow recovery of these expenses. [*109]

8. Predictive Maintenance

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $ 189,335 ($ 202,000 system) for Predictive Maintenance.

FPC has credited its predictive maintenance program with avoided fuel and maintenance cost savings in 1988, 1989, and 1990 which far outweigh the expense of implementing the program (Schedule C-57a Supplemental, page 21). Expenses related to FPC's predictive maintenance program have been fully justified, and we will allow recovery of program expenses which exceeded the 1987 Fossil O&M benchmark.

9. Engineering Services

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $ 538,948 ($ 575,000 system) for Engineering Services.

FPC stated in its 1987 MFR that the outage planning program was strengthened to minimize total outage costs, to "reduce overall outage costs through detailed planning, material staging, and daily control of all aspects from labor performance, to parts requisitioning and expediting, to purchasing." (Schedule C-57a Supplemental, p. 21).

Occidental's Witness Kollen testified that FPC didn't identify any offsetting savings in [*110] O&M expenses resulting from its outage planning program; thus, the expenses are not justified. (Tr. 2871) FPC made no claim that a reduction in O&M expenses would result from this program. FPC said that improved productivity of its work force allows the size of the work scope to increase for the same amount of O&M dollars (Schedule C-57a Supplemental, p. 21). FPC cited a test of the outage planning program on a turbine outage at Anclote Unit 1 in 1985, which was performed with an eleven percent (11%) improvement in productivity over similar previous outages.

FPC has justified its expenditures in excess of the 1987 Fossil O&M benchmark. We will allow recovery of these expenses related to FPC's outage planning program.

10. Non-Fossil Departments

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $ 373,045 ($ 398,000 system) for Non-Fossil Departments.

11. Wages Above CPI

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $ 2,066,747 ($ 2,205,000 system) for Wages above CPI.

12. Budgeted 1991 O&M Expenses Deferred into 1992 Test Year

We make an adjustment of $ 2,522,346 ($ 2,800,000 [*111] system) to FPC's Fossil O&M expenses in 1992. This adjustment stems from FPC's corporate budget (Exhibit 117), which shows that some maintenance work was deferred from 1991 into 1992 because FPC's management ordered a 4% reduction of expenses in 1991 to protect 1991 earnings. As a result, $ 2,800,000 (system) in O&M expenses were deferred into the 1992 test year. We will not allow these expenses to be included in the allowed Fossil O&M expenses for purposes of setting permanent rates for 1992.

V. Customer Accounts Expense

Florida Power's requested level of Customer Accounts Expense in the amount of $ 36,456,000 ($ 36,569,000 system) for the current 1992 test year and $ 38,845,000 ($ 38,845,000 system) for the 1993 projected test year is appropriate.

Florida Power's Customer Accounts Expense for the 1992 and 1993 test years is below the Customer Accounts O&M benchmark. These expenses have been fully justified in the testimony of Mr. Phillips and supporting MFR Schedule C-57c.

W. Customer Services Expense

Florida Power's requested level of Customer Service Expense in the amount of $ 7,984,000 ($ 7,984,000 system) for the 1992 current test year and $ 8,541,000 ($ 8,541,000 [*112] system) for the 1993 projected test year is not appropriate.

The appropriate level of Customer Service Expense is $ 7,564,000 for 1992 and $ 8,091,000 for 1993.

The company stated that it is under the benchmark in Customer Service. This is true only if one looks at the overall variance for Transmission, Distribution, Customer Accounts, Customer Service and Sales. FPC is over the benchmark by $ 4,079,000 in the Customer Service functional area for the 1987-92 period and under the benchmark by $ 385,000 for the 1984-87 period as reflected in MFR Schedule C-53.

The following is a table of the Customer Services functional group.

Account	Variance from the Benchmark 1992	1993
	(000)	
907 Customer Serv. & Info.	$ 477	$ 1
908 Customer Assistance	2,856	18
909 Infor. & Instutl. Ad.	484	7
910 Misc. Cust. Ser.& Info.	292	2
	$ 4,079	$ 28

The greatest variance from the benchmark occurred in Account 908, Customer assistance. FPC witness Phillips explained that this variance, as well as those in Accounts 907 and 910, was due to the reclassification of Customer Field and District Representatives from the Distribution area to the Customer Service area in order [*113] to better match the work performed to the appropriate FERC category. The variance in Account 909, Information and Institutional Advertising is due to advertising expenses associated with the company's strategic planning efforts. We have disallowed $ 420,000 for 1992 and $ 450,000 for 1993 in Account 909. Those adjustments should be made here for purposes of the benchmark calculation. Based on the above, we have no further adjustments to the Customer Services functional area.

X. Sales Expense

Florida Power's requested level of Sales Expense in the amount of $ 942,000, ($ 942,000 system) for the 1992 current test year and $ 1,007,000 ($ 1,007,000 system) for the 1993 projected test year is not appropriate.

Actual Sales Expense was significantly under budget in 1987 and 1988, and slightly under budget in 1990 - 1992. The increase to the Demonstration and Sales Expense accounts reflects activity in the areas of economic development and new products and services.

Economic development expenses are projected to increase by 22.8% from 1991 to the 1992 test year. These economic development activities are carried out in connection with the Florida Department of Commerce, the [*114] Florida Economic Development Council, the Florida Chamber of Commerce, and local economic development groups, to improve the overall economy of the state.

All economic development expenses were disallowed by this Commission in Order No. 23573, Docket No. 891345-EI:

It appears that Gulf has assumed some of the responsibilities of local chambers of commerce of development boards. . . . In seeking to expand industry or business activity in general, Gulf is actively attempting to increase sales of electricity.

Consistent with Order No. 23573, we disallow all economic development expenses in this docket. Sales Expense shall be reduced by $ 487,147 ($ 487,147 system) for 1992 and by $ 511,504 ($ 511,504 system) for 1993.

Y. Administrative And General Expense

Florida Power's requested level of Administrative and General Expense in the amount of $ 103,584,000 ($ 110,816,000 system) for the current test year and $ 107,648,000 ($ 115,093,000 system) for the 1993 projected test year is appropriate.

Other than the specific disallowances we have previously made, no additional adjustments to the A&G function are appropriate.

Z. Post Retirement Benefits Other Than Pensions [*115]

For the 1984-87 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $ 3,001,000 for Post Retirement Benefits Other than Pensions.

As we have previously discussed, FAS No. 106 will be used for ratemaking purposes. We believe that accrual accounting as prescribed by FAS No. 106 appropriately recognizes the future liability for OPEBs and properly matches the OPEB costs to the period in which the employees earn the benefits. We note that Schedule C-57d Supplemental of the MFRs provides an explanation for OPEB costs above the benchmark. In December, 1985, FPC began accruing the cost of OPEBs for current retirees of the company. The company believed that this accrual was appropriate since the OPEB liability was similar in certain respects to pension liability. Both represented a form of deferred compensation that should be recognized during the employees' active service instead of the post-employment period. For this reason, we believe that the increase above the Administrative and General Benchmark is justified.

AA. Management **Incentive** Compensation Plan

For the 1984-87 time period, FPC has justified expenses in excess of the Administrative [*116] and General Benchmark of $ 600,000 for Management **Incentive** Compensation Plan.

Florida Power Corp. filed MFR Schedule C-57D, O&M Benchmark Variance by Function, comparing the 1984 O&M expenses allowed versus the 1987 benchmark. The benchmark variance for the A&G function was $ 13,153,000. A number of new activities or scope changes between the 1984 case and 1987 justify the variance. One is the Management **Incentive** Compensation Plan (MICP).

In 1985 FPC developed an **incentive** compensation plan which is a part of the total compensation plan for its key employees. Witness Scardino in his rebuttal testimony stated that the company "has used **incentive** compensation to focus the attention and efforts of our key employees on achieving goals that have a direct and significant influence on individual, organizational and corporate performance." "The amount of the total **incentive** award is influenced by the degree to which the company meets its return on equity expectations." This prevents an award payment if the current year's financial performance is subpar. Achieving individual goals determines how the award is allocated. Many of the goals relate directly to controlling costs, encouraging [*117] good customer service and energy efficiency.

The company has placed a portion of the total compensation of specific key employees at risk by requiring the achievement of goals and objectives. Placing part of executives' pay at risk has proven to be a substantial performance motivator.

The company provided the MICP expense for 1987-1991 and projected for 1992 and 1993. The 1992 and 1993 projections were much less than for the previous years. The company budgets on a midpoint value, never on the assumption that there will be a 100% payout.

FPC's **incentive** plans are similar to plans adopted by other electric utilities in Florida. In the last Gulf Power Company rate case we allowed recovery of the expenses associated with its **incentive** compensation plan. (Order No. 23573, Docket No. 891345-EI) In the recent Peoples Gas rate case, we accepted that company's plan with an adjustment to recognize that Peoples' projected a 100% payout but in reality the historical payout percentage was less than 100%.

Incentive plans that are tied to the achievement of corporate goals are appropriate and provide an **incentive** to control costs. FPC has controlled the increase in O&M expense to some [*118] extent. We believe that the **incentive** plans have contributed to this control.

BB. Pension Expense

For the 1987-92 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $ 5,794,000 for Pension Expense.

As we have previously discussed, we believe the use of FAS No. 87 is appropriate in ratemaking. FPC's increase over the benchmark is justified since FAS No. 87 requires accrual accounting for pension expense thus recognizing the cost of benefits as the employees earn the benefits.

CC. Post Retirement Benefits Other Than Pension

For the 1987-92 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $ 18,287,000 for Post Retirement Benefits Other than Pensions.

The increase over the benchmark is justified since FAS No. 106 requires accrual accounting for OPEBs, thus recognizing the cost of benefits as the employees earn the benefits.

IX. DEPRECIATION EXPENSE

Florida Power's requested Depreciation Expense of $ 210,428,000 ($ 231,898,000 system) for the 1992 current test year and $ 226,109,000 ($ 251,178,000 system) for the 1993 projected test year is not appropriate.

The appropriate [*119] jurisdictional Depreciation Expense is $ 203,439,000 for 1992 and $ 219,829,000 for 1993.

A. Crystal River #3 Depreciation Expense

Florida Power's requested adjustment to depreciation expense for 1992 and 1993 associated with Sebring's portion of Crystal River #3 is appropriate.

The company correctly calculated the depreciation expense for Crystal River #3 based on the plant in service and using the depreciation rates we have prescribed. No contradictory evidence was presented in opposition to the company's calculations.

B. Fossil Fuel Dismantlement Expense

Florida Power's adjustment to increase Fossil Fuel Dismantlement Expense in 1992 by $ 3,919,000 ($ 4,643,000 system) and to decrease the expense in 1993 by $ 3,590,000 ($ 4,390,000 system) is not appropriate.

FPC's fossil fuel dismantlement expense adjustment should be increased by $ 1,983,000 for 1992 and by $ 1,868,000 in 1993 from what was filed in the MFRs. The adjustments are to be effective November, 1992.

The methodology for calculating dismantlement accrual was examined in fossil fuel dismantlement Docket 890186-EI, Order No. 24741. This methodology has been used to calculate the appropriate dismantlement [*120] accrual in the depreciation studies for FPL in Docket No. 910081-EI and Tampa Electric in Docket No. 910686-EI.

In general, FPC has followed the directive of Order No. 24741, although we have made changes to increase the expense adjustment filed in the MFRs. The first and most important change was use of the most current inflation indices. As stated in Order No. 24741, the "indices should come from the most current DRI Review of the U.S. Economy that is available." When the company filed its MFRs, the Summer 1991 edition was the most current. In February, the Winter 1991-92 edition was released. We have updated the indices accordingly.

Once the indices are used to compute the future cost of dismantlement, the dollars must be discounted back to a current accrual. FPC discounted the dollars with CPI because it "more closely matches the expected change in our customer's purchasing power." We believe the cost to the customer should relate to the increase in the cost of dismantling the plant. The increase in the annual accrual should be designed to capture the rising cost of labor and material to dismantle a plant. Therefore, the DRI inflation rates used to escalate the expenses [*121] in the cost study are also used to discount the future costs.

We have also adjusted the retirement date. The company forecasts a mid-year retirement with "dismantling to begin in the same year the retirement was recorded". We prefer a year-end retirement method recognizes that the plant will retire at some time before the end of a specific year with the dismantlement process beginning in the following year.

We accept FPC's use of the Metal and Metal Products Index for inflating the salvage value of the plants. Order No. 24741 directs the use of the Intermediate Materials, Supplies and Components Index for inflating salvage value but further states "we are willing to accept evidence from a utility that adjustments may be necessary to the escalation rates." Witness Scardino, at his deposition, explained that salvage is driven by scrap value which is best represented by the metals index. The record further reflects that "price movements for metals and metal products and scrap metal are highly correlated."

C. Contingency Factor

We do not believe FPC's practice of increasing fossil plant dismantlement expense by a contingency factor of 25% is appropriate. A 20% contingency [*122] factor should be adequate to address FPC's concerns.

The company believes the uncertainties and difficulties that may arise when a plant is dismantled call for a 25% contingency factor to be included in the dismantlement cost study. Witness Carlson representing FIPUG and Witness Kollen representing Occidental assert there is no need for the 25% contingency because the dismantlement cost study is periodically updated. Witness Kollen also testifies that the estimate itself is inherently uncertain and adding a contingency adds to the uncertainty.

The validity of the 25% contingency factor can be determined if it is segmented into its two components, the 15% scope omission and error contingency and the 10% pricing contingency. The scope contingency is determined "considering the conceptual nature of the estimate and the difficulty in obtaining quantity records on such old units." The pricing contingency provides "confidence that the estimate will not overrun due to pricing error."

The scope omission and error contingency is designed to accommodate surprises or unexpected costs during the actual dismantlement. These would include weather conditions that may slow down the dismantlement [*123] process, labor strikes, or unexpected environmental concerns. Company witnesses Hancock and Scardino acknowledged that although this contingency is needed, it could change in the future as the industry gains experience from actually dismantling some plants. Witness Scardino testified

As we complete these dismantlements, we will have a much better feel for what we anticipated the cost to be and what the actual turns out to be. And I think as we gain more experience, we'll be able to better focus in on the contingency factor.

We agree that a contingency factor for unexpected costs should continue to be factored into the cost study. The amount should be reevaluated every four years in the dismantlement studies filed with the Commission.

The pricing contingency was discussed by Witness Hancock. He testified

. . . The pricing of what the marketplace requires that we spend to get the job done, with various specialty contractors and engineers, and whatever the case may be, it has an uncertainty of that, that we attach 10% to.

Difficulties in this type of pricing decrease as dismantlement dates approach. Changes in the cost of "specialty contractors and engineers" needed to dismantle [*124] the plants should be captured in the periodic updates of the inflation indices. We believe that pricing will become more clear in the few years preceding dismantlement. This contingency should be further analyzed in the company's next depreciation/dismantlement study.

We do not believe a contingency will cause a disincentive for the company to control costs. Although dollars have been booked to the reserve through the years prior to dismantlement, those dollars have actually already been spent. In Docket No. 890186, we decided that an unfunded reserve is appropriate. This means the company could use those revenues for any utility purposes and have the opportunity to earn FPC's internal rate of return on those dollars. At the plant dismantlement date, the dollars used to dismantle the plant are dollars taken from other company uses. The company will have to fund the dismantlement of the plants while continuing to finance its regular operations. Witness Kollen testified that if there were less dollars than the company anticipated spending, the company would be behaviorally oriented towards trying to bring the cost of dismantling in at a lower level. Since it is an unfunded [*125] reserve, there will be no cash dollars at the time of dismantlement.

We believe that a 25% contingency may overcompensate the dismantlement revenue. We find that a 20% contingency is appropriate and is amply supported by the record herein.

D. Future Value Of Land

FPC should not consider the future value of the land on which the plants to be dismantled are located in calculating the appropriate fossil fuel dismantlement expense.

Witness Carlson representing FIPUG addressed the question of whether the value of land should be offset with the cost of dismantlement. Witness Carlson supported factoring the land value into the dismantlement cost study to reduce the accrual "just as the positive salvage value of other salable items is factored into the study." She testified that if land is not factored into the study, there is an intergenerational inequity when the land is sold after dismantlement because the future ratepayers receive the benefit of the gain while past ratepayers paid for the cost of dismantlement.

FPC argued that selling the land is an entirely different transaction that should not be considered as part of dismantling a plant. Witness Scardino summarized the [*126] company's position in the following statement

The facility depreciates over time, wears out, is consumed. The land still has value. The land still has functional purpose for the utility. And so we are just not, in the general sense, in the business of selling off our raw property, whether it has use as a replacement for the facility that was there or some new application. Land is a resource that is difficult to come by for us and so we maintain what we have.

If land value is considered as an offset to dismantlement costs, and FPC does not sell the land at the end of dismantlement, FPC will not have accrued enough expense to pay for the cost of dismantlement. Future ratepayers will have to pay this unrecovered cost after the plant is no longer serving the public. Intergenerational inequities will still exist. The misconception in Witness Carlson's testimony is that the company will sell the land when the plant is dismantled.

The treatment of land is a separate issue from fossil fuel dismantlement. Under the current Commission practice, as long as the land is retained by the company, it will remain in rate base at its original cost and continually earn a return from each [*127] generation of ratepayers. An intergenerational inequity will occur only when and if the land is finally sold.

Using historical based accounting, intergenerational inequities concerning the sale of land cannot be resolved. If the sale-date of the land could be determined, one alternative would be to forecast the future value of the land. The future value could then be recovered equitably over the remaining life of the plant site. This would solve some of the inequity concerns raised at the hearing. Witness Scardino testified however that forecasting land value is beyond the scope of reasonableness. We agree.

As long as land is considered a part of rate base at its historical cost, there will be an intergenerational inequity when the land is finally sold. This phenomenon exists without regard to fossil fuel dismantlement. Netting the value of land against the cost of dismantling the current site may cause a reserve deficiency because more plants may be built at the same location. We favor keeping the value of land and the cost of plant dismantlement separate.

X. TAXES OTHER THAN INCOME TAX

Florida Power's requested level of Taxes Other Than Income Taxes in the amount [*128] of $ 63,617,000 ($ 69,969,000 system) for the 1992 current test year and $ 72,911,000 ($ 80,785,000 system) for the 1993 projected test year is not appropriate. Taxes Other Than Income Taxes should be reduced by $ 1,047,000 for 1992 and by $ 1,151,000 for 1993.

The company's position in the prehearing order was that an adjustment is required for the change in the rate of the Regulatory Assessment Fee. At the time of the filing, the rate was 0.125%. Since that time, the rate was changed to 0.083% for the period of January 1992 and beyond. (Docket No. 911130-EI, Order No. 25585, dated January 8, 1992.) The company's prehearing position was that the Regulatory Assessment Fees should be revised along with the revenue expansion factor. The revenue expansion factor reflects the new rate of 0.083%. The effect of these adjustments is a decrease to Taxes other than Income of $ 745,000 in 1992 and $ 845,000 in 1993.

We also agree with the company that, as a result of the company's adjustment for the Sebring Acquisition, Taxes Other Than Income Taxes should also be reduced.

Based upon these adjustments, as well as others previously discussed herein, we reduce taxes other than income [*129] by $ 1,047,000 for 1992 and by $ 1,151,000 for 1993.

XI. INCOME TAX EXPENSE

Florida Power's requested Income Tax expenses in the amount of $ 58,597,000 ($ 63,234,000 system) for the 1992 current test year and $ 49,316,000 ($ 51,587,000 system) for the 1993 projected test year is not appropriate.

Based on adjustments previously made, Jurisdictional Income Tax expense is $ 60,174,000 for the 1992 current test year and $ 54,711,000 for the 1993 projected test year.

An adjustment, increasing working capital by $ 2,606,000 in 1992 and by $ 1,440,000 in 1993, is made to income taxes payable for the effect of revenue and expense adjustments on income tax expense.

A. Consolidating Tax Adjustments

We believe that Consolidating Tax Adjustments (CTAs) are inappropriate in the ratemaking process. Consequently, no CTA adjustments shall be made for the 1992 current test year and for the 1993 projected test year.

"The term 'consolidated tax adjustment' (CTA) refers to the controversial ratemaking procedure whereby utility regulators pass through to ratepayers tax benefits attributable to the losses of non-regulated corporate affiliates. A CTA can be made either by (1) adjusting [*130] the ratemaking tax expense (and, ultimately, cost of service) of the utility for a portion of the tax benefits arising from the loss affiliates; or (2) treating as no-cost capital or, alternatively, excluding from rate base, an amount representing the utility's share of the federal income tax benefits attributable to the filing of a consolidated tax return." (Tr. 2267)

The Commission has a long-standing policy of not considering CTAs in the cost of service of Florida utilities:

A basic premise of regulation is that utility operations should not subsidize other operations nor should they be subsidized by other operations. This is true whether the operations are those of an affiliate joining in the filing of a consolidated federal tax return or the utility. Regulators remove the assets, capital, revenue and expenses associated with these activities from rate base, cost of service and capital structure. Most of these adjustments would have a tax effect. However, the tax effect is coincidental to the adjustment. That is, the adjustment to taxes is not made in an effort to alter the tax expense. It is a result of allowing the tax effect of the regulatory changes to follow the [*131] related revenue or expense item. (Tr. 2269)

The record adequately supports continuing our current policy of excluding CTAs from cost of service consideration.

Accordingly, no CTA adjustments shall be made for the 1992 current test year and for the 1993 projected test year.

XII. TOTAL NET OPERATING INCOME

The net operating income is determined by subtracting total operating expenses from operating revenues. The appropriate net operating income for FPC is $ 211,495,000 and $ 212,756,000 for 1992 and 1993, respectively.

XIII. REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the company's net operating income deficiency to compensate for income taxes and revenue taxes that the company will incur as the result of any revenue increase. We find that the appropriate expansion factor for 1992 and 1993 is 1.607157, which excludes the gross receipts tax component and includes the current regulatory assessment fee rate of 0.0830.

The company originally included a regulatory assessment fee of 0.125% in its revenue expansion factor, the assessment fee rate in effect at the time this case was filed. After the case [*132] was filed the rate was changed to 0.083%. We believe it appropriate to recognize the Regulatory Assessment Fee rate currently in effect in calculating FPC's revenue expansion factor.

The company also proposed to exclude the gross receipts tax as a component of the expansion factor and recover it through base rates. We find it appropriate instead to approve recovery of the gross receipts tax as a separate line item on customers' bills, as we have done in other cases.

XIV. REVENUE REQUIREMENTS

The revenue requirements of a utility are derived by establishing its rate base, net operating income (NOI) and fair rate of return. A test year of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating income deficiency or excess. The total test year revenue deficiency or excess is determined by adjusting the deficiency or excess by the revenue expansion factor.

Multiplying the rate base value of $ 2,950,832,000 [*133] for 1992 by the fair overall rate of return of 8.39% yields an NOI requirement for 1992 of $ 247,575,000 for 1992. The adjusted net operating income for the 1992 test year amounted to $ 211,495,000 and resulted in an NOI Deficiency of $ 36,080,000.

Multiplying the rate base value of $ 3,179,393,000 for 1993, by the fair overall rate of return of 8.37% yields an NOI requirement for 1993 of $ 266,115,000. The adjusted net operating income for the 1993 test year amounted to $ 212,756,000 and resulted in an NOI Deficiency of $ 53,359,000.

We find that the total appropriate revenue for the 1992 current test year and for the 1993 projected test year is $ 85,757,000.

XV. INTERIM INCREASE

Florida Power Corporation was granted an interim increase of $ 31,208,000 by Order No. PSC-92-0208-FOF-EI dated April 14, 1992 and effective April 23, 1992. The interim increase was based on a November 30, 1991 test year and a 12.60% return on equity, the floor of the company's last authorized return on equity.

Interim rates were in effect from April through October of 1992, and we are therefore using calendar year 1992 revenue requirements to determine the appropriate amount of interim rate [*134] relief. Any significant items that fall outside of the period that interim rates are in effect need to be adjusted. The Debary Unit, FAS No. 106, and increased dismantlement costs are all assumed to be effective in November, 1992, coincident with the rate increase. Accordingly, they should be adjusted for interim purposes.

The company has proposed to refund $ 907,000 of the interim increase using the interim test year and adjusted for certain audit disclosures contained in staff's audit report covering the interim test year. The company's proposal, however, was based on 1991 information and does not reflect the newly authorized rate of return, as the interim statute requires.

After the above three adjustments we find that Florida Power Corporation's interim revenue requirements are calculated to be $ 37.3 million. Since the interim increase was $ 31.2 million, a refund is not appropriate.

We considered the effective dates for implementation of FAS No. 106 concerning Other Post Employment Benefits and of increased dismantlement costs along with our consideration of the appropriateness of interim rates. Since we have decided that the interim rates ordered in this case were [*135] not excessive, the effective dates of FAS No. 106 and increased dismantlement costs will be established as November 1, 1992, after the period interim rates were in effect, and coincident with the effective date of the new permanent rates.

Calculation of Interim Revenue Requirements (000)

1992 Rate Base		$ 2,950,832
FAS No. 106	5,981	
Fossil Fuel dismantlement	2,459	
DeBary	(48,104)	
Rate Base for Interim purposes		$ 2,911,168
Cost of Capital		8.39%
Required NOI		244,247

1992 NOI	$ 211,495	
FAS No. 106	5,235	
Fossil Fuel dismantlement	3,061	
DeBary	1,646	
Interest Reconciliation	(428)	
NOI for Interim purposes		$ 221,009
NOI deficiency for Interim purposes		23,238
Expansion Factor		1.607157
Interim Revenue Requirements		$ 37,347
Interim Increase		$ 31,208

XVI. COST OF SERVICE AND RATE DESIGN

We have ascertained the company's revenue requirement and the amount of revenue increase necessary to fulfill that requirement. We now consider rate design: the rate of return currently earned by each rate class; and how each class's responsibility will be spread between the customer, energy, and demand [*136] charges. At the Prehearing Conference, stipulations were proposed on two rate design issues: (1) lowering the minimum KW demand for the Curtailable Rate Schedule to 25 KW and eliminating the minimum KW demand for the Interruptible Rates Schedules (Issue 183): and (2) consolidation of the Outdoor Lighting Schedule and the Street Lighting Schedule into a single Lighting Schedule (LS) (Issue 184). We find both proposals appropriate and approve these proposed stipulations. The balance of issues on Cost of Service and Rate Design were addressed in a separate stipulation.

The parties who took positions on the cost of service and rate design issues in the case entered into a comprehensive stipulation of those issues, dated July 22, 1992. We have carefully reviewed the comprehensive stipulation, we approve it, and we adopt it as our decision on all cost of service and rate design issues in the case. A copy of the Cost of Service and Rate Design Stipulation is attached to this order as Attachment 2. A copy of a spread sheet of approved rates is attached to this order as Attachment 3.

XVII. OTHER ISSUES

A. Performance Reward

We have carefully reviewed Florida Power [*137] Corporation's $ 9,990,000 request for a performance reward for superior management. We are unanimous in our praise of Florida Power Corporation as a well-run, successful utility. We do not believe, however, on the basis of the record in this proceeding, that it is appropriate at this time to approve a general performance reward of the type requested here. Florida Power Corporation's request is therefore denied. We must reassert that we are pleased with the way Florida Power Corporation conducts its business, and we encourage the company to continue on its successful path. We want it clearly understood that our decision to deny the requested reward here in no way precludes us from approving a reward for superior management, or, for that matter, a penalty for inferior management, at another time.

B. Management Audit

One of the issues in this docket was whether we should direct FPC to undergo a management audit focused upon the achievement of operating efficiencies and cost reductions.

We do not believe it is appropriate to require one utility to undergo a management audit without requiring all similarly situated utilities to also undergo a management audit. If we decided [*138] to require each utility with O&M expense growth in excess of a specified level to undergo a management audit, adoption of a rule would be a reasonable way to proceed. We will, however, forward pertinent information to the Bureau of Regulatory Review in the Division of Research for its consideration in scheduling the next PSC management audit of FPC.

C. Transactions With Affiliated Companies

One of the issues raised at the prehearing was whether adjustments should be made for the rate base effects of transactions with affiliated companies.

This issue was not addressed in the testimony of any intervenor witness nor in the cross-examination of any Florida Power witness. Accordingly, there is no basis for any such adjustment.

The related issue of whether adjustments should be made for the capital structure effects of transactions with affiliated companies was also not addressed the hearing. There is no record basis for any adjustment.

Finally, the issue of whether adjustments should be made for the net operating income effects of transactions with affiliated companies was not addressed adequately at the hearing. There is insufficient record basis for any adjustment.

D. [*139] Revenue And Sales Decoupling

FPC has agreed to file a decoupling proposal with this Commission within 60 days after the issuance of the Order in this docket. We will conduct a more thorough evaluation at that time to determine whether revenue and sales decoupling should be implemented by FPC.

FPC will not be required to implement a decoupling mechanism at this time. FPC has agreed on the record at the Prehearing Conference and at the hearing to file a proposal for the decoupling of revenues and sales within 60 days of the issuance of the Order in this docket. This will provide an opportunity for a more thorough evaluation of the concept of decoupling, with focus on a specific plan. At that time a more thorough study will be conducted, to determine whether the decoupling of revenues and sales should be implemented by FPC.

E. Demand Side Management **Incentive**

FPC has agreed to file an **incentives** proposal with the Commission within 60 days of the issuance of the Order in this docket. A more thorough evaluation will be conducted at that time to determine whether a special demand side management **incentive** (DSM) program for FPC should be implemented.

XVIII. [*140] PROPOSED FINDINGS OF FACT

LEAF has submitted proposed findings of facts regarding the decoupling and conservation **incentives** issues. As previously discussed, FPC has agreed to submit decoupling and conservation **incentive** proposal for our consideration within 60 days. These issues will be evaluated in another docket which will be opened based on the specific decoupling and **incentive** plans filed. The proposed findings of facts submitted by LEAF are unnecessary for us to reach the decisions we have made in this order. These matters will be carefully studied in a new docket. We are not rejecting them on their merit, but only because they are unnecessary in deciding the matters at issue here.

An "agency head is not required to make explicit rulings on subordinate, cumulate, immaterial or unnecessary proposed facts." Such proposed facts may be rejected by a "simple statement that they are immaterial or irrelevant." Forrester v. Career Service Commission, 361 So.2d 220, 221 (Fla. 1st DCA 1978); Iturralde v. Department of Professional Regulation, 484 So.2d 1315 (Fla. 1st DCA 1986); Health Care Management, Inc. v. Department of Health & Rehabilitative Services, 479 So.2d 193 (Fla. 1st DCA 1985). [*141]

1. The current regulatory connection between FPC's sales and revenues creates strong economic disincentives to FPC's provision of reliable energy services at the lowest cost.

This proposed finding is immaterial, unnecessary or irrelevant.

2. A level playing field for demand and supply-side resource options is necessary to support FPC's provision of reliable energy services at least cost. The current regulatory connection between FPC's sales and revenues operates as a disincentive to demand-side resource options and thus provides an unbalanced playing field for demand and supply-side resource options.

This proposed finding is immaterial, unnecessary or irrelevant.

3. FPC needs to be more aggressive in the area of energy reducing programs.

This proposed finding is immaterial, unnecessary or irrelevant.

4. The current regulatory connection between FPC's sales and revenues creates strong economic disincentives to FPC's implementation of energy efficiency programs that reduce energy usage.

This proposed finding is immaterial, unnecessary or irrelevant.

5. Decoupling FPC's sales and revenues would improve FPC's achievements in energy reducing programs.

This proposed finding [*142] is immaterial, unnecessary or irrelevant.

6. Decoupling FPC's sales and revenues would minimize load forecast gaming.

This proposed finding is immaterial, unnecessary or irrelevant.

7. Decoupling FPC's sales and revenues would help stabilize utility earnings.

This proposed finding is immaterial, unnecessary or irrelevant.

8. Decoupling FPC's sales and revenues would reduce the risk of innovative rate designs.

This proposed finding is immaterial, unnecessary or irrelevant.

9. Decoupling does not remove all significant financial and institutional barriers to that quantity of DSM that would be part of FPC's least cost plan to provide reliable electric service.

This proposed finding is immaterial, unnecessary or irrelevant.

10. DSM **incentives** are required to remove the significant financial and institutional barriers that remain after decoupling FPC's revenues and sales.

This proposed finding is immaterial, unnecessary or irrelevant.

11. DSM **incentives** are required to make successful implementation of a least cost plan *FPC's most profitable course of action.*

This proposed finding is immaterial, unnecessary or irrelevant.

12. DSM **Incentives** would improve FPC's performance [*143] in energy efficiency programs, particularly energy reducing programs.

This proposed finding is immaterial, unnecessary or irrelevant.

13. Economically reasonable levels of energy conservation and load management will not be implemented without utility intervention, i.e., through utility investment in DSM measures that allow provision energy services at least cost.

This proposed finding is immaterial, unnecessary or irrelevant.

14. Decoupling FPC's sales and revenues and adopting DSM **Incentives** for FPC would minimize environmental damage and reduce the financial costs and risks posed by supply side resource options.

This proposed finding is immaterial, unnecessary or irrelevant.

15. Decoupling and DSM **incentives** are required to make successful implementation of a least cost plan FPC's most profitable course of action.

This proposed finding is immaterial, unnecessary or irrelevant.

16. Decoupling and **incentives** together are necessary to get the very best utility performance in the area of DSM acquisition over the long run.

This proposed finding is immaterial, unnecessary or irrelevant.

17. There are a variety of tools, including rate design, that may be used to minimize [*144] any adverse financial impacts on low income consumers from demand and supply-side programs.

This proposed finding is immaterial, unnecessary or irrelevant.

18. DSM programs can help FPC's low- or fixed-income consumers to get a higher quality of life out of the dollars they can budget for energy.

This proposed finding is immaterial, unnecessary or irrelevant.

19. Decoupling methods should meet the following standards:

a. remove the lost sales disincentive to conservation, and so avoid the "conflicting **incentives**" problem with respect to marketing both energy sales and energy conservation.

b. be as practical and administratively convenient as is reasonably feasible.

c. not have unacceptable side effects. In particular, decoupling-related shifts in risk are limited.

This proposed finding is immaterial, unnecessary or irrelevant.

20. Only the RPC and ERAM methods remove the "lost sales" disincentive to energy efficiency programs.

This proposed finding is immaterial, unnecessary or irrelevant.

21. The RPC method as described in Appendix A, attached hereto and hereby incorporated herein, is very simple and creates very little, if any additional administrative burden. [*145]

This proposed finding is immaterial, unnecessary or irrelevant.

22. An RPC method in which various customer classes are not aggregated is unnecessarily complex and not likely to be worth the effort.

This proposed finding is immaterial, unnecessary or irrelevant.

23. ERAM, as implemented in California, is a very elaborate system and involves additional regulatory procedures, "little mini-yearly rate cases," where a complicated set of adjustments are made.

This proposed finding is immaterial, unnecessary or irrelevant.

24. The linkage between revenues and customers is at least as soundly based in both theory and statistics as the current regulatory linkage between revenues and sales.

This proposed finding is immaterial, unnecessary or irrelevant.

25. RPC best avoids unacceptable side effects and limits decoupling-related shifts in risk.

This proposed finding is immaterial, unnecessary or irrelevant.

26. DSM **incentives** for FPC should:

a. limit FPC's economic rewards from DSM investments to no more than 15% of the net financial benefits (above established target levels) that said investments create for FPC's customers; and

b. be designed to make FPC's least-cost resource [*146] plan its most profitable plan, provide appropriate impacts on stockholder and customers, and be simple, understandable and easy to administer (as more fully described in Appendix B, attached hereto and incorporated herein by this reference.)

This proposed finding is immaterial, unnecessary or irrelevant.

27. FPC's resource planning process rejects any DSM program that does not pass the rate impact measure ("RIM") test -- without even considering whether revenue requirements would be less if that program was included in the company's DSM portfolio.

This proposed finding is immaterial, unnecessary or irrelevant.

28. DSM programs rejected by FPC for failure to pass the RIM test are not submitted for the Commission's consideration or approval.

This proposed finding is immaterial, unnecessary or irrelevant.

29. A single demand-side management measure, even if the measure were free and even if the measure saved significant amounts of electricity, could still fail the rate impact test because a certain amount of fixed costs would be spread over a smaller number of kilowatt hours.

This proposed finding is immaterial, unnecessary or irrelevant.

30. Any DSM programs that pass the [*147] TRC test will be less expensive than new generating resources (even if said programs failed the RIM test).

This proposed finding is immaterial, unnecessary or irrelevant.

31. Since any DSM program that fails the RIM test is excluded from FPC's DSM portfolio, DSM programs that would save significant amounts of electricity at little or no cost would be rejected by FPC without even being submitted for consideration by the Commission.

This proposed finding is immaterial, unnecessary or irrelevant.

32. Supply-side resources are selected primarily on the basis of least cost, that is, to minimize the present value of revenue requirements, and are not eliminated because they have a rate impact on nonparticipating customers.

This proposed finding is immaterial, unnecessary or irrelevant.

XIX. CONCLUSIONS OF LAW

1) Florida Power Corporation is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2) The Commission has the legal authority to approve and use historical or projected test periods for ratemaking purposes. Calendar years 1992 and 1993 are appropriate base [*148] test periods.

3) The adjustments to rate base made herein are reasonable and proper. The value of the company's 1992 rate base for ratemaking purposes is $ 2,950,832,000. The company's 1993 rate base for ratemaking purposes is $ 3,179,393,000.

4) The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Florida Power Corporation's net operating income for 1992 is $ 211,495,000. Its net operating income for 1993 is $ 212,756,000.

5) The fair **rate** of return on the equity capital of **Florida Power Corporation** is 12%.

6) **Florida Power Corporation** should be authorized to increase its **rates** and charges by $ 57,986,000 in annual gross revenues beginning November, 1992. In should be authorized to increase its **rates** and charges by $ 9,660,000 beginning April, 1993. It should be authorized to increase its **rates** and charges by $ 18,111,000 beginning November, 1993. The total of the increase authorized for **Florida Power Corporation** shall be $ 85,757,000.

7) The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

8) The new rate schedules shall become [*149] effective with the company's first billing cycle of each month for which permanent new rates have been approved.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the stipulated issues and positions identified in the Prehearing Order in this docket (Order No. PSC-92-0606-PHO-EI; Issued July 7, 1992) are hereby approved. It is further

ORDERED that the petition of **Florida Power Corporation** for authority to increase its **rates** and charges is granted to the extent delineated herein. It is further

ORDERED that **Florida Power Corporation** is hereby authorized to submit revised **rate** schedules consistent herewith designed to generate $ 57,986,000 in additional gross revenues annual beginning November, 1992. It is further

ORDERED that **Florida Power Corporation** is hereby authorized to submit revised **rate** schedules consistent herewith designed to generate $ 9,660,000 in additional gross revenues annually beginning April, 1993. It is further

ORDERED that **Florida Power Corporation** is hereby authorized to submit revised **rate** schedules consistent herewith designed [*150] to generate $ 18,111,000 in additional gross revenues annually beginning November, 1993. It is further

ORDERED that the rate changes authorized herein shall become effective with the company's first billing cycle of each month for which permanent new rates have been approved. It is further

ORDERED that Florida Power Corporation shall include in each customer's bill in the first billing of which the increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons therefore. The bill stuffers shall be submitted to the Division of Electric and Gas of the Florida Public Service Commission for approval before implementation. It is further

ORDERED that this docket be closed should no petition for reconsideration or notice of appeal be timely filed.

DISSENTING VOTES

Chairman Beard dissented as follows:

1.) From the Commission's vote concerning level of sales expense.

Commissioner Clark dissented as follows:

1.) From the Commission's vote concerning FPC's Motor Operated Valve Testing System.

2.) From the Commission's vote concerning FPC's nuclear long term maintenance plan.

3.) [*151] From the Commission's vote concerning FPC's nuclear operator training simulator.

4.) From the Commission's vote concerning FPC's nuclear valve reliability program.

Commissioner Deason dissented as follows:

1.) From the Commission's vote concerning FPC's forecasts of customers and KWH by Revenue Class and System KW.

2.) From the Commission's vote concerning FPC's forecast of inflation rates.

3.) From the Commission's vote concerning the appropriate consumer price index (CPI) factor.

Commissioner Easley dissented as follows:

1.) From the Commission's vote concerning FPC's forecasts of customers and KWH by Revenue Class and System KW.

Commissioner Lauredo dissented as follows:

1.) From the Commission's vote concerning advertising expenses.

2.) From the Commission's vote concerning level of sales expense.

By ORDER of the Florida Public Service Commission, this 22nd day of OCTOBER, 1992.

ATTACHMENT 1

SCHEDULE 1

Company: Florida Power Corporation

Test Year: December 31, 1992

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION

DOCKET 090079-EI
Progress Energy Florida
Exhibit No. ____ (MSD-8)
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LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
1	RATE BASE PER FILING:		
2			
3	Plant in Service	$ 4,245,287	
4	Depreciation Reserve	(1,483,255)	
5			
6	Net Plant in Service	$ 2,762,032	
7	Construction Work in Progress	124,340	
8	Property Held for Future Use	9,559	
9	Nuclear Fuel (Net)	58,351	
10	Allowance for Working Capital	52,493	
11			
12			
13	Total rate base	$ 3,006,775	3,006,775
14			
15			
16	ADJUSTMENTS TO COMPANY FILING:		
17			
18	ISSUE:		
19	4. Plant in Service	0	0
20	5. Aircraft	0	(2,994)
21	12. CWIP	0	(31,938)
22	14. Avon Park Unit 2	0	(1,047)
23	19. FAC & ECCR Overrecoveries	0	(8,434)
24	21. FAS 106 Assets	2,761	3,168
25	23. Interest on Tax Deficiencies	0	0
26	24. Light Oil Inventory	0	(575)
27	25. Accumulated Depreciation	0	5,596
28	27. Fossil Fuel Dismantlement	0	(992)
29	46. OPEB Level	(2,287)	(454)
30	47. Pensions	(454)	1,440
31	48. Unamortized Pension Asset	0	(832)
32	102. Accrued Income Taxes Payable	0	2,606
33	S166. Sebring Distribution System	(14,306)	(14,306)
34	S178. Prepaid Interest	0	(229)
35	S193. Reserve Transfer Reversal	(6,952)	(6,952)
36			
37			
38	Total Adjustment	($ 21,238)	($ 55,943)
39			
40			
41	ADJUSTED RATE BASE:	$ 2,985,537	$ 2,950,832
42			

[*152]

SCHEDULE 2

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
1	COMPANY				
2					
3	Long Term Debt	$ 1,033,252	34.36%	8.32%	2.86%
4	Short Term Debt	83,541	2.78%	7.40%	0.21%
5	Preferred Stock	188,185	6.26%	7.28%	0.46%
6	Customer Deposits	70,454	2.34%	8.17%	0.19%
7	Common Equity	1,136,208	37.79%	13.60%	5.14%
8	Deferred ITC - Weighted Cost	105,488	3.51%	10.78%	0.38%

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
9	Accumulated Deferred Income Taxes	389,647	12.96%		
10					
11					
12	Total Capital	$ 3,006,775	100.00%		9.24%
13					
14					
15					
16	COMMISSION				
17					
18	Long Term Debt	$ 1,010,503	34.24%	8.06%	2.76%
19	Short Term Debt	81,702	2.77%	4.00%	0.11%
20	Preferred Stock	184,042	6.24%	7.28%	0.45%
21	Customer Deposits	68,902	2.34%	8.17%	0.19%
22	Common Equity	1,111,192	37.66%	12.00%	4.52%
23	Deferred ITC - Weighted Cost	105,030	3.56%	9.90%	0.35%
24	Accumulated Deferred Income Taxes	389,461	13.20%		
25					
26					
27	Total Capital	$ 2,950,832	100.00%		8.39%
28					
29					

SCHEDULE 3

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
1	OPERATING REVENUE PER FILING:		
2			
3	Revenue From Sales of Electricity	$ 915,054	
4	Other Operating Revenue	43,408	
5			
6			
7	Total Operating Revenue	$ 958,462	$ 958,462
8			
9			
10	ADJUSTMENTS TO COMPANY FILING:		
11			
12	ISSUE:		
13	2. Revenue Forecast	0	(24,280)
14	35. Load Forecast	$ 0	$ 0
15	S167. Sebring Distribution System	(7,467)	(7,467)
16			
17			
18	Total Adjustments	($ 7,467)	($ 31,747)
19			
20			
21	ADJUSTED OPERATING REVENUE	$ 950,995	$ 926,715
22			
23	OPERATING EXPENSES PER FILING:		
24			
25	Operation & Maintenance	$ 409,492	
26	Depreciation & Amortization	210,428	
27			
28			
29	Total Operating Expense	$ 619,920	$ 619,920
30			

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
31			
32	ADJUSTMENTS TO COMPANY FILING:		
33			
34	ISSUE:		
35	4. Plant in Service	$ 0	$ 0
36	5. Aircraft	0	(222)
37	35. Load Forecast	0	0
38	38. Advertising Expense	(11)	(420)
39	40. Industry Association Dues	0	(500)
40	43. Salaries & Wages	0	(931)
41	46. OPEB Level	(4,381)	(5,197)
42	47. Pensions	(1,683)	(2,653)
43	48. Unamortized Pension Asset	0	(916)
44	49. Outside Services	0	0
45	53. Interest on Tax Deficiencies	0	0
46	55. Rate Case Expense	0	(63)
47	59. Nuclear O&M	0	0
48	60. Nuclear O&M - Increased Personnel	0	0
49	62. Nuclear O&M - Valve Testing System	0	0
50	63. Nuclear O&M - Long Term Maintenance	0	0
51	64. Nuclear Operator Training Simulator	0	0
52	72. Nuclear - Valve Reliability Program	0	0
53	75. Fossil O&M	0	(2,523)
54	77. Fossil O&M - Environmental Changes	0	0
55	87. Tree Trimming Expense	(1,554)	(1,555)
56	88. Customer Accounts	0	0
57	90. Sales Expense	0	(487)
58	93. Management **Incentive** Plan	0	0
59	98. Fossil Fuel Dismantlement	0	1,983
60	101. Regulatory Assessment Fee	0	0
61	S167. Sebring Distribution System	(6,810)	(6,810)
62	S181. Membership Dues	0	(72)
63	S194. Reserve Transfer Reversals	(3,850)	(2,693)
64	R195. Nuclear Decommissioning Accrual	(2,943)	(4,100)
65			
66			
67	Total Adjustment	($ 21,232)	($ 27,159)
68			
69			
70	ADJUSTED OPERATING EXPENSES	$ 598,688	$ 592,761
71			
72	OTHER OPERATING TAXES PER FILING	$ 63,617	$ 63,617
73			
74			
75	ADJUSTMENTS TO COMPANY FILING:		
76	ISSUE:		
77	Tax Effect of Revenue Adjustments	$ 0	($ 20)
78	43. Salaries & Wages	0	(57)
79	101. Regulatory Assessment Fee	0	(745)
80	S167. Sebring Distribution System	(257)	(225)
81			
82			
83	Total Adjustments	($ 257)	($ 1,047)
84			

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
85			
86	ADJUSTED OTHER OPERATING TAXES	$ 63,360	$ 62,570
87			
88			
89			
90	INCOME TAXES PER FILING:		
91	Current Income Taxes	$ 89,061	
92	Deferred Income Taxes	(23,230)	
93	Investment Tax Credit	(7,234)	
94			
95			
96	Total Income Tax	$ 58,597	$ 58,597
97			
98			
99	ADJUSTMENTS TO COMPANY FILING:		
100	ISSUE:		
101	Tax Effect of Other Adjustments	$ 5,375	($ 7,024)
102	Interest Expense Reconciliation	0	2,973
103	46. OPEB Level	0	1,956
104	47. Pensions	0	998
105	48. Unamortized Pension Asset	0	345
106	S167. Sebring Distribution System	0	39
107	S194. Reserve Transfer Reversals	0	747
108	R195. Nuclear Decommissioning Accrual	0	1,543
109			
110			
111	Total Adjustments	$ 5,375	$ 1,577
112			
113			
114	ADJUSTED INCOME TAXES	$ 63,972	$ 60,174
115			
116			
117			
118	OTHER ITEMS PER FILING:		
119	(Gain)/Loss on Sale	($ 84)	
120	Regulatory Practices Reconciliation	(199)	
121			
122			
123	Total	($ 283)	($ 283)
124			
125	ADJUSTMENTS TO COMPANY FILING:		
126	ISSUE:		
127	S167. Sebring Distribution System	($ 2)	($ 2)
128			
129			
130	ADJUSTED OTHER ITEMS	($ 285)	($ 285)
131			
132	NET OPERATING INCOME:		
133	Operating Revenue	$ 950,995	$ 926,715
134	Operating Expenses	(598,688)	(592,761)
135	Taxes Other than Income	(63,360)	(62,570)
136	Income Taxes	(63,972)	(60,174)
137	Other Items	285	285
138			

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
139			
140	Net operating income	$ 225,260	$ 211,495
141			

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SCHEDULE 4

FLORIDA POWER CORPORATION

O & M BENCHMARK VARIANCE BY FUNCTION

1992

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)
1987 FPSC Allowed O&M-System	$ 67,696	$ 70,854	$ 1,540	$ 13,262
1987-1992 Compound Multiplier	1.2425	1.2425	1.4389	1.4389
1992 O&M Benchmark - System	84,112	88,036	2,216	19,083
1992 Adj. O&M - System	101,071	97,819	1,692	13,981
Benchmark Variance	16,959	9,783	(524)	(5,102)
Staff Adjustments-System	(2,800)	0	0	0
Adjustments to all Functions				
Adjusted Variance-System	14,159	9,783	(524)	(5,102)
1992 O&M Benchmark - System	84,112	88,036	2,216	19,083
Juris. Separation Factors	0.8853	0.9409	0.8145	0.7537
1992 Benchmark - Juris.	74,464	82,833	1,805	14,383
1992 Adj. O&M - Juris.	88,844	91,854	1,438	10,540
Juris. Benchmark Variance	14,379	9,018	(367)	(3,843)
Staff Adjustments-Juris.	(2,523)	0	0	0
Adj. to all Functions-Juris.				
Adjusted Variance-Juris.	$ 11,856	$ 9,018	($ 367)	($ 3,843)

	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)
1987 FPSC Allowed O&M-System	$ 45,173	$ 26,996	$ 2,662	$ 879
1987-1992 Compound Multiplier	1.4389	1.4389	1.4389	1.4389
1992 O&M Benchmark - System	64,999	38,845	3,830	1,265
1992 Adj. O&M - System	60,917	36,269	7,090	917
Benchmark Variance	(4,082)	(2,576)	4,079	(348)
Staff Adjustments-System	(8,282)	0	(420)	(487)
Adjustments to all Functions				
Adjusted Variance-System	(12,364)	(2,576)	3,659	(835)
1992 O&M Benchmark - System	64,999	38,845	3,830	1,265
Juris. Separation Factors	0.9918	0.9969	1.0000	0.9992
1992 Benchmark - Juris.	64,466	38,725	3,830	1,264
1992 Adj. O&M - Juris.	60,410	36,157	7,909	917
Juris. Benchmark Variance	(4,055)	(2,569)	4,079	(347)
Staff Adjustments-Juris.	(7,565)	0	(420)	(487)
Adj. to all Functions-Juris.				
Adjusted Variance-Juris.	($ 11,620)	($ 2,569)	$ 3,659	($ 834)

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	Admin. & General (000)	Other Adjustments (000)	Total (000)
1987 FPSC Allowed O&M-System	$ 72,105	$ 2,277	$ 303,444

	Admin. & General (000)	Other Adjustments (000)	Total (000)
1987-1992 Compound Multiplier	1.4389	0	
1992 O&M Benchmark - System	103,752	2,277	408,415
1992 Adj. O&M - System	110,616	* 9,101	440,292
Benchmark Variance	6,864	6,824	31,877
Staff Adjustments-System	(10,033)	0	(22,022)
Adjustments to all Functions		209	209
Adjusted Variance-System	(3,169)	7,033	10,064
1992 O&M Benchmark - System	103,752	2,277	408,415
Juris. Separation Factors	0.9346	0.9003	
1992 Benchmark - Juris.	96,967	2,050	0
1992 Adj. O&M - Juris.	103,397	** 8,029	409,495
Juris. Benchmark Variance	6,426	5,979	28,700
Staff Adjustments-Juris.	(9,401)	0	(20,396)
Adj. to all Functions-Juris.		226	226
Adjusted Variance-Juris.	($ 2,975)	$ 6,205	$ 8,531

Includes: Interest on Tax Deficiency Sebring Acquisition

* System	** Jurisd.
$ 2,378	$ 2,141
6,723	5,888
$ 9,101	$ 8,029

FLORIDA POWER CORPORATION

1992 O & M BENCHMARK VARIANCE BY FUNCTION (JURISDICTIONAL)

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)
38	ADVERTISING EXPENSE			
40	INDUSTRY ASSOC. DUES			
43	SALARIES & WAGES			
46	FAS 106 ACCRUAL			
47	PENSION EXPENSE			
48	PENSION ASSET AMORT.			
55	RATE CASE EXPENSE			
60	INCREASED PERSONNEL		0	
62	VALVE TESTING SYS.		0	
63	LONG TERM MAINT. PLAN		0	
64	OPERATOR TRAIN. SIMULATOR		0	
72	VALVE RELIABILITY PROG.		0	
75	1991 DEFERRED O&M	(2,523)		
77	ENVIRONMENTAL CHANGES	0		
87	TREE TRIMMING EXP.			
90	SALES EXPENSE			
S167	SEBRING DISTR. SYS.			
S181	MEMBERSHIP DUES			
S194	REVERSAL OF RES. TRANSFERS			
TOTAL JURISDICTIONAL		(2,523)	0	0

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		Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)
38	ADVERTISING EXPENSE				(420)
40	INDUSTRY ASSOC. DUES				

	Trans- mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)
43 SALARIES & WAGES				
46 FAS 106 ACCRUAL				
47 PENSION EXPENSE				
48 PENSION ASSET AMORT.				
55 RATE CASE EXPENSE				
60 INCREASED PERSONNEL				
62 VALVE TESTING SYS.				
63 LONG TERM MAINT. PLAN				
64 OPERATOR TRAIN. SIMULATOR				
72 VALVE RELIABILITY PROG.				
75 1991 DEFERRED O&M				
77 ENVIRONMENTAL CHANGES				
87 TREE TRIMMING EXP.		(1,555)		
90 SALES EXPENSE				
S167 SEBRING DISTR. SYS.		(6,010)		
S181 MEMBERSHIP DUES				
S194 REVERSAL OF RES. TRANSFERS				
TOTAL JURISDICTIONAL	0	(7,565)	0	(420)

	Sales (000)	Admin. & General (000)	Total (000)
38 ADVERTISING EXPENSE			(420)
40 INDUSTRY ASSOC. DUES		(500)	(500)
43 SALARIES & WAGES			(931) *
46 FAS 106 ACCRUAL		(5,197)	(5,197)
47 PENSION EXPENSE		(2,653)	(2,653)
48 PENSION ASSET AMORT.		(916)	(916)
55 RATE CASE EXPENSE		(63)	(63)
60 INCREASED PERSONNEL			0
62 VALVE TESTING SYS.			0
63 LONG TERM MAINT. PLAN			0
64 OPERATOR TRAIN. SIMULATOR			0
72 VALVE RELIABILITY PROG.			0
75 1991 DEFERRED O&M			(2,523)
77 ENVIRONMENTAL CHANGES			0
87 TREE TRIMMING EXP.			(1,555)
90 SALES EXPENSE	(487)		(487)
S167 SEBRING DISTR. SYS.			(6,010)
S181 MEMBERSHIP DUES		(72)	(72)
S194 REVERSAL OF RES. TRANSFERS			1,157 *
TOTAL JURISDICTIONAL	(487)	(9,401)	(20,170)

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* THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER CORPORATION

1992 O & M BENCHMARK VARIANCE BY FUNCTION (SYSTEM)

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans- mission (000)	Distri bution (000)

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)
38	ADVERTISING EXPENSE					
40	INDUSTRY ASSOC. DUES					
43	SALARIES & WAGES					
46	FAS 106 ACCRUAL					
47	PENSION EXPENSE					
48	PENSION ASSET AMORT.					
55	RATE CASE EXPENSE					
60	INCREASED PERSONNEL		0			
62	VALVE TESTING SYS.		0			
63	LONG TERM MAINT. PLAN		0			
64	OPERATOR TRAIN. SIMULATOR		0			
72	VALVE RELIABILITY PROG.		0			
75	1991 DEFERRED O&M	(2,800)				
77	ENVIRONMENTAL CHANGES	0				
87	TREE TRIMMING EXP.					(1,559)
90	SALES EXPENSE					
S167	SEBRING DISTR. SYS.					(6,723)
S181	MEMBERSHIP DUES					
S194	REVERSAL OF RES. TRANSFERS					
TOTAL SYSTEM		(2,800)	0	0	0	(8,282)

		Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE		(420)			(420)
40	INDUSTRY ASSOC. DUES				(523)	(523)
43	SALARIES & WAGES					* (994)
46	FAS 106 ACCRUAL				(5,557)	(5,557)
47	PENSION EXPENSE				(2,836)	(2,836)
48	PENSION ASSET AMORT.				(979)	(979)
55	RATE CASE EXPENSE				(63)	(63)
60	INCREASED PERSONNEL					0
62	VALVE TESTING SYS.					0
63	LONG TERM MAINT. PLAN					0
64	OPERATOR TRAIN. SIMULATOR					0
72	VALVE RELIABILITY PROG.					0
75	1991 DEFERRED O&M					(2,800)
77	ENVIRONMENTAL CHANGES					0
87	TREE TRIMMING EXP.					(1,559)
90	SALES EXPENSE			(487)		(487)
S167	SEBRING DISTR. SYS.					(6,723)
S181	MEMBERSHIP DUES				(75)	(75)
S194	REVERSAL OF RES. TRANSFERS					* 1,203
TOTAL SYSTEM		0	(420)	(487)	(10,033)	(21,813)

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* THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER COMPANY

O & M COMPOUND MULTIPLIERS

Total Customers

Year	Amount	%Increase	Compound Multiplier
1987	1,023,222		1.0000
1988	1,060,971	3.69%	1.0369
1989	1,101,817	3.85%	1.0768
1990	1,135,499	3.06%	1.1098
1991	1,159,538	2.12%	1.1333
1992	1,184,915	2.19%	1.1581
1993	1,217,404	2.74%	1.1898
1993 USING 1992 AS BASE YR.	1,217,404	2.74%	1.0274

Average CPI-U (1982-1984=100)

Year	Amount	& Increase	Compound Multiplier	Inflation and Growth Compound Multiplier
1987	113.6		1.0000	1.0000
1988	118.3	4.10%	1.0410	1.0794
1989	124.0	4.80%	1.0910	1.1748
1990	130.7	5.40%	1.1499	1.2762
1991	136.2	4.20%	1.1982	1.3579
1992	141.2	3.70%	1.2425	1.4389
1993	146.6	3.80%	1.2897	1.5345
1993 USING 1992 AS BASE YR.	146.6	3.80%	1.0380	1.0664

Schedule 5

Company: Florida Power Corporation

Test Year: December 31, 1992

LN NO	COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
1	Adjusted Intrastate Rate Base	$ 3,006,775	$ 2,950,832
2			
3	Required Rate of Return	9.24%	8.39%
4			
5			
6			
7	Required Net Operating Income	$ 277,826	$ 247,575
8			
9	Adjusted Achieved Test Year		
10	Intrastate Net Operating Income	216,611	211,495
11			
12			
13			
14	Intrastate NOI Deficiency (Excess)	$ 61,215	$ 36,080
15			
16	Revenue Expansion Factor	1.607828	1.607157
17			
18			
19			
20	Revenue Increase (Decrease) - Test Year	$ 98,427	$ 57,986
21	Performance Reward	9,669	0

LN NO	COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
22			
23			
24	Total Revenue Increase	$ 108,096	$ 57,986
25			

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SCHEDULE 6

Company: Florida Power Corporation

Test Year: December 31, 1992 & 1993

LN NO	REVENUE EXPANSION FACTOR	COMPANY POSITION	COMMISSION
1	Revenue Requirement	100.000000	100.000000
2			
3			
4	Uncollectible Rate	0.154500	0.154500
5			
6	Gross Receipts Tax	0.000000	0.000000
7			
8	Regulatory Assessment Fee	0.125000	0.083300
9			
10			
11	Net Before Income Taxes	99.720500	99.762200
12			
13	State Income Tax	0.055000	0.055000
14	Rate		
15			
16	Amount	5.484628	5.486921
17			
18			
19	Net Before Federal Income Taxes	94.235872	94.275279
20			
21	Federal Income Tax		
22	Rate	0.340000	0.340000
23			
24			
25	Amount	32.040196	32.053595
26			
27			
28	Net Operating Income	62.195676	62.221684
29			
30			
31			
32	Net Operating Income Multiplier	1.607828	1.607157
33			

Schedule 7

Company: Florida Power Corporation

Test Year: December 31, 1993

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
1	RATE BASE PER FILING:		
2			
3	Plant in Service	$ 4,617,090	

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
4	Depreciation Reserve	(1,628,030)	
5			
6	Net Plant in Service	$ 2,989,060	
7	Construction Work in Progress	110,667	
8	Property Held for Future Use	9,436	
9	Nuclear Fuel (Net)	50,487	
10	Allowance for Working Capital	51,589	
11			
12			
13	Total rate base	$ 3,211,239	3,211,239
14			
15			
16	ADJUSTMENTS TO COMPANY FILING:		
17			
18	ISSUE:		
19	4. Plant in Service	0	0
20	5. Aircraft	0	(2,774)
21	12. CWIP	0	(27,640)
22	14. Avon Park Unit 2	0	(734)
	17. Property Insurance Reserve	0	(46)
23	19. FAC & ECCR Overrecoveries	0	0
24	21. FAS 106 Assets	9,308	10,565
25	23. Interest on Tax Deficiencies	0	0
26	24. Light Oil Inventory	0	0
27	25. Accumulated Depreciation	0	10,581
28	27. Fossil Fuel Dismantlement	0	(934)
29	46. OPEB Level	1,025	(479)
30	47. Pensions	593	4,845
31	48. Unamortized Pension Asset	0	(2,708)
32	102. Accrued Income Taxes Payable	0	1,440
33	S166. Sebring Distribution System	(15,153)	(15,153)
34	S178. Prepaid Interest	0	(330)
35	S193. Reserve Transfer Reversal	(8,214)	(8,479)
36			
37			
38	Total Adjustment	($ 12,441)	($ 31,846)
39			
40			
41	ADJUSTED RATE BASE:	$ 3,198,798	$ 3,179,393
42			

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Schedule 8

Company: Florida Power Corporation

Test Year: December 31, 1993

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
1	COMPANY				
2					
3	Long Term Debt	$ 1,102,212	34.32%	8.42%	2.89%
4	Short Term Debt	147,347	4.59%	7.50%	0.34%
5	Preferred Stock	182,022	5.67%	7.18%	0.41%
6	Customer Deposits	74,561	2.32%	8.17%	0.19%

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
7	Common Equity	1,211,778	37.74%	13.60%	5.13%
8	Deferred ITC - Weighted Cost	101,273	3.15%	10.85%	0.34%
9	Accumulated Deferred Income Taxes	392,046	12.21%		
10					
11					
12	Total Capital	$ 3,211,239	100.00%		9.30%
13					
14					
15					
16	COMMISSION				
17					
18	Long Term Debt	$ 1,087,808	34.21%	8.08%	2.77%
19	Short Term Debt	145,421	4.57%	4.00%	0.18%
20	Preferred Stock	179,643	5.65%	7.18%	0.41%
21	Customer Deposits	73,587	2.31%	8.17%	0.19%
22	Common Equity	1,195,942	37.62%	12.00%	4.51%
23	Deferred ITC - Weighted Cost	100,854	3.17%	9.92%	0.31%
24	Accumulated Deferred Income Taxes	396,137	12.46%		
25					
26					
27	Total Capital	$ 3,179,393	100.00%		8.37%
28					
29					

Schedule 9

Company: Florida Power Corporation

Test Year: December 31, 1993

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
1	OPERATING REVENUE PER FILING:		
2			
3	Revenue From Sales of Electricity	$ 951,042	
4	Other Operating Revenue	46,252	
5			
6			
7	Total Operating Revenue	$ 997,294	$ 997,294
8			
9			
10	ADJUSTMENTS TO COMPANY FILING:		
11			
12	ISSUE:		
13	2. Revenue Forecast	0	(15,515)
14	35. Load Forecast	$ 0	$ 0
15	S167. Sebring Distribution System	(7,771)	(7,771)
16			
17			
18	Total Adjustments	($ 7,771)	($ 23,286)
19			
20			
21	ADJUSTED OPERATING REVENUE	$ 989,523	$ 974,008
22			

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LN COMPARATIVE NET OPERATING INCOME (000) COMPANY

NO		OPERATING EXPENSE	POSITION	COMMISSION
23	OPERATING EXPENSES PER FILING:			
24				
25	Operation & Maintenance		$ 435,083	
26	Depreciation & Amortization		226,109	
27				
28				
29		Total Operating Expense	$ 661,192	$ 661,192
30				
31				
32	ADJUSTMENTS TO COMPANY FILING:			
33				
34	ISSUE:			
35	4.	Plant in Service	$ 0	$ 0
36	5.	Aircraft	0	(223)
37	35.	Load Forecast	0	0
38	38.	Advertising Expense	(11)	(450)
39	40.	Industry Association Dues	0	(526)
40	43.	Salaries & Wages	0	(1,072)
41	46.	OPEB Level	(4,995)	(5,875)
42	47.	Pensions	(1,498)	(2,464)
43	48.	Unamortized Pension Asset	0	(927)
44	49.	Outside Services	0	0
45	51.	Storm Damage Accrual	0	(266)
46	53.	Interest on Tax Deficiencies	0	0
47	55.	Rate Case Expense	0	(63)
48	59.	Nuclear O&M	0	0
49	60.	Nuclear O&M - Increased Personnel	0	0
50	62.	Nuclear O&M - Valve Testing System	0	0
51	63.	Nuclear O&M - Long Term Maintenance	0	0
52	64.	Nuclear Operator Training Simulator	0	0
53	72.	Nuclear - Valve Reliability Program	0	0
54	75.	Fossil O&M	0	(2,560)
55	77.	Fossil O&M - Environmental Changes	0	0
56	87.	Tree Trimming Expense	0	0
57	88.	Customer Accounts	0	0
58	90.	Sales Expense	0	(512)
59	93.	Management **Incentive** Plan	0	0
60	98.	Fossil Fuel Dismantlement	0	1,868
61	101.	Regulatory Assessment Fee	0	0
62	S167.	Sebring Distribution System	(7,051)	(7,051)
63	S181.	Membership Dues	0	(75)
64	S194.	Reserve Transfer Reversals	(1,855)	(1,855)
65	R195.	Nuclear Decommissioning Accrual	(4,090)	(4,090)
66				
67				
68		Total Adjustment	($ 19,500)	($ 26,141)
69				
70				
71	ADJUSTED OPERATING EXPENSES		$ 641,692	$ 635,051

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LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
72	OTHER OPERATING TAXES PER FILING	$ 72,911	$ 72,911
73			
74			

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
75	ADJUSTMENTS TO COMPANY FILING:		
76	ISSUE:		
77	Tax Effect of Revenue Adjustments	$ 0	($ 13)
78	43. Salaries & Wages	0	(60)
79	101. Regulatory Assessment Fee	0	(845)
80	S167. Sebring Distribution System	(279)	(233)
81			
82			
83	Total Adjustments	($ 279)	($ 1,151)
84			
85			
86	ADJUSTED OTHER OPERATING TAXES	$ 72,632	$ 71,760
87			
88			
89			
90	INCOME TAXES PER FILING:		
91	Current Income Taxes	$ 84,644	
92	Deferred Income Taxes	(28,160)	
93	Investment Tax Credit	(7,168)	
94			
95			
96	Total Income Tax	$ 49,316	$ 49,316
97			
98			
99	ADJUSTMENTS TO COMPANY FILING:		
100	ISSUE:		
101	Tax Effect of Other Adjustments	$ 4,505	($ 4,032)
102	Interest Expense Reconciliation	0	3,880
103	46. OPEB Level	0	2,211
104	47. Pensions	0	927
105	48. Unamortized Pension Asset	0	349
106	S167. Sebring Distribution System	44	44
107	S194. Reserve Transfer Reversals	0	477
108	R195. Nuclear Decommissioning Accrual	0	1,539
109			
110			
111	Total Adjustments	$ 4,549	$ 5,395
112			
113			
114	ADJUSTED INCOME TAXES	$ 53,865	$ 54,711
115			
116			
117			
118	OTHER ITEMS PER FILING:		
119	(Gain)/Loss on Sale	($ 65)	
120	Regulatory Practices Reconciliation	(204)	
121			
122			
123	Total	($ 269)	($ 269)
124			
125	ADJUSTMENTS TO COMPANY FILING:		
126	ISSUE:		
127	S167. Sebring Distribution System	($ 1)	($ 1)
128			

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
129			
130	ADJUSTED OTHER ITEMS	($ 270)	($ 270)
131			
132	NET OPERATING INCOME:		
133	Operating Revenue	$ 989,523	$ 974,008
134	Operating Expenses	(641,692)	(635,051)
135	Taxes Other than Income	(72,632)	(71,760)
136	Income Taxes	(53,865)	(54,711)
137	Other Items	270	270
138			
139			
140	Net operating income	$ 221,604	$ 212,756
141			

[*162]

SCHEDULE 10

FLORIDA POWER CORPORATION

O & M BENCHMARK VARIANCE BY FUNCTION

1993

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)
1992 FPSC Allowed O&M-System	$ 98,271	$ 97,819	$ 1,692
1992-1993 Compound Multiplier	1.0380	1.0380	1.0664
1993 O&M Benchmark - System	102,005	101,536	1,804
1993 Adj. O&M - System	114,336	101,779	1,934
Benchmark Variance	12,331	243	130
Staff Adjustments-System	(2,823)	0	0
Adjustments to all Functions			
Adjusted Variance-System	9,508	243	130
1993 O&M Benchmark - System	102,005	101,536	1,804
Juris. Separation Factors	0.8824	0.9370	0.8387
1993 Benchmark - Juris.	90,009	95,139	1,513
1993 Adj. O&M - Juris.	100,496	95,326	1,622
Juris. Benchmark Variance	10,487	187	109
Staff Adjustments-Juris.	(2,560)	0	0
Adjustments to all Functions			
Adjusted Variance-Juris.	$ 7,927	$ 187	$ 109

	Trans- mission (000)	Distribution (000)	Customer Accounts (000)
1992 FPSC Allowed O&M-System	$ 13,981	$ 52,635	$ 36,269
1992-1993 Compound Multiplier	1.0664	1.0664	1.0664
1993 O&M Benchmark - System	14,909	56,130	38,677
1993 Adj. O&M - System	14,862	64,560	38,528
Benchmark Variance	(47)	8,430	(149)
Staff Adjustments-System	0	(6,964)	0
Adjustments to all Functions			
Adjusted Variance-System	(47)	1,466	(149)
1993 O&M Benchmark - System	14,909	56,130	38,677
Juris. Separation Factors	0.7493	0.9918	0.9971
1993 Benchmark - Juris.	11,172	55,670	38,565

	Transmission (000)	Distribution (000)	Customer Accounts (000)
1993 Adj. O&M - Juris.	11,136	64,028	38,414
Juris. Benchmark Variance	(36)	8,358	(151)
Staff Adjustments-Juris.	0	(6,203)	0
Adjustments to all Functions			
Adjusted Variance-Juris.	($ 36)	$ 2,155	($ 151)

[*163]

	Customer Service (000)	Sales (000)	Admin. & General (000)
1992 FPSC Allowed O&M-System	$ 7,489	$ 430	$ 100,583
1992-1993 Compound Multiplier	1.0664	1.0664	1.0664
1993 O&M Benchmark - System	7,986	459	107,262
1993 Adj. O&M - System	8,462	981	114,881
Benchmark Variance	476	522	7,619
Staff Adjustments-System	(450)	(512)	(10,884)
Adjustments to all Functions			
Adjusted Variance-System	26	10	(3,265)
1993 O&M Benchmark - System	7,986	459	107,262
Juris. Separation Factors	1.0000	1.0000	0.9349
1993 Benchmark - Juris.	7,986	459	100,279
1993 Adj. O&M - Juris.	8,462	981	107,447
Juris. Benchmark Variance	476	522	7,168
Staff Adjustments-Juris.	(450)	(512)	(10,196)
Adjustments to all Functions			
Adjusted Variance-Juris.	$ 26	$ 10	($ 3,028)

	Other Adjustments (000)	Total (000)
1992 FPSC Allowed O&M-System	$ 9,310	$ 418,479
1992-1993 Compound Multiplier	0	
1993 O&M Benchmark - System	9,310	440,079
1993 Adj. L&M - System	* 8,272	468,595
Benchmark Variance	(1,038)	28,516
Staff Adjustments-System	0	(21,633)
Adjustments to all Functions	31	31
Adjusted Variance-System	(1,007)	6,914
1993 O&M Benchmark - System	9,310	440,979
Juris. Separation Factors	0.8696	
1993 Benchmark - Juris.	8,096	408,888
1993 Adj. L&M - Juris.	** 7,170	435,082
Juris. Benchmark Variance	(926)	26,194
Staff Adjustments-Juris.	0	(19,921)
Adjustments to all Functions	60	60
Adjusted Variance-Juris.	($ 866)	$ 6,333

[*164]

Includes: Interest on Tax Deficiency Sebring Acquisition

* System	** Jurisd
$ 1,308	$ 1,167
6,964	6,003
$ 8,272	$ 7,170

FLORIDA POWER CORPORATION

1993 O & M BENCHMARK VARIANCE BY FUNCTION (JURISDICTIONAL)

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)
38 ADVERTISING EXPENSE			
40 INDUSTRY ASSOC. DUES			
43 SALARIES & WAGES			
46 FAS 106 ACCRUAL			
47 PENSION EXPENSE			
48 PENSION ASSET AMORT.			
51 STORM DAMAGE			
55 RATE CASE EXPENSE			
60 INCREASED PERSONNEL		0	
62 VALVE TESTING PROG.		0	
63 LONG TERM MAINT. PLAN		0	
64 OPERATOR TRAIN. SIMULATOR		0	
72 VALVE RELIABILITY PROG.		0	
75 SCHEDULED OUTAGES	(2,560)		
90 SALES EXPENSE			
S167 SEBRING DISTR. SYS.			
S181 MEMBERSHIP DUES			
S194 REVERSAL OF RES. TRANSFERS			
TOTAL JURISDICTIONAL	(2,560)	0	0

	Trans-mission (000)	Distribution (000)	Customer Accounts (000)
38 ADVERTISING EXPENSE			
40 INDUSTRY ASSOC. DUES			
43 SALARIES & WAGES			
46 FAS 106 ACCRUAL			
47 PENSION EXPENSE			
48 PENSION ASSET AMORT.			
51 STORM DAMAGE			
55 RATE CASE EXPENSE			
60 INCREASED PERSONNEL			
62 VALVE TESTING PROG.			
63 LONG TERM MAINT. PLAN			
64 OPERATOR TRAIN. SIMULATOR			
72 VALVE RELIABILITY PROG.			
75 SCHEDULED OUTAGES			
90 SALES EXPENSE			
S167 SEBRING DISTR. SYS.		(6,203)	
S181 MEMBERSHIP DUES			
S194 REVERSAL OF RES. TRANSFERS			
TOTAL JURISDICTIONAL	0	(6,203)	0

[*165]

	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38 ADVERTISING EXPENSE	(450)			(450)
40 INDUSTRY ASSOC. DUES			(526)	(526)
43 SALARIES & WAGES				* (1,072)
46 FAS 106 ACCRUAL			(5,875)	(5,875)
47 PENSION EXPENSE			(2,464)	(2,464)
48 PENSION ASSET AMORT.			(927)	(927)

	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
51 STORM DAMAGE			(266)	(266)
55 RATE CASE EXPENSE			(63)	(63)
60 INCREASED PERSONNEL				0
62 VALVE TESTING PROG.				0
63 LONG TERM MAINT. PLAN				0
64 OPERATOR TRAIN. SIMULATOR				0
72 VALVE RELIABILITY PROG.				0
75 SCHEDULED OUTAGES				(2,560)
90 SALES EXPENSE		(512)		(512)
S167 SEBRING DISTR. SYS.				(6,203)
S181 MEMBERSHIP DUES			(75)	(75)
S194 REVERSAL OF RES. TRANSFERS				* 1,132
TOTAL JURISDICTIONAL	(450)	(512)	(10,196)	(19,861)

* THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER CORPORATION

1993 O & M BENCHMARK VARIANCE BY FUNCTION (SYSTEM)

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)
38 ADVERTISING EXPENSE			
40 INDUSTRY ASSOC. DUES			
43 SALARIES & WAGES			
46 FAS 106 ACCRUAL			
47 PENSION EXPENSE			
48 PENSION ASSET AMORT.			
51 STORM DAMAGE			
55 RATE CASE EXPENSE			
60 INCREASED PERSONNEL		0	
62 VALVE TESTING PROG.		0	
63 LONG TERM MAINT. PLAN		0	
64 OPERATOR TRAIN. SIMULATOR		0	
72 VALVE RELIABILITY PROG.		0	
75 SCHEDULED OUTAGES	(2,823)		
90 SALES EXPENSE			
S167 SEBRING DISTR. SYS.			
S181 MEMBERSHIP DUES			
S194 REVERSAL OF RES. TRANSFERS			
TOTAL SYSTEM	(2,823)	0	0

[*166]

	Trans-mission (000)	Distribution (000)	Customer Accounts (000)
38 ADVERTISING EXPENSE			
40 INDUSTRY ASSOC. DUES			
43 SALARIES & WAGES			
46 FAS 106 ACCRUAL			
47 PENSION EXPENSE			
48 PENSION ASSET AMORT.			
51 STORM DAMAGE			

		Trans-mission (000)	Distribution (000)	Customer Accounts (000)
55	RATE CASE EXPENSE			
60	INCREASED PERSONNEL			
62	VALVE TESTING PROG.			
63	LONG TERM MAINT. PLAN			
64	OPERATOR TRAIN. SIMULATOR			
72	VALVE RELIABILITY PROG.			
75	SCHEDULED OUTAGES			
90	SALES EXPENSE			
S167	SEBRING DISTR. SYS.		(6,964)	
S181	MEMBERSHIP DUES			
S194	REVERSAL OF RES. TRANSFERS			
TOTAL SYSTEM		0	(6,964)	0

		Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE	(450)			(450)
40	INDUSTRY ASSOC. DUES			(551)	(551)
43	SALARIES & WAGES				* (1,145)
46	FAS 106 ACCRUAL			(6,277)	(6,277)
47	PENSION EXPENSE			(2,632)	(2,632)
48	PENSION ASSET AMORT.			(992)	(992)
51	STORM DAMAGE			(289)	(289)
55	RATE CASE EXPENSE			(63)	(63)
60	INCREASED PERSONNEL				0
62	VALVE TESTING PROG.				0
63	LONG TERM MAINT. PLAN				0
64	OPERATOR TRAIN. SIMULATOR				0
72	VALVE RELIABILITY PROG.				0
75	SCHEDULED OUTAGES				(2,823)
90	SALES EXPENSE		(512)		(512)
S167	SEBRING DISTR. SYS.				(6,964)
S181	MEMBERSHIP DUES			(80)	(80)
S194	REVERSAL OF RES. TRANSFERS				* 1,176
TOTAL SYSTEM		(450)	(512)	(10,884)	(21,602)

[*167]

* THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER COMPANY

O & M COMPOUND MULTIPLIERS

Total Customers

Year	Amount	%Increase	Compound Multiplier
1987	1,023,222		1.0000
1988	1,060,971	3.69%	1.0369
1989	1,101,817	3.85%	1.0768
1990	1,135,499	3.06%	1.1098
1991	1,159,538	2.12%	1.1333
1992	1,184,915	2.19%	1.1581
1993	1,217,404	2.74%	1.1898
1993 USING	1,217,404	2.74%	1.0274

	Total Customers		
Year	Amount	%Increase	Compound Multiplier
1992 AS BASE YR.			

	Average CPI-U (1982-1984=100)			
Year	Amount	& Increase	Compound Multiplier	Inflation and Growth Compound Multiplier
1987	113.6		1.0000	1.0000
1988	118.3	4.10%	1.0410	1.0794
1989	124.0	4.80%	1.0910	1.1748
1990	130.7	5.40%	1.1499	1.2762
1991	136.2	4.20%	1.1982	1.3579
1992	141.2	3.70%	1.2425	1.4389
1993	146.6	3.80%	1.2897	1.5345
1993 USING 1992 AS BASE YR.	146.6	3.80%	1.0380	1.0664

Schedule 11

NOVEMBER 1993 REVENUE REQUIREMENT

Jurisdictional Revenue Requirements

Intercession City Peaking Units and University of Florida Project

	Jurisdictional (000)	
Rate Base Annualization Adjustment	Company	Commission Vote
Electric Plant in Service	$ 86,407	$ 86,407
Accumulated Depreciation	(2,552)	(2,552)
Fuel Inventory	0	0
Working Capital-Income Taxes Payable	(3,862)	(3,862)
TOTAL Rate Base Annualization	$ 79,993	$ 79,993
NOI Annualization		
O&M	$ 3,164	$ 3,164
Property Taxes	3,107	3,107
Depreciation	3,887	3,887
Income Taxes -		
Direct Current	(5,757)	(5,757)
Direct Deferred	1,148	1,148
Imputed Interest	(1,066)	(975)
Total NOI Annualization	($ 4,483)	($ 4,574)
Calculation of Revenue Requirement		
Fully adjusted Cost of Capital	9.30%	8.37%
NOI Requirement	$ 7,439	$ 6,695
NOI Deficiency	$ 11,923	$ 11,269
NOI Multiplier	1.607157	1.607157
Revenue Requirement	$ 19,162	$ 18,111
Calculation of Taxes on Imputed Interest		
Weighted Cost of Debt Capital		
Long Term Debt Fixed Rate	2.72%	2.59%
Long Term Debt Variable Rate	0.17%	0.17%
Short Term Debt	0.34%	0.18%
Customer Deposits	0.19%	0.19%
JDIC	0.12%	0.11%

	Jurisdictional (000) Company	Commission Vote
Rate Base Annualization Adjustment	3.54%	3.24%
Imputed Interest	$ 2,832	$ 2,592
Income Taxes on Imputed Interest at 37.63%	($ 1,066)	($ 975)

[*168]

Schedule 12

Company: Florida Power Corporation

Test Year: December 31, 1993

LN NO	COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
1	Adjusted Intrastate Rate Base	$ 3,211,239	$ 3,179,393
2			
3	Required Rate of Return	9.30%	8.37%
4			
5			
6			
7	Required Net Operating Income	$ 298,645	$ 266,115
8			
9	Adjusted Achieved Test Year		
10	Intrastate Net Operating Income	214,144	212,756
11			
12			
13			
14	Intrastate NOI Deficiency (Excess)	$ 84,501	$ 53,359
15			
16	Revenue Expansion Factor	1.607828	1.607157
17			
18			
19			
20	Revenue Increase (Decrease) - Test Year	$ 135,863	$ 85,757
21	Performance Reward - 1993	9,990	0
22			
23			
24	Total Revenue Increase	$ 145,853	$ 85,757
25			
26	Less 1992 Revenue Increase	(98,427)	(57,986)
27	Less Performance Reward - 1992	(9,669)	0
ERR	LESS NOVEMBER 1993 STEP INCREASE	(23,684)	(18,111)
ERR			
ERR	APRIL 1993 STEP INCREASE	$ 14,073	$ 9,660
ERR			

COST OF SERVICE AND RATE DESIGN STIPULATION

Florida Power Corporation (the Company), the **Florida** Industrial **Power** Users Group (FIPUG), Occidental Chemical **Corporation** (Occidental), and the Ad Hoc Committee [*169] of Local Governments (collectively, the Parties), by and through their undersigned counsel, hereby stipulate and agree to resolve Issues 120 through 159 contained in the Prehearing Order No. PSC-92-0606-PHO-EI, pertaining to Cost of Service and **Rate** Design, as follows:

1. The Company's separation of joint system costs between the wholesale and retail jurisdiction for 1992 and 1993 contained in Exhibits 40 and 41 is accepted. (Issue 120)

2. The 12 CP and 1/13 Average Demand cost of service methodology as contained in Exhibits 40 and 41 is accepted for determining the class revenue requirements and unit costs used in designing the Company's rates. (Issue 122)

3. The interruptible and curtailable service rate classes will be assigned costs within the Company's cost of service study based on each class's respective use characteristics, without adjustment to coincident demands; the fact that such customers accept nonfirm service will be recognized in the form of credits to the demand charges developed for these classes. The Parties have negotiated, for purposes of settlement, credits of $ 6.30 and $ 3.15 per coincident KW for interruptible and curtailable tariffs, respectively. [*170] The negotiated values have been tested by the Commission's conservation cost-effectiveness methodology based on the avoidance of a January 1, 1993 combustion turbine which produces a benefit-to-cost ratio of 1.2 to 1. In addition, the negotiated values are reasonable based on the embedded cost standards preferred by FIPUG and Occidental. The Parties further agree that the stipulation with respect to these credits is for settlement purposes only, shall have no precedential value, and shall be without prejudice to the right and opportunity of Parties to present and argue the rate design considerations and rate levels they deem to be appropriate for non-firm rates in future rate proceedings before this Commission. (Issues 121, 147, 148, 149, 151)

4. The Parties stipulate to the approval of interruptible and curtailable service as demand-side management (DSM) programs with authorized recovery of the credit through the Company's Energy Conservation Cost Recovery (ECCR) clause as a program cost. (Issues 146, 153)

5. The ECCR expenses associated with load management, interruptible and curtailable programs (including the interruptible and curtailable credits for the period of November [*171] 1992 through March 1993, which will be included in the ECCR true-up provision, and all other similar future dispatchable DSM programs) will be allocated to rate classes based on the methodology currently employed in the Capacity Cost Recovery mechanism of the Fuel and Purchased Power Cost Recovery clause, beginning with the six-month period of April through September, 1993. (Issue 153)

6. The credits for interruptible and curtailable service will be distributed based on the interruptible and curtailable customers' billing KW for the standard rate and the customers' on-peak billing KW for the time-of-use rate. Expressed on a billing KW basis, the credits for interruptible and curtailable service are $ 3.37 and $ 2.33 per billing KW, respectively. (Issue 152)

7. The interruptible rate will be stated at secondary voltage in order to make this rate consistent with the statement of the Company's other rates. The Demand charge for the interruptible and curtailable service will include the classes unit costs for Transmission Plant and Distribution Plant developed from the cost of service study, plus the absolute amount of the credit per billing KW for interruptible and curtailable [*172] service, respectively. (Issues 135, 154)

8. The curtailable class will be treated as a separate rate class with rates designed to produce the revenue requirements of that class identified in the cost of service study. Curtailable service will be limited to those customers who agree to curtail the greater of 25 KW or 25% of their maximum annual billing KW. (Issue 136)

9. The interruptible and curtailable credits will remain fixed at the level established in paragraphs 3 and 6 above until the Company's next rate case. (Issue 150)

10. The Company's proposed "Purchase Power" special provision contained in the interruptible and curtailable rate schedules shall be modified such that the customer will pay the actual purchase power cost in lieu of the otherwise applicable energy charges (including fuel charges), plus 3 mills. In addition, the Company will attempt to develop a procedure which provides the customer with real-time estimates of the cost of such purchases. (Issues 155, 156)

11. The Company commits to designing and proposing at least two additional interruptible rates as DSM programs for Commission approval, based on the criteria that the programs are beneficial to [*173] both the general body of ratepayers and the Company. (Issue 124)

12. (a) The Company's proposed general service rate structure, which allows general service customers with annual consumption of 24,000 KWH or greater to opt for the rate schedule (GS-1 or GSD-1) most cost effective for them and which eliminates mandatory demand billing, minimum billing demands, optional transition rates, the municipal transition rate, and the general service large demand rate (GSLD-1), is accepted. In addition, the customer migration identified in Exhibits 38 and 39 and in Attachment 1 and 2 hereto is accepted for establishing rates and revenues for the general service class. (Issues 123, 125, 126, 127, 144, 145)

(b) The general service demand and energy charges will be set such that the combination of the two charges closely tracks the general service cost curve which produces the revenue requirements established from the cost of service study. (Issue 134)

(c) The general service non-demand rates (GS-1 and GST-1) will provide only a metering voltage adjustment of 1% for distribution primary delivery and 2% for transmission delivery. (Issue 139)

13. The Standby rates (SS-1, SS-2, SS-3) [*174] will be developed from the final cost of service study consistent with the methodology contained in the Commission's standby rate Order No. 17159 in Docket No. 850673-EU. (Issues 157, 158)

14. The rate design for all Time-Of-Use (TOU) rates will set the off-peak energy rate at the average system energy component from the cost of service study (approximately 0.580 cents per KWH). The on-peak charge will then be the result of a break even calculation with the standard rate, based on the rate class's or combined rate classes' on-peak and off-peak energy consumption. (The combined classes will be the RS-1 and GS-1 classes and GSD-1 and GSLD-1 classes; the CS-1 class and IS-1 class will be individual classes.) For Demand TOU rates, a demand charge equivalent to 1/2 of the unit cost for Distribution Plant will be applicable to the customer's maximum measured demand. The on-peak demand charge shall include the on-peak unit cost for Transmission Plant and 1/2 of the on-peak unit cost for Distribution Plant. The on-peak demand charge for interruptible and curtailable TOU rates shall also include the absolute amount of the credit per billing KW for interruptible and curtailable service, [*175] respectively. (Issue 131)

15. The Parties agree that for purposes of apportioning among rate classes matters for which an individual rate class's share is dependent upon the revenues of the rate class relative to the overall total revenues, the nonfirm rate classes' allocators will be based on the difference between the firm base reve-

nue requirements and the nonfirm credits paid to these rate classes for DSM programs (RSL-1, GSLM-1, CS-1, IS-1). (Issue 159)

16. (a) The allocation of the rate increase among the classes will be determined by the cost of service study which incorporates all Commission decisions on issues affecting the Company's revenue requirements. (Issue 128)

(b) The Company's method for calculating the increase in unbilled revenues by rate class identified in MFR Schedule E-15 is appropriate. (Issue 129)

(c) The appropriate service charges are as follows:

Service	1992	1993
Initial Service	$ 24.50	$ 30.50
Re-establishment of service with field trip	$ 14.50	$ 15.00
Transfer of account	$ 5.50	$ 5.50
Reconnection for nonpayment	$ 25.50	$ 27.00
Temporary Service	$ 71.00	$ 74.00

(Issue 130)

(d) The customer charges will be designed [*176] to produce the customer cost component from the cost of service study. For the general service rates (GS-1 and GSD-1) the customer charges will be stated by voltage delivery. For unmetered general service accounts, the customer charge will be based on average unit cost excluding metering investment (approximately $ 6.25). For all time of use rates except CST-1 and IST-1, the customer charge will reflect the average additional TOU metering costs (approximately $ 7.50). For the curtailable service rates (CS-1 and CST-1), the customer charge will be the customer charges contained in the general service rates plus the additional costs for hourly metering (approximately $ 65). For the interruptible service rates (IS-1 and IST-1), the customer charge will be the customer charges contained in the general service rates plus the additional costs for hourly metering and interruptible equipment (approximately $ 270). For the Lighting service rate (LS-1) the unmetered customer charge shall be based on lines of billing, with an additional charge for metered accounts to reflect the average cost of metering investment (approximately $ 2.25). (Issue 132)

(e) The appropriate contribution in [*177] aid of construction for time of use customers opting to make a lump sum meter payment is $ 258 for single-phase service and $ 393 for three-phase service. (Issue 133)

(f) The delivery voltage credits will be 30 cents per KW of billing demand for distribution primary delivery voltage and 69 cents per KW of billing demand for transmission delivery voltage. (Issue 137)

(g) The metering voltage credits will be 1% for distribution primary delivery and 2% for transmission delivery. (Issue 138)

17. The Company's proposed Lighting rate schedule LS-1 is accepted subject to Commission approved revenue requirements for the lighting class developed from the cost of service study, provided that proposed special provision No. 9 shall be eliminated and proposed special provision No. 7 shall be modified to eliminate the requirement of written notification. The methodology used in Attachment No. 3 of this stipulation will be used to develop final fixture and maintenance charges. The monthly fixed carrying charge for poles of a type not listed in rate schedule LS-1, and for distribution equipment that the Company may optionally provide to a customer under any rate schedule shall be 1.67 percent [*178] of the installed cost. (Issues 140, 141, 142, 143)

18. The term "cost of service study" as used herein is intended by the Parties to refer to a compliance cost of service study prepared by the Company which incorporates the Commission's decisions on all issues in this proceeding affecting the Company's revenue requirements or billing determinants. The Parties recognize, however, that due to the timing of the Commission's decisions, such final compliance cost of service study may not be available for such use. In that event, the Parties intend that the cost of service study prepared by the Company based on Staff's recommendations regarding revenue requirements issues, as adjusted by Staff to reflect the Commission's decisions, will be used.

19. Nothing in this stipulation is intended to preclude the Commission from using the Company's updated sales forecast, identified as Exhibit 148. In the event the Commission determines that the updated sales forecast should be utilized, this stipulation shall be modified as necessary to incorporate the effects of the updated sales forecast on the provisions hereof.

20. Each of the provisions set forth in paragraphs 1 through 19 above [*179] have been negotiated as essential, interdependent components to a comprehensive settlement of the cost of service and rate design issues in this proceeding and, therefore, collectively constitute a single stipulation between the Parties. As such, the Parties agree that if this stipulation is not approved by the Commission in its entirety, it shall be null and void and of no binding effect on the Parties. The Parties further agree that this stipulation is for settlement purposes only, shall have no precedential value, and shall be without prejudice to the right and opportunity of the Parties to present and argue the cost of service and rate design considerations and rate levels they deem to be appropriate in future rate proceedings before this Commission.

Dated: July 22, 1992.

FLORIDA POWER CORPORATION

By James A. McGee

Office of the General Counsel

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OCCIDENTAL CHEMICAL CORPORATION

By Zori G. Ferkin

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AD HOC COMMITTEE OF LOCAL GOVERNMENTS

By Robert R. Morrow

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ATTACHMENT 3

SPREADSHEET OF APPROVED RATES

RATE COMPARISON BASED ON APPROVED REVENUE REQUIREMENTS

	1992 Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge	$ 5.32	$ 8.50	$ 8.50
Standard			
TOU			
Company owned	$ 8.36	$ 16.00	$ 16.00
Customer owned	$ 5.32	$ 8.50	$ 8.50
KWH Charge (Cents/KWH)			
Standard	3.964	4.138	3.841
TOU			
On-peak	11.118	11.875	10.857
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$ 5.32	$ 11.50	$ 11.50
Primary		$ 145.00	$ 145.00
Transmission		$ 720.00	$ 720.00
Unmetered	$ 2.61	$ 6.25	$ 6.25
TOU			
Secondary single phase			
Company owned	$ 8.36	$ 19.00	$ 19.00
Customer owned	$ 5.32	$ 11.50	$ 11.50
Secondary Three phase	$ 9.83	$ 25.00	$ 25.00
Primary (cust. own)	$ 15.46	$ 145.00	$ 145.00
Primary (co. own)	$ 19.98	$ 152.50	$ 152.50
KWH Charge (cents/KWH)			
Standard	3.964	4.138	3.841
TOU			
On-peak	10.707	11.875	10.857
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$ 15.46	$ 11.50	$ 11.50
Primary	$ 15.46	$ 145.00	$ 145.00
Transmission	$ 720.00	$ 720.00	$ 720.00
TOU			
Secondary single phase			
Company owned	$ 15.46	$ 19.00	$ 19.00
Customer owned	$ 15.46	$ 11.50	$ 11.50
Primary (cust. own)	$ 15.46	$ 145.00	$ 145.00
Primary (co. own)	$ 19.98	$ 152.50	$ 152.50

	1992 Current Rates	FPC Proposed	Commission Approved
KWH Charge			
Standard	1.307	1.702	1.606
TOU			
On-peak	1.396	4.396	4.503
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 3.50	$ 3.50
TOU			
On-peak	$ 5.45	$ 2.59	$ 2.59
Maximum demand		$ 0.91	$ 0.91

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RATE COMPARISON

1992

	Current Rates	FPC Proposed	Commission Approved
GS-2			
Customer Charge			
Metered	$ 2.61	$ 6.25	$ 6.25
Unmetered	$ 5.32	$ 11.50	$ 11.50
KWH Charge (cents/KWH)	3.003	2.150	1.431
Curtailable			
Customer Charge			
Standard			
Secondary	$ 152.49	$ 210.00	$ 210.00
Primary	$ 152.49	$ 210.00	$ 210.00
Transmission	$ 152.49	$ 785.00	$ 785.00
TOU			
Primary (co. own)	$ 152.49	$ 210.00	$ 210.00
Transmission(co. own)	$ 152.49	$ 785.00	$ 785.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.026
TOU			
On-peak	2.068	2.342	2.139
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 5.83	$ 5.83
TOU			
On-peak	$ 5.45	$ 5.14	$ 5.14
Maximum demand	na	$ 0.93	$ 0.93
Curtailable credit	$ 1.91	$ 2.33	$ 2.33
Interruptible			
Customer Charge			
Standard			
Primary	$ 413.91	$ 41.500	$ 415.00
Primary/Transmission	$ 413.91	$ 415.00	$ 415.00
Transmission	$ 413.91	$ 990.00	$ 990.00
TOU			
Primary	$ 413.91	$ 415.00	$ 415.00
Primary/Transmission	$ 413.91	$ 415.00	$ 415.00
Transmission	$ 413.91	$ 990.00	$ 990.00

	Current Rates	FPC Proposed	Commission Approved
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.608
TOU			
On-peak	1.497	1.239	1.154
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$ 1.09	$ 5.14	$ 5.14
TOU			
On-peak	$ 1.09	$ 4.51	$ 4.51
Maximum demand		$ 0.80	$ 0.80
Credit per stipulation		$ 3.37	$ 3.37
Standby (SS-1)			
Customer charge			
Standard			
Primary	$ 174.28	$ 235.00	$ 235.00
Transmission	$ 174.28	$ 810.00	$ 810.00
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.10	$ 1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.91	$ 0.80	$ 0.80
Daily Demand	$ 0.44	$ 0.38	$ 0.38
Transmission			
Specified SB Cap	$ 0.91	$ 0.80	$ 0.80
Daily Demand	$ 0.44	$ 0.38	$ 0.38
Energy			
Standard			
Primary	5.590	7.210	7.210
Transmission	5.590	7.210	7.210
Standby (SS-2)			
Customer charge			
Standard			
Primary	$ 435.69	$ 440.00	$ 440.00
Transmission	$ 435.69	$ 1015.00	$ 1015.00
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.03	$ 1.10	$ 1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.23	$ 0.80	$ 0.80
Daily Demand	$ 0.11	$ 0.38	$ 0.38
Transmission			
Specified SB Cap	$ 0.23	$ 0.80	$ 0.80
Daily Demand	$ 0.11	$ 0.38	$ 0.38
Energy			
Standard			
Primary	5.470	7.210	7.210
Transmission	5.470	7.210	7.210

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-3)			
Customer charge			
Standard			
Primary	$ 174.28	$ 235.00	$ 235.00
Transmission	$ 174.28	$ 810.00	$ 810.00
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.10	$ 1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.72	$ 0.80	$ 0.80
Daily Demand	$ 0.34	$ 0.38	$ 0.38
Transmission			
Specified SB Cap	$ 0.72	$ 0.80	$ 0.80
Daily Demand	$ 0.34	$ 0.38	$ 0.38
Energy			
Standard			
Primary	5.590	7.210	7.210
Transmission	5.590	7.210	7.210

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RATE COMPARISON

April 1993

	Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge	$ 5.32	$ 8.85	$ 8.85
Standard			
TOU			
Company owned	$ 8.36	$ 16.35	$ 16.35
Customer owned	$ 5.32	$ 8.85	$ 8.85
KWH Charge (Cents/KWH)			
Standard	3.964	4.154	3.856
TOU			
On-peak	11.118	11.926	10.879
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$ 5.32	$ 11.70	$ 11.70
Primary		$ 148.00	$ 148.00
Transmission		$ 730.00	$ 730.00
Unmetered	$ 2.61	$ 6.60	$ 6.60
TOU			
Secondary single phase			
Company owned	$ 8.36	$ 19.20	$ 19.20
Customer owned	$ 5.32	$ 11.70	$ 11.70
Secondary Three phase	$ 9.83	$ 25.20	$ 25.20
Primary (cust. own)	$ 15.46	$ 148.00	$ 148.00
Primary (co. own)	$ 19.98	$ 155.50	$ 155.50
KWH Charge (cents/KWH)			
Standard	3.964	4.154	3.856

	Current Rates	FPC Proposed	Commission Approved
TOU			
On-peak	10.707	11.926	10.879
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$ 15.46	$ 11.70	$ 11.70
Primary	$ 15.46	$ 148.00	$ 148.00
Transmission		$ 730.00	$ 730.00
TOU			
Secondary single phase			
Company owned	$ 15.46	$ 19.20	$ 19.20
Customer owned	$ 15.46	$ 11.70	$ 11.70
Primary (cust. own)	$ 15.46	$ 148.00	$ 148.00
Primary (co. own)	$ 19.98	$ 155.50	$ 155.50
KWH Charge (cents/KWH)			
Standard	1.307	1.702	1.612
TOU			
On-peak	1.396	4.396	4.496
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 3.54	$ 3.54
TOU			
On-peak	$ 5.45	$ 2.63	$ 2.63
Maximum demand		$ 0.91	$ 0.91
GS-2			
Customer Charge			
Metered	$ 2.61	$ 6.60	$ 6.60
Unmetered	$ 5.32	$ 11.70	$ 11.70
KWH Charge (cents/KWH)	3.003	2.150	1.450
Curtailable			
Customer Charge			
Standard			
Secondary	$ 152.49	$ 213.00	$ 213.00
Primary	$ 152.49	$ 213.00	$ 213.00
Transmission	$ 152.49	$ 795.00	$ 795.00
TOU			
Primary (co. own)	$ 152.49	$ 213.00	$ 213.00
Transmission(co. own)	$ 152.49	$ 795.00	$ 795.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.057
TOU			
On-peak	2.068	2.342	2.245
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 5.87	$ 5.87
TOU			
On-peak	$ 5.45	$ 5.15	$ 5.15
Maximum demand	na	$ 0.97	$ 0.97
Curtailable credit	$ 1.91	$ 2.33	$ 2.33

	Current Rates	FPC Proposed	Commission Approved
Interruptible			
Customer Charge			
Standard			
Primary	$ 413.91	$ 418.00	$ 418.00
Primary/Transmission	$ 413.91	$ 418.00	$ 418.00
Transmission	$ 413.91	$ 1000.00	$ 1000.00
TOU			
Primary	$ 413.91	$ 418.00	$ 418.00
Primary/Transmission	$ 413.91	$ 418.00	$ 418.00
Transmission	$ 413.91	$ 1000.00	$ 1000.00
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.624
TOU			
On-peak	1.497	1.239	1.275
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$ 1.09	$ 5.23	$ 5.23
TOU			
On-peak	$ 1.09	$ 4.53	$ 4.53
Maximum demand		$ 0.84	$ 0.84
Credit per stipulation		$ 3.37	$ 3.37
Standby (SS-1)			
Customer charge			
Standard			
Primary	$ 174.28	$ 238.00	$ 238.00
Transmission	$ 174.28	$ 820.00	$ 820.00
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.91	$ 0.83	$ 0.83
Daily Demand	$ 0.44	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.91	$ 0.83	$ 0.83
Daily Demand	$ 0.44	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970
Standby (SS-2)			
Customer charge			
Standard			
Primary	$ 435.69	$ 443.80	$ 443.80
Transmission	$ 435.69	$ 1025.00	$ 1028.80
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.03	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			

	Current Rates	FPC Proposed	Commission Approved
Specified SB Cap	$ 0.23	$ 0.83	$ 0.83
Daily Demand	$ 0.11	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.23	$ 0.83	$ 0.83
Daily Demand	$ 0.11	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.470	6.970	6.970
Transmission	5.470	6.970	6.970
Standby (SS-3)			
Customer charge			
Standard			
Primary	$ 174.28	$ 238.00	$ 238.80
Transmission	$ 174.28	$ 820.00	$ 820.80
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.72	$ 0.83	$ 0.83
Daily Demand	$ 0.34	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.72	$ 0.83	$ 0.83
Daily Demand	$ 0.34	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970

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RATE COMPARISON

November 1993

	Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge	$ 5.32	$ 8.85	$ 8.85
Standard			
TOU			
Company owned	$ 8.36	$ 16.35	$ 16.35
Customer owned	$ 5.32	$ 8.85	$ 8.85
KWH Charge (Cents/KWH)			
Standard	3.964	4.396	3.941
TOU			
On-peak	11.118	12.272	11.134
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$ 5.32	$ 11.70	$ 11.70
Primary		$ 148.00	$ 148.00
Transmission		$ 730.00	$ 730.00

	Current Rates	FPC Proposed	Commission Approved
Unmetered	$ 2.61	$ 6.60	$ 6.60
TOU			
Secondary single phase			
Company owned	$ 8.36	$ 19.20	$ 19.20
Customer owned	$ 5.32	$ 11.70	$ 11.70
Secondary Three phase	$ 9.83	$ 25.20	$ 25.20
Primary (cust. own)	$ 15.46	$ 148.00	$ 148.00
Primary (co. own)	$ 19.98	$ 155.50	$ 155.50
KWH Charge (cents/KWH)			
Standard	3.964	4.396	3.941
TOU			
On-peak	10.707	12.272	11.134
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$ 15.46	$ 11.70	$ 11.70
Primary	$ 15.46	$ 148.00	$ 148.00
Transmission		$ 730.00	$ 730.00
TOU			
Secondary single phase			
Company owned	$ 15.46	$ 19.20	$ 19.20
Customer owned	$ 15.46	$ 11.70	$ 11.70
Primary (cust. own)	$ 15.46	$ 148.00	$ 148.00
Primary (co. own)	$ 19.98	$ 155.50	$ 155.50
KWH Charge (cents/KWH)			
Standard	1.307	1.702	1.600
TOU			
On-peak	1.396	4.396	4.457
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 3.80	$ 3.80
TOU			
On-peak	$ 5.45	$ 2.81	$ 2.81
Maximum demand		$ 1.00	$ 1.00
GS-2			
Customer Charge			
Metered	$ 2.61	$ 6.60	$ 6.60
Unmetered	$ 5.32	$ 11.70	$ 11.70
KWH Charge (cents/KWH)	3.003	2.206	1.497
Curtailable			
Customer Charge			
Standard			
Secondary	$ 152.49	$ 213.00	$ 213.50
Primary	$ 152.49	$ 213.00	$ 213.00
Transmission	$ 152.49	$ 795.00	$ 795.00
TOU			
Primary (co. own)	$ 152.49	$ 213.00	$ 213.00
Transmission(co. own)	$ 152.49	$ 795.00	$ 795.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.049

	Current Rates	FPC Proposed	Commission Approved
TOU			
On-peak	2.068	2.342	2.221
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$ 5.45	$ 6.13	$ 6.13
TOU			
On-peak	$ 5.45	$ 5.41	$ 5.41
Maximum demand	na	$ 0.97	$ 0.97
Curtailable credit	$ 1.91	$ 2.33	$ 2.33
Interruptible			
Customer Charge			
Standard			
Primary	$ 413.91	$ 418.00	$ 418.00
Primary/Transmission	$ 413.91	$ 418.00	$ 418.00
Transmission	$ 413.91	$ 1000.00	$ 1000.00
TOU			
Primary	$ 413.91	$ 418.00	$ 418.00
Primary/Transmission	$ 413.91	$ 418.00	$ 418.00
Transmission	$ 413.91	$ 1000.00	$ 1000.00
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.663
TOU			
On-peak	1.497	1.239	1.445
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$ 1.09	$ 5.23	$ 5.23
TOU			
On-peak	$ 1.09	$ 4.53	$ 4.53
Maximum demand		$ 0.84	$ 0.84
Credit per stipulation		$ 3.37	$ 3.37
Standby (SS-1)			
Customer charge			
Standard			
Primary	$ 174.28	$ 238.00	$ 238.00
Transmission	$ 174.28	$ 820.00	$ 820.00
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.91	$ 0.83	$ 0.83
Daily Demand	$ 0.44	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.91	$ 0.83	$ 0.83
Daily Demand	$ 0.44	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970

Standby (SS-2)

	Current Rates	FPC Proposed	Commission Approved
Customer charge			
Standard			
Primary	$ 435.69	$ 443.80	$ 443.80
Transmission	$ 435.69	$ 1025.00	$ 1028.80
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.03	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.23	$ 0.83	$ 0.83
Daily Demand	$ 0.11	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.23	$ 0.83	$ 0.83
Daily Demand	$ 0.11	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.470	6.970	6.970
Transmission	5.470	6.970	6.970
Standby (SS-3)			
Customer charge			
Standard			
Primary	$ 174.28	$ 238.00	$ 238.80
Transmission	$ 174.28	$ 820.00	$ 820.80
Demand Charge			
Local Transmission/Dist.			
Primary	$ 1.06	$ 1.18	$ 1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$ 0.72	$ 0.83	$ 0.83
Daily Demand	$ 0.34	$ 0.40	$ 0.40
Transmission			
Specified SB Cap	$ 0.72	$ 0.83	$ 0.83
Daily Demand	$ 0.34	$ 0.40	$ 0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970

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FLORIDA POWER CORPORATION

RATE SCHEDULE LS-1 LIGHTING SERVICE

1992 FINAL RATES

NON-FUEL ENERGY CHARGE: $ 0.01548 PER KWH

CUSTOMER CHARGES

UNMETERED: $ 1.13 PER LINE OF BILLING

METERED: $ 3.38 PER LINE OF BILLING

MONTHLY FIXED CARRYING CHARGES

FIXTURES: 1.67% OF INSTALLED COST

POLES AND OTHER DIST. EQUIP.: 1.43% OF INSTALLED COST

BILLING NO.	TYPE OF FACILITY	LUMENS	EST. KWH	FIXTURE CHARGE	MAINT. CHARGE	ENERGY CHARGE	TOTAL CHARGE
INCANDESCENT							
110	ROADWAY	1,000	32	$ 0.92	$ 3.29	$ 0.50	$ 4.71
115	ROADWAY	2,500	66	$ 1.45	$ 3.33	$ 1.02	$ 5.80
MERCURY VAPOR							
205	OPEN BOTTOM	4,000	44	$ 2.29	$ 0.93	$ 0.68	$ 3.90
210	ROADWAY	4,000	44	$ 2.65	$ 0.93	$ 0.68	$ 4.26
215	POST TOP	4,000	44	$ 3.12	$ 0.93	$ 0.68	$ 4.73
220	ROADWAY	8,000	71	$ 3.00	$ 0.92	$ 1.10	$ 5.02
235	ROADWAY	21,000	158	$ 3.63	$ 0.95	$ 2.45	$ 7.03
240	ROADWAY	62,000	386	$ 4.76	$ 1.10	$ 5.98	$ 11.84
245	FLOOD	21,000	158	$ 4.76	$ 0.95	$ 2.45	$ 8.16
250	FLOOD	62,000	386	$ 5.57	$ 1.10	$ 5.98	$ 12.65
SODIUM VAPOR							
305	OPEN BOTTOM	4,000	21	$ 1.99	$ 1.28	$ 0.33	$ 3.60
310	ROADWAY	4,000	21	$ 2.44	$ 1.28	$ 0.33	$ 4.05
315	P.T. COL/CONTP	4,000	21	$ 3.71	$ 1.28	$ 0.33	$ 5.32
320	ROADWAY	9,500	42	$ 2.47	$ 1.28	$ 0.65	$ 4.40
325	ROADWAY	16,000	65	$ 2.57	$ 1.30	$ 1.01	$ 4.88
330	ROADWAY	22,000	87	$ 2.84	$ 1.32	$ 1.35	$ 5.51
335	ROADWAY	27,500	104	$ 2.82	$ 1.32	$ 1.61	$ 5.75
340	ROADWAY	50,000	169	$ 3.42	$ 1.33	$ 2.62	$ 7.37
345	FLOOD	27,500	103	$ 3.65	$ 1.32	$ 1.59	$ 6.56
350	FLOOD	50,000	170	$ 3.81	$ 1.33	$ 2.63	$ 7.77
360	DECO ROADWAY RECT.	9,500	47	$ 8.51	$ 1.28	$ 0.73	$ 10.52
365	DECO ROADWAY RECT.	27,500	108	$ 8.51	$ 1.32	$ 1.67	$ 11.50
370	DECO ROADWAY RND.	27,500	108	$ 10.47	$ 1.32	$ 1.67	$ 13.46
375	DECO ROADWAY RND.	50,000	168	$ 10.48	$ 1.33	$ 2.60	$ 14.41
380	DECO P.T. ACORN	9,500	49	$ 5.97	$ 1.28	$ 0.76	$ 8.01
385	DECO P.T. SALEM	9,500	49	$ 5.63	$ 1.28	$ 0.76	$ 7.67

[*185]

POLES

BILLING NO.	DESCRIPTION	MONTHLY CHARGE
425	Wood, 14' Laminated	$ 1.51
420	Wood, 30/35'	$ 1.51
480	Wood, 40/45'	$ 3.37
415	Concrete, Curved	$ 4.12
450	Concrete, 1/2 Special	$ 1.51
410	Concrete, 15'	$ 2.00
405	Concrete, 30/35'	$ 3.04
485	Concrete, 40/45'	$ 8.32
435	Aluminum, Type A	$ 5.70
440	Aluminum, Type B	$ 6.34
445	Aluminum, Type C	$ 12.39
455	Steel, Type A	$ 3.56
460	Steel, Type B	$ 3.81
465	Steel, Type C	$ 5.33
430	Fiberglass, 14' Black	$ 1.51
437	Fiberglass, 16' Black, Fluted, Dual Mount	$ 18.98
449	Deco Fiberglass, 16' Black, Fluted, AB	$ 15.00

POLES

BILLING NO.	DESCRIPTION	MONTHLY CHARGE
436	Deco Fiberglass, 16' Black, Fluted	$ 16.86
438	Deco Fiberglass, 20' Black	$ 5.06
434	Deco Fiberglass, 20' Black, Deco Base	$ 10.59
446	Deco Fiberglass, 35' Bronze	$ 10.00
433	Deco Fiberglass, 35' Bronze	$ 9.61
432	Deco Fiberglass, 35' Bronze, Anchor Base	$ 23.69
428	Deco Fiberglass, 35' Bronze, Reinforced	$ 16.52
447	Deco Fiberglass, 35' Silver, Anchor Base	$ 18.51
431	Deco Fiberglass, 40' Bronze	$ 12.93
429	Deco Fiberglass, 40' Bronze, Reinforced	$ 18.94
448	Deco Fiberglass, 41' Silver, Anchor Base	$ 15.55

[*186]

FLORIDA POWER CORPORATION

RATE SCHEDULE LS-1 LIGHTING SERVICE

APRIL AND NOVEMBER 1993 FINAL RATES

NON-FUEL ENERGY CHARGE: $ 0.01591 PER KWH

CUSTOMER CHARGES

UNMETERED $ 1.20 PER LINE OF BILLING

METERED: $ 3.45 PER LINE OF BILLING

MONTHLY FIXED CARRYING CHARGES

FIXTURES: 1.67% OF INSTALLED COST

POLES AND OTHER DIST. EQUIP.: 1.46% OF INSTALLED COST

BILLING NO.	TYPE OF FACILITY	LUMENS	EST. KWH	FIXTURE CHARGE	MAINT. CHARGE	ENERGY CHARGE	TOTAL CHARGE
INCANDESCENT							
110	ROADWAY	1,000	32	$ 0.94	$ 3.29	$ 0.51	$ 4.74
115	ROADWAY	2,500	66	$ 1.48	$ 3.33	$ 1.05	$ 5.86
MERCURY VAPOR							
205	OPEN BOTTOM	4,000	44	$ 2.34	$ 0.93	$ 0.70	$ 3.97
210	ROADWAY	4,000	44	$ 2.70	$ 0.93	$ 0.70	$ 4.33
215	POST TOP	4,000	44	$ 3.18	$ 0.93	$ 0.70	$ 4.81
220	ROADWAY	8,000	71	$ 3.06	$ 0.92	$ 1.13	$ 5.11
235	ROADWAY	21,000	158	$ 3.70	$ 0.95	$ 2.51	$ 7.16
240	ROADWAY	62,000	386	$ 4.85	$ 1.10	$ 6.14	$ 12.09
245	FLOOD	21,000	158	$ 4.85	$ 0.95	$ 2.51	$ 8.31
250	FLOOD	62,000	386	$ 5.68	$ 1.10	$ 6.14	$ 12.92
SODIUM VAPOR							
305	OPEN BOTTOM	4,000	21	$ 2.03	$ 1.28	$ 0.33	$ 3.64
310	ROADWAY	4,000	21	$ 2.49	$ 1.28	$ 0.33	$ 4.10
315	P.T. COL/CONTP	4,000	21	$ 3.78	$ 1.28	$ 0.33	$ 5.39
320	ROADWAY	9,500	42	$ 2.52	$ 1.28	$ 0.67	$ 4.47
325	ROADWAY	16,000	65	$ 2.62	$ 1.30	$ 1.03	$ 4.95
330	ROADWAY	22,000	87	$ 2.90	$ 1.32	$ 1.38	$ 5.60
335	ROADWAY	27,500	104	$ 2.88	$ 1.32	$ 1.65	$ 5.85
340	ROADWAY	50,000	169	$ 3.49	$ 1.33	$ 2.69	$ 7.51
345	FLOOD	27,500	103	$ 3.72	$ 1.32	$ 1.64	$ 6.68

BILLING NO.	TYPE OF FACILITY	LUMENS	EST. KWH	FIXTURE CHARGE	MAINT. CHARGE	ENERGY CHARGE	TOTAL CHARGE
350	FLOOD	50,000	170	$ 3.89	$ 1.33	$ 2.70	$ 7.92
360	DECO ROADWAY RECT.	9,500	47	$ 8.68	$ 1.28	$ 0.75	$ 10.71
365	DECO ROADWAY RECT.	27,500	108	$ 8.68	$ 1.32	$ 1.72	$ 11.72
370	DECO ROADWAY RND.	27,500	108	$ 10.68	$ 1.32	$ 1.72	$ 13.72
375	DECO ROADWAY RND.	50,000	168	$ 10.69	$ 1.33	$ 2.67	$ 14.69
380	DECO P.T. ACORN	9,500	49	$ 6.09	$ 1.28	$ 0.78	$ 8.15
385	DECO P.T. SALEM	9,500	49	$ 5.74	$ 1.28	$ 0.78	$ 7.80

[*187]

POLES

BILLING NO.	DESCRIPTION	MONTHLY CHARGE
425	Wood, 14' Laminated	$ 1.60
420	Wood, 30/35'	$ 1.60
480	Wood, 40/45'	$ 3.57
415	Concrete, Curved	$ 4.37
450	Concrete, 1/2 Special	$ 1.60
410	Concrete, 15'	$ 2.12
405	Concrete, 30/35'	$ 3.22
485	Concrete, 40/45'	$ 8.82
435	Aluminum, Type A	$ 6.04
440	Aluminum, Type B	$ 6.72
445	Aluminum, Type C	$ 13.13
455	Steel, Type A	$ 3.77
460	Steel, Type B	$ 4.04
465	Steel, Type C	$ 5.65
430	Fiberglass, 14' Black	$ 1.60
437	Fiberglass, 16' Black, Fluted, Dual Mount	$ 20.11
449	Deco Fiberglass, 16' Black, Fluted, AB	$ 15.90
436	Deco Fiberglass, 16' Black, Fluted	$ 17.87
438	Deco Fiberglass, 20' Black	$ 5.36
434	Deco Fiberglass, 20' Black, Deco Base	$ 11.22
446	Deco Fiberglass, 35' Bronze	$ 10.60
433	Deco Fiberglass, 35' Bronze	$ 10.18
432	Deco Fiberglass, 35' Bronze, Anchor Base	$ 25.19
428	Deco Fiberglass, 35' Bronze, Reinforced	$ 17.51
447	Deco Fiberglass, 35' Silver, Anchor Base	$ 19.61
431	Deco Fiberglass, 40' Bronze	$ 13.70
429	Deco Fiberglass, 40' Bronze, Reinforced	$ 20.07
448	Deco Fiberglass, 41' Silver, Anchor Base	$ 16.50

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Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawAdministrative ProceedingsPublic Utility CommissionsGeneral OverviewEnergy & Utilities LawAdministrative ProceedingsU.S. Federal Energy Regulatory CommissionGeneral OverviewEnergy & Utilities LawUtility Companies-RatesRatemaking FactorsRate Base

LexisNexis

LEXSEE 218 PUR 4TH 205

In re: Request for rate increase by Gulf Power Company.

DOCKET NO. 010949-EI; ORDER NO. PSC-02-0787-FOF-EI

Florida Public Service Commission

2002 Fla. PUC LEXIS 419; 218 P.U.R.4th 205

02 FPSC 6:97

June 10, 2002, Issued

DISPOSITION: [*1] ORDER GRANTING IN PART AND DENYING IN PART GULF POWER COMPANY'S PETITION FOR RATE INCREASE

APPEARANCES: JEFFREY A. STONE, Esquire, RUSSELL A. BADDERS, Esquire, and R. ANDREW KENT of Beggs & Lane, Pensacola, Florida and RICHARD D. MELSON, Esquire of Hopping Green & Sams, P.A., Tallahassee, Florida On behalf of Gulf Power Company.

ALLEN ERICKSON, Major DOUGLAS A. SHROPSHIRE, Lieutenant Colonel, USAFR, c/o USAF Utility Litigation Team AFCESA/ULT, Tyndall AFB, Florida On behalf of Federal Executive Agencies.

MICHAEL A. GROSS, Vice President, Regulatory Affairs & Regulatory Counsel, Tallahassee, Florida On behalf of Florida Cable Telecommunications Association.

JOHN W. MCWHIRTER, JR., McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P.A., Tampa, Florida and VICKI GORDON KAUFMAN and TIMOTHY J. PERRY, McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P.A., Tallahassee, Florida On behalf of the Florida Industrial Power Users Group.

STEPHEN C. BURGESS, Esquire, Deputy Public Counsel, Office of Public Counsel, c/o The Florida Legislature, Tallahassee, Florida On behalf of the Citizens of the State of Florida.

MARLENE K. STERN, Esquire, ROBERT V. [*2] ELIAS, Esquire, LAWRENCE D. HARRIS, Esquire, and LORENA ESPINOZA, Esquire, Florida Public Service Commission, Tallahassee, Florida On behalf of the Commission.

PANEL: The following Commissioners participated in the disposition of this matter: LILA A. JABER, Chairman; J. TERRY DEASON; BRAULIO L. BAEZ; MICHAEL A. PALECKI; RUDOLPH "RUDY" BRADLEY

OPINIONBY: BAYO

OPINION: BY THE COMMISSION:

I. CASE BACKGROUND

On September 10, 2001, Gulf Power Company (Gulf or Company) filed a petition for a permanent rate increase. Gulf requested an increase in its retail rates and charges designed to generate $ 69,867,000 in additional gross annual revenues which would allow the Company to earn an overall rate of return of 8.64% or a 13.00% return on equity (range of 12.00% to 14.00%). This request was based upon a projected June 2002 through May 2003 test year and a 13-month average jurisdictional rate base of $ 1,198,502,000. The Company filed new rate schedules reflecting the proposed increases. The most significant basis for the requested increase was the addition of Smith Unit 3, a 574 megawatt gas fired combined cycle generating unit along with the associated operation and maintenance (O&M) expenses. Other significant [*3] factors included the addition since the last rate case of 100,000 new customers; 1,400 miles of new distribution lines; and 90 miles of new transmission lines; the replacement and repair of an aging electrical infrastructure; and the increased O&M costs associated with aging generating plants.

Pursuant to Order No. PSC-99-2131-S-EI, issued October 28, 1999, in Docket Nos. 990250-EI and 990947-EI, the Commission approved a stipulation that established a revenue sharing plan. Included in the stipulation was a provision whereby Gulf could not request an increase in base rates before the earlier of the commercial in-service date for Smith Unit 3 or December 31, 2002, the expiration date of the Stipulation. Smith Unit 3 began commercial service on April 22, 2002.

Gulf did not request interim rate relief but specifically asked that all or a portion of the requested increase of $ 69,867,000 be granted beginning on the commercial in-service date of Smith Unit 3 pending a final decision on this petition.

Pursuant to Section 366.06, Florida Statutes, Order No. PSC-01-2300-PCO-EI, issued November 21, 2001, suspended Gulf's permanent rate schedules pending [*4] review.

The Federal Executive Agencies (FEA), Florida Cable Telecommunications Association, Inc. (FCTA) and the Florida Industrial Power Users Group, (FIPUG) were granted intervention status in this docket by Order Nos. PSC-01-1934-PCO-EI, PSC-01-1949 PCO-EI, and PSC-01-1703-PCO-EI respectively. The Office of Public Counsel (OPC) is a party to this docket pursuant to Section 350.0611, Florida Statutes; Order No. PSC-01-2024 PCO-EI, acknowledged OPC's intervention. All parties except FCTA filed post-hearing briefs. The parties reached stipulations on a number of topics and these stipulations are attached in Appendix A to this Order.

Customer service hearings were held in Pensacola and Panama City on January 16, 2002. The final hearing was held February 25-26, 2002.

II. SUMMARY OF DECISION

We found Gulf's rate base to be $ 1,199,732,000. We found the average cost of capital to be 7.92% and the return on common equity to be 11.75% with a range of 10.75% to 12.75%. For rate setting purposes we granted Gulf an additional .25% return on common equity for providing superior service. We granted Gulf a revenue increase of $ 53,240,000.

III. [*5] **TEST PERIOD**

Gulf proposed a test period, for rate setting purposes, of 12 months ending May 31, 2003. With certain adjustment to Gulf's financial forecast, we find that this test period is appropriate.

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. The projected period June 1, 2002, through May 31, 2003, represents the test year on which Gulf calculated its revenue deficiency in this case. Gulf used this projected test period because it best represents future operations after Smith Unit 3 begins commercial operation. Smith Unit 3 is the major factor behind Gulf's need for rate relief. Of the $ 69.9 million request for rate relief, approximately $ 48 million is associated with Smith Unit 3. The test year used will more accurately reflect the operations of the Company during the first 12 months after the new rates go into effect than a historical test year that does not include this investment.

OPC concedes Gulf's need to cover the costs associated with Smith Unit 3. OPC's position is that we would have received far more reliable data from a historic actual test year, with the projected [*6] costs associated with Smith 3 superimposed and a historically based earnings attrition allowance.

OPC witness Schultz testified that the use of budgeted information provides significant difficulty in determining the appropriate level of future plant and cost operations. The budget must be in sufficient detail to determine whether the assumptions and cost budgeted by the Company are reasonable. In OPC's opinion Gulf did not supply sufficient detail necessary to properly examine the assumptions.

Witness Schultz testified that he made a number of adjustments based upon a historical level of spending that he considered sufficient to provide the quality of service. In his opinion, the historical spending should be used when establishing rates, especially when considering the lack of detail in the Company's budget. Mr. Schultz further testified that the budget provided by the Company does not appear to support $ 201 million in costs.

There are primarily two options for evaluating Gulf's expected financial operations. The first option is to use a historical test year and make pro forma adjustments to the test year. The second is to use a projected test year. Both of these options have strengths [*7] and weaknesses.

The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

The main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the Company's ability to forecast. Many companies are not able to forecast accurately enough to use the forecast for setting rates.

The parties and the Commission staff have conducted extensive discovery on Gulf's forecast. As will be addressed later in this Order, certain adjustments will be made to Gulf's forecast to increase its accuracy. With the inclusion of these adjustments, the forecast of Gulf's financial operations for the year ending May 31, 2003, is sufficiently accurate to use as a basis for setting rates.

IV. RATE [*8] **BASE**

A. PLANT IN SERVICE - PRODUCTION

Over the four-year period from January 1, 1997, to December 31, 2000, gross production additions to Gulf's Plant in Service averaged $ 15,294,572 per year. For the 17-month period from January 1, 2001, to May 31, 2002, Gulf's production budget expenditures total $ 238,059,000. The vast majority of this total, $ 188,232,000, is associated with the construction of Smith Unit 3. Expenditures associated with the construction of Smith Unit 3 were subject to a stipulation which was approved at the beginning of the hearing.

For the period from June 1, 2002, to May 31, 2003 (projected test year), production-related items are forecasted to be $ 13,008,999. Approximately $ 677,000 of this total is associated with the construction of Smith Unit 3. These Smith Unit 3 expenditures were subject to the same stipulation.

The record evidence provides considerable identification and description of Gulf's specific capital projects associated with budgeted production expenses. Gulf provided detailed cost estimates for these capital projects. We agree with Gulf witness Moore's testimony that these projects are necessary to improve the efficiency and availability [*9] of Gulf's generating units. Further, even though budgeted production plant items for the projected test year ($ 13,008,999) include some dollars associated with Smith Unit 3, the budgeted amount is still less than the four-year average for the 1997-2000 period ($ 15,294,572).

Prior to hearing, OPC took the position that, "a number of budgeted items for production related items appear to be overstated. OPC is awaiting further information from Gulf to explain the items more fully." OPC witness Schultz's prefiled testimony stated that, "tentatively, I believe the production plant additions were overstated." FIPUG adopted OPC's position prior to hearing. However, at the hearing, Mr. Schultz did not identify any specific adjustments to production plant. OPC took no position on this issue in its post-hearing brief.

In summary, we find that Gulf provided substantial detail on its production-related additions. OPC offered no evidence or argument to refute Gulf's position and did not recommend any adjustments to production plant items. We find that the documentation provided by Gulf is adequate to support the reasonableness of budgeted production plant additions. Therefore, we find that no [*10] adjustment shall be made.

B. PLANT IN SERVICE - TRANSMISSION AND DISTRIBUTION

Over the four-year period from January 1, 1997, to December 31, 2000, Gulf's transmission plant additions averaged $ 5,704,145 per year. During the same four-year historic period, distribution plant additions averaged $ 31,126,711.

For the 17-month period from January 1, 2001, to May 31, 2002 (prior year), Gulf's transmission plant budget totals $ 48,530,000, while the distribution plant budget totals $ 57,113,000.

For the period from June 1, 2002, to May 31, 2003 (projected test year), the transmission plant budget is estimated to be $ 7,505,000. For the same period, the distribution plant budget is estimated to be $ 38,305,000.

The evidentiary record provides sufficient detail on specific capital projects associated with transmission expenses budgeted by Gulf. Detailed cost estimates are given for these transmission capital projects. Based on this information we find that these projects are necessary to ensure that the transmission system can keep up with increases in the number of customers served and load growth, and to repair and replace facilities.

The evidentiary record also provides sufficient [*11] detail on distribution expenses budgeted by Gulf. Detailed cost estimates were given for distribution capital projects. Budgeted transmission and distribution Plant in Service items for the projected test year are comparable to the four-year average for the 1997-2000 period.

OPC witness Schultz testified that $ 162,822,000 of budgeted additions for distribution, transmission, and general plant should be disallowed because Gulf did not adequately justify their inclusion in rate base. Mr. Schultz testified:

> The transmission, distribution and general plant additions are not identified by the Company. The Company's failure to provide a description of the $ 162,822,000 of distribution, transmission and general plant additions is an attempt to shift the burden of proof.

Gulf provided a level of detail on budgeted transmission, distribution, and general plant additions similar to that provided on the production plant additions as discussed in Section A, above. At the hearing, Mr. Schultz did not identify any specific adjustments to the transmission or distribution budget.

In summary, we find that the record supports Gulf's requested transmission and distribution-related additions. [*12] OPC and FIPUG did not recommend any adjustments to these items. The documentation provided by Gulf is adequate support and justification for the reasonableness of its budgeted transmission and distribution plant additions. Therefore, we find that no adjustment shall be made.

C. PLANT IN SERVICE - GENERAL PLANT RELATED ADDITIONS

Gulf provided its construction budget for the period January 1, 2001, to May 31, 2003, totaling $ 413,891,000 in capital expenditures. The amount relating to transmission, distribution, and general plant totals $ 162,822,000. The general plant budgeted additions total $ 11,400,000.

Gulf's witnesses Fisher and Saxon testified that $ 5,300,000 reflect budgeted additions for the January 2001 through May 2002 period, and $ 6,113,000 relates to the test year budgeted additions. The majority of the additions budgeted for the test year relate to improvements to buildings and land, and purchases of automotive equipment including mechanized line and service trucks, and purchases of telecommunications, computer, and other equipment.

Gulf's witness Saxon asserts that the budgeted general plant additions are well within the range of normal spending compared to the [*13] last three years and the period of January 2001 through May 2002. Mr. Saxon notes that the total actual 2001 capital expenditures are 1.85 percent under the 2001 budget. Both witnesses Saxon and Fisher provided documentation regarding the general plant additions showing the specific project description, identification, and dollar amounts for the test year.

OPC witness Schultz testified that Gulf's $ 162,822,000 budgeted additions for distribution, transmission, and general plant should be disallowed on the basis of inadequate support being provided. Mr. Schultz testified:

> The transmission, distribution and general plant additions are not identified by the Company. The Company's failure to provide a description of the $ 162,822,000 of distribution, transmission and general plant additions is an attempt to shift the burden of proof.

We find that the evidentiary record contains an identification and description of the specific projects associated with the budgeted general plant additions. Moreover, the evidence indicates that the $ 6.2 million in test year general plant additions is within the range of additions recorded during the 1998 - 2000 period for this function.

Since OPC [*14] takes no exception to Gulf's supporting information for budgeted production plant additions, we compared that documentation with the documentation provided for the transmission, distribution, and general plant additions. Specific items included in the construction budget for general plant additions are detailed in much the same format and contain much of the same information as provided for the production plant additions. For example, the production budget information includes individual project numbers with descriptions and estimated expenditures. Likewise, general plant budgeted information also includes individual project numbers with descriptions and estimated expenditures.

In conclusion, OPC argued that Gulf's budgeted additions for distribution, transmission, and general plant should be disallowed based on Gulf's failure to provide supporting identification or description of the additions. However, Gulf provided a similar level of detail for the production plant additions and OPC did not object to that documentation. The supporting detail identifies and describes specific projects relating to the budgeted general plant additions. OPC provided no other specific disagreement [*15] with Gulf's budgeted additions. We find that the documentation provided by Gulf is adequate support and justification for the reasonableness of its budgeted general plant additions, and find that no adjustment is necessary to Plant in Service - General Plant Related Additions.

D. DEFERRAL OF RETURN ON THE THIRD FLOOR OF THE CORPORATE OFFICE

The cost of the third floor of Gulf's corporate office, $ 3,840,000, was removed from rate base in the Company's last rate case. See Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI. The reason was that Gulf had adequate storage space and maintenance facilities at other locations, and that the ratepayers would not benefit from the use of the third floor of the headquarters building for these purposes. Gulf was, however, allowed to earn a return on this plant investment equal to the allowance for funds used during construction (AFUDC).

Order No. PSC-99-2131-S-EI, approving a Stipulation and Settlement, was issued on October 28, 1999, in Docket No. 990947-EI. This Order addressed, among other things, Gulf's regulatory assets including the accumulated balance of the deferred return on the third floor of the corporate offices. [*16] The starting date of the Settlement was October 1, 1999, and expires with the earlier of the day before the commercial in-service date of Smith Unit 3 or December 31, 2002. The agreement authorizes Gulf to record at its discretion, up to $ 1 million per year through the expiration date to reduce the accumulated balance of the deferred return.

Gulf amortized $ 1 million in 2000 and in 2001. The MFR balance of the deferred return at the end of May 2002 is $ 3,470,595 system, which includes the $ 1 million in discretionary amortization in the year 2000 but does not reflect the additional amortization in 2001. The 2001 amortization was recorded after the MFRs were filed. Based on Witness Labrato's Exhibit 54, Schedule 1, the adjusted balance at May 2002 reflecting the 2001 amortization is $ 2,444,958.

Gulf is requesting that the deferred return be allowed in rate base and amortized over three years since 100% of the third floor is now being utilized for record retention, spare office furniture, miscellaneous supplies, and other storage for the print shop, safety and health, and power delivery functions. The amortization period is discussed below in Part VI, Section T. The third floor [*17] also contains space for building maintenance. Witness Labrato testified that in 1999 a FPSC auditor toured the third floor and found that over 90% of the space was being utilized. Also, based on Disclosure No. 2 in the staff audit report (Exhibit 47, attached to the testimony of staff witness Bass), the utilization of the space was confirmed by the audit staff.

OPC witness Schultz testified that the third floor was initially used for storage space which was originally intended as additional office space to accommodate Gulf's growth. Gulf's employee complement in 1989 was 1,626 and in the year 2000 was 1,319. OPC stated in its brief that the space was never converted to offices as expected. OPC also expressed concern that current customers would be required to pay deferred earnings on something that is not providing service. Accordingly, working capital should be reduced $ 2,893,000 and amortization expenses should be reduced $ 1,157,000.

Gulf Witness Labrato testified that at the time of the last rate case, Gulf had adequate space for storage and maintenance functions at other locations. When the office was built, it was built with the additional floor, and that it was not needed [*18] for office space at that time. Also, it was anticipated that it would be utilized in the future, and that because of the deferred return, future recovery would be allowed. In addition, it was not anticipated that the period of time would go this long, which is why the amount is so large.

Mr. Labrato further testified that for surveillance purposes the investment was removed from rate base, the deferral was recorded as a regulatory asset, and the earnings were below-the-line so it did not impact the surveillance earnings. For financial accounting purposes it was accounted for the same way. The investors and the financial community realized the amount was deferred and anticipated future recovery.

We find it appropriate to include the deferral of the return on the third floor in rate base. Although the third floor is not being used as it was originally intended, it is being used. Also, it was intended that recovery of the deferred return would ultimately be allowed. Therefore, $ 2,138,760, which reflects the additional amortization booked during 2001, and a four year amortization period as discussed in Part IV, Section T, below, shall be included in rate base.

E. INVESTMENT IN THE [*19] THIRD FLOOR OF THE CORPORATE OFFICE

Gulf's witness Labrato testified that the third floor of the corporate office is being utilized and that the investment should be allowed in rate base. The projected test year rate base includes the $ 3.8 million of plant-in-service and $ 338,000 in accumulated depreciation, which were removed in the last case.

Mr. Labrato testified that the space is less expensive than the rest of the building because the space is unfinished with no walls. He further testified that the investment has allowed for convenient, secure, and humidity-controlled space for items that are used in the corporate office. In addition, he noted that if this space were not available, the Company would be required to build or lease additional space.

OPC states in its brief that it accepts the conclusion of the audit report that the third floor is currently being used for storage space and therefore provides some value to the public. However, two concerns were raised by OPC.

First, the space was not originally intended to be used for storage space, but for office space. Accordingly, the "storage rooms" occupy space in a near waterfront building. The space is more expensive [*20] than that normally associated with storage space.

Second, the third floor has not been depreciated in the 12 1/2 years since Order No. 23573 was issued in Docket No. 891345-EI. The depreciable life of the office building is approximately 25 years. Therefore, if the third floor is being depreciated over the remaining life of the building, then the current and future customers would be charged double the depreciation rate for a storage area. OPC is therefore recommending that we allow half the investment in rate base and reduce depreciation by half.

The FPSC staff who conducted the audit toured the third floor of the corporate office and indicated that over 90% of the space is utilized. The third floor is primarily used for storage of records, spare office furniture, miscellaneous supplies for the kitchen, print shop, safety and health, and power delivery. It also contains a workshop for building maintenance. Staff witness Bass concluded in Audit Disclosure No. 2 of Exhibit 47 that the third floor of the corporate office is used and useful for utility operations. OPC accepted staff witness Bass' conclusion.

The third floor investment of $ 3.8 million will be recorded in Account 390, [*21] Structures and Improvement, where the investment in the corporate office is recorded. The third floor investment of $ 3.8 million will be depreciated over the remaining life of Account 390 and not over the remaining life of the individual unit or building. The remaining life of Account 390 is 30 years, not 25 years. The inclusion of the third floor investment will naturally increase depreciation expense. However, the additional investment will not affect the remaining life nor the depreciation rate for Account 390. This is because the $ 3.8 million associated with the third floor represents only about 7% of the total account investment. Compositing the age of the third floor (15.5 years) with the 16.2 year age given for Account 390 will result in no change in the average remaining life. While OPC is correct that there will be an inherent reserve deficiency associated with the third floor due to its exclusion from rate base for 12 1/2 years, it has no affect on the 2.2% depreciation rate. Moreover, Account 390 has sufficient existing reserve surplus to correct the deficiency. According to the information provided in Gulf's depreciation study, Account 390 has a perceived reserve surplus [*22] which could be used to offset the reserve deficit due to the exclusion of third floor investment from rate base.

We find that the third floor is used and useful, therefore the investment and reserve for the third floor shall be included in rate base and the Company shall begin depreciating this investment using a 2.2% depreciation rate.

F. SECURITY MEASURES

Gulf's MFRs and direct testimony were filed on September 10, 2001, and thus do not account for the impact, on test year rate base, of the increased threat of terrorist attacks since September 11, 2001. Staff requested information pertaining to the impact of the increased terrorist threat on Gulf's costs in Staff's Seventh Set of Interrogatories Nos. 235-238. Gulf filed its response to these interrogatories under a request for confidential classification on February 4, 2002. Order No. PSC-02-0220-CFO-EI, issued February 22, 2002, granted confidential classification to the interrogatory responses. The confidential interrogatory responses were identified as Exhibit 7 at the hearing.

Having reviewed Exhibit 7, we find that the rate base information provided is reasonable and appropriate. Based on Exhibit 7 we find that a $ 683,000 [*23] adjustment ($ 714,000 system) should be made to increase rate base for the May 2003 projected test year for investments in additional security measures made in response to the increased threat of terrorist attacks since September 11, 2001.

G. ENVIRONMENTAL COST RECOVERY CLAUSE

We find that the capitalized items currently approved for recovery through the Environmental Cost Recovery Clause (ECRC) need not be included in base rates. During this rate proceeding, no benefit to customers has been shown by including such costs in base rates. In fact, the impact on customers is essentially the same whether the costs are recovered through base rates or the ECRC.

Section 366.8255(5), Florida Statutes, provides in part that "recovery of environmental compliance costs under this section does not preclude inclusion of such costs in base rates in a subsequent rate proceeding, if that inclusion is necessary and appropriate." This section grants us some discretion to decide whether costs approved for recovery through the ECRC should be moved into base rates.

According to Order No. PSC-94-0044-FOF-EI, issued January 12, 1994, in Docket No. 930613-EI, [*24] Gulf is allowed to earn its currently authorized ROE for capitalized items recovered through the ECRC. This fixed midpoint ROE policy is reaffirmed by Order No. PSC-99-2513-FOF-EI, issued December 22, 1999, in Docket No. 990007-EI. Because a company has an opportunity to earn a return higher than the midpoint ROE in base rates, including capitalized ECRC items in rate base may reward Gulf for the costs that are outside its control. For the reasons discussed above, we conclude that not including Gulf's currently capitalized ECRC items in rate base is reasonable and appropriate.

H. PLANT IN SERVICE - TOTAL

Gulf's requested level of Plant in Service was $ 1,966,492,000 ($ 2,015,013,000 system) for the May 2003 projected test year. Based on the adjustments described below for house power panels (Account 369.3), anti-terrorism security measures, and cable inspection expense, Plant in Service should be increased $ 125,000 ($ 156,000 system). The appropriate amount of Plant in Service is $ 1,966,617,000 ($ 2,015,169,000 System) for the May 2003 projected test year, as shown in Attachment 1.

Gulf's policy is to retire house power panels by abandoning them in place rather than physically [*25] removing them. Gulf indicates that the rate case budget inadvertently understated the retirements of house power panels, which overstated the plant in service for this account.

We find that the cumulative effect of the relevant adjustments is an increase of $ 125,000 to test year Plant in Service as shown below:

Test Year Plant in Service Adjustments

Issues	Jurisdictional	System
Security Measures	$ 683,000	$ 714,000
Cable Injection	83,000	83,000
House Power Panels	(641,000)	(641,000)
Total Adjustment	$ 125,000	$ 156,000

I. ACCUMULATED DEPRECIATION

Gulf requested a level of accumulated depreciation in the amount of $ 854,099,000 ($ 876,236,000 system) for the May 2003 projected test year. We find that the test year accumulated depreciation must be decreased $ 1,716,000 ($ 1,754,000 System) as shown in the table below. The appropriate amount of accumulated depreciation for the May 2003 projected test year is $ 852,383,000 ($ 874,482,000 System), as shown in Attachment 1.

Test Year Accumulated Depreciation Adjustments

Issues	Jurisdictional	System
Cable Injection	$ (1)	$ (1)
House Power Panels	698	698
Stipulated 25-year life for Smith Unit 3	1,019	1,057
Total Adjustment	$ 1,716	$ 1,754

[*26]
J. FUEL INVENTORY

Gulf requested a total fuel inventory of $ 42.6 million (13-month average) which is comprised of $ 29.4 million for fuel stored at its generating plants and $ 13.1 million for in-transit fuel. We find that this amount is appropriate.

Under Order No. 12645, we apply a 90 day projected burn plus base coal volumes as a "generic policy" for coal inventory if two conditions are present: 1) the utility fails to justify its fuel inventory levels; and 2) the optimum policy cannot be determined from the evidentiary record.

When calibrating the days supply of its fuel inventory, Gulf must balance two competing concerns. First, if Gulf has too little inventory, Gulf may incur additional costs to purchase fuel on the spot market to maintain reliable service. Second, if Gulf has too much inventory, Gulf will incur greater carrying costs associated with its fuel inventory. Gulf establishes its fuel inventory levels to optimize Gulf's total costs associated with its fuel inventory.

In its brief, OPC advocated that Gulf's coal inventory should be set at the sum of the actual 2000 historical amount and Gulf's requested in-transit amount. OPC witness Schultz testified that Gulf's [*27] historic costs are representative of what is necessary to provide the quality of electric service that Gulf has provided. According to Mr. Schultz, Gulf did not provide sufficiently detailed information about its costs in the projected test year to provide much assurance about the accuracy of these projected costs.

Gulf requested a coal inventory of 52 days supply (695,289 tons) in this docket compared with the 90 days supply of coal inventory that was authorized in Gulf's last rate case. Despite a 37 percent increase in Gulf's electric generation needs since 1990, the value of Gulf's coal inventory is $ 10.2 million less than what was authorized in the last rate case. Mr. Schultz advocates that Gulf's coal inventory should be adjusted downward by 218,808 tons. With an average price of $ 38.463 per ton, the adjustment to Gulf's working capital balance would be a decrease of approximately $ 8,416,000.

Robert G. Moore, another Gulf witness, testified on rebuttal that year 2000 was extraordinary and atypical for Gulf on a going forward basis. Gulf's coal inventory levels fell sharply during the last three months of 2000 because the demand for coal was high due to early and prolonged [*28] winter conditions, and the increased cost of natural gas-fired generation. Also, the winter conditions negatively impacted coal production and delivery schedules. After the winter conditions subsided, Gulf steadily increased its coal inventory back to normal levels.

In summary, witness Moore stated that a smaller coal inventory amount would adversely affect Gulf's ability to provide reliable electric service and could cause higher coal procurement costs on the spot market for Gulf's ratepayers.

We find that the year 2000 was atypical and therefore unrepresentative of Gulf's coal inventory requirements on a going-forward basis. Gulf has justified the amount and value of its fuel inventory levels. Therefore, no adjustment to Gulf's fuel inventories for the projected test year ending May 31, 2003, is necessary.

K. WORKING CAPITAL

Gulf's requested level of Working Capital was $ 67,194,000 ($ 69,342,000 system) for the May 2003 projected test year. However, based on our decision on the amortization of the third floor of Gulf's corporate office, working capital must be reduced by $ 611,000 ($ 753,403 system), for a total working capital of $ 66,583,000 ($ 68,589,000 system).

L. [*29] RATE BASE

Gulf's requested rate base in the amount of $ 1,198,502,000 for the May 2003 projected test year, as shown on the table below. We find that the appropriate rate base for Gulf is $ 1,199,732,000 as shown on the table below and in Attachment 1.

2003 Jurisdictional Rate Base

(000's)

	Gulf	Approved
Utility Plant-in-Service	$ 1,966,492	$ 1,966,617
Accumulated Depreciation	(854,099)	(852,383)
Net Plant-in-Service	1,112393	1,114,234
Construction Work in Progress	15,850	15,850
Property Held for Future Use	3,065	3,065
Net Utility Plant	1,131,308	1,133,149
Working Capital	67,194	66,583
Total Rate Base	$ 1,198,502	1,199,732

V. COST OF CAPITAL

A. ACCUMULATED DEFERRED TAXES

Per MFR Schedule D-1, Page 2 of 6, the "Company Total per Books" deferred taxes for the test year ending May 31, 2003, was $ 164,672,000. To the $

164,672,000, the Company made adjustments to remove $ 33,458,000 of deferred taxes specifically identified with unit power sales contracts and to remove $ 6,757,000 of deferred taxes for the appropriate portion of other rate base adjustments which were made on a pro rata basis over all sources [*30] of capital. The result is total system adjusted deferred taxes of $ 124,457,000. The Company then applied a jurisdictional factor of .9760026 to this amount, resulting in adjusted jurisdictional deferred taxes of $ 121,471,000.

On January 18, 2002, the Company revised its projected capital structure as Exhibit 2 to Mr. Labrato's deposition. The revised capital structure also reflected jurisdictional deferred taxes of $ 121,471,000.

OPC did not take issue with the methodology or the amount of deferred taxes in rate base prior to Commission adjustments, but it did state that the actual dollar amount is dependent on our adjustments to rate base.

We agree with OPC. In addition, we find it necessary to make a specific adjustment of $ 662,000 related to the Smith Unit 3 life, as addressed in the Depreciation Stipulation. The result is adjusted jurisdictional deferred taxes of $ 122,133,000. Accordingly, we find that the adjusted jurisdictional Accumulated Deferred Taxes is $ 122,133,000 for the May 31, 2003, projected test year.

B. UNAMORTIZED INVESTMENT TAX CREDITS

Per MFR D-1, Page 2 of 6, the "Company Total per Books" weighted cost investment tax credits for the projected test [*31] year ending May 31, 2003, is $ 22,113,000 and the cost rate is 9.70%. To the $ 22,113,000, the Company made adjustments to remove $ 4,201,000 of investment tax credits specifically identified with unit power sales contracts and to remove $ 920,000 of investment tax credits for the appropriate portion of other rate base adjustments which were made on a pro rata basis over all sources of capital. The result is total system adjusted investment tax credits of $ 16,992,000. The Company then applied a jurisdictional factor of .9760026 to this amount, resulting in adjusted jurisdictional investment tax credits of $ 16,584,000 with a cost rate of 9.70%. The cost rate is derived from long-term debt, preferred stock, and common equity.

On January 18, 2002, the Company revised its projected capital structure in Exhibit 2 to Mr. Labrato's deposition. The revised capital structure also reflects jurisdictional investment tax credits of $ 16,584,000, but alters the cost rate from 9.70% to 9.48%.

OPC's position is that the actual dollar amount is dependent on the adjustments to rate base and the cost rate is dependent upon the allowed return on equity.

We agree with OPC, but do not believe that [*32] there are any rate base adjustments that would affect investment tax credits. The result is that no adjustment is necessary and the balance therefore remains at $ 16,584,000. We recalculated the investment tax credit cost rate based on other adjustments and the return on equity, resulting in a 8.99% weighted average cost rate for the investment tax credits. Accordingly, we find that the adjusted jurisdictional investment tax credits of $ 16,584,000 with a weighted average cost of 8.99% for the May 31, 2003 projected test year is appropriate.

C. RECONCILING RATE BASE AND CAPITAL STRUCTURE

The Company presented its reconciliation of rate base and capital structure on MFR Schedules D-12a and D-12b. On January 18, 2002, the Company revised its projected capital structure in Exhibit 2 to Mr. Labrato's deposition. The Company made a specific adjustment to remove non-utility investment from equity and made specific adjustments to remove the unit power sales capital structure amounts from the per books capital structure balances. The Company also properly removed dividends declared from its capital structure. The remaining rate base adjustments required to reconcile the rate base [*33] and capital structure were made on a pro rata basis over all sources of capital. Finally, the jurisdictional factors were applied to these balances, resulting in the reconciliation of rate base and capital structure.

As stated, the Company removed all other rate base adjustments on a pro rata basis from all sources of capital. It has been our practice to make specific adjustments where possible and to prorate other rate base adjustments over investor sources only. However, Gulf's per books capital structure includes deferred taxes and investment tax credits that are being considered, along with the related assets, in cost recovery clauses. We believe that it is appropriate for the Company, in this case, to make pro rata adjustments for the remaining rate base items over all sources. This will allow the Company to match the related deferred taxes and investment tax credits with the assets being recovered through these clauses. For this reason it is appropriate to recognize the recovered clause treatment so as not to penalize the Company through the double counting of lower cost capital items.

OPC did not take issue with the methodology of reconciliation, but it did state that the actual [*34] reconciled amounts will depend on the rate base allowed. We agree with OPC and have also made a pro rata adjustment over all investor's sources of capital. We also agree with the revised capital structure provided in Mr. Labrato's deposition Exhibit 2. Accordingly, we find that with the specific capital structure adjustments and the pro rata adjustment, capital structure and rate base have been reconciled appropriately.

D. RETURN ON EQUITY TO USE FOR ESTABLISHING GULF'S REVENUE REQUIREMENT

For the reasons provided below, we find that the appropriate ROE to use in establishing Gulf's revenue requirement is 11.75%.

Mr. Benore, the Company's primary witness on cost of capital, based his ROE analysis on a group of 8 companies involved in the regulated electric utility business. He employed 9 risk measures to select this comparable risk group. These measures included a Value Line beta no greater than .60, a Value Line safety rank of at least 2, and a Standard and Poor's (S & P) bond rating of A- or higher. He also eliminated any company involved in a merger. Mr. Benore updated his analysis, which resulted in the exclusion of 1 of the 8 original companies. His recommended ROE remained [*35] at 13.0%.

To estimate Gulf's ROE, Mr. Benore relied upon the results of three market-based models: a discounted cash flow (DCF) model, an equity risk premium model, and a capital asset pricing model (CAPM). For his DCF model, Mr. Benore used stock prices for his comparable risk companies from July 16, 2001, to August 14, 2001, and a growth rate of 6% based on earnings growth. He obtained a DCF result of 11.7% without flotation costs and 11.9% with flotation costs.

Mr. Benore calculated a 5.0% equity risk premium using actual, annual returns realized by investors for investments in the common stocks of Moody's Electric Power Companies and in long-term Treasury bonds. The premium was calculated for the period 1932 to 1993. Mr. Benore stopped at 1993 because he believes this year marked the onset of structural changes in the industry from regulated monopoly to competition. He added the 5.0% equity risk premium to the 6.4% yield on long-term Treasury bonds. Mr. Benore's estimate of the risk-free rate was normalized for the impact of the Treasury's planned buyback of long-term debt. The equity risk premium result is 11.4% before flotation costs.

Mr. Benore's CAPM model result is 11.4% [*36] before flotation costs. This is based on the average of a standard CAPM and an empirical CAPM, a model which adjusts for underestimation problems associated with low beta stocks. The inputs for the CAPM are a risk-free rate, a beta, and a market equity risk premium. The risk-free rate is the same 6.4% "normalized" Treasury yield discussed above and the average beta for his comparable risk companies is .51. Mr. Benore used both historical and projected market equity risk premiums in his CAPM analysis.

In addition to the three market-based models, Mr. Benore used a comparable earnings analysis. This method is based on the projected returns on book common equity, as reported by Value Line, for the comparable risk companies. The result of the comparable earnings method is 13.3%.

Mr. Benore noted that the proceeds to a company from the sale of common stock are reduced by issuance or flotation costs. Using flotation costs of 3% of proceeds, Mr. Benore recommended that the ROE be increased by 20 basis points.

Throughout his direct and rebuttal testimony, Mr. Benore emphasized that his DCF, risk premium, and CAPM results should be adjusted because the stock prices (market value) of his comparable [*37] risk group are above book value per share. He refers to this adjustment as "transformation." Mr. Benore believes that transformation, accomplished through an iterative process, determines the necessary, regulatory book return so that investors have an opportunity to earn their required market return. Using a mathematical example of transformation, Mr. Benore believes that, when the market price of a utility stock exceeds it's book value, the regulatory return based on a DCF model must be increased to maintain the market value of the stock.

For the comparable risk companies, the market price per share currently exceeds book value per share. Thus, Mr. Benore's transformation adjustment is an increase to the results of his models. According to Mr. Benore, the result of the comparable earnings analysis is a book-to-book test and no transformation adjustment is needed.

Mr. Benore updated his DCF, equity risk premium, and CAPM results. The updated DCF result is 12.1%. The equity risk premium result is 11.2% and the updated CAPM result is 11.1%. The comparable earnings test is 13.5%. With the transformation adjustment, the DCF result is 14.2%, the equity risk premium result is 13.3%, and [*38] the CAPM result is 13.2%. All these results exclude flotation costs.

Mr. Benore recommends 13.0% as the appropriate ROE for Gulf. He notes that flotation costs should be considered along with Gulf's lower risk compared to the comparable risk companies. Gulf's smaller size relative to the comparable risk companies also should be considered.

For his analysis, OPC witness Rothschild used Mr. Benore's comparable risk companies. Mr. Rothschild used two DCF models and two risk premium/CAPM models. He also applied a DCF model to Southern Company.

Mr. Rothschild's constant growth DCF model used stock prices as of November 30, 2001, and the average of the high and low stock price for the year ended November 30, 2001. He derived the growth rate using the retention growth method whereby the Company's retention rate - the percent of earnings not paid out as dividends - is multiplied by the future expected earned return on book equity. The results of the constant growth DCF model range from 8.86% to 9.64%. Using dividend information from Value Line and his analysis of long term growth trends, Mr. Rothschild's multi-stage DCF model produced results ranging from 9.28% to 10.73%.

For his inflation [*39] risk premium method, Mr. Rothschild used historical returns on common stocks, net of inflation, ranging from 6.60% to 7.20%. With his expected inflation of 2.0%, the mid-point cost of equity for a company of average risk is 8.90%. Using a beta of .52 for electric companies, he calculated a risk premium applicable to electric companies of 6.23%. Mr. Rothschild employed a debt risk premium method whereby he measured the equity risk premium over the yields on short-term treasury bills, long-term treasury bonds, and corporate bonds. The results of this method range from 8.94% to 10.62%.

Mr. Rothschild believes that pending recession fears currently cause the DCF to overstate the cost of equity. He notes that his inflation premium method is difficult to interpret due to the "flight to quality" impact on Treasury bond yields. He recommends 10.0% as the appropriate ROE and notes that this is conservatively high given the results of his multistage DCF model.

Mr. Rothschild disagrees with Mr. Benore's transformation adjustment. He notes that the Federal Energy Regulatory Commission (FERC) and the Federal Communications Commission (FCC) have rejected the argument. Specifically, FERC found [*40] that, when the cost of capital and interest rates decline, market prices of utility stock rise above book value per share. This occurs because the utility earns a higher ROE than that required by investors. Regulators have traditionally viewed market-to-book ratios above 1.0 as a possible indicator that the Company's return is higher than the return required by investors. The FCC found that setting the revenue requirement at investors' required return might cause the stock price to decline but "the requirement that we balance ratepayer and investor interest does not allow us to insulate investors from a diminution in the value of their stock." Mr. Rothschild believes Mr. Benore's transformation adjustment is circular because it suggests, once excessive earnings have caused the utility's stock price to increase, regulators must keep earnings at that level to prevent a decline in the stock price.

Regarding the specifics of Mr. Benore's models, Mr. Rothschild disagreed with Mr. Benore's risk premium method noting that the arithmetic average for historical returns is upwardly biased and that the geometric average should be used. Mr. Benore's CAPM result also has the problem of using [*41] arithmetic instead of geometric averages in calculating the market risk premium, according to Mr. Rothschild. Mr. Rothschild disagreed with Mr. Benore's comparable earnings model because the earned return on book equity is a separate and distinct concept of investors' required return. Regarding flotation costs, Mr. Rothschild notes that flotation costs, as allowed by FERC, are very small and similar to rounding error.

In rebuttal to Mr. Rothschild's testimony, Mr. Benore notes that Mr. Rothschild's results need a transformation adjustment to produce the return that investors require. Mr. Benore found errors and inconsistencies with Mr. Rothschild's models and results.

In particular, Mr. Benore noted that Mr. Rothschild substituted his own judgement in using a ROE of 13.0% in developing the sustainable growth rate for his DCF model. The comparable rate reported by Value Line was 13.5%. Regarding Mr. Rothschild's multi-stage DCF model, Mr. Benore again noted that Mr. Rothschild ignored the use of expected ROEs as reported by Value Line and Zacks in favor of his own judgement.

Regarding Mr Rothschild's inflation risk premium/CAPM results, Mr. Benore noted the results are untenable - [*42] ROEs below the current yield on "A" rated utility bonds. He also noted that Mr. Rothschild mixed real and nominal rates in calculating his results. Regarding Mr. Rothschild's debt risk premium/CAPM model, Mr. Benore notes that the arithmetic average of historical risk premiums, instead of the geometric average, is appropriate to reflect investors' expected risk premium. Mr. Benore also noted that certain empirical studies show that the standard CAPM underestimates investors' required returns for low beta stocks like utilities.

Using his recommended corrections, Mr. Benore recalculated the results of Mr. Rothschild's models. These results range from 11.5% to 12.4% for the DCF models and 10.6% to 11.6% for the risk premium/CAPM models. Mr. Benore noted these results are before flotation costs and transformation.

Regarding risk premium methods, Mr. Rothschild and Mr. Benore disagree on the calculation of the historical risk premium, specifically on whether a geometric average or an arithmetic average should be used. We find that prospective risk premium analyses are more appropriate because historical risk premiums rely on earned returns instead of investors' required returns. Historical, [*43] earned returns can and do vary significantly from current, required returns. Also, both calculations of historical risk premiums include periods when returns on debt exceeded returns on common stock, i.e., periods of negative risk premiums. In his CAPM, Mr. Benore used both prospective and historical risk premiums.

We reject the transformation adjustment to ROE recommended by Mr. Benore. Given current market conditions in which prices of utility stocks exceed the book value per share, the transformation adjustment is convenient for utility witnesses because it results in an increase beyond the results of ROE models. In the past, when prices of utility stocks were below book value per share, Mr. Benore did not recommend the transformation adjustment. He apparently became aware of the supposed need for the adjustment when utility stock prices exceeded book value.

Though Mr. Benore states that he would make the adjustment if utility stock prices fell below book value, it is not known whether that situation will recur in the foreseeable future. The market price-to-book ratio of the comparable risk companies is approximately 1.38. At the same time, Mr. Benore testified that utility stocks [*44] have underperformed the market.

In addition to these shortcomings, both the FCC and the FERC have rejected the transformation adjustment. See FERC Docket RM87-35-000, P. 3348 of the Federal Register/Vol. 53, No. 24, Friday Feb. 5, 1988; FCC Docket 89-624, Order 90-315, P. 15, Sep. 19, 1990. These decisions note that a utility may earn a return higher than that required by investors, causing the stock price to exceed book value. Resetting the allowed return at the investors' required return may cause the stock price to decline but the required return is reasonable and balances the interests of ratepayers and investors. Further, the FCC decision suggested investors may have anticipated and discounted reductions in the utility's ROE so that the reduction would have no effect on the stock price.

Regulators may not be capable of maintaining a certain market price to book value ratio for a utility, even if they wanted to do this. We note that book value of utility stocks, and stocks in general, can be affected by one-time changes in accounting rules. The market price-to-book ratio may be substantially outside the influence of regulators.

Mr. Rothschild disagreed with the growth rates [*45] that Mr. Benore used in his DCF model. In particular, Mr. Rothschild notes that the long-term growth rate is based on 5-year earnings per share forecasts by analysts. Mr. Rothschild believes this results in projecting a continued increase in the cost of equity. We note that dividend growth is less volatile than earnings growth.

We agree with Mr. Benore that some of the results of Mr. Rothschild's models are untenable. We also agree that the standard or simple CAPM may underestimate the cost of equity for low beta stocks. Further, we agree with Mr. Benore that Gulf has lower regulatory risk compared to the comparable companies and that Florida's adjustment clauses reduce risk.

Regarding flotation costs, we agree with Mr. Benore that these costs should be included in the ROE. The Hope and Bluefield decisions mandate a return that can attract capital, and flotation costs are a necessary part of attracting capital. See Federal Power Comm'n, et al. v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Public Service Comm'n, 262 U.S. 679 (1923). We find that Mr. Benore's allowance of [*46] 20 basis points for flotation cost is reasonable.

Mr. Benore bases part of his recommendation on his opinion that Gulf is a small company, a point with which Mr. Rothschild disagrees. We note that Gulf has an "A+" bond rating by Standard and Poor's. We believe that companies that can issue rated debt should not be considered small, even though Gulf is smaller than the comparable risk companies. We agree with Mr. Benore that Gulf should be treated on a stand-alone basis for purposes of deciding the ROE issue.

We note that determination of the appropriate ROE is ultimately a subjective process. Considering Mr. Benore's updated results without the transformation adjustment, and Mr. Benore's adjustments to Mr. Rothschild's results, we find the appropriate range for Gulf's ROE is 10.8% to 11.8%, and we choose 11.75% as the appropriate ROE for Gulf. We note that Mr. Benore used stock prices from November 27, 2001, to December 27, 2001, in his updated results. We further note that this update resulted in a moderate increase in the cost of common equity, Recognizing this moderate increase along with Gulf's reasonable equity ratio of 47% and it's A+ bond rating, we believe an ROE near the [*47] top of the reasonable range is appropriate.

E. REWARDS FOR GULF'S PAST PERFORMANCE AND INCENTIVES FOR GULF'S FUTURE PERFORMANCE

Several issues in this docket addressed whether Gulf should be rewarded for its high quality of service or penalized if its service deteriorated to something less than adequate. Specifically, those issues were: 1) whether we should establish a mechanism that would provide payment or credit to customers if Gulf had frequent outages in the future; and, 2) whether Gulf should be rewarded for its current and past high quality of service in the form of an adder to the midpoint ROE and/or a broader range on equity.

During his live testimony, Mr. Bowden proposed an earnings sharing plan that incorporated some of the same issues identified above. His proposal was very general and we asked Gulf to file a late-filed exhibit filling in the details of the plan and demonstrating that those details were in the evidentiary record. The parties were given an opportunity to respond to the late-filed exhibit, identified as number 25, by filing comments after a two week review period.

OPC and FIPUG claimed that the details contained in the late-filed exhibit were [*48] not contained in the evidentiary record. They argued that to allow the late-filed exhibit to be moved into the record would violate their due process rights because they would have had no chance to conduct discovery, file testimony, or conduct cross-examination on the contents of the late-filed exhibit. We agree, and thus the late-filed exhibit shall not be entered into the record.

As a result, we will address the issues of penalties and rewards individually, as they were raised during the course of the proceeding. We note that the earnings sharing plan included components not addressed in this proceeding, and that the idea of a comprehensive plan has merit. We also believe it is beneficial for OPC and other interested parties to participate in shaping such a plan. For these reasons, Gulf shall have until July 26, 2002, to file a petition for approval of an incentive sharing plan.

The issues related to rewards and penalties are discussed below.

1. Performance Based Incentives to Promote High Quality Service in the Future

Staff witness Breman proposed an incentive mechanism to promote reliability of service. The mechanism involves routine reporting of the measurement of Customers [*49] Experiencing More than Five Interruptions (CEMI5). His proposed annual minimum performance standard for Gulf is a CEMI5 of 2 percent. The Company would fail this standard if more than 2 percent of its customers experienced more than 5 interruptions a year. Based on the proposed mechanism, Gulf would be required to make an annual refund to its retail customers when CEMI5 exceeds 2 percent in any consecutive 12 month period. This penalty for poor performance is capped at the equivalent of 10 basis points of ROE.

Gulf argued that a penalty mechanism is unnecessary because the Company has demonstrated a record of good performance and a commitment to satisfying its customers. Gulf witness Fisher cited the results of customer surveys and distribution reliability indices to demonstrate its record of good performance in customer satisfaction and distribution reliability. In addition, Mr. Fisher argued that Gulf's commitment comes willingly.

We find that Gulf's arguments are not sufficient to support its position. A company's past performance and stated commitment to customer satisfaction do not obviate the need for a minimum performance standard, and incentives for a company to maintain [*50] such a standard in the future. If willing commitment could be an argument against a penalty, it could also be an argument against a reward, which would contradict Gulf's position on its proposed ROE adjustments.

Although Gulf has proven its capability to achieve a CEMI5 of 1 percent in 2001, Gulf appears to believe that it could be penalized by the standard of 2 percent CEMI5. We believe that a performance guarantee would be a more concrete form of commitment.

The idea that a proactive incentive approach is more effective than a reactive intervention approach is unchallenged in the record. The evidence suggests that our intervention in 1997, after several years of declines in distribution reliability, resulted in improved distribution reliability. Although the intervention was a reaction to poor performance by other companies, the collaborative efforts of the utilities and our staff have improved reliability performance statewide, including Gulf's. Similarly, we believe a well designed proactive incentive mechanism will be effective whether a company has demonstrated poor performance or not.

At the hearing, Gulf witness Bowden proposed, in his live testimony, a performance based concept [*51] that would provide rewards and sharing of earnings based on performance ratings and availability of earnings. Mr. Breman testified that he is not opposed to rewards for future performance if there is a balanced "carrot and stick" approach with properly defined standards. We find that both penalty and reward provisions should be addressed in a performance based mechanism and such a mechanism should be based on future instead of past or current performance. This is one reason why we invited Gulf to file a petition for approval of an earnings sharing plan.

Gulf's major concern is that Mr. Breman's proposed incentive mechanism offers no opportunity for a reward. Gulf also expressed a number of other concerns about the specifics of Mr. Breman's proposed mechanism. First, Mr. Fisher argued that to use a single indicator of reliability could cause Gulf's focus to shift away from other measures which Gulf deems more effective. Second, Gulf suggested that a number of factors that might affect customer interruptions (CEMI5), such as weather and accidents, are outside the utility's control. Finally, Gulf suggests that the administrative costs for such a program could be substantial and these [*52] dollars could be better spent to correct the reliability problem.

First, we find that CEMI5 is too narrow a measure to assess performance adequately. Other meaningful measures of distribution reliability such as average minutes of interruption should also be considered. We believe that combining price and service performance measures to form a composite customer value indicator is a good idea.

Second, we find that factors outside of Gulf's control should be considered. Such factors may act to Gulf's benefit or detriment. Extreme weather conditions such as named storms are currently excluded from distribution reliability performance calculations. However, Gulf frequently points to its low rates as a benefit to its customers and a factor that should be considered in granting rewards. Gulf does not mention that its geographic location contributes to its low rates. We believe that all these factors should be considered when establishing performance based incentives. Third we find that administrative costs should be considered.

In summary, we find that Mr. Breman's proposal may be appropriate as a component of a comprehensive incentive mechanism, but alone it is not adequate. We believe [*53] that an incentive plan should include both rewards and penalties. A properly balanced incentive mechanism cannot be established at this time. That is why we offer Gulf the opportunity to file a petition for approval of an incentive plan.

2. Adjustment to Return on Equity to Reflect Gulf's Performance

Gulf contends that it deserves an upward adjustment to its return on equity (ROE) as a reward for its continuing high level of performance in customer satisfaction, customer complaints, transmission and distribution reliability, and generating plant availability. Gulf's position is that increasing the ROE sends a message to the Company and the customers that superior performance is important. Furthermore, such an increase provides an incentive to continue to provide superior service. Gulf notes that staff witness Breman supports the concept of rewarding a utility for providing superior service.

FIPUG opposes an upward adjustment to ROE. FIPUG contends that Gulf operates under the current regulatory bargain and should not be further rewarded.

The testimony of Gulf witnesses Labrato and Fisher demonstrates that Gulf's service is excellent. In addition, testimony of customers at the [*54] customer service hearings was very favorable. We find that Gulf's past performance has been superior and we expect that level of performance to continue into the future. In recognition of this, we find that Gulf deserves to have 25 basis points added to the mid-point ROE of 11.75%. Thus, a 12% ROE shall be used for all regulatory purposes, including, for example, implementing the cost recovery clauses and allowances for funds used during construction.

2. Range on ROE

Gulf witness Bowden proposes to expand the range for ROE from the traditional 100 basis points on either side of the ROE mid-point to 150 basis points or more. We note that the record for this issue is more qualitative than quantitative. Mr. Bowden and Gulf witness Labrato provided only general statements supporting a wider range. Two reasons they cited were: 1) an expanded range for Gulf, according to Mr. Bowden, would encourage the high level of service; and, 2) an expanded range would aid Gulf in retaining its credit rating. We find that the record in this case does not contain specific evidence on how the expanded range would enhance the Company's bond rating.

Mr. Bowden provided a third reason for expanding [*55] the range. In his summary of his direct testimony, he stated:

> As I mentioned earlier, regulatory commissions are considering incentive-based approaches. I think to recognize our superior performance and the importance of continuing that performance in the future, at the low rates that I mentioned on page 7 of my testimony, I suggest two thoughts for the Commission's consideration: One is to increase the return on equity by some 50 to 100 basis points. The second one is to consider expanding the Commission's range that it uses from two hundred basis points to three hundred basis points.
>
> I believe these suggestions could be included in an incentive sharing plan, a plan that would be based on the performance measures that incent this company to provide highly reliable service at low rates with high levels of customer satisfaction.

We have historically allowed 100 basis points on either side of the ROE mid-point used to set rates. Gulf's current authorized ROE is 11.5% with a range of 10.5% to 12.5%. See Order No. PSC-99-1970-PAA-EI, issued October 8, 1999, in Docket No. 991487-EI. In recent gas rate cases, we set the range at 100 basis points around the ROE mid-point. See [*56] Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, in Docket No. 000108-GU; see also Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, in Docket No. 000768-GU.

We find that increasing the range should be the subject of an incentive plan addressed in a future proceeding. We also find that the range shall be set at 100 basis points because no witness has provided specific reasons for quantifying a specific range, either more or less than 100 basis points. Therefore, using 11.75% as the mid-point ROE, the range on ROE shall be 10.75% to 12.75%.

F. WEIGHTED AVERAGE COST OF CAPITAL

The appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with Gulf's projected test year ending May 31, 2003, is 7.92%. Gulf specifically identified the balances for ITCs, deferred income taxes, and customer deposits.

Based on the stipulations among the parties, the appropriate cost rate of long-term debt is 6.44% and the appropriate cost rate of short-term debt is 4.61%. The cost rate for preferred stock is 4.93%, and the cost rate for customer deposits is 5.98%. The deferred taxes should have a zero-cost rate. The cost rate for [*57] ITCs is 8.99%, based on the weighted average cost of investor's capital. For rate setting purposes the cost rate for common equity is 12.00%.

Using the Company's reconciled capital structure, we made the following three adjustments to the Company's jurisdictional capital structure. First, due to the change in depreciation, a specific adjustment of $ 662,000 to deferred taxes was made. Next, specific adjustments were made to reconcile investor sources with

Exhibit 11. Finally, a pro-rata adjustment was made over investor sources to reconcile capital structure to rate base.

Based on the relative amounts of investor capital, ITCs, deferred income taxes, customer deposits, and the respective cost rates, discussed above, the resulting weighted average cost of capital is 7.92%. Attachment 2 shows the components, amounts, cost rates and weighted average cost of capital associated with the May 31, 2003, projected test year capital structure.

VI. NET OPERATING INCOME

A. ZERO BASED BUDGET

Gulf Witness Saxon testified that the financial forecast is the basis for Gulf's projected data for the test year used in this rate case. The financial forecast is comprised of eight individual [*58] budgets: Construction, O&M, Interchange, Fuel, Revenue, Customer, Energy, and Peak Demand. Each of these budgets is reviewed and approved by the Company's Leadership Team, consisting of Gulf's executive officers.

The budget process begins with five major functional areas that are broken into 29 individual planning units. These planning units provide input into each of the eight individual budgets mentioned above. Each individual planning unit uses a modified zero based budget which gives the planning unit the ability to build its budget program each year.

Staff witness Bass testified that each planning unit develops its budget by FERC Subaccount. Each planning unit maintains supporting documentation for these developed amounts. If the planning unit is unable to develop budgeted amounts for a given expenditure, then inflation rates or customer growth rates may be used.

Corporate Planning reviews submittals for compliance with the Company guidelines and compiles the data for review by the CFO and leadership team. Any changes are documented and then the approved budget is sent to the planning units. Each planning unit monitors its budget to an actual comparison, using the accounting [*59] on-line system referred to as Southern Financial Information Access System (SOFIA). Quarterly reports are required that explain any variance of plus or minus 10 percent when the variance amount is greater than or equal to $ 25,000. Year-end projections are also received from each planning unit.

OPC stated in its brief that Gulf's budgeting process has resulted in numerous illogical results, such as those for substation maintenance expense, tree trimming expense, and pole line inspection expense. OPC observes that many account balances have been in a constant gradual growth pattern for years only to expand by an unprecedented increase in the projected test year. OPC maintains that any utility has the ability to "load up" the test year for setting rates, but this Commission must decide whether the projected activity will be the new norm. In other words, it is OPC's position that Gulf has the discretion to unilaterally decide to engage in the activity projected for the test year, but that fact alone does not make those activity levels representative of Gulf's ongoing future needs.

We find that Gulf's modified zero based budget shall be accepted. Staff's audit report (Exhibit 47) provided [*60] a disclosure on the budget process; no exceptions were taken. In addition, after the adjustments made in related issues are coupled with Gulf's budget, the projected test year budget resulting from the zero based budget methodology appears reasonable and appropriate.

B. OPERATION AND MAINTENANCE EXPENSE

Operation and maintenance (O&M) expense is a fallout calculation based on our decision in the following sections, as shown in Attachment 3. The appropriate level of O&M expense is $ 180,731,000.

C. SECURITY MEASURES

As discussed in Part IV, Section F, above, Gulf's MFRs and direct testimony were filed on September 10, 2001, and do not contain the impact of the increased threat of terrorist attacks since September 11, 2001 on test year operating expenses. Through discovery, Gulf provided information on these expenses. The discovery responses were granted confidential classification in Order No. PSC-02-0220-CFO-EI, issued February 22, 2002, in this docket.

Gulf Witness McMillan stated in his rebuttal testimony that premiums for the Company's all-risk property insurance policy, which covers both generating plants and general plant, increased by $ 380,000 (system) as a result [*61] of the terrorist events of September 11, 2001, and the deductible increased from $ 1 million to $ 10 million. In addition, Gulf elected to self-insure for property losses between $ 2 million and $ 10 million at an estimated cost of $ 243,000 per year (system). The sum of these property insurance expense adjustments is $ 578,000 ($ 623,000 system).

We find that the adjustment for depreciation expense related to the rate base security adjustments described in Part IV, Section F is $ 101,000 ($ 105,000 system). In addition, we find that the additional security-related operating expenses, not specified above, but approved for confidential treatment, are reasonable and appropriate. Those additional expenses are $ 166,000 ($ 173,000 system). The sum of the incremental property insurance expenses, depreciation expense, and other confidential expenses related to the increased terrorist threat for the test year is $ 845,000 ($ 901,000 system). Thus, we find that a jurisdictional adjustment (increase) of $ 845,000 ($ 901,000 system) should be made to test year operating expenses to reflect the cost of additional security measures implemented in response to the increased threat of terrorist [*62] attacks since September 11, 2001.

D. ADVERTISING EXPENSES

Gulf requested recovery of $ 1,145,000 in advertising expenses in the projected test year. Gulf seeks to recover $ 595,000 (system & jurisdictional) in advertising for Customer Service and Information Expense. Gulf also seeks to recover $ 550,000 ($ 539,000 jurisdictional) for Corporate Communications and Advertising.

Gulf witness Neyman explained that the utility has a two-step advertising expense philosophy. The first step is to develop trust, loyalty, and confidence in the utility. Once the customer believes in the utility, then the second step is to advertise to affect the customers' behaviors.

In its brief, OPC stated that advertising expense for corporate image building has been disallowed in the past because the ratepayers of any regulated utility are customers that are provided services in a monopolistic environment. Consequently, these customers cannot exercise a choice as to whether or not to pay for such advertising expenses.

OPC noted that its witness, Ms. Dismukes, pointed out that the requested advertising expense of $ 550,000 is purely image-enhancing in nature because the examples of ads do not inform [*63] the customers about products or services nor do they assist customers in any way. Ms. Dismukes explained that these ads are the type that have been disallowed.

Under cross-examination, Ms. Neyman agreed that the ads that the utility was requesting recovery for did not promote the utility's products and services but supported the efforts of the utility in an indirect way. She explained that the ads in the historical year ended December 31, 2000, were the same type of advertisements disallowed in the last rate case and would be the same that would be used in the projected test year. Further, Ms. Neyman is asking us to reconsider our past position on this type of advertising.

Ms. Dismukes testified that Order No. 6465, issued January 17, 1975, disallowed advertising expense related to enhancing the Company's image, and goodwill-type advertising. Ms. Dismukes referred to the ads in "Part C" of Exhibit 22 and states that these ads have been disallowed by Order No. 6465.

Contrary to Ms. Neyman's suggestion, Ms. Dismukes noted that not one of the ads in Part C of Exhibit 22 informs the customer about products and services available to assist customers "in making their home and businesses [*64] more enjoyable, comfortable and safe and provide for operation which is more energy efficient and, therefore, cost efficient." Ms. Dismukes further asserted that the ads do nothing to educate customers. The ads merely enhance Gulf's image with the customers.

Ms. Dismukes further noted that in Order No. PSC-96-1320-FOF-WS, issued on October 30, 1996, in Docket NO. 950495-WS, the Commission disallowed advertising costs related to image enhancement. Consequently, Ms. Dismukes argued that $ 550,000 in advertising expenses be disallowed.

Staff Witness Bass testified the utility removed $ 226,000 for image enhancing ads for the historical year, 2000, but did not remove $ 550,000 for image enhancing ads in the projected test year.

Mr. Bass identified two problems with Gulf's request to recover the cost of image enhancing ads in base rates. First, it runs afoul of Order No. 6465, issued January 17, 1975, in Docket No. 9046-EU. Docket No. 9046-EU was a general investigation into promotional practices of electric utilities. The order expressly disallows, for rate making purposes, "advertising which has as its primary objective the enhancement of or preservation of the corporate image of the [*65] utility." Recovery of image enhancement expenses was disallowed in Order No. 6465 because:

> Most, if not all, of this advertising is merely designed to improve the image of the utility in the eyes of the public. It has not been proven, in our judgment, that such programs reduce operating costs or result in greater operating efficiency nor do we see any tangible benefits to the customers.

The second problem Mr. Bass identified with Gulf's request was that the cost of image enhancing advertising increased dramatically from the historical year, 2000, to the projected test year. Gulf spent $ 226,000 on image enhancing ads in 2000 but requested $ 550,000 for the projected test year.

Under cross examination, Mr. Bass identified only one requirement that need be present in an ad in order to recover the full cost of the ad. The requirement was that the ad offer any information on conservation, safety or electric efficiency. Thus, even if the ad was also image enhancing, the full cost of the ad could be recovered if it also included, for example, the GoodCents logo. Mr. Bass also explained that if the ads contained information pertaining to conservation, safety, or customer information, [*66] the ad was allowed. Further, Mr. Bass agreed that the customer should not have to pay for image enhancing ads because the customer does not have a choice of electric utilities and to change this policy would break precedent established in Order No. 6465.

Under cross-examination, Ms. Neyman noted that Commission Order No. PSC-96-1320-FOF-WS, issued on October 30, 1996, in Docket NO. 950495-WS, stated:

> However, we recognize that the utility's conservation efforts need to gain support and trust from its customer in order to be successful.

Again, Ms. Neyman explained that these ads are critical to the success of Gulf's conservation programs.

OPC argued, that Mr. Bass disagreed with Ms. Neyman's premise about the need for the recovery of indirect advertising expense. OPC noted that Mr. Bass did testify that Gulf could communicate the substance of its educational messages, without engaging in these image enhancement types of advertising.

Gulf argued that Mr. Bass said that if the Commission should choose to change its policy that he would no longer have a concern with the Company's requested advertising expense being included in base rates. Gulf also argued that times have changed [*67] since Order No. 6465 because today's ads are focused on educating the consumer regarding product and services available to ensure the efficient use of energy.

We find that the Orders 6465 and PSC-96-1320-FOF-WS dictate that the cost of advertising that is purely image enhancing should not be recovered through base rates. Order No. PSC-96-1320-FOF-WS states:

> We agree with OPC that advertising expense only for image enhancement purposes should not be borne by the ratepayers.

However, that Order clearly acknowledged that it may be impossible to distinguish between advertising expense for image enhancement and advertising expense for public education and conservation. We allowed recovery of the advertising expense because it was not purely image enhancing. Rather, the advertisements were such that a single purpose for the ads could not be isolated.

We note that under Order 6465, the cost of ads that are both image enhancing and educational can be allowed in rate base. It is only ads that are purely image enhancing that are not allowed in rate base. The Orders are not in conflict.

We find that the ads in Part C of Exhibit 22 are purely image enhancing. Gulf does not refute this. [*68] For this reason the cost of the ads shall not be included in base rates, and Gulf shall not be allowed to recover the advertising expense of $ 539,000 ($ 550,000 system). The utility shall recover advertising expenses of $ 595,000, in Account 909, for Customer Service and Information Expense in the test year.

E. ACCRUAL FOR INCENTIVE COMPENSATION

OPC witness Schultz testified that the gross payroll and fringe benefits on Schedule C-33 in the MFRs included all compensation and benefits. Mr. Schultz further stated that the 2000 historical test year costs included an accrual of $ 10.8 million for bonuses or performance pay, which was an 83% increase over 1999. Mr. Schultz also compared the accrual for the compensation plan with the total gross payroll and fringe benefits and stated that the compensation plan was material to the total gross payroll and fringe benefits. Witness Schultz recommended disallowing the accrual and reducing expenses by $ 4,917,000.

Gulf witness Bell testified that Gulf's compensation philosophy is centered on the need to attract, retain, and motivate talented employees. In order to achieve these goals, Mr. Bell stated that Gulf offers a compensation plan [*69] that consists of base salaries and incentive compensation. Mr. Bell explained that base salaries are targeted at or near the median of a similar group of salaries. The additional incentive pay plan above the base pay allows the employees an opportunity to earn in the top quartile of the industry.

Mr. Bell asserted that in order to keep the employees focused on their performance, the incentive compensation must be re-earned each year. Mr. Bell explained that even though the incentive compensation portion for an individual employee may decline, the utility's total compensation expense will remain relatively constant over time because the base salaries rarely decline in amount. Therefore, the utility offers total pay that is market competitive. Lastly, only through performing well and meeting customer needs do employees have the opportunity to be paid at the top quartile of the industry.

Each year Gulf conducts an analysis of overall compensation using compensation surveys that are developed by independent consulting firms. Current analysis of these approximately 40 surveys shows that the utility's pay for each position is both consistent with its compensation philosophy and the current [*70] market.

On rebuttal, Gulf Witnesses Silva and Twery testified that Mr. Schultz's concerns were unfounded because the comparison of incentive compensation to gross payroll and fringe benefits is inappropriate. It is more appropriate to evaluate Gulf's total cash compensation against the market to insure competitiveness. The survey data (approximately 40 surveys) provides total cash compensation for various jobs in the relevant market.

Witnesses Silva and Twery explained that to ensure Gulf's pay policy is competitive, Gulf produces a Market Position report on an annual basis. Organizations are considered to be "at market" if their pay policy falls between +/- 10% of the market. An analysis of Gulf's pay policy to the market was conducted in August of 2001. The report confirmed Gulf's total compensation pay policy was within +/-5% for all job groups, on average, to the actual market pay levels.

Gulf's philosophy is to pay employees at the 75th percentile. To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore, an incentive pay plan is necessary for Gulf salaries to be competitive in the market. Another [*71] benefit of the plan is that 25% of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When the employees excel, we believe that the customers benefit from a higher quality of service.

We believe that OPC's adjustment to remove the increase in costs from 1999 to the 2000 historical test year is not justified. The utility did implement a new incentive compensation plan in 2000. Also, to compare the total incentive "cash" compensation to gross payroll is not a valid comparison. The total compensation plan should be compared to the market value for similar job groups.

We also believe that to analyze each individual's compensation for whether the base salary and incentive compensation, within each job group, is appropriate would be beyond the scope of the data collected from the individual utilities in the industry. Lastly, the utility is within +/- 5% of the market values for their overall compensation policy. As a result, its employees will be paid based on market value and the customers will receive quality service and low rates.

Based on the above, no adjustment shall be made to the accrual for incentive compensation.
[*72]
F. EMPLOYEE RELOCATION EXPENSE

Gulf's employee relocation plan covers a variety of costs involved in moving an employee and the employee's family. These costs include cost of living allowances, transportation, household goods moving and storage cost, closing costs, and other associated costs. The Company included in projected test year expenses $ 461,754 for employee relocations. The Company stated that it budgets relocation expenses based on the previous four years actual relocation expenses escalated for inflation.

In Gulf's last rate case, the $ 324,100 budgeted for relocations was found to be too high and was reduced. See Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI. In that Order we found that a reasonable approach was to use a four year average. Actual amounts were used in calculating the average and the average was not escalated for inflation. This approach was used because relocation expenses show wide variations from year to year and cannot be neatly extrapolated like salaries or plant maintenance expenses. For example, in this case the Company expensed $ 371,664 in 1997 to relocate nine employees or $ 43,516 each, compared with $ 335,664 in [*73] 1998 to relocate thirteen employees or only $ 27,179 each.

Based on Order No. 23573, we find that relocation expenses shall be reduced $ 15,832 ($ 16,832 system) based on a four year average of expenses. This adjustment reduces the Company's projected relocation expenses from $ 461,754 to $ 445,922.

G. SALARIES AND EMPLOYEE BENEFITS

OPC witness Schultz, testified that the projected test year had an increase of 48 employees and that he agreed with the 29 additional employees needed for Smith Unit 3. Mr. Schultz further stated that the remaining increase of 19 positions in the projected test year were not explained because in 1998 downsizing was the trend. In 1999, eight positions were added and in 2000 only five positions were added. Mr. Schultz emphasized that the utility should not have incorporated a significant increase in employee complement without providing any justification for the increase. Lastly, Mr. Schultz testified that an adjustment should be made to reduce payroll expense by $ 701,410, fringe benefits should be reduced by $ 131,177, and payroll tax expense should be reduced by $ 58,475 in order to remove the 19 positions from the projected test year.

On rebuttal [*74] testimony, Gulf witness Saxon testified that the projected test year expenses include additional expense for six cooperative educational students, 11 positions in Power Delivery for which employees are trained in an earned progression program, and two positions in the Company's Leadership Development program. Therefore, Mr. Saxon stated that these 19 positions should not be removed from the projected test year.

We find that the 29 positions are needed for Smith Unit 3. The utility should have positions in which the employees are trained in Power Delivery so that the qualified employees can fill vacant positions and power delivery will be uninterrupted. In addition, a Leadership Program is essential for the development of qualified employees as well as a qualified management team.

Gulf projected a test year complement of 1,367 employees. Mr. Saxon stated in his deposition, Exhibit 21, that the Company did not take into account a hiring lag in projecting the 1,367 employee complement. A hiring lag is the length of time before an employee is hired to fill a vacant position. Mr. Saxon further agreed that it would be appropriate to include a hiring lag adjustment that would reduce the [*75] projected payroll expenses. Mr. Saxon filed a late-filed exhibit to his deposition that reflected a hiring lag equivalent to 34 employees, and this hiring lag would reduce projected O&M expenses by $ 323,635, ($ 330,628 system) including fringe benefits and a payroll tax adjustment of $ 19,274 ($ 19,690 system). We find that the hiring lag adjustment is consistent with a similar adjustment made in the Company's last rate case, Order No. 23573.

Based on the above, projected O&M expenses shall be reduced by $ 323,635 ($ 330,628 system) and payroll taxes be reduced by $ 19,274 ($ 19,690 system).

H. TRANSACTIONS WITH AFFILIATED COMPANIES

Gulf is a wholly owned subsidiary of Southern Company, which is the parent company of five southeastern utilities and other direct and indirect subsidiaries. The Public Utility Holding Company Act (PUHCA) regulates Southern Company and its subsidiaries. With the exception of Southern LINC, all affiliates provide services and materials to Gulf at cost in accordance with PUHCA. Southern LINC provides telecommunications services to Gulf at market cost.

Contracts among the southeastern utilities related to jointly owned generating facilities, interconnecting [*76] transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). Southern Company Services (SCS), the system service company, provides at cost specialized services to Southern Company and its subsidiary companies. SCS services include general executive and advisory services, engineering, purchasing, accounting and auditing, finance, marketing and public relations, insurance, rate, employee relations, and, in the case of the operating utilities, power pool operations. All SCS costs are either directly charged or allocated to Southern's affiliates through a work order system.

The SCS allocation methodology is approved and periodically audited by the SEC. All of the allocation methods are derived from system statistics that reflect the size of each company relative to the entire Southern Company. Percentages for these allocation methods are updated annually by Gulf. To derive the allocation factors, Gulf uses historical statistics based on a single year with a one-year lag; therefore, 2001 allocations were based on 1999 statistics.

The allocation factors applied by the Company in [*77] its MFRs were based upon 1999 data. OPC witness Dismukes testified that because Gulf's allocation factors do not reflect the high growth of its non-regulated affiliates for the period 1999 to 2003, Gulf's customers will end up subsidizing non-regulated activities. Therefore, Ms. Dismukes modified the allocation factors to include additional allocations to Southern Power Company (SPC), a new subsidiary that the Southern Company expects to grow at a rate of 15% per year. SPC will own, manage, and finance wholesale generating assets in the Southeast.

Ms. Dismukes modified data to reflect what could be expected for SPC in 2003. The fossil allocation factor, which is based upon the KW capacity of the various companies' plants, was modified to recognize the expected generation from SPC in 2003. There were several allocation factors where 2003 information was not readily available. For these factors, Ms. Dismukes adjusted the amounts for SPC by increasing them by a factor of seven based upon the relationship between the 2001 KW capacity of SPC compared to the KW capacity expected for SPC by 2003.

For allocation factors where no information for SPC was available (e.g., for allocation factors [*78] that use employees as the allocation basis) Ms. Dismukes adjusted the factor for Gulf downward by the average of the change in all other allocation factors where data was available.

In addition, Ms. Dismukes removed the revenue component from two allocation factors that included revenue, expenses, and investment as components. She believes that including revenue in these two factors underallocates costs to new non-regulated companies because new companies in the start-up phase of operations produce little revenue relative to investment expenses. Allocation factors that used customers as the basis were not modified. Ms. Dismukes' factors did not reflect increases for growth in the other non-regulated companies. The above adjustments to the allocation factors resulted in Ms. Dismukes recommending a reduction in costs allocated to Gulf of $ 1.4 million.

Gulf witness McMillan testified that the amounts used to project O&M related to affiliate transactions were based upon the best information available at the time Gulf prepared the test year data for the original filing in this case. He believes that Ms. Dismukes' modification of the allocation factors using projected or estimated 2003 [*79] data for SPC is flawed by numerous errors and inappropriate assumptions.

Mr. McMillan stated that components of allocation factors reviewed and approved by the SEC can not be arbitrarily changed. Another criticism he had of Ms. Dismukes' testimony was that overall increases in total SCS allocated costs were ignored, as were changes in other affiliates' statistics; these allocations may offset the impact of adding SPC into the allocation. For example, while increasing capacity related allocations to include SPC, the increase in capacity related to Gulf's Smith Unit 3 and other Southern generating capacity additions were ignored. It appears that Mr. McMillan's position is that increasing the capacity factor for SPC and the other affiliates would reduce the amount allocated to Gulf while increasing the factor for Gulf would increase the allocation to Gulf.

In addition, Mr. McMillan stated that Ms. Dismukes assumed that all allocated costs were charged to O&M expense, when in fact, her proposed adjustment to O&M included capital and below-the-line charges. Mr. McMillan disagreed with Ms. Dismukes' use of a factor of seven to estimate some of SPC's statistics. He stated that there is [*80] no basis for using such a factor because there is no support for a correlation in the relationship between the increase in SPC's KW capacity and the statistics. A larger portion of SCS's costs were allocated to SPC by using this methodology.

Mr. McMillan further noted that the period of time selected by Ms. Dismukes, calendar year 2003, extends beyond the test year which ends in May of 2003, and she incorrectly assumes that SPC should receive allocations for all SCS activities except those based on customers. For example, she failed to exclude activities, such as transmission and distribution related activities, which are not related to generation, and therefore not applicable to SPC.

Mr. McMillan tested the reasonableness of the projected test year allocated amounts by looking at two scenarios. First, he updated the allocation factors to include year 2000 data, the most current historical data available, which reflects the inclusion of SPC. These factors were applied to the 2003 projected test year amounts used in preparing the MFRs. Next, he compared the test year SCS O&M amounts to the recently completed SCS 2002 budget. In both cases, the amount allocated to Gulf was more than [*81] the amount included in the projected test year. Therefore, Mr. McMillan concluded that the projected test year

O&M expenses related to affiliated transactions are conservative, and are understated.

In the 2003 projected test year, $ 20,420,000 of SCS costs (capital, expense, and below-the-line charges) were allocated to Gulf. Ms. Dismukes made many assumptions, projections, and estimates in modifying the allocation factors she applied to the 2003 SCS costs.

We find that Mr. McMillan's evaluation of Ms. Dismukes' modifications is correct. In particular, we are influenced by the fact that costs were allocated to SPC for all SCS activities when SPC should not have received allocations for transmission and distribution. SPC owns generation only, therefore costs related to transmission and distribution are not applicable to SPC. This would incorrectly reduce allocations to the other affiliates.

We also find that the components of the SEC approved allocation factors should not be changed. When Gulf desires to change its allocation methodology, approval must be obtained from the SEC. By removing the revenue component, Ms. Dismukes' factors are no longer in compliance with SEC approved methodology. [*82]

In addition, we find that in order to calculate the appropriate allocations, statistics for all the affiliates should reflect the same time period in accordance with the matching principle. If factors are updated to reflect 2003 statistics for SPC, then the factors should be updated to reflect 2003 statistics for all the affiliates in order to create a level playing field and to fairly allocate costs. Total SCS costs will also be increased by updating to 2003, amounts and some affiliates will have increases while others will have decreases to their statistics as a result of changes in 2003. It is not appropriate to pick and choose which affiliates' statistics to update.

Further, Ms. Dismukes allocated costs that should have been capitalized or recorded below-the-line. This would incorrectly increase O&M expenses for all affiliates. Finally, we find that the use of a factor of seven to increase SPC amounts and adjusting some factors downward by the average of the change in all other allocation factors is arbitrary. There is no true correlation between these measures and the statistics to which Ms. Dismukes applies them.

Based on the above, we find that the level of allocated costs [*83] included in the 2003 test year is reasonable and representative of future costs. No adjustments are necessary.

I. ACCRUAL FOR PROPERTY DAMAGES

Gulf included in projected test year expenses, $ 3,245,000 ($ 3,500,000 system) for the accrual to the Accumulated Provision for Property Insurance (reserve). The accrual, which was approved in Order No. PSC-96-1334-FOF-EI, issued November 5, 1996, in Docket No. 951433-EI, increased the reserve balance at the end of the projected test year to $ 16.5 million, including projected charges to the reserve. In his rebuttal testimony, Gulf witness McMillan testified that the projected charges to the reserve were based on very conservative estimates, for example, no costs were projected for hurricane damages. Mr. McMillan further testified that as a result of the terrorist events of September 11, 2001, property insurance costs increased. Premiums for its insurance policies covering its generating and general plant increased $ 380,000 or 60% while increasing uninsured deductibles $ 1 million. Mr. McMillan states that this increase in uninsured deductibles will increase future charges to the reserve.

OPC witness Schultz testified that the [*84] Company's authorized annual accrual of $ 3,500,000 since 1996, and average annual charges against the reserve of $ 1,536,000 since 1996, have resulted in an increase in the reserve balance to $ 8,731,000. Based on a continuation of the accrual the reserve balance will be $ 16,488,000 at May 31, 2003. Mr. Schultz further testified that the annual accrual should be reduced to $ 1,679,616 resulting in a reduction of $ 1,680,384 to the projected test year expense. The reduced accrual is based on a five year average of annual charges to the reserve escalated by an inflation multiplier. In his opinion, the adjusted accrual is reasonable and would offset any charges and still maintain the current reserve balance.

Gulf had a balance of approximately $ 12 million in its reserve as of August 2, 1995. On August 3, 1995, Hurricane Erin caused $ 11 million in damages which were chargeable against the reserve. Two months later Hurricane Opal caused an additional $ 9 million in damages, also chargeable against the reserve. The damages from the two storms resulted in a negative balance in the reserve of approximately $ 9 million.

Based on the financial impact of the two storms, Gulf filed a petition [*85] requesting that it be allowed to increase its annual accrual to the reserve from $ 1.2 million to $ 3.5 million. In Order No. PSC-96-0023-FOF-EI, issued January 8, 1996, in Docket No. 951433-EI, we recognized that even increasing the accrual to $ 3.5 million, effective October 1, 1995, with additional charges, the reserve would have a negative balance until late 1997. In that Order we found the situation to be undesirable because the Company was in a self-insurance position. Gulf's request to increase its accrual was temporarily approved and the Company was ordered to file a storm damage study to determine the reasonableness of the proposed $ 3.5 million accrual.

Upon our receipt and review of the study, we allowed Gulf to continue the annual accrual of $ 3.5 million. In approving Gulf's request we stated that the primary concern was that the level of the accrual be sufficient to cover annual damages and promote growth in the reserve. We also required the appropriate target level for the reserve to be between $ 25.1 and $ 36 million. The balance in the accumulated provision account was $ 8.7 million as of December 31, 2000, and the balance is projected to be $ 16.5 million by May [*86] 31, 2003. The projected balance is based on $ 297,000 in charges to the reserve in the year 2000, and $ 324,000 in each of the years ending May 2002 and 2003.

We find that Gulf shall continue its $ 3.5 million annual accrual until the ordered target level is reached. The accrual and target levels shall only be changed based on a review of an in depth storm damage study. We find that OPC's proposal is not reasonable because it would not allow Gulf to reach the approved target level especially if Gulf were to sustain hurricane damage as in the past. If this were the case, Gulf could possibly have charges to the reserve which would put it in a negative reserve balance. This is contrary to the above referenced Order which states that it would not be desirable to have a negative balance since the Company is in a self-insurance position.

J. RATE CASE EXPENSE

In Direct Testimony, Gulf witness Labrato requested $ 1,383,500 in rate case expense to be amortized over four years. Gulf explained that in its last rate case, a four year amortization period was approved. The rate case expense for this case would be $ 345,875 using a four year amortization period.

OPC witness Schultz testified [*87] that an adjustment is needed to the $ 603,000 in legal expense because in the prior rate case the legal expense was $ 188,953, and this requested increase would be a 219.13% increase. Mr. Schultz reduced estimated legal fees by $ 153,223 for a total rate case expense of $

1,230,277. Mr. Schultz also used a six year amortization period for annual rate case expense of $ 205,046, and a recommended test year reduction of $ 140,829.

Because of the shortened hearing schedule Mr. Labrato was asked to file a late-filed exhibit reflecting the Company's most up to date estimate of rate case expense. Accordingly, Gulf filed late-filed Exhibit 55 showing the Company's revised expense compared to its original estimate. The table below shows the comparison, along with our approved expenses.

Item	Original Filing	Gulf's Revised Rate Case Estimate	Approved Rate Case Expense
Outside Consultants	$ 200,000	$ 240,000	$ 200,000
Legal Services	603,000	$ 550,000	$ 550,000
Meals and Travel	125,000	$ 55,000	$ 55,000
Paid Overtime	40,000	$ 70,000	$ 40,000
Other Expenses	415,500	$ 418,000	$ 418,000
Total	$ 1,383,500	$ 1,333,000	$ 1,263,000

In its brief, OPC argued that [*88] late-filed Exhibit 55 raises additional concerns because the "Outside Consultants" estimate increased from $ 200,000 to $ 240,000 and "Paid Overtime" also increased $ 30,000 without any additional justification from the utility. OPC recommends $ 200,000 for outside consultants, $ 449,777 for legal services, $ 55,000 for meals and travel, $ 40,000 for paid overtime, and $ 418,000 in Other Expenses for a total of $ 1,162,777 in rate case expense. With a six year amortization period, the annual amortized rate case expense would be $ 193,796.

We have broad discretion in deciding what should be allowed in rate case expense. See Meadowbrook Utility Systems v. Florida Public Service Commission, 518 So.2d 326 (Fla. 1st DCA 1987). We find that the utility has not provided sufficient justification to recover the additional $ 40,000 for Outside Consultants or the additional $ 30,000 for overtime costs. A late-filed exhibit was required because the hearing lasted two days instead of five, an undisputed fact. The increases in "Outside Consultants" and "Paid Overtime" are unsupported by the record.

Based on the above, the Company's per filing amount of rate case [*89] expense shall be reduced by $ 120,500. Using a four year amortization period, the annual rate case expense is $ 315,750 for a test year reduction of $ 30,125 ($ 345,875 - $ 315,750) to O&M expenses.

K. MARKETING EXPENSES FOR ELECTRIC APPLIANCES

Gulf's Water Heating Conversion Program allows customers to replace existing gas-fired water heaters with free, energy-efficient electric water heaters. As a result, the Program increases Gulf's winter peak demand by 0.25 KW per customer and annual energy consumption by 4,367 KWh per customer. Although the program does not reduce peak load or kwh consumption, it is cost effective and reduces the bills of participating and non-participating customers. It also improves Gulf's load factor, thereby increasing the efficiency with which Gulf's plants are used.

We find that this program has a net benefit for the general body of rate payers and that it is appropriate to recover, through base rates, the cost of marketing the program. However, we also find that Gulf has the burden of demonstrating, on an ongoing basis, that the program continues to be cost effective. If the program stops being cost effective, Gulf shall bring this matter back before [*90] us.

L. PRODUCTION EXPENSES

For the projected test year period from June, 2002, to May, 2003, Gulf estimates that production O&M expense will be $ 77,202,000. This level exceeds the test year benchmark by approximately $ 10,714,000. We note, however, that the baseline for benchmark comparisons was set twelve years ago in 1990, at Gulf's last rate case. Furthermore, Gulf's requested test year production O&M expense is approximately $ 9.5 million less than the 5-year average projected for the 2002-2006 time period.

Gulf witness Moore identified and justified the reasons for the increase in production O&M. He cited three primary factors for the increase:

> The addition of new generating units - Mr. Moore testified that the addition of Smith Unit 3 and the Pea Ridge cogeneration station, both combined cycle units, result in a benchmark variance of $ 3,840,000 in the "Production Steam" subcategory.
>
> The increase in generation from an aging steam generation fleet, coupled with a more proactive maintenance philosophy - Mr. Moore testified that substantially increased costs to maintain and operate Gulf's aging fleet of steam generating units have resulted in improved reliability [*91] and reductions in outages. These factors, coupled with a 37% increase in generation, result in a benchmark variance of $ 5,786,000 in the "Production Other" subcategory.
>
> The $ 1,088,000 benchmark variance for the "Production Other Power Supply" subcategory - This variance results from two items: (1) increased costs related to Gulf's share of operating the Southern Company's wholesale energy trading floor; and, (2) increased costs to operate the Power Coordination Center, whose responsibility is to carry out bulk power supply operations including those required by FERC Orders 888, 889, and 2000.

OPC Witness Schultz recommends that production expenses be reduced by $ 10,251,700. However, he did not identify any specific items to be disallowed. In forming his opinion, Mr. Schultz relied on his prefiled testimony exhibit which appears to show that Gulf's production expenses in the test year are forecasted to exceed 2000 levels. Mr. Moore testified that Mr. Schultz made an erroneous conclusion because his prefiled testimony exhibit does not include all dollars allocated to production expense.

We find that Gulf has provided sufficient identification and justification of its test-year [*92] production expenses. Therefore, no adjustments shall be made. OPC did not identify any specific item in Gulf's testimony or exhibits on which it disagreed with Gulf's conclusions.

M. CABLE INSPECTION EXPENSE

The Company budgeted $ 166,000 in the 2003 projected test year for a cable inspection and injection program. Before 1990, Gulf had over 600 trench miles of underground cable installed. Gulf is instituting a program to inject a silicone fluid into the cable to remove water and fill voids. This process has proven to retard the deterioration of the cable insulation and extend the life of the underground cable. A warranty by the manufacturer of the cable injection process carries an unconditional 20-year guaranty. Through implementation of the program, Gulf believes the likelihood of future outages caused by the premature failure of the older cables can be reduced. The Company has identified 28 miles of cable that will benefit from the injection process and anticipates injecting approximately four and a half miles per year. The project is anticipated to take about six years to complete.

Projects designed to extend the life of capital assets are normally capitalized. The cable [*93] injection process has been treated as a maintenance expense by Gulf because there was no installation or removal of a plant or property unit involved. Further, the cable injection did not qualify for a retirement unit code under the Company's capitalization guidelines, and Gulf believed its accounting treatment was consistent with that of other utilities. However, by Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, in Docket No. 931231-EI, we determined that cable injection costs should be capitalized and recovered over the associated guarantee period. Cable injection costs will be recorded with underground cable costs in Account 367 which has a stipulated 20-year average remaining life and resulting 3.0% remaining life rate. Since the guarantee period matches the remaining life of the account, the cable injection costs shall be capitalized and depreciated over the life of the associated cable.

FEA, FIPUG, and OPC are in agreement that the cable injection costs should be capitalized. However, the parties have not proposed specific adjustments to rate base, maintenance expense, or depreciation expense. Although Gulf believes that it has properly classified the costs as an [*94] expense, it has no objection to capitalizing these costs.

In its brief, Gulf stated that if the cable injection program is capitalized, O&M expense should be reduced by $ 166,000 and Plant-in-Service, Accumulated Depreciation, and Depreciation Expense should be increased by $ 152,000, $ 2,000, and $ 4,000, respectively. It appears that Gulf assumed that the project will go into plant in the first month of the projected test year. Staff can find no record basis for Gulf's adjustments to rate base and depreciation expense. No evidence was presented as to the date the project begins or the months in which the injections will take place. Based on our prior practice when project dates are unknown, adjustments are calculated based on the assumption that the $ 166,000 project will go into plant evenly over the 2003 test year at one twelfth per month. Therefore, we find cable injection expense shall be removed from O&M expense, capitalized in Account NO. 367, Underground Conductors and Devices, and depreciated over the life of the associated cable. We also find O&M Expense shall be reduced by $ 166,000 and Plant-in-Service, Accumulated Depreciation, and Depreciation Expense be increased [*95] by $ 83,000, $ 865, and $ 2,490, respectively.

N. SUBSTATION MAINTENANCE EXPENSE

Gulf Witness Fisher presented direct testimony stating that test-year substation maintenance expense should be increased over the total for 2000 due to three factors: 1) an additional $ 555,000 to prevent failures of aging substation equipment; 2) $ 200,000 increased maintenance expenses for new substation transformer banks, breakers, and capacitor banks installed between 2001 and 2003; and 3) $ 60,000 additional annual expense to prevent insulator arching due to salt contamination at one distribution substation. These factors account for $ 815,000 of the total requested test-year increase in substation maintenance expense over the total for the year 2000 of $ 829,744. The total substation maintenance expense requested by Gulf is $ 1,647,000. This requested amount exceeds its benchmark level by $ 266,000.

OPC Witness Schultz presented testimony questioning the need for these proposed increases, noting that Gulf's actual substation maintenance expense in 1999 and 2000 and budgeted substation maintenance expense for 2001 were lower than the benchmark levels for those years, and that Gulf's requested [*96] increase was not reflected in its 2001 budgeted expenses.

Mr. Schultz calculated an Indexed Five-Year Average of Gulf's substation maintenance expenses over the years 1996 through 2000. Mr. Schultz inflated each historic year's total annual expenses to make them comparable to test year expenses in terms of customers served and price levels and averaged the inflated expenses over the five years. Mr. Schultz's Indexed Five-Year Average of Gulf's substation maintenance expense is $ 1,255,684. Mr. Schultz offered this average as the reasonable level of substation maintenance expense, noting that this recommended expense level is $ 438,838 or 54% more than was actually expended in the year 2000. This recommended expense level represents an adjustment of $ 391,000.

On rebuttal, Mr. Fisher testified that in the years 1999, 2000, and 2001, substation maintenance expense was lower than normal due to six substation electricians normally assigned to substation maintenance being temporarily assigned to substation plant construction. These six substation electricians returned to their maintenance activities at the beginning of 2002. Mr. Fisher thus contends that Mr. Schultz's Adjusted Five-Year [*97] Average is not representative of future periods.

Mr. Fisher detailed the additional $ 555,000 over actual 2000 expense intended to prevent failures to aging substation equipment as consisting of $ 422,200 in additional salaries and $ 132,800 in additional material cost, and he detailed the $ 200,000 expense increase intended for maintenance of the new substation facilities as $ 141,000 in additional salaries and $ 59,000 in additional material cost.

Mr. Fisher explained the need for $ 60,000 additional annual expense to prevent insulator arching due to salt contamination at one distribution substation. This substation is located near the Escambia River. In periods of low rain, the salt content of the river water increases. This causes salt corrosion to build up on the substation's insulators. The $ 60,000 is requested to clean the insulators in this substation to prevent arching and outages.

Mr. Schultz compared Gulf's 1999 and 2000 substation maintenance expenses with their respective benchmark levels which exceeded actual expenditures. Those years' actual expenses and benchmark expense levels appear in the following table along with the same data for 1996-1998. The benchmark levels [*98] for 1996-1998 are calculated using the $ 754,000 Commission approved expense level in 1990 and the Inflation and Growth Compound Multipliers for those years.

Actual and Benchmark Expense Levels

Substation Maintenance

Year	Actual Expense	Benchmark Level	Difference
1996	$ 1,059,337	$ 1,033,915	$ 25,422
1997	$ 938,694	$ 1,092,184	(153,490)
1998	$ 1,488,667	$ 1,148,478	$ 340,189
1999	$ 861,904	$ 1,196,666	(334,762)
2000	$ 817,256	$ 1,263,056	(445,800)

We note that in the three years prior to the reassignment of the six substation electricians, Gulf's substation maintenance expenses exceeded the annual benchmark levels by an average of approximately $ 70,000 per year. We find that Gulf has accounted for the decreases in 1999 and 2000, and its expenses falling short of their benchmark expense levels in those years.

With Gulf's explanation of its decreases in substation maintenance expense by the transfer of the substation electricians away from substation maintenance for 1999-2001 and their return in 2002, its additional substation maintenance activities planned for the test year, and its pre-1999 annual substation maintenance expenses, we find that [*99] Gulf's requested test-year substation maintenance expense is a reasonable estimate of an appropriate level of test year expenses. We find that Gulf demonstrated the need for the expense level it requested for the test year, and no adjustment shall be made to this category.

O. TREE TRIMMING EXPENSE

Gulf witness Fisher presented testimony requesting $ 4,123,000 for annual tree-trimming expense, $ 2,488,000 greater than the actual tree-trimming expense for the year 2000. Mr. Fisher stated that as a result of efforts to reduce costs, Gulf is presently relying on spot trimming. He also noted that Gulf started to depend more on spot trimming beginning 5 years after the last rate case, and that as a result, tree related outages have risen. The present level of tree trimming is estimated by the witness to be roughly a "seven year cycle that includes the use of spot trimming." Mr. Fisher stated that the increase in tree-trimming expense is intended to cover a three-year tree-trimming cycle, which would result in reduced outages. Mr. Fisher does not believe that Gulf has achieved a three-year tree-trimming cycle since determining this to be the optimal cycle in 1981.

OPC Witness Schultz [*100] questioned the need for the increase of $ 2,488,000. Mr. Schultz noted that in the year 2000, Gulf budgeted $ 3,010,997 and expended only $ 1,634,914 for this activity, and for the year 2001, Gulf budgeted only $ 1,639,694. Mr. Schultz further questioned the need for a more proactive position with regard to improving distribution reliability, since Gulf's customers site reliability as one the Company's strengths.

Mr. Schultz calculated an Indexed Five-Year Average of Gulf's tree-trimming expenses over the years 1996 through 2000. He inflated each historic year's total annual expenses to make them comparable to test year expenses in terms of customers served and price levels and averaged the inflated expenses over the five years. Mr. Schultz' Indexed Five-Year Average of Gulf's tree-trimming expense is $ 2,743,625. Mr. Schultz offers this average as the reasonable level of tree-trimming expense. This recommended expense level represents an adjustment of $ 1,379,000.

Mr. Fisher testified on rebuttal testimony that the number of miles trimmed has declined from 889 miles in 1998 to 241 in 2000. The expenses associated with these numbers of miles trimmed are $ 2,656,185 and $ 1,634,914, [*101] respectively. The numbers of minutes of interruption due to tree related outages increased from 1,557,000 minutes to 5,988,000 minutes over the same period. The planned number of miles trimmed in the test year is 1,710 miles. This is the number of miles of tree-trimming activity for which the $ 4,123,000 test year expense request is made.

We find that more tree-trimming activity is needed to counter the increased interruption minutes that have accompanied the reduced numbers of miles trimmed since 1998. We agree that Gulf's level of distribution reliability is presently at a satisfactory level.

Due to the satisfactory performance by Gulf in spite of declining tree-trimming activity, not all of the additional expense requested is necessary. We do not agree with Mr. Schultz that including the 1999 and 2000 expenses in an Indexed Average is appropriate for test-year tree-trimming budgeting purposes, when tree-trimming activity during those years was significantly reduced from previous years' levels and those reductions were accompanied by increased numbers of tree-related interruption minutes.

We find that the level of service that Gulf delivers to its customers in this area should [*102] return to, at a minimum, the level delivered in 1998. In that year, Gulf trimmed 889 miles of distribution line with associated expenses of $ 2,656,185. For purposes of calculating OPC's Adjusted Five-Year Average, Mr. Schultz inflated that level of expense to the test year, accounting for customer growth and price level increases. The inflated number of dollars is $ 3,193,000. This expense level should be great enough to fund a level of activity comparable to the tree trimming carried out before Gulf switched to the less systematic program of spot trimming.

We find that tree trimming is an expense category wherein the budgeted amount should be closely tied to the benchmark, and the budgeted amount should be spent for the purpose intended in order to avoid significant increases in minutes of interruption. We find that the annual expense of $ 3,193,000 is sufficient for Gulf to perform a reasonable level of tree trimming and maintain its present level of distribution reliability. This represents a $ 930,000 (jurisdictional) reduction of the requested test-year expense for Account 593, maintenance of overhead lines.

P. POLE LINE INSPECTION EXPENSE

Gulf Witness Fisher requested [*103] $ 734,000 for Gulf's pole-line inspection program for the test year. This amount is a $ 734,000 increase over the pole-line expenses for the year 2000. Mr. Fisher described the pole-line inspection program as an effort to treat, repair, or replace 60,000 poles installed prior to 1980.

Mr. Fisher explained that in the early 1980's, Gulf switched to using Chromium Copper Arsenate (CCA) treated wood poles with superior decay resistance. Plans for treating the 60,000 poles, over the next five years are based on Gulf's experience so far in treating 48,000 such poles beginning in 1991.

OPC witness Schultz calculated an Indexed Five-Year Average of Gulf's pole line inspection expenses over the years 1996 through 2000. Mr. Schultz inflated each historic year's total annual expenses to make them comparable to test-year expenses in terms of customers served and price levels he then averaged the inflated expenses over the five years. Mr. Schultz's Indexed Five-Year Average of Gulf's pole line inspection expense is $ 207,274. Mr. Schultz offered this average as the reasonable level of pole line inspection expense. This recommended expense level represents an adjustment of $ 527,000.

On rebuttal [*104] Mr. Fisher testified that the age of the poles remaining to be treated - now all the poles are over 20 years old - is a factor to be considered in projecting expenses to the test year. Mr. Fisher described the process envisioned for the proposed pole line inspection program. Following its work with the remaining 60,000 line poles, Gulf will need to reinspect the original 48,000 line poles treated in the 1990's.

Mr. Fisher stated that in the future, Gulf will need to inspect the poles installed since 1980, which have superior wood decay properties compared to those installed prior to 1980. He noted that some of those poles are now twenty years old and their exact condition is not known. Mr. Fisher stated that although the numbers of poles to be inspected should be smaller at the end of five years, the number of poles in service to be inspected and maintained will continue to grow, so Gulf will continue to incur expenses for this activity.

Mr. Schultz's claim that the requested $ 734,000 is excessive is based partly on the difference between the rate of replacement before the test year (48,000 poles in 10 years) and the rate proposed for the test year and beyond (60,000 poles in 5 [*105] years). Mr. Schultz also questions Gulf's intentions to engage in this activity to the extent planned due to the absence of any expenses in 1999 or 2000, and no expenses budgeted for 2001.

Mr. Fisher pointed out that Gulf embarked on the pole line inspection program in the early 1990's and that its funding has had to come from existing programs. Mr. Fisher also noted that in the late 1990's, funding for this program and others was reduced due to Gulf's efforts to prepare for the transition to Y2K.

We find that this inspection program enables Gulf to make repairs necessary to avoid more expensive repairs in the future. We also find that Gulf's efforts to inspect, treat, reinforce, or replace the remaining 60,000 poles should be accelerated, as all of these poles are now over 20 years old. For these reasons no adjustment shall be made to pole line inspection expense.

Q. STREET AND OUTDOOR LIGHT MAINTENANCE EXPENSE

Gulf Witness Fisher estimated the test year street and outdoor light maintenance expense based on the growth in the number of street lights and the effects of group relamping in certain areas. Between 1990 and 2000, the number of lights maintained by Gulf increased [*106] by 263%. To account for increases in total maintenance expense, the number of dollars allowed in 1990 was escalated by that percentage to $ 1,328,000. To that amount, Mr. Fisher added $ 110,000 to account for additional lights and planned group relamping. Thus, the test-year expense proposed by Mr. Fisher is $ 1,438,000. This amount is proposed for two accounts, Account 585, street lighting and signal system expense, and Account 596, maintenance of street lighting and signal systems.

OPC Witness Schultz testified that applying the growth rate since 1990 for the number of lights is not the appropriate method for projecting future expenses, as maintenance expense per light has declined since 1990. Mr. Schultz calculated the Five-Year Average of Gulf's street and outdoor light maintenance expenses over the years 1996 through 2000. This average was not adjusted for cost of living increases or for customer growth. Mr. Schultz's claim that maintenance expense per light has decreased since 1990 is supported by the fact that while the number of lights doubled during this period, expenses increased by only 63 percent.

Mr. Schultz calculated the annual average expense per light and average [*107] of annual averages for 1996 - 2000. The average of the five annual averages is $ 7.86. Mr. Schultz then multiplied the five-year average by his estimated number of lights in service for the test year, 142,255, to arrive at the estimated total street and outdoor light maintenance expense of $ 1,118,000, which he recommended as the total expense for this category. Mr. Schultz thus recommends a reduction of $ 320,000 in street and outdoor light maintenance expense.

On rebuttal Mr. Fisher testified that the cost of group relamping in the test year was $ 425,600, or $ 38 per unit for the 11,200 lights expected to be replaced, On direct Mr. Fisher stated that the group relamping program reduces inefficiencies of individually relamping street lights as they fail. However, he was not able to demonstrate how greater efficiency could be achieved by adding the expense of group relamping for a subset of Gulf's lights to the total cost of maintaining all lights.

We find that expense maintenance per light has decreased since. 1990. We also find that the component of Gulf's proposed expense consisting of the total expense inflated by growth in the number of lights since 1990 would overstate the [*108] appropriate expenses for street and outdoor light maintenance. Therefore, the additional expense proposed by Gulf for group relamping is not justified.

Although we do not believe that the additional expense for group relamping in the test year is justified, we note that Gulf performed some group relamping in 1998 and the expenses for that year are included in Mr. Schultz's five-year average. We agree with Mr. Schultz that the product of the Five-Year-Average of Gulf's street and outdoor light maintenance expense and the estimated number of lights in the test year represents a reasonable level for street and outdoor light maintenance expense ($ 1,118,000). For these reasons a jurisdictional adjustment (reduction) of $ 320,000 shall be made to Gulf's test-year street and outdoor light maintenance expense.

R. CUSTOMER ACCOUNTS - POSTAGE EXPENSE

OPC witness Schultz testified that the postage expense was $ 1,114,054 in 2000 and $ 1,645,717 in the test year which was an increase of $ 531,663, or 48%. Mr. Schultz stated that Gulf's filing does not provide any explanation for such an increase and requested detail was not provided. Consequently, Mr. Schultz recommended a $ 427,975 decrease [*109] in postage expense.

On rebuttal, Gulf witness Saxon testified that an error was found in the breakdown of expenses budgeted to Account 903-Postage and Account 903-Operations. The budgeted postage expense should have been reduced by $ 489,000, and, instead, budgeted in the operations account. If the correct amount were budgeted in the test year, the balance in Account 903-Postage Expense would have been $ 1,156,635, which compares favorably to the 2000 actual postage expense of $ 1,114,054. Even with the budgeted increase of $ 489,000 for Account 903-Operations, the test year amount would still be under the 2000 actual expenses for this account.

We find that no adjustment is necessary after the correction of the $ 489,000 error in the budgeted postage and operation accounts for the test year was made.

S. CUSTOMER RECORDS EXPENSE

OPC witness Shultz testified that the utility requested customer record expense of $ 3,102,769 for the projected test year is $ 743,942 higher than the 2000 actual expense of $ 2,338,827.

On rebuttal, Gulf witness Saxon testified that a change in the allocation of corporate and district facility operation and maintenance expenses was made in 2001 to [*110] more accurately assign the expenses to the various business functions. Mr. Saxon testified that the customer expense accounts would then be $ 657,754 higher in the projected test year. Mr. Saxon explained that an adjustment is not justified because of the change in the allocation method.

In its brief, OPC accepted Gulf's explanation that a change in the Company's accounting mechanics was the cause for the apparent excess in this account. We also find Gulf's explanation to be acceptable. Therefore, no adjustment shall be made to the Customer Accounts Expense because of the utility's change in its allocation method.

T. AMORTIZATION OF THE DEFERRAL OF THE RETURN ON THE THIRD FLOOR OF THE CORPORATE OFFICE

Gulf is requesting that the deferred return be amortized over three years. Gulf witness Labrato testified that the requested level of amortization is consistent with the revenue sharing plan approved in Order No. PSC-99-2131-S-EI, which permitted amortization of up to $ 1 million per year.

OPC witness Schultz testified that Gulf based its three year amortization period on the above referenced order, but Gulf did not make the election in the time frame established by the revenue [*111] sharing agreement, to defer up to $ 1 million per year. The witness further testified that the deferral should not be included in rate base and that the requested amortization period was not appropriate. However, if the deferral is allowed in rate base then the deferral should be amortized over the life of the building.

We find that the deferral shall be amortized over four years, the same time period used for amortizing rate case expense. Mr. Schultz was in error when he testified that Gulf did not elect to write-off up to $ 1 million per year. It is clear that it was the intent of the parties to the revenue sharing agreement to allow the write-off of the deferral over a short period of time by authorizing Gulf to record at its discretion, up to $ 1 million per year to reduce the deferred return. We find that the four year period is reasonable and would allow a fast write-off of the regulatory asset. In addition, the Company shall be allowed to continue its discretion to write-off up to an additional $ 1 million per year. Therefore, expenses shall be reduced $ 535,057 ($ 544,469 system).

U. DEPRECIATION AND AMORTIZATION EXPENSE

Based on the adjustments made by us above, Depreciation [*112] and Amortization expense shall reduced by $ 2,522,000 ($ 2,603,000 System) for the May, 2003 projected test year, as shown in the table below. The appropriate jurisdictional depreciation and amortization expense is $ 75,042,000 for the projected test year, as shown in Attachment 3.

Test Year Accumulated Depreciation Adjustments

Issues	Jurisdictional	System
House Power Panels	$ (49)	$ (49)
Security Measures	101	105
Cable Injection	2	2
3rd Floor Corp. Office- Amortization of Deferred Return	(535)	(544)
Stipulated 25-year life for Smith Unit 3	(2,041)	(2,117)
Total Adjustment	$ (2,522)	$ (2,603)

V. TAXES OTHER THAN INCOME TAXES

Per MFR Schedule C-38a, page 1 of 2, the adjusted jurisdictional May 31, 2003, projected Taxes Other Than Income Taxes is $ 36,969,000. This amount includes taxes primarily related to revenues, property, and payroll. Gulf takes the position that Taxes Other Than Income Taxes should be reduced by $ 11,110,000 to reflect the unbundling of its gross receipts tax, and by $ 20,000 to reflect the adjustment to payroll taxes discussed in Part VI, Section G. OPC contends that property taxes should be reduced by $ 1,251,000 [*113] to reflect the tax exemption that Gulf received on Smith Unit 3.

We find that with the unbundling of the gross receipts taxes, it is appropriate to reduce this account by $ 11,110,000. We also find that it is appropriate to reduce this account for payroll-related taxes discussed in Part VI, Section G. However, the adjustment shall be rounded down to $ 19,000 rather than up to $ 20,000 to reflect the jurisdictional adjustment of $ 19,274 that is recommended in Part VI, Section G.

Regarding property taxes, because only five months of property taxes for Smith Unit 3 were included in the test year, the Company made an annualization adjustment of $ 1,853,000. Per Gulf witness McMillan, these estimated taxes do not reflect a county tax exemption for the Smith plant. Gulf requested and was granted a tax exemption by the Bay County Board of Commissioners. However, Mr. McMillan testified that the Bay County Property Appraiser has taken the position that the exemption for Smith Unit 3 is unlawful. Further, in a lawsuit testing the legality of the exemption, Gulf received a Summary Judgement in its favor in circuit court. The decision was affirmed by the First District Court of Appeal, which [*114] affirmed. See Davis v. Gulf Power Corp. 799 So. 2d 298 (1st DCA 2001). The decision was appealed to the Florida Supreme Court. Per Mr. McMillan, the timing and final outcome related to this lawsuit cannot be determined at this time. However, if the Company prevails in court and the property appraiser is required to honor the tax exemption, the annual property taxes would be reduced by $ 1,251,000 based upon the 2000 millage rates.

In its brief, the OPC argued that property taxes should be reduced by the $ 1,251,000 to reflect the exemption that Gulf currently has. Gulf will retain that exemption unless the Bay County Property Appraiser can succeed in overturning the Commission decision on appeal. OPC believes that Gulf should have filed this case on the existing status, rather than on the assumption that it would lose the appeal.

We find that a $ 1,251,000 reduction to property taxes is appropriate. First Gulf has not actually paid the tax. Second, the decision of the First DCA has legal effect because that court has issued its mandate and review by the Florida Supreme Court is discretionary. See Rule 9.310, Florida Rules of Appellate Procedure [*115] ; Section 12.5, Florida Appellate Practice, 2001-2002 Edition. Therefore, Gulf has no legal obligation to pay at this time. Finally if the decision of the First DCA is reversed, and Gulf has to pay, Gulf may seek relief at that time. Given the above, the most conservative approach under the current circumstances is to reduce and property taxes by $ 1,206,00 ($ 1,251,000 system) for the May 31, 2003 test year.

Based on the above three adjustments, Taxes Other Than Income by shall be reduced by $ 12,335,000 from $ 36,969,000 to $ 24,634,000.

W. INCOME TAX EXPENSE

Per MFR Schedule C-2, page 3 of 3, jurisdictional adjusted income tax expense for the May 31, 2003 projected test year is $ 15,846,000. None of the parties took issue with this amount. We find that this amount is reasonable, based on the other financial information provided in the Company's MFRs for the test year.

However Gulf, FIPUG, and OPC agree that adjustments are required for: 1) other revenue, expense and rate base adjustments that have been proposed by the Company; and 2) adjustments on related issues. We find that this is appropriate as well. To accomplish this, income tax expense shall be increased by $ 1,460,000 [*116] for the adjustments made to revenues and expenses. In addition, the interest synchronization adjustment shall be increased by $ 1,282,000 based on adjustments made to rate base. The result, as shown in Attachment 3, is an income tax expense increase of $ 2,742,000, which increases income tax expense from $ 15,846,000 to $ 18,588,000 for the May 31, 2003 projected test year.

X. NET OPERATING INCOME

Gulf requested a Net Operating Income of $ 61,378,000 ($ 61,658,000 system) for the May 2003 projected test year. Based on the adjustments made above, in Part VI of this Order, the Company's Net Operating Income is $ 62,419,000.

VII. REVENUE REQUIREMENT

A. REQUESTED ANNUAL OPERATING REVENUE

Gulf requested an annual operating revenue increase of $ 69,867,000 for the May 2003 projected test year. We find that the appropriate annual operating revenue increase for the May 2003 projected test year is $ 53,240,000, as shown in Attachment 5.

The annual operating revenue is a fallout decision and is affected by adjustments made to rate base and net operating income. A summary of the adjustments and the final approved value for annual operating income are shown in the table below. [*117]

Calculation of Revenue Requirements
(000's)
May 31, 2003 Test Year

Rate Base	$ 1,199,732
Rate of Return	7.92%
Required NOI	$ 95,019
Adjusted Achieved NOI	($ 62,419)
NOI Deficiency	$ 32,600
Revenue Expansion Factor	1.633125
Total Revenue Increase	$ 53,240

VIII. COST OF SERVICE AND RATE DESIGN

A. COST OF SERVICE METHODOLOGY

The appropriate cost of service methodology utilizes the 12 Monthly Coincident Peak and 1/13 Average Demand method for the allocation of production plant, and classifies only the meter and service drop components of the distribution system as customer related. The appropriate study is contained in Hearing Exhibit 20, which is Attachment 4B to Late-filed Deposition Exhibit 2 of Gulf Witness Robert L. McGee.

In its MFR Schedule E-1, Gulf filed two Cost of Service (COS) studies. In Attachment B to Schedule E-1 (non-MDS study), Gulf filed a COS study utilizing a methodology identical to that approved by the Commission in Gulf's last rate case. In Gulf's last approved COS study, only the meter and service drop portions of the distribution system were classified as customer related.

The COS study filed as Attachment A to MFR [*118] Schedule E-1 (MDS study) is supported by Gulf for use in this case. In this study, the Minimum Distribution System (MDS) methodology was used, which classifies a significant portion of the distribution system as customer related. We find that the MDS is not the appropriate methodology, for the reasons explained below and in the following section on treatment of distribution costs.

Both of the COS studies filed by Gulf use the 12 Monthly Coincident Peak (MCP) and 1/13 Average Demand (AD) method for the allocation of production plant costs. No party has objected to the use of this method, which was approved for use in Gulf's last rate case. It was also approved in the most recent rate cases of Florida Power Corporation, Florida Power & Light Company, and Tampa Electric Company. (Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324; Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI; Order No. 13537, issued July 24, 1984, in Docket No. 830465-EI)

Gulf witness McGee provided two revised COS studies in a late-filed exhibit to his deposition in this case. These studies are [*119] identical to the MDS and Non-MDS studies filed as Attachments A and B in MFR Schedule E-1, with three minor exceptions.

First, there was a change to the 12 CP demand allocators used for the Street (OS-I) and Outdoor (OS-II) rate classes. The initial filing developed these allocators using historical calendar year 1999 estimates of CP demand responsibility for these classes. The revised COS studies used a five-year (1996-2000) historical average. Use of a five-year average avoids unusual circumstances that might occur when a single year is used. For the same reason, a similar adjustment was made to the 12 CP demand allocators for the Sports Fields (OS-IV) rate class. Finally, there was also an adjustment made to the non-coincident (NCP) peak allocators for the OS-IV rate class to correct for errors made in the original filing.

We approved a stipulation that the proper estimates of 12 CP and NCP demand responsibility by rate class are reflected in the COS studies contained in Mr. McGee's late-filed COS studies. Gulf's rates shall therefore be designed based on the revised non-MDS study contained in Attachment 4B to Late-filed Deposition Exhibit 2 of Mr. McGee, which was identified [*120] as Exhibit 20 at hearing.

B. TREATMENT OF DISTRIBUTION COSTS

We find that the appropriate treatment of distribution costs shall remain consistent with past decisions where we required that only Accounts 369 (Services) and 370 (Meters) be classified as customer related.

As explained above, two cost of service studies were under consideration in this case. Both methods are based on the same underlying cost allocation methodology. The significant difference is how Gulf's proposal allocates distribution costs to customer classes.

1. Description of Methodologies

Previously Approved Methodology. The purpose of a cost of service methodology is to perform three activities. First, it functionalizes costs into production, transmission, distribution, customer and administrative/general categories. Second, these functionalized costs are separated into classifications based on the utility service being provided. There are three principal classifications of costs: (1) demand costs that are costs that vary with the KW demand imposed by the customer; (2) energy costs that are costs that vary with the energy or KWH used; and (3) customer costs that are costs that are directly related [*121] to the number of customers served. Under the methodology approved in Gulf's last rate case, only investment in two accounts, Account 369 (Service Drops) and 370 (Meters) were considered to be directly related to the number of customers served. The rationale as stated in all IOU rate cases since the 1980's is that only the line from the transformer to the meter and the meter itself are clearly customer related and, therefore should be the only accounts that are allocated on the basis of number of customers. All other distribution facilities are allocated on a demand allocator on the theory that load determines the size of these facilities, not the mere presence of the customer.

Proposed MDS Application. Gulf's proposed cost study classifies certain distribution costs, other than those in Accounts 369 and 370, as "customer" related. Specifically, Gulf's approach divides the distribution facilities from five additional accounts (Accounts 364-368) between demand and customer classification on the idea that a certain amount of poles, transformers, and conductors are necessary to extend service to a customer even if that customer never uses any energy. To arrive at this allocation [*122] requires the development of a hypothetical minimum distribution system to determine how much of each account is to be allocated on demand and how much on customers.

The MDS classification methodology uses a Zero Intercept (ZI) method to determine how much of the account should be allocated on a demand basis and how much is allocated on a customer basis by constructing the cost of investment at a zero load. The ZI approach uses a regression analysis to determine the zero capacity unit cost. This analysis plots the current replacement costs of the each type and size of equipment in each account against the various sizes of equipment (transformers, poles, conductors) and interpolates back to a 'zero,' or no-load, size. This provides a theoretical replacement cost for the equipment with no load capability which the MDS then attributes as customer related.

Once the ZI cost is determined, that cost is multiplied by the number of units in inventory to arrive at a theoretical base cost of the distribution facilities designed to carry no load. Then, using the ZI ratio and the replacement costs for all equipment, the ratio of customer costs to demand costs is determined. This ratio is then [*123] multiplied times the actual booked costs to determine the actual dollars to be allocated on a customer and demand basis in the cost of service. This zero intercept analysis must be conducted for each piece of equipment in each distribution account which is deemed to have both a customer and demand component.

2. Evaluation of Cost of Service Studies

Gulf relies on four basic tenets to support the use of the MDS methodology. First, Gulf maintains that the National Association of Regulatory Utility Commissioners (NARUC) Cost of Service Manual endorses the methodology. Second, Gulf contends that the complexity of the ZI methodology is necessary to accurately identify customer related costs. Third, Gulf argues that the Commission's reason for rejecting the MDS is that it increases customer related costs for the residential class. Fourth, Gulf maintains that the cost allocation methodology may or may not be used to set rates if the Commission believes the results are unacceptable for any reason.

NARUC Manual. In this filing, Gulf's COS witness Mr. O'Sheasy and other intervenors, rely heavily on a publication by the NARUC entitled, "Electric Utility Cost Allocation Manual" (Manual) [*124] to support the use of MDS. In particular, Mr. O'Sheasy cites language from Chapter 6 of this document in which the Manual describes the MDS methodology. He, along with FEA and FIPUG, appear to place great importance on the fact that this publication includes the MDS. However, the Preface states three objectives of the Manual: (1) it should be simple enough to be used as a primer on the subject of cost allocation yet offer enough substance for experienced witnesses; (2) it must be comprehensive yet fit in one volume; and (3) the writing style should be non-judgmental; not advocating any one particular method, but trying to include all currently used methods with pros and cons. In other words, the Manual was designed to educate, not mandate any particular methodology.

The manual also notes that it discusses only major methodologies and recognizes that no single costing methodology will be superior to any other and the choice of the methodology will depend on the unique circumstances of each utility. Mr. O'Sheasy acknowledged that we are not bound by the manual. Furthermore, Gulf provided no evidence on the circumstances that made it choose the MDS methodology over the method approved [*125] in its last rate case.

Hypothetical System - ZI Methodology. As described above, the MDS methodology requires construction of a hypothetical system consisting of equipment that is designed to carry zero load for each account identified as having both a customer and a demand component. Artificial no-load costs are created using replacement costs. Ratios of replacement cost are derived, which must then be translated in booked costs to determine the actual dollars to be allocated. According to Mr. O'Sheasy, that process must be applied to FERC Accounts 363-368. Each account may contain multiple sizes or types of items such as poles, transformers, and conductors. Replacement costs must be determined for each piece of equipment in each account.

This approach assumes that the cost relationships between items in an account remain constant over time. If they do not, it can skew the trend analysis. For example, replacement costs for older smaller equipment may be more expensive than newer products simply because there are fewer sources. In addition, if new technology allows a larger transformer to be sold at a cost comparable or less than a smaller transformer, due to economies of scale, [*126] the mathematical result of the zero intercept regression could conceivably show a cost at zero intercept for a no-load situation higher than the use of a larger transformer. Conversely, Mr. O'Sheasy and the NARUC Cost Manual agree that there is common agreement that Accounts 369 and 370 are fully customer related.

The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load. There is no real equipment that equates to the costs identified by the ZI methodology. We have rejected MDS in the past for this very reason.

> The Company and staff have proposed the use of a theoretical minimum distribution cost as part of the customer cost . . . . While we agree that sound regulatory practice should provide for a customer charge to defray otherwise fixed costs, as proposed by the Company and Staff, we do not agree that a theoretical cost of a minimum distribution system is appropriate . . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. [*127] Reliance on such a mechanism is speculative at best. Instead, we believe the appropriate customer charge should be based on the cost

> of the meter, service drop, meter reading and basic customer service costs (not including uncollectibles).

Order 9599, issued October 17, 1980, in Docket No. 800011-EU, p. 18.

Distinction Between COS and Rate Design. Mr. O'Sheasy repeatedly makes a distinction between the cost allocation methodology employed to determine costs, and rate design to set actual charges to customers. However, he also states that the primary purpose of a cost study is to determine if rates need to be changed. Indeed, the primary purpose of a cost of service is to determine the reasonableness of rates. "The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers and segments of the utility's business."

Mr. O'Sheasy agreed that we can stray from the cost allocation results to mitigate the perceived impact of a particular cost allocation or level. In fact, he noted that Georgia employs the MDS cost methodology but that its customer charges were not set at the full cost of service. We believe, [*128] however, that typically the COS study directs how any increase in revenue requirement is allocated across classes for the purpose of setting new rates.

To maintain that cost classification is no more than a theoretical exercise that does not have to affect rates is nonsensical. If a cost study were not used to design rates, there would be no purpose in performing the cost study. Although Mr. O'Sheasy states that it is his belief that this Commission rejected the MDS in previous rate cases because of the impact on residential customers, our prior orders show that it was the theoretical construct with which we disagreed, not the end result.

The NARUC Cost Manual defines customer costs as "...the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection and customer information and service." This is precisely the approach we have taken in the past. Only the investment in the service drop and meters were allocated on a customer basis.

Commission Precedent. Mr. O'Sheasy contends that staff opposes the MDS methodology because the Commission has consistently ruled against it. This Commission is not bound by any prior decision [*129] in this matter, if it deems that circumstances warrant a change. Similarly, the NARUC manual states that the choice of methodology will depend on the unique circumstances of the case. We find that Gulf has not offered any evidence to show how its circumstances have changed since the last rate case that would justify a change in cost methodology.

Internal Inconsistencies. Mr. O'Sheasy describes MDS as identifying the costs of the facilities needed to simply hook-up a customer to the power system. Yet, distribution lines must be connected to subtransmission and transmission lines and ultimately to the busbar at the power plant in order to be able to deliver a single kWh. To artificially separate distribution accounts on the basis that these facilities are necessary to make service available ignores the way the electric system works. MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines. As cited in the order in Gulf's last rate case:

> There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission [*130] system would be classified as

> customer-related. Hence, customers served at primary voltage through dedicated substations, and customer served at higher voltages would not pay for any of this network path.
>
> We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.
>
> In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer related.

Order 23573, issued October 3, 1990, in Docket No. 891345-EI, p. 51. (Emphasis in original)

Impact on Residential Customers. Gulf suggested that there was concern about the shifting of costs to the residential class. This Commission has consistently rejected the use of the Minimum Distribution System for the last twenty years. See Order 9599, issued October 17, 1980, in Docket No. 800011-EU; Order [*131] 9864, issued March 11, 1981, in Docket No. 800119-EU; Order 10557, issued February 1, 1982, in Docket No. 810136-EU; Order 11498, issued January 11, 1983, in Docket No. 820150-EU; Order 11628, issued February 17, 1983, in Docket No. 820100-EU; Order 23573, issued October 3, 1990, in Docket No 891345-EI. None of these Orders cite, as a reason for rejecting MDS, the impact on any particular class of customers. The criticisms have all addressed the merits of the methodology, not its eventual impact on rates. Specifically, as noted above, MDS has been rejected because of inconsistencies in the methodology and because it does not reflect the way a utility incurs costs.

Competitive Pressure. Mr. O'Sheasy also cited as a reason for adopting the MDS in this case the fact that cross-subsidies are bigger issues now than they have ever been. He noted that commercial and industrial customers face greater competitive challenges in their own markets. However, the MDS has been proposed in rate cases for over 20 years. We cannot assign much weight to Mr. O'Sheasy's generalization that competitive pressures are greater now than at any time in the past 20 years. Gulf provided no factual support [*132] for the generalization.

Further, we question Mr. O'Sheasy's qualifications to assess competitive trends in unregulated industries. In his background, Mr. O'Sheasy notes that he joined Southern Company in 1980 and has continued in various capacities in a regulated environment until his retirement in 2001. There is no evidence to indicate that he has any special knowledge as a competitive market analyst or an expert of competitive pressures in manufacturing or industrial applications. In fact, FIPUG, a trade association of large industrial customers in the state, presented no evidence that its members faced unusual or significantly changed competitive pressures. Every private enterprise desires to lower the costs of inputs to its production process in order to increase its income. This desire should not, however, drive a cost allocation.

We find that the simpler, more straight forward approach of allocating only service drops and meters on a customer basis adequately captures the distribution investment that is solely required to extend service to a new customer. This methodology is clear, generally accepted, and requires no series of hypothetical cost and system design calculations [*133] that do not reflect how the actual system is designed. Despite the Mr. O'Sheasy's claim that the electric industry is very different from 12 1/2 years ago, he presented no evidence to support this statement. When asked what had changed, he again referred to the competitive pressure on commercial and industrial groups and market pressures, and cross subsidies, but did not mention any changes to the electric industry itself which would justify a change in methodology. Changes in competitive markets should not drive the allocation of costs in a regulated electric cost study.

For the reasons provided above, we find that the treatment of distribution costs shall remain consistent with our past decisions, and accordingly, only Accounts 369 and 370 shall be classified as customer related.

C. ALLOCATION OF THE REVENUE INCREASE AMONG THE CUSTOMER CLASSES

The revenue increase shall be allocated to the rate classes in a manner that moves the class rate of return indices as close to parity as practicable based on the approved cost allocation methodology, and subject to the following constraints: 1) no class shall receive an increase greater than 1.5 times the system average percentage [*134] increase in total; and, 2) no class shall receive a decrease. The allocation of the increase is shown in Attachment 6.

The allocation of the increase in revenues shown in Attachment 6 moves each rate class closer to parity, and does not impose an increase on any rate class that exceeds 1.5 times the system average increase, including adjustment clause revenues. In addition, no class receives a rate decrease.

No increases are allocated for the Other Outdoor (OS-III), Standby (SBS), Real Time Pricing (RTP), and Large High Load Factor (PX/PXT) rate schedules because they are all significantly above parity. Although the Contract Service Agreement (CSA) customers are significantly below parity, the rates paid by these customers were negotiated pursuant to Gulf's Commercial/Industrial Service Rider, and thus are not subject to change.

D. DEMAND CHARGES

The appropriate demand charges are shown in Attachment 7. The demand charges were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

E. ENERGY CHARGES

The appropriate energy charges are shown in Attachment 7. The energy charges [*135] were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

F. CUSTOMER CHARGES

The customer charges are shown below:

RATE CLASS	NON-MDS UNIT COST	CURRENT CHARGES	GULF PROPOSED	APPROVED
RS, RSVP	$ 11.43	$ 8.07	$ 12.00	$ 10.00
GS, OSIV	$ 17.50	$ 10.09	$ 15.00	$ 13.00
GSD	$ 31.88	$ 40.35	$ 40.00	$ 35.00
GSDT	$ 31.88	$ 45.80	$ 40.00	$ 35.00
GSTOU	$ 31.88	N/A	$ 40.00	$ 35.00
LP, LPT	$ 154.72	$ 226.98	$ 226.00	$ 155.00

RATE CLASS	NON-MDS UNIT COST	CURRENT CHARGES	GULF PROPOSED	APPROVED
PX, PXT	$ 416.64	$ 575.01	$ 566.38	$ 566.38
RTP	$ 452,37	$ 1000.00	$ 1000.00	$ 1000.00

Customer charges are flat monthly per-customer rates that do not vary with energy usage. They are designed to recover costs that typically vary with the number of customers served, rather than with kilowatt hour consumption. Customer costs include metering, billing, and customer service.

To the extent practicable, the customer charges are be set to reflect the customer unit costs developed in the cost of service study approved by us. With the exception of the PX, PXT, and RTP rate schedules, the customer charges meet this objective. [*136] The PX, PXT, and RTP customer charges are left at current levels because no increase is being made to these classes.

The RS and RSVP customer charges are being increased from their current level of $ 8.07 to $ 10.00. While this is below the unit cost of $ 11.43, we find that because the customer charge is a large portion of the customer bill for these classes, the increase in the customer charge should be limited in order to avoid an excessive increase to low-use customers. Similarly for the GS and OS-IV classes, the customer charges shall be increased from their current level of $ 10.09 to $ 13.00, which is below the unit cost of $ 17.50.

G. CHARGES UNDER THE INTERRUPTIBLE STANDBY SERVICE (ISS) RATE SCHEDULE

The appropriate Interruptible Standby Service charges are shown in Attachment 7, page 4. Because no increase was allocated to this rate class, the ISS rates approved by us have been adjusted only to remove the embedded 1.5% Florida gross receipts taxes.

H. CHARGES UNDER THE STANDBY AND SUPPLEMENTARY SERVICE (SBS) RATE SCHEDULE

The appropriate Standby and Supplementary Service charges are shown in Attachment 7, page 3. Because no increase was allocated to this [*137] rate class, the SBS rates approved by us have been adjusted only to remove the embedded 1.5% Florida gross receipts taxes.

I. RATE DESIGN FOR REAL TIME PRICING (RTP) RATE SCHEDULE

Because no rate increase was allocated to this rate class, the existing rate design shall be retained. Under the RTP rate, customers pay a unique rate for each hour of the day based on the Southern Company's incremental cost to serve the next kilowatt hour.

J. EFFECTIVE DATE

By stipulation, the revised rates are to become effective for bills rendered on or after the commercial in-service date of Smith Unit 3, or 30 days after the date of the our vote in this docket, whichever is later. Smith Unit 3 entered into commercial operation on April 22, 2002. The new rates will therefore become effective on June 7, 2002, which is 30 days after our vote on May 8, 2002.

K. APPROVAL OF TARIFF SHEETS

Gulf shall submit its tariff sheets showing gross receipts tax removed from base rates and from the recovery clause factors. Our staff shall approve the tariff sheets administratively.

IX. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes [*138] , and is subject to the jurisdiction of this Commission.

, 2. The adjustments to rate base made herein are reasonable and proper. The value of Gulf's rate base for rate making purposes is $ 1,199,732,000.

3. The adjustments made to the calculation of required net operating income are reasonable and proper. Gulf's required net operating income for rate making purposes is $ 95,019,000.

4. The fair rate of return on the equity capital of Gulf is 11.75%.

5. Gulf has provided superior service in the past and is expected to continue to do so in the future. In recognition of Gulf's accomplishment, we increased rate of return on equity capital to 12.00%.

6. Gulf Power Company is authorized to increase its rates and charges by $ 53,240,000 in gross annual revenues effective June 7, 2002.

7. The rate schedules approved herein are fair, just and reasonable within theAutoList22 Chapter 366, Florida Statutes.

8. The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after June 7, 2002.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further [*139]

ORDERED that Gulf Power Company's Petition for Rate Increase is granted in part and denied in part as described herein. It is further

ORDERED that Gulf Power Company is authorized to submit revised tariff sheets consistent with the rate schedules approved herein. The Commission staff shall administratively approve the tariff sheets. It is further

ORDERED that Gulf Power Company shall include in each customer's bill, in the first billing for which the rate increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons for those charges. The bill stuffers shall be submitted for review and approval to the Florida Public Service Commission before they are mailed. It is further

ORDERED that if Gulf Power Company wishes to file an Earnings Sharing Plan or other type of incentive plan, it shall do so within 90 days of April 26, 2002, the date of the vote on revenue requirements. It is further

ORDERED that the stipulations contained in Appendix A to this Order are hereby approved. It is further

ORDERED that this docket shall be closed 32 days after the issuance of this Order to allow the time for filing [*140] an appeal to run.

By ORDER of the Florida Public Service Commission this 10th day of June, 2002.

BLANCA S. BAYO, Director

Division of the Commission Clerk and Administrative Services

CONCURBY: Jaber, Palecki (In Part)

DISSENTBY: Jaber (In Part)

CONCURRING AND DISSENTING OPINIONS

Chairman Jaber concurs in part and dissents in part with the following opinion:

I commend Gulf Power for its good service and consumer relations program. I truly believe that this company has attempted to ensure that its customers receive the best affordable electric service. With that said, Gulf Power sought the approval of an incentive program (Late Filed Hearing Exhibit 25) that would have rewarded the company for past performance and service. As I stated during our deliberation on this case, I believe that properly balanced incentive-based approaches to regulation, where feasible, are appropriate. An incentive-based program that both rewards and penalizes the company for service performance may be appropriate. I prefer that such a program be based upon consensus which maximizes the creative ideas of all of the stakeholders. Here, because Gulf Power's proposal crystalized during a witness' summary, OPC and FIPUG successfully [*141] argued that they were not afforded sufficient time and opportunity to review and respond to the proposal. Therefore, I concur in the majority's decision to grant OPC's and FIPUG's objections to the admission of Gulf's Late-filed Exhibit 25.

I also concur with the decision to allow Gulf Power to file a new balanced incentive plan within 90 days. However, because I believe the majority's decision to reward Gulf Power at this time by adjusting the company's return on equity upward may have taken away one of the tools that was available to the parties in negotiating the incentive program, I respectfully dissent with regard to the majority's decision to add 25 basis points to the midpoint return on equity.

Finally, I must point out that Gulf Power's last full rate case was conducted in 1990. After 11 years, Gulf Power filed this request for rate relief to include the addition of Smith Unit 3, a combined cycle generating unit designed to provide 574 megawatts of power to meet growing demand. Prior to the hearing, Gulf Power, the parties, and our staff reached many stipulations on issues and witness testimony, resulting in a shortening of the hearing from five scheduled days to only a day [*142] and a half. The company and the parties are to be commended for this cooperation and coordination, which minimized rate case expense that ultimately would have been borne by customers though their rates.

Commissioner Palecki concurred in part with the Commission's decision regarding advertising expenses with the following opinion:

ADVERTISING EXPENSES

I concur with the majority's opinion regarding the *level* of advertising expenses Gulf should be allowed to recover. The per customer expense for this activity is within the range of reasonableness that I would approve. However, I believe that the Commission's scrutiny of every advertisement, television commercial, and public relations expenditure for a conservation, safety, or customer information message amounts to micro-management. Furthermore, constant audits on this matter are not a good use of the Commission's time and resources.

Ratepayers are concerned about the dollars companies spend on these ads -- not the detail of the message. Whether ads are designed to build customer confidence, to enhance the company's image, or to help them compete, companies should have the flexibility to appropriately manage the subject matter [*143] of the ads. Although I would encourage our companies to continue to use advertisements to educate customers regarding safety, conservation, and energy efficiency, I think we should recognize that utilities are in the best position to determine the messages that need to be sent to their customers.

Commissioner Palecki dissented from the Commission's decisions on two issues with the following opinion:

REWARD FOR GULF'S PAST PERFORMANCE

I dissent from the majority's decision to adjust Gulf's return on equity (ROE) upward to 12% for Gulf's performance. In this Order, we have suggested that the parties, including Gulf and OPC, negotiate an incentive plan, and we have given Gulf until July 26, 2002, to file a petition for approval of such a plan. I believe that the Commission's decision to reward Gulf at this time for its performance in the form of a higher ROE undermines the ability of the parties to craft an effective incentive sharing proposal.

I applaud Gulf for its superior performance. I have recognized this performance by voting to allow Gulf an ROE of 11.75%, instead of 11.6% as recommended by our staff. I believe that 12% is too high unless authorized by the Commission as [*144] part of a comprehensive incentive program designed to improve efficiency by allowing a sharing of revenues between Gulf and its ratepayers.

EXPENSES FOR PROGRAM TO CONVERT GAS WATER HEATERS TO ELECTRIC

I dissent from the majority's decision to allow Gulf to include expenses for its program to allow customers to replace existing gas-fired water heaters with free, energy-efficient electric water heaters (Water Heating Conversion Program). This decision contrasts starkly with long-standing Commission precedent designed to encourage the opposite -- conversion of electric water heaters to gas - in order to reduce the need for additional power plants in Florida.

The Commission has historically approved gas companies' expenditures to convert electric water heaters to gas as a means of reducing the state's consumption and the need for additional generation under the Florida Energy Efficiency and Conservation Act (FEECA). The legislative intent of FEECA states in part that FEECA is "to be liberally construed in order to meet the complex problems of reducing and controlling the growth rates of electric consumption . . ." Section 366.81, Florida Statutes. [*145] The majority's decision undermines the purpose of FEECA by encouraging Gulf to engage in behavior to increase generation needed to serve our state. It is significant that the primary driver of this rate increase is Gulf's need to build a new power plant.

The Commission's actions here send conflicting signals. On one hand, we uphold the purpose of FEECA by encouraging ratepayers to conserve and convert from electric to gas. On the other hand, we allow Gulf to spend ratepayer money to undermine the purpose of FEECA by promoting consumption that could result in the need for more power plants. I believe that the majority's decision to allow Gulf to include Water Heating Conversion Program expenses violates the letter and spirit of FEECA and sets a poor precedent. I hope that the Commission will reconsider this policy if similar requests are filed by other Florida electric utilities in the future.

APPENDIX A

APPROVED STIPULATIONS

The stipulations listed below are approved.

I. Depreciation Stipulation

The Stipulation for Settlement of Depreciation Related Issues between OPC, FEA, FIPUG, and Gulf filed on February 22, 2002, was accepted. The Stipulation reflects a [*146] compromise settlement between the parties regarding depreciation rates and dismantlement accrual levels. It is not construed as an admission by any party that these rates or dismantlement provisions are appropriate in any other proceeding.

The accepted settlement reflects the depreciation rates and dismantlement accruals initially proposed by Gulf in its May 29, 2001, filing in Docket No. 010789-EI. For Smith Unit 3, the agreement reflects the depreciation rate and dismantlement accrual proposed by Gulf in Docket No. 010949-EI, except the depreciable life for the unit is set at 25 years (instead of the 20 years initially proposed by Gulf). As a result, the May 2003, depreciation expense will be reduced $ 2,041,000 ($ 2,117,000 system); the level of accumulated depreciation will be reduced by $ 1,019,000 ($ 1,057,000 system).

The Depreciation Stipulation also provides that the depreciation rates and dismantlement provisions be effective on January 1, 2002, except for Smith Unit 3. The depreciation rate and dismantlement provision relating to Smith Unit 3 will be effective on the commercial in-service date of the unit. Finally, the Stipulation provided that the prefiled testimony of [*147] witnesses Majoros, Zaetz, and Roff would be inserted into the record as though read.

Accordingly, Issues 17, 73, and 74 are fully resolved. Although, with respect to depreciation rates and dismantlement accruals, the Depreciation Stipulation likewise resolves Issues 18 and 75, those issues remain open for the purpose of identifying adjustments to accumulated depreciation and depreciation expense that fallout from other issues.

In addition, on its own motion, the Commission voted that acceptance of the Depreciation Stipulation rendered moot the Commission's vote in Docket No. 010789-EI made at the February 19, 2002 Agenda Conference. That vote had not been issued as a Proposed Agency Action Order at the time this Stipulation was accepted (February 25, 2002). Accordingly, the Commission voted that Docket No. 010789-EI should be closed administratively.

II. Motion for Judicial Notice

A Motion for Judicial Notice was filed by the Federal Executive Agencies on February 22, 2002, which requested judicial notice for certain parts of the Electric Utility Cost Allocation Manual published by NARUC in 1992. The parts to be noticed were the cover pages, table of contents, preface, [*148] and Chapter Six. The parties agreed to stipulate the material into the record as an exhibit, which was accepted by the Commission and so the Motion was effectively withdrawn.

III. Stipulated Issues

A. Category One Stipulations

Category One stipulations are those to which Gulf, Staff, FEA, FIPUG, and OPC agree and for which FCTA takes no position.

1. The testimony and exhibits of OPC's witness, Michael J. Majoros, including his deposition testimony, shall be stipulated into evidence without cross examination by any party.

B. Category Two Stipulations

Category Two stipulations are those to which Gulf and Staff agree, and for which FCTA, FEA, FIPUG, and OPC have no position.

2. Gulf shall be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (Issue 124)

C. Category Three Stipulations

Category Three stipulations are those to which Gulf, FEA, OPC, and Staff agree and for which FIPUG and FCTA have no position.

3. The appropriate cost of short-term [*149] debt for the May 2003 projected test year is 4.61%. The short-term debt cost rate has been revised from 6.02% as originally filed based on the most recent forecast of short-term interest rates for the test year. (Issue 32)

4. The appropriate cost rate for long-term debt for the May 2003 projected test year is 6.44%. The long-term debt cost rate has been revised from 7.08% as originally filed to 6.44%. The Company has completed the issuance of all permanent financing impacting the May 2003 projected test year. Therefore, the long-term debt cost rate was revised to reflect the actual rates of senior notes issued. In addition, the cost rates for the Company's variable rate pollution control bonds were revised based on the most recent forecast of short-term interest rates for the test year. (Issue 33)

D. Category Four Stipulations

Category Four stipulations are those to which Gulf, FEA, FIPUG, and Staff agree, and for which FCTA and OPC have no position or no opposition.

5. Based upon the Stipulation approved in Order No. PSC-99-2131-S-EI, the rates approved in this docket will be effective for bills rendered on or after (i) the commercial in-service date of Smith Unit 3, or (ii) [*150] 30 days after the date of the Commission's vote in this docket, whichever is later. (Issue 123)

E. Category Five Stipulations

Category Five stipulations are those to which Gulf and Staff agree, and for which FEA, FCTA, FIPUG, and OPC have no position.

6. Gulf's forecasts of Customers, KWH, and KW by Rate Class, for the May 2003 projected test year are appropriate. (Issue 2)

7. No adjustments shall be made to Gulf's projected test year due to customer complaints. (Issue 4)

8. The quality of electric service provided by Gulf is adequate as evidenced by Gulf's complaint activity being low and its rankings across all service and reliability attributes in customer surveys being consistently among the best in the industry. (Issue 5)

9. No adjustment shall be made to Smith Unit 3. The $ 220,495,000 requested for the construction of Plant Smith Unit 3 is reasonable, prudent, and should be allowed. (Issue 10)

10. The company has removed from rate base all non-utility activities, including the investment, accumulated depreciation, and working capital amounts related to the Company's non-utility activities. (Issue 15)

11. The requested level of construction work in progress in the amount [*151] of $ 15,850,000 jurisdictional ($ 16,361,000 system) is appropriate for purposes of computing base rate revenue requirements. This amount properly reflects the

construction expenditures and plant clearings that are expected in the May 2003 projected test year. (Issue 19)

12. No adjustment shall be made to Plant Held for Future Use for Gulf's inclusion of the Caryville site in rate base. While Gulf has allowed the Caryville site to be used for various non-utility activities in recent years, the site was certified by the Power Plant Siting Board in 1976 and continues to be viable for building coal-fired capacity in the future. It is anticipated that certifying new plant sites will become increasingly more difficult in the future. Caryville has been in Gulf's rate base as Plant Held for Future Use for well over 35 years. Inclusion of this site in rate base is still a prudent decision. (Issue 20)

13. The requested level of Property Held for Future Use in the amount of $ 3,065,000 ($ 3,164,000 system) is appropriate for purposes of computing base rate revenue requirements. (Issue 21)

14. No adjustment shall be made to prepaid pension expense. The projected balance of prepaid expense has [*152] been properly reflected in the calculation of working capital. (Issue 22)

15. No adjustment shall be made to rate base for unfunded Other Post-retirement Employee Benefit (OPEB) liability. The projected balance of Other Post-retirement Employee Benefits has been properly reflected in the calculation of working capital. (Issue 23)

16. Gulf's projected level of Total Operating Revenues in the amount of $ 372,714,000 ($ 379,009,000 system) for the May 2003 test year should be reduced by $ 1,652,000 to reflect the impact of the Commission approved change to the Purchased Power and Capacity Cost Recovery Clause calculation as discussed in Issue 45. Total Operating Revenues should also be reduced if the Commission chooses to remove gross receipts tax from revenues and expenses in the calculation of Net Operating Income, rather than removing gross receipts tax from total revenue requirements in the calculation of proposed base rates. (Issue 38)

17. The appropriate inflation factors are those shown on Gulf's response to Staff Interrogatory No. 192. This results in a $ 100,000 reduction to O&M expense. (Issue 39)

18. Gulf has made the appropriate test year adjustments to remove fuel revenues [*153] and fuel expenses recoverable through the Fuel Adjustment Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 9, the Company has removed from NOI the fuel revenues and expenses recoverable through the Fuel Clause for purposes of determining base rate revenue requirements. (Issue 43)

19. Gulf has made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 10, the Company has removed from NOI the conservation revenues and expenses recoverable through the Energy Conservation Cost Recovery Clause for purposes of determining base rate revenue requirements. (Issue 44)

20. Gulf has not made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause. Gulf made adjustments to remove capacity revenues and expenses from NOI currently recoverable through the Capacity Cost Recovery Clause. Included in the adjustments are $ 1,652,000 in revenues currently embedded in base rates. Pursuant to Order [*154] No. PSC-01-2516-FOF-EI in Docket No. 010001-EI an adjustment should be made in this docket to Gulf's new base rate request. Accord-

ingly, revenues shall be reduced by $ 1,652,000 to ensure that new base rates and the clause factors are calculated on a consistent basis. (Issue 45)

21. Gulf has made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 12, the Company has removed from NOI the environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause for purposes of determining base rate revenue requirements. (Issue 46)

22. Gulf has not made the appropriate adjustments to remove lobbying expenses from the May 2003 projected test year. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8, page 3 of 3, adjustments 13 and 24 were made consistent with the Commission's direction in the last rate case to exclude lobbying expenses. However, an additional adjustment in the amount of $ 7,000 jurisdictional ($ 7,000 system) shall also be made to remove the industry [*155] association dues for Associated Industries of Florida, as noted in the Commission Staff's audit report Exception No. 2, since these dues relate to lobbying activities. (Issue 49)

23. The appropriate amount for other post employee benefits expense is included in the May 2003 projected test year, and no adjustment shall be made. (Issue 52)

24. No adjustment shall be made to pension expense for the May 2003 projected test year. (Issue 53)

25. No adjustment shall be made to the accrual for the Injuries and Damages reserve for the May 2003 projected test year. The appropriate amount for the injuries and damages reserve accrual of $ 1,144,000 jurisdictional ($ 1,200,000 system) is included in the May 2003 projected test year. (Issue 56)

26. No interest on tax deficiencies for the May 2003 projected test year shall be included above-the-line, and the net operating income for the May 2003 projected test year does not include any interest on tax deficiencies. (Issue 57)

27. No adjustment shall be made to Transmission Expenses for the May, 2003 projected test year. The total requested transmission O&M expenses of $ 7,922,000 jurisdictional ($ 8,210,000 system) for the May 2003 projected test [*156] year are under the benchmark and are reasonable, prudent, and necessary in order for Gulf to provide a high level of reliability to its growing number of customers. (Issue 63)

28. No adjustment shall be made to Bad Debt Expense for the May, 2003 projected test year. The amount of bad debt expense of $ 1,544,000 jurisdictional ($ 1,544,000 system) included in the May 2003 projected test year is appropriate for purposes of determining base rate revenue requirements. (Issue 70)

29. Gross receipts tax shall be removed from base rates and shown on customer bills as a separate line item. (Issue 78)

30. No adjustment shall be made to the consolidating tax adjustments for the May 2003 projected test year. (Issue 80)

31. The appropriate revenue expansion factor for Gulf is 60.3110 and the appropriate net operating income multiplier is 1.658072. These factors are different from the factors included in the Company's original filing. The numerator of the bad debt rate calculation, as shown on MFR Schedule C-58, was found to be in error. A revised calculation of the revenue expansion factor and NOI multiplier was provided in response to Staff's Interrogatory No. 75. These factors also in-

clude [*157] the gross receipts tax rate of 1.5%. The gross receipts tax was removed from total revenue requirements in the calculation of proposed base rates, since the Company is proposing to remove the gross receipts tax from base rates and show it as a separate line item on the bill.

If the Commission were to choose to remove gross receipts tax from revenues and expenses in the calculation of NOI, then the appropriate revenue expansion factor for Gulf is 61.2323 and the appropriate net operating income multiplier is 1.633125, and it would no longer be necessary to remove gross receipts tax from total revenue requirements in the calculation of proposed base rates. (Issue 83)

32. Gulf's proposed separation of costs and revenues between wholesale and retail jurisdictions is appropriate. Wholesale allocations are predominantly based upon the 12 MCP methodology with some revenues and expenses allocated upon the energy allocator. These methods are based upon cost causation. This is consistent with Gulf's prior rate case and was approved by this Commission. It also has traditionally been FERC's preferred methodology. (Issue 85)

33. Gulf has accurately applied the appropriate tariffs to the billing [*158] determinants projected for the May 2003 test year. The resulting estimated revenues from sales of electricity by rate class at present rates for the May 2003 test year as filed in this docket are appropriate. (Issue 86)

34. The method used by Gulf to develop its estimate by rate class of the 12 monthly coincident peak hour demands and the class non-coincident peak hour demands is appropriate. The method is reflected in the Cost of Service study attached to Mr. McGee's late-filed deposition exhibit no. 2. (Issue 87)

35. The appropriate service charges are listed below: (Issue 94)

Connection of Initial Service	$ 27.00
Connection of Existing Service	$ 27.00
Restoration of Service (after violation of rules)	$ 35.00
Restoration of Service After Hours (after violation of rules)	$ 55.00
Restoration of Service at Pole (after violation of rules)	$ 95.00
Premise Visit	$ 20.00
Connection of Temporary Service	$ 110.00
Investigation of Unauthorized Use	$ 75.00
Returned Item Charge $ 50	$ 25.00
Returned Item Charge > $ 50 and $ 300	$ 30.00
Returned Item Charge > $ 300	$ 40.00

36. The OS-I and OS-II energy charges shall be set to recover the total non-fuel energy, [*159] demand and customer-related costs allocated to the classes in the Commission-approved cost of service study. The maintenance charges shall be set to recover the total maintenance and associated A&G costs allocated to

the classes in the Commission-approved cost of service study. The fixture, pole and other additional facilities charges shall be set to recover the remaining revenue requirement for the OS-I and OS-II classes. (Issue 95)

37. Gulf's time-of-use rates shall be designed using the Existing Time-of-Use Modification (ETM) method, as described in the response to Staff Interrogatory No. 21, for revising incumbent, or existing, commercial/industrial Time-of-Use Rates. (Issue 96)

38. The appropriate monthly charge under Gulf's GoodCents Surge Protection (GCSP) rate schedule is $ 3.45? (Issue 100)

39. The distribution primary and transmission transformer ownership discounts shall be calculated in the same manner they were calculated in Gulf's last rate case, using the Commission-approved cost of service study. (Issue 101)

40. The minimum monthly bill demand charge under the PX rate shall be set using the methodology described in Gulf's response to Interrogatory No. 233, as adjusted [*160] to reflect the final rates established for the PX rate. (Issue 102)

41. The minimum monthly bill demand charge under the PXT rate should be set using the methodology described in Gulf's response to Interrogatory No. 234, as adjusted to reflect the final rates established for the PXT rate. (Issue 103)

42. Gulf Power's proposed rates are designed recognizing that customers may migrate, or move, to different rates for which they are eligible but are not currently on. This occurs when rate changes make alternative rates more economical. Recognition of this migration should be handled by allowing consideration of such migrations in the rate design process, as Gulf has done. (Issue 104)

43. Gulf's GST and RST rate schedules shall be eliminated because of the historically minimal participation in these optional rates. (Issue 105)

44. Gulf's Supplemental Energy Rate Rider shall be eliminated. Gulf's Commercial/Industrial customers have other options, including Time of Use rates and the Real Time Pricing rate, that allow them to change their consumption in response to price signals. Gulf currently has no customers on the SE Rider. (Issue 106)

45. The Optional Method of Meter Payment provision [*161] in Gulf's GSDT rate schedule shall be eliminated. The Optional Method of Meter Payment is not necessary since the proposed customer charge for rate GSDT is identical to that for rate GSD. These customer charges are the same because there is no longer additional cost to the Company associated with time-of-use metering for GSDT. (Issue 107)

46. Gulf shall eliminate its OS-IV rate schedule and transfer the customers served under the rate to an otherwise applicable rate no later than 24 months after the final order in this Docket, 010949-EI. (Issue 108)

47. Gulf has proposed to eliminate the SE Rider option available to SBS customers. Consistent with Gulf's proposed elimination of the SE Rider, the proposed changes to the SBS rate should be approved. (Issue 109)

48. The monthly fixed charge carrying rate to be applied to the installed cost of OS-I and OS-II additional lighting facilities shall be calculated based on the methodology shown in Gulf's response to Staff's Interrogatory No. 42, and shall reflect the Commission-approved rate of return including the Commission-approved rate setting point ROE. (Issue 110)

49. The proposed revisions to the estimated KWH consumption of Gulf's high [*162] pressure sodium and metal halide lighting fixtures are based on manufacturer's specifications for the equipment involved, and are appropriate. (Issue 111)

50. Gulf shall add a provision to its OS-I and OS-II lighting schedules that allows customers to change to different fixtures prior to the expiration of the initial contract lighting term. This change, requested by Gulf's customers, allows greater flexibility to customers in choosing lighting offerings during the term of their contracts. (Issue 112)

51. The Street Lighting (OS-I) and Outdoor Lighting (OS-II) subparts of Gulf's Outdoor Service rate schedule shall be merged. Merging the subparts of OS-I and OS-II serves to simplify the tariff and avoid unnecessary complication for customers and employees. (Issue 113)

52. The proposed methodology for determining the price of new street and outdoor lighting offerings shall be approved and shall be used to determine the monthly charges incorporating the Commission-approved rate of return including the rate setting point return on equity (ROE). (Issue 114)

53. Gulf's new FlatBill pilot program shall be approved provided that: 1) the fuel and other cost recovery clauses revenues associated [*163] with FlatBill customers are credited to the clauses at the then-current tariffed adjustment clause rates, and based on the customer's actual metered kWh usage; and 2) any shortfall in base rate revenues between the customer's bill at standard rates and the FlatBill revenues will be absorbed by the company. (Issue 115)

54. Gulf's new rate schedule, GSTOU, shall be approved. This is an additional option for the GSD/GSDT customers with a different structure since it does not contain a distinct demand charge. The rate is simpler for customers to understand and would allow customers to more effectively manage energy costs. (Issue 116)

55. Gulf's proposed reduction in the contract term required under its Real Time Pricing rate schedule from five years to one year is appropriate. (Issue 117)

56. Gulf's GoodCents Select Program incorporating the proposed changes to Gulf's Rate Schedule RSVP continues to be cost-effective. (Issue 118)

57. The RSVP rate schedule shall be designed so that the RSVP charges are compatible with the RS rate schedule, enhance the GoodCents Select program, and are designed consistent with the currently approved charges, as described in response to Staff's Interrogatory [*164] No. 271. (Issue 119)

58. Gulf's proposed change to the P2 and P3 pricing periods under the RSVP rate schedule is appropriate. This change removes a disincentive for participation, and does so without negatively affecting conservation benefits. (Issue 120)

59. Gulf's proposed changes to the Participation Charge and Reinstallation Fee charged under the RSVP rate schedule are appropriate. The proposed amounts represent updated costs of the equipment that is installed and maintained in participating households. (Issue 121)

60. The proposed addition of the RSVP, GSTOU, PX, PXT, and RTP rate schedules to the Budget Billing optional rider is appropriate. (Issue 122)

61. Gulf shall be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its an-

nual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (Issue 124)

F. Miscellaneous

62. Staff, Gulf and OPC agree that the wholesale related costs allocated to Gulf were properly allocated and support the sale and purchase of energy and capacity for the benefit of Gulf's retail customers. [*165] Therefore, no adjustment to NOI is needed to remove wholesale costs allocated to Gulf. FIPUG, FEA and FCTA take no position. (Issue 42)

ATTACHMENT 1

DOCKET NO. 010949-EI
DATE: April 26, 2002

JURISDICTIONAL COMPARATIVE AVERAGE RATE BASES

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
($ 000)

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY
	PLANT IN SERVICE	2,037,530		
C	Remove Appliance Sales		(289)	
C	Remove ECRC Amounts		(65,763)	
C	Remove ECCR Amounts		(4,986)	
12	Security Measures (Net)			
16	House Power Panels (541)			
64	Cable Injection Expense			
	Total Plan In Service	2,037,530	(71,038)	1,966,492
	ACCUMULATED DEPRECIATION AND AMORTIZATION	(870,595)		
C	Remove Appliance Sales		115	
C	Depreciation Study Adjustment		(1,170)	
C	Smith CC Life Adjustment		(1,690)	
C	Remove ECRC Amounts		19,037	
C	Remove ECCR Amounts		204	
S	Smith Unit 3 - 25 Year Life			
16	House Power Panels			
64	Cable Injection Expense			
	Total Accumulated Depreciation & Amort.	(870,595)	16,496	(854,099)
	NET PLANT IN SERVICE	1,168,935	(54,542)	1,112,393
	CONSTRUCTION WORK IN PROGRESS	27,081		
C	Remove CWIP Eligible for AFUDC		(8,734)	
C	Remove ECRC Amounts		(414)	
C	Remove ECCR Amounts		(2,083)	
S-11	Total Construction Work in Progress	27,081	(11,231)	15,850
S-13	PLANT HELD FOR FUTURE USE	3,066	0	3,065
	NET UTILITY PLANT	1,197,081	(65,773)	1,131,308
	WORKING CAPITAL	66,244		

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY
C	Remove Non-Utility Investments		(55)	
C	Environmental Cost Recovery Clause		583	
C	Funded Property Insurance Reserve		(8,095)	
C	Employee Loans		(797)	
C	Interest and Dividends Receivable		(180)	
C	Loss on Railcars		522	
C	Non-Current Liabilities		8,973	
9A	Office Building - 3rd Floor			
	Total Working Capital	66,244	950	67,194
	TOTAL RATE BASE	1,263,325	(64,823)	1,198,502

[*166]

ISSUE NO.		COMMISSION ADJS.	VOTE ADJUSTED
	PLANT IN SERVICE		
C	Remove Appliance Sales		
C	Remove ECRC Amounts		
C	Remove ECCR Amounts		
12	Security Measures (Net)	683	
16	House Power Panels	(641)	
64	Cable Injection Expense	83	
	Total Plant In Service	125	1,966,617
	ACCUMULATED DEPRECIATION AND AMORTIZATION		
C	Remove Appliance Sales		
C	Depreciation Study Adjustment		
C	Smith CC Life Adjustment		
C	Remove ECRC Amounts		
C	Remove ECCR Amounts		
S	Smith Unit 3 - 25 Year Life	1,019	
16	House Power Panels	698	
64	Cable Injection Expense	(1)	
	Total Accumulated Depreciation & Amort.	1,716	(852,383)
	NET PLANT IN SERVICE	1,641	1,114,234
	CONSTRUCTION WORK IN PROGRESS		
C	Remove CWIP Eligible for AFUDC		
C	Remove ECRC Amounts		
C	Remove ECCR Amounts		
S-11	Total Construction Work in Progress	0	15,850
S-13	PLANT HELD FOR FUTURE USE	0	3,065
	NET UTILITY PLANT	1,641	1,133,149
	WORKING CAPITAL		
C	Remove Non-Utility Investments		
C	Environmental Cost Recovery Clause		
C	Funded Property Insurance Reserve		
C	Employee Loans		
C	Interest and Dividends Receivable		

ISSUE NO.		COMMISSION VOTE ADJS.	ADJUSTED
C	Loss on Ralicars		
C	Non-Current Liabilities		
9A	Office Building - 3rd Floor	(611)	
	Total Working Capital	(611)	66,583
	TOTAL RATE BASE	1,230	1,199,732

[*167]

ATTACHMENT 2

DOCKET NO. 010949-EI
DATE: April 26, 2002

JURISDICTIONAL COMPARATIVE AVERAGE CAPITAL STRUCTURES

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
GULF POWER COMPANY

	Amount ($ 000)	Ratio	Cost Rate
Long-Term Debt	437,913	36.54%	7.08%
Short-Term Debt	17,801	1.49%	6.02%
Preferred Stock	99,565	8.31%	5.01%
Common Equity	491,919	41.04%	13.00%
Customer Deposits	13,249	1.11%	5.98%
Deferred Taxes	121,471	10.14%	0.00%
Investment Cr. - Wt. Cost	16,584	1.38%	9.70%
Total	1,198,502	100.00%	

COMMISSION VOTE
Capital Structure:

	Amount ($ 000)	Adjustments ($ 000) Specific	Pro Rate
Long-Term Debt	437,913	(14,957)	229
Short-Term Debt	17,801	15,895	18
Preferred Stock	99,565	(938)	53
Common Equity	491,919		267
Customer Deposits	13,249		0
Deferred Taxes	121,471	662	0
Investment Cr. - Wt. Cost	16,584		0
Total	1,198,502	662	568

Investment Credit Weighted Cost:

	Amount	Ratio	Cost Rate
Long Term Debt	$ 423,165	41.73%	6.44%
Preferred Stock	98,680	9.73%	4.93%
Common Equity	492,186	48.54%	12.00%
Total	$ 1,014,052	100.00%	8.99%

Interest Synchronization:

Adjustment	Cost Rate	Effect on Interest Exp.

Long Term Debt	($ 14,728)	6.44%	($ 948)
Short Term Debt	15,913	4.61%	734
Customer Deposits	0	5.98%	0
Investment Cr. - Wt. Cost	(134)	6.44%	(9)
Total	$ 1,052		($ 223)

Change in Cost Rates:

Long Term Debt	$ 437,913	-0.64%	($ 2,803)
Short Term Debt	17,801	-1.41%	(251)
Investment Cr. - Wt. Cost	7,055	-0.64%	(45)
Total	$ 455,714		($ 3,054)

Total Interest Synchronization
[*168]
GULF POWER COMPANY

	Weighted Cost Rate
Long-Term Debt	2.59%
Short-Term Debt	0.09%
Preferred Stock	0.42%
Common Equity	5.34%
Customer Deposits	0.07%
Deferred Taxes	0.00%
Investment Cr. - Wt. Cost	0.13%
Total	864%

COMMISSION VOTE
Capital Structure:

	Adjusted Total ($ 000)	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	423,185	35.27%	6.44%	2.27%
Short-Term Debt	33,714	2.81%	4.61%	0.13%
Preferred Stock	98,680	8.23%	4.93%	0.41%
Common Equity	492,186	41.02%	12.00%	4.92%
Customer Deposits	13,249	1.10%	5.98%	0.07%
Deferred Taxes	122,133	10.18%	0.00%	0.00%
Investment Cr. - Wt. Cost	16,584	1.38%	8.99%	0.12%
Total	1,189,732	100.00%		7.92%

Investment Credit Weighted Cost:

	Wtd. Cost
Long Term Debt	2.69%
Preferred Stock	0.48%
Common Equity	5.82%
Total	8.99%

Interest Synchronization:

	Tax Rate	Effect on Income Taxes
Long Term Debt	38.575%	$ 366
Short Term Debt	38.575%	(283)
Customer Deposits	38.575%	0
Investment Cr. - Wt. Cost	38.575%	3
Total		$ 86

Change in Cost Rates:		
Long Term Debt	38.575%	$ 1,081
Short Term Debt	38.575%	97
Investment Cr. - Wt. Cost	38.575%	17
Total		$ 1,195
Total Interest Synchronization		$ 1,282

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ATTACHMENT 3

DOCKET NO. 010949-EI
DATE: April 26, 2002

JURISDICTIONAL COMPARATIVE NET OPERATING INCOME

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
($ 000)

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY
	OPERATING REVENUES	633,347		
C	Remove Franchise fee Revenues		(18,934)	
S-18	Remove Fuel Revenues		(221,901)	
S-19	Remove ECCR Revenues		(6,414)	
S-20	Remove PPCC Revenues		(3,455)	
S-20	Remove PPCC Revenues In Base Rates			
S-21	Remove ECRC Revenues		(10,929)	
78	Gross Receipts Tax			
	Total Operating Revenues	633,347	(260,633)	372,714
	OPERATING EXPENSES:			
	OPERATION & MAINTENANCE EXPENSE	411,649		
C	Remove Industry Association dues		(15)	
C	Remove Economic Development Expenses		(53)	
C	Remove Management Tax Preparation Expenses		(4)	
C	Remove Tallahassee Liaison Office Expenses		(221)	
C	Remove Purchased Transmission Expenses		(135)	
C	Remove Marketing and Wholesale expenses		(304)	
C	Depreciation Study Adjustment		547	
S-17	Inflation Factors			
S-18	Remove Fuel Expenses		(218,280)	
S-19	Remove ECCR Expenses		(4,312)	
S-20	Remove PPCC Expenses		(3,387)	
S-21	Remove ECRC Expenses		(3,086)	
S-22	Remove Lobbying Expenses			
47	Security Measures			
48	Advertising Expenses			
50A	Relocation Expense			
51	Hiring Lag			
58	Rate Case Expenses			
59	Marketing Expense			
64	Cable Injection Expense			

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY
65	Tree Trimming Expenses			
68	Street & Outdoor Lighting Expenses			
	Total Operating & Maintenance Expense	411,649	(229,230)	182,419
	DEPRECIATION & AMORTIZATION EXP.	75,942		
C	Depreciation Study Adjustment		795	
C	Smith CC Life Adjustment		3,383	
S-19	Remove ECCR Expenses		(144)	
S-21	Remove ECRC Expenses		(2,412)	
8	Smith Unit 3 - 25 Year Life			
16	House Power Panels			
47	Security Measures			
64	Cable Injection Expense			
72	Office Building - 3rd Floor			
	Total Depreciation & Amortization Expense	75,942	1,622	77,584
	TAXES OTHER THAN INCOME	58,498		
C	Remove Franchise Fee Expenses		(18,446)	
C	Smith CC Property Tax Annualization		1,787	
C	Remove Recovery Clause Revenue Taxes		(4,307)	
C	Remove Tellahasse Office Property Taxes		(10)	
S-19	Remove ECCR Expenses		(164)	
S-21	Remove ECRC Expenses		(389)	
51	Hiring Lag			
78	Gross Receipts Tax			
79	Smith Unit 3 Property Taxes			
	Total Taxes Other Than Income	58,498	(21,529)	36,969
	CURRENT/DEFERRED INCOME TAXES	16,599		
C	Effect of NOI Adjustments		(4,435)	
C	Interest Synchronization		3,682	
	Total Current/Deferred Income Taxes	16,599	(753)	15,846
	INVESTMENT TAX CREDIT	(1,462)		
	Total Investment Tax Credit	(1,462)	0	(1,462)
	(GAIN)/LOSS ON SALE OF PROPERTY	0		
	Total (Gain)/Loss on Sale of Property	0	0	0
	TOTAL OPERATING EXPENSES	561,226	(249,890)	311,336
	NET OPERATING INCOME	72,121	(10,743)	61,378

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ISSUE NO.		COMMISSION VOTE ADJS.	ADJUSTED
	OPERATING REVENUES		
C	Remove Franchise fee Revenues		
S-18	Remove Fuel Revenues		
S-19	Remove ECCR Revenues		

ISSUE NO.		COMMISSION VOTE ADJS.	ADJUSTED
S-20	Remove PPCC Revenues		
S-20	Remove PPCC Revenues In Base Rates	(1,652)	
S-21	Remove ECRC Revenues		
78	Gross Receipts Tax	(11,110)	
	Total Operating Revenues	(12,762)	359,952
	OPERATING EXPENSES:		
	OPERATION & MAINTENANCE EXPENSE		
C	Remove Industry Association dues		
C	Remove Economic Development Expenses		
C	Remove Management Tax Preparation Expenses		
C	Remove Tallahassee Liaison Office Expenses		
C	Remove Purchased Transmission Expenses		
C	Remove Marketing and Wholesale expenses		
C	Depreciation Study Adjustment		
S-17	Inflation Factors	(100)	
S-18	Remove Fuel Expenses		
S-19	Remove ECCR Expenses		
S-20	Remove PPCC Expenses		
S-21	Remove ECRC Expenses		
S-22	Remove Lobbying Expenses	(7)	
47	Security Measures	744	
48	Advertising Expenses	(539)	
50A	Relocation Expense	(16)	
51	Hiring Lag	(324)	
58	Rate Case Expenses	(30)	
59	Marketing Expense	0	
64	Cable Injection Expense	(168)	
65	Tree Trimming Expenses	(930)	
68	Street & Outdoor Lighting Expenses	(320)	
	Total Operating & Maintenance Expense	(1,688)	180,731
	DEPRECIATION & AMORTIZATION EXP.		
C	Depreciation Study Adjustment		
C	Smith CC Life Adjustment		
S-19	Remove ECCR Expenses		
S-21	Remove ECRC Expenses		
8	Smith Unit 3 - 25 Year Life	(2,041)	
16	House Power Panels	(49)	
47	Security Measures	101	
64	Cable Injection Expense	2	
72	Office Building - 3rd Floor	(535)	
	Total Depreciation & Amortization Expense	(2,522)	75,042
	TAXES OTHER THAN INCOME		
C	Remove Franchise Fee Expenses		
C	Smith CC Property Tax Annualization		
C	Remove Recovery Clause Revenue Taxes		
C	Remove Tellahasse Office Property Taxes		
S-19	Remove ECCR Expenses		
S-21	Remove ECRC Expenses		
51	Hiring Lag	(19)	

ISSUE NO.		COMMISSION VOTE ADJS.	ADJUSTED
78	Gross Receipts Tax	(11,110)	
79	Smith Unit 3 Property Taxes	(1,206)	
	Total Taxes Other Than Income	(12,335)	24,634
	CURRENT/DEFERRED INCOME TAXES		
C	Effect of NOI Adjustments	1,460	
C	Interest Synchronization	1,282	
	Total Current/Deferred Income Taxes	2,742	18,588
	INVESTMENT TAX CREDIT		
	Total Investment Tax Credit	0	(1,462)
	(GAIN)/LOSS ON SALE OF PROPERTY		
	Total (Gain)/Loss on Sale of Property	0	0
	TOTAL OPERATING EXPENSES	(13,803)	297,533
	NET OPERATING INCOME	1,041	62,419

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ATTACHMENT 4

DOCKET NO. 010949-EI
DATE: April 26, 2002

COMPARATIVE NET OPERATING INCOME MULTIPLIERS

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003

	Company As Filed	Stipulation 30 W/O Gross Receipts Tax
Revenue Requirement	100.0000%	100.0000%
Gross Receipts Tax	-1.5000%	0.0000%
Regulatory Assessment Fee	-0.0720%	-0.0720%
Bad Debt Rate	-0.1583%	-0.2416%
Net Before Income Taxes	98,2697%	99.6864%
Income Taxes @ 38.575%	-37.9075%	-38.4540%
Revenue Expansion Factor	60.3622%	61.2323%
Net Operating Income Multiplier	1.656667	1.633125

ATTACHMENT 5

COMPARATIVE REVENUE REQUIREMENTS

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003

	Company As Filed ($ 000)	COMMISSION VOTE ($ 000)
Jurisdictional Adjusted Rate Base	1,198,502	1,199.732
Required Rate of Return	8.54%	7.92%
Required Net Operating Income	103,551	95,019
Achieved Net Operating Income	(61,378)	(62,419)
Net Operating Income Deficiency/(Excess)	42,173	32,600
Net Operating Income Multiplier	1.656666	1.633125
Operating Revenue Increase/(Decrease)	69,867	53,240

ATTACHMENT [*172] 6

GULF POWER COMPANY

DOCKET NO. 010949-EI

COMMISSION APPROVED REVENUE INCREASE BY RATE CLASS

SUMMARY OF CLASS RATES OF RETURN AND PERCENTAGE INCREASES

($ 000s)

(1)	(2)	(3)	(4)	
RATE CLASS	RATE BASE	PRESENT NOI	PRESENT ROR	INDEX
RS/RSVP	$ 675,728	531.853	4.71%	0.91
GS	$ 46,505	$ 3,617	7.78%	1.50
GSD/GSDT/GSTOU	$ 238,613	$ 13,875	5.81%	1.12
LP/LPT	$ 148,389	$ 8,611	5.80%	1.12
OS-I/II	$ 36,234	$ 1,346	3.72%	$ 0
OS-III	$ 2,452	$ 290	11.82%	2.27
OS-IV	$ 771	$ 36	4.62%	0.89
CSA	$ 20,504	($ 263)	-1.28%	-0.25
SBS, ISS, RPT, PX, PXT	$ 30,537	$ 3,055	10.00%	1.92
TOTAL RETAIL	$ 1,199,732	$ 62,419	5.20%	1.00

(1)	(5)	(6)	(7)	(8)
RATE CLASS	INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF ELECTRICITY	TOTAL INCREASE IN REVENUE	REQUIRED NOI
RS/RSVP	$ 1,808	$ 35,348	$ 37,156	$ 54,604
GS	$ 152	$ 109	$ 261	$ 3,777
GSD/GSDT/GSTOU	$ 80	$ 8,768	$ 8,848	$ 19,292
LP/LPT	$ 0	$ 5,596	$ 5,596	$ 12,037
OS-I/II	$ 0	$ 1,343	$ 1,343	$ 2,169
OS-III	$ 0	$ 0	$ 0	$ 290
OS-IV	$ 0	$ 36	$ 36	$ 58

(1) RATE CLASS	(2) RATE BASE	(3) PRESENT NOI	(4) PRESENT ROR	INDEX
CSA	$ 0	$ 0	$ 0	($ 263)
SBS, ISS, RPT, PX, PXT	$ 0	$ 0	$ 0	$ 3,055
TOTAL RETAIL	$ 2,040	$ 51,200	$ 53,240	$ 95,019

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(1) RATE CLASS	(9) APPROVED ROR	INDEX	(10) % INCREASE IN REVENUE FROM SALES OF ELECTRICITY WITH ADJUSTMENT CLAUSES	BASE
RS/RSVP	8.08%	1.02	11.7%	18.6%
GS	8.12%	1.03	0.5%	0.6%
GSD/GSDT/GSTOU	8.09%	1.02	7.4%	13.3%
LP/LPT	8.11%	1.02	6.6%	13.8%
OS-I/II	5.99%	0.76	13.1%	16.9%
OS-III	11.82%	1.49	0.0%	0.0%
OS-IV	7.48%	0.94	13.2%	20.6%
CSA	-1.28%	-0.16	0.0%	0.0%
SBS, ISS, RPT, PX, PXT	10.00%	1.26	0.0%	0.0%
TATAL RETAIL	7.92%	1.00	8.9%	15.2%

ATTACHMENT 7

GULF POWER COMPANY

DOCKET NO. 010949-EI

COMMISSION APPROVED RATES

RATE COMPONENT	PRESENT	COMMISSION APPROVED
RESIDENTIAL SERVICE (RS)		
CUSTOMER CHARGE (PER MO.):	$ 8.07	$ 10.00
NON-FUEL CHARGE (PER KWH):	$ 0.03413	$ 0.03930
RESIDENTIAL SERVICE VARIABLE PRICING (RSVP)		
CUSTOMER CHARGE (PER MO.):	$ 8.07	$ 10.00
PARTICIPATION CHARGE (PER MO.): *	$ 4.53	$ 4.95
NON-FUEL CHARGE (PER KWH):		
LOW	$ 0.01164	$ 0.01785
MEDIUM	$ 0.02301	$ 0.03021
HIGH	$0.07029	$ 0.075989
CRITICAL	$ 0.26746	$ 0.28500
GENERAL SERVICE - NON DEMAND (GS)		
CUSTOMER CHARGE (PER MO.):	$ 10.09	$ 13.00

RATE COMPONENT	PRESENT	COMMISSION APPROVED
NON-FUEL CHARGE (PER KWH):	$ 0.05026	$ 0.04837
GENERAL SERVICE - DEMAND (GSD)		
CUSTOMER CHARGE (PER MO.):	$ 40.35	$ 35.00
DEMAND CHARGE (PER KW):	$ 4.56	$ 5.42
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.01195	$ 0.01396
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW) *	($ 0.35)	($ 0.44)
GENERAL SERVICE - DEMAND TIME-OF-USE CONSERVATION (GSDT)		
CUSTOMER CHARGE (PER MO.):	$ 45.80	$ 35.00
DEMAND CHARGE (PER KW):		
MAXIMUM DEMAND	$ 2.17	$ 2.58
ON-PEAK DEMAND	$ 2.45	$ 2.01
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.01195	$ 0.01396
TRANS OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($ 0.35)	($ 0.44)
GENERAL SERVICE - TIME-OF-USE CONSERVATION (GSTOU)		
CUSTOMER CHARGE (PER MO.):	N/A	$ 35.00
NON-FUEL ENERGY CHARGE (PER KWH):		
SUMMER - ON PEAK	N/A	0.16068
SUMMER INTERMEDIATE	N/A	0.05785
SUMMER - OFF-PEAK	N/A	0.02201
WINTER - ALL HOURS	N/A	0.03221

* Stipulated

LARGE POWER (LP)		
CUSTOMER CHARGE (PER MO.):	$ 226.98	$ 155.00
DEMAND CHARGE (PER KW):	$ 8.57	$ 8.75
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00428	$ 0.00668
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW): *	($ 0.42)	($ 0.53)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($ 0.52)	($ 0.67)
LARGE POWER - TIME-OF-USE CONSERVATION (LPT)		
CUSTOMER CHARGE (PER MO.):	$ 226.98	$ 155.00
DEMAND CHARGES (PER KW)		
MAXIMUM DEMAND	$ 1.83	$ 1.77
ON-PEAK DEMAND	$ 7.27	$ 7.03
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00316	$ 0.00668
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW): *	($ 0.42)	($ 0.53)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($ 0.52)	($ 0.67)

LARGE HIGH LOAD FACTOR POWER (PX) **

RATE COMPONENT	PRESENT	COMMISSION APPROVED
CUSTOMER CHARGE (PER MO.):	$ 575.01	$ 568.38
DEMAND CHARGE (PER KW):	$ 6.32	$ 8.20
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00306	$ 0.00303
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($ 0.11)	($ 0.16)
MINIMUM BILL MAXIMUM DEMAND CHARGE (PER KW): *	$ 10.561	$ 9.659
LARGE HIGH LOAD FACTOR POWER TIME-OF-USE CONSERVATION (PXT) **		
CUSTOMER CHARGE (PER MO.):	$ 575.01	$ 566.38
DEMAND CHARGE (PER KW)		
MAXIMUM DEMAND	$ 0.69	$ 0.68
ON-PEAK DEMAND	$ 7.73	$ 7.61
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00305	$ 0.00300
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($ 0.11)	($ 0.18)
MINIMUM BILL MAXIMUM DEMAND CHARGE (PER KW): *	$ 9.960	$ 9.819
OTHER OUTDOOR SERVICE (OS-III) **		
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.03679	$ 0.03624
OUTDOOR SERVICE RECREATIONAL LIGHTING (OS-IV)		
CUSTOMER CHARGE (PER MO.):	$ 10.09	513.00
NON-FUEL ENERGY (PER KWH):	$ 0.03639	$ 0.04239

* Stipulated.
** No Increases were allocated to these classes. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1.5%.

STANDBY AND SUPPLEMENTARY (SBS) **		
100-499 KW		
CUSTOMER CHARGE (PER MO.):	$ 251.98	$ 246.20
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$ 1.69	$ 1.66
RESERVATION CHARGE (PER KW OF BC):	$ 1.01	$ 0.99
DAILY DEMAND CHARGE (PER KW):	$ 0.47	$ 0.46
ON-PEAK DEMAND CHARGE (PER KW):	$ 2.45	$ 2.41
NON FUEL ENERGY CHARGE (PER KWH):	$ 0.01195	$ 0.01177
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($ 0.27)	($ 0.27)
600 - 7,499 KW		
CUSTOMER CHARGE (PER MO.):	$ 251.98	$ 248.20
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$ 1.25	$ 1.23
RESERVATION CHARGE (PER KW OF BC):	$ 1.01	$ 0.99
DAILY DEMAND CHARGE (PER KW):	$ 0.47	$ 0.46
ON-PEAK DEMAND CHARGE (PER KW):	$ 7.27	$ 7.16
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00316	$ 0.00311
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($ 0.41)	($ 0.41)
TRANS. OWNERSHIP DISCOUNT - TRANS (PER KW):	($ 0.48)	($ 0.48)

ABOVE 7,499 KW

RATE COMPONENT	PRESENT	COMMISSION APPROVED
CUSTOMER CHARGE (PER MO.):	$ 600.01	$ 591.01
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$ 0.52	$ 0.51
RESERVATION CHARGE (PER KW OF BC):	$ 1.00	$ 0.98
DAILY DEMAND CHARGE (PER KW):	$ 0.47	$ 0.46
ON-PEAK DEMAND CHARGE (PER KW):	$ 7.73	$ 7.61
NON-FUEL ENERGY CHARGE (PER KW):	$ 0.00305	$ 0.00300
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($ 0.07)	($ 0.07)

** No increase was allocated to this class. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1.5%.

INTERRUPTIBLE STANDBY SERVICE (ISS) **

100 - 499 KW		
CUSTOMER CHARGE (PER MO.) *	$ 25.00	$ 24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$ 1.69	$ 1.66
RESERVATION CHARGE (PER KW OF IC):	$ 0.81	$ 0.80
SUMMER DAILY DEMAND CHARGE (PER KW):	$ 0.46	$ 0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$ 0.34	$ 0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00357	$ 0.00352
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($ 0.27)	($ 0.27)
500 - 7,499 KW		
CUSTOMER CHARGE (PER MO.) *	$ 25.00	$ 24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$ 1.25	$ 1.23
RESERVATION CHARGE (PER KW OF IC):	$ 0.81	$ 1.60
SUMMER DAILY DEMAND CHARGE (PER KW):	$ 0.46	$ 0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$ 0.34	$ 0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00357	$ 0.00352
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($ 0.41)	($ 0.41)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($ 0.48)	($ 0.48)
ABOVE 7.499 KW		
CUSTOMER CHARGE (PER MO.) *	$ 25.00	$ 24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$ 0.62	$ 0.61
RESERVATION CHARGE (PER KW OF IC):	$ 0.81	$ 0.80
SUMMER DAILY DEMAND CHARGE (PER KW):	$ 0.46	$ 0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$ 0.34	$ 0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$ 0.00357	$ 0.00352
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($ 0.07)	($ 0.07)

* Customers also pay LP/LPT customer charge, except those taking supplementary service under PX/PXT. These customers pay the PX/PXT customer charge in addition to the ISS customer charge.

** No increase was allocated to this class. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1.5%.
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COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

		Fixture Charge		Maintenance Charge	
Type of Facility	Description	Present	Commission Approved	Present	Commission Approved

Type of Facility	Description	Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved
HIGH PRESSURE SODIUM					
5,400 LUMEN	Open Bottom	$ 1.97	$ 2.42	$ 2.85	$ 1.30
8,600 LUMEN	Open Bottom	$ 1.77	$ 2.07	$ 0.80	$ 1.18
8,600 LUMEN	Acom	$ 3.98	$ 10.32	$ 1.83	$ 3.48
8,600 LUMEN	Colonies	$ 3.15	$ 2.76	$ 0.77	$ 1.37
8,800 LUMEN	English Coach	$ 10.10	$ 11.27	$ 3.59	$ 3.74
5,400 LUMEN	Cobrahead	$ 1.97	$ 3.40	$ 1.35	$ 1.57
8,800 LUMEN	Cobrahead	$ 1.98	$ 2.84	$ 1.07	$ 1.39
20,000 LUMEN	Cobrahead	$ 2.28	$ 3.91	$ 1.57	$ 1.70
25,000 LUMEN	Cobrahead	$ 2.83	$ 3.80	$ 2.05	$ 1.53
46,000 LUMEN	Cobrahead	$ 3.20	$ 4.00	$ 1.62	$ 1.73
20,000 LUMEN	Coastal ORL **	$ 4.35	N/A	$ 1.81	N/A
20,000 LUMEN	Small ORL	N/A	$ 9.03	N/A	$ 3.13
25,000 LUMEN	Small ORL	N/A	$ 8.69	N/A	$ 3.04
46,000 LUMEN	Small ORL	$ 7.23	$ 9.10	$ 3.29	$ 3.15
20,000 LUMEN	Large ORL	$ 9.37	$ 14.71	$ 1.81	$ 4.71
46,000 LUMEN	Large ORL	$ 9.17	$ 16.57	$ 2.02	$ 5.23
46,000 LUMEN	Shoebox A **	$ 5.20	N/A	$ 2.20	N/A
46,000 LUMEN	Shoebox B **	$ 5.12	N/A	$ 2.14	N/A
46,000 LUMEN	Shoebox *	N/A	$ 7.60	N/A	$ 2.73
20,000 LUMEN	Directional	$ 4.31	$ 6.17	$ 1.94	$ 2.34
46,000 LUMEN	Directional	$ 3.84	$ 4.58	$ 1.81	$ 1.89

* Combined rate offering
** Discontinued rate offering

HIGH PRESSURE SODIUM - PAID UP FRONT					
8,800 LUMEN	Open Bottom PUF	N/A	N/A	$ 0.80	$ 1.18
8,800 LUMEN	Acom PUF	N/A	N/A	$ 1.83	$ 3.48
8,800 LUMEN	Colonial PUF	N/A	N/A	$ 0.77	$ 1.37
8,800 LUMEN	English Coach PUF	N/A	N/A	$ 3.59	$ 3.74
8,800 LUMEN	Cobrahead PUF	N/A	N/A	$ 1.07	$ 1.39
20,000 LUMEN	Cobrahead PUF	N/A	N/A	$ 1.57	$ 1.70
25,000 LUMEN	Cobrahead PUF	N/A	N/A	$ 1.62	$ 1.65
46,000 LUMEN	Cobrahead PUF	N/A	N/A	$ 1.11	$ 1.73
46,000 LUMEN	Small ORL PUF	N/A	N/A	$ 3.29	$ 3.15
20,000 LUMEN	Large ORL PUF	N/A	N/A	$ 1.81	$ 4.71
46,000 LUMEN	Directional PUF	N/A	N/A	$ 1.81	$ 1.89
46,000 LUMEN	Shoebox PUF	N/A	N/A	$ 2.20	$ 2.73
20,000 LUMEN	Coastal ORL PUF **	N/A	N/A	$ 1.61	N/A

** Discontinued rate offering

METAL HALIDE (OS-II)					
12,000 LUMEN	Acom - NEW +	N/A	$ 10.42	N/A	$ 4.38

Type of Facility	Description	Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved
12,000 LUMEN	Colonial - NEW +	N/A	$ 2.88	N/A	$ 2.29
12,000 LUMEN	English Coach - NEW +	N/A	$ 11.37	N/A	$ 4.65
32,000 LUMEN	Small Flood	$ 2.75	$ 4.68	$ 1.92	$ 2.03
32,000 LUMEN	Parking Lot A **	$ 8.17	N/A	$ 3.48	N/A
32,000 LUMEN	Parking Lot B **	$ 8.10	N/A	$ 3.38	N/A
32,000 LUMEN	Parking Lot *	N/A	$ 6.65	N/A	$ 3.14
100,000 LUMEN	Large Flood	$ 4.48	$ 6.72	$ 3.79	$ 4.02
100,000 LUMEN	Large Parking Lot	$ 11.51	$ 14.93	$ 5.14	$ 5.57
METAL HALIDE (OS-II) PAID UP FRONT					
32,000 LUMEN	Parking Lot PUF	N/A	N/A	$ 3.48	$ 3.14
32,000 LUMEN	MTRD Pk Lot PUF	N/A	N/A	$ 3.48	$ 3.14
MERCURY VAPOR					
7,000 LUMEN	Open Bottom	$ 1.42	$ 1.65	$ 0.66	$ 1.04
3,200 LUMEN	Cobrahead	$ 1.45	$ 3.11	$ 1.41	$ 1.46
7,000 LUMEN	Cobrahead	$ 1.44	$ 2.83	$ 1.05	$ 1.36
9,400 LUMEN	Cobrahead	$ 1.93	$ 3.71	$ 1.67	$ 1.68
17,000 LUMEN	Cobrahead	$ 2.24	$ 4.05	$ 1.75	$ 1.73
46,000 LUMEN	Cobrahead	$ 6.08	$ 6.14	$ 3.19	$ 3.00
17,000 LUMEN	Directional	$ 4.15	$ 6.10	$ 1.86	$ 2.31
CUSTOMER-OWNED MISC. STREET/ OUTDOOR LIGHTING (OS-I/II)		N/A	N/A	N/A	N/A

+ New rate offering
* Combined rate offering
** Discontinued rate offering

Type of Facility	Description	Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved
CUSTOMER OWNED W/RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR					
8,500 LUMEN	Unmetered	N/A	N/A	$ 0.32	$ 0.53
20,000 LUMEN	Unmetered	N/A	N/A	$ 0.34	$ 0.54
25,000 LUMEN	Unmetered	N/A	N/A	N/A	$ 0.55
46,000 LUMEN	Unmetered	N/A	N/A	$ 0.34	$ 0.54
8,800 LUMEN	Metered	N/A	N/A	$ 0.32	$ 0.53
20,000 LUMEN	Metered	N/A	N/A	N/A	$ 0.54
25,000 LUMEN	Metered	N/A	N/A	$ 0.35	$ 0.55
46,000 LUMEN	Metered	N/A	N/A	$ 0.34	$ 0.54

CUSTOMER OWNED
W/RELAMPING

		Fixture Charge		Maintenance Charge	
Type of Facility	Description	Present	Commission Approved	Present	Commission Approved
SERVICE AGREEMENT - METAL HALIDE					
32,000 LUMEN	Unmetered	N/A	N/A	$ 0.76	$ 0.65
32,000 LUMEN	Metered	N/A	N/A	N/A	$ 0.65
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED-CUSTOMER MAINTAINED					
8,800 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A
20,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A
46,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A
METAL HALIDE - CUSTOMER OWNED/ CUSTOMER MAINTAINED					
32,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A

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	Energy Charge		Total Monthly Charge	
Type of Facility	Present	Commission Approved	Commission Present	Approved
HIGH PRESSURE SODIUM				
5,400 LUMEN	$ 0.71	$ 0.56	$ 3.56	$ 4.28
8,600 LUMEN	$ 1.02	$ 0.79	$ 3.59	$ 4.04
8,600 LUMEN	$ 1.02	$ 0.79	$ 6.83	$ 14.59
8,600 LUMEN	$ 1.02	$ 0.79	$ 4.94	$ 4.94
8,800 LUMEN	$ 1.02	$ 0.79	$ 14.71	$ 15.80
5,400 LUMEN	$ 0.71	$ 0.56	$ 4.03	$ 5.53
8,800 LUMEN	$ 1.02	$ 0.79	$ 4.07	$ 5.02
20,000 LUMEN	$ 2.06	$ 1.54	$ 5.91	$ 7.15
25,000 LUMEN	$ 2.60	$ 1.92	$ 7.48	$ 7.40
46,000 LUMEN	$ 4.10	$ 3.15	$ 8.92	$ 8.88
20,000 LUMEN	$ 2.06	N/A	$ 5.22	N/A
20,000 LUMEN	N/A	$ 1.54	N/A	$ 13.70
25,000 LUMEN	N/A	$ 1.92	N/A	$ 13.65
46,000 LUMEN	$ 4.10	$ 3.15	$ 14.62	$ 15.40
20,000 LUMEN	$ 2.06	$ 1.54	$ 13.24	$ 20.96
46,000 LUMEN	$ 4.10	$ 3.15	$ 15.29	$ 24.95
46,000 LUMEN	$ 4.10	N/A	$ 11.50	N/A
46,000 LUMEN	$ 4.10	N/A	$ 11.38	N/A
46,000 LUMEN	N/A	$ 3.15	N/A	$ 13.48
20,000 LUMEN	$ 2.14	$ 1.54	$ 5.39	$ 10.05
46,000 LUMEN	$ 4.28	$ 3.15	$ 9.91	$ 9.62

HIGH PRESSURE

	Energy Charge		Total Monthly Charge	
Type of Facility	Present	Commission Approved	Commission Present	Approved
SODIUM - PAID UP FRONT				
8,800 LUMEN	$ 1.02	$ 0.79	$ 1.82	$ 1.97
8,800 LUMEN	$ 1.02	$ 0.79	$ 2.85	$ 4.27
8,800 LUMEN	$ 1.02	$ 0.79	$ 1.79	$ 2.16
8,800 LUMEN	$ 1.02	$ 0.79	$ 4.81	$ 4.53
8,800 LUMEN	$ 1.02	$ 0.79	$ 2.09	$ 2.18
20,000 LUMEN	$ 2.06	$ 1.54	$ 3.63	$ 3.24
25,000 LUMEN	$ 2.50	$ 1.92	$ 4.22	$ 3.60
46,000 LUMEN	$ 4.10	$ 3.15	$ 5.21	$ 4.85
46,000 LUMEN	$ 4.10	$ 3.15	$ 7.39	$ 6.30
20,000 LUMEN	$ 2.06	$ 1.54	$ 3.87	$ 6.25
46,000 LUMEN	$ 4.25	$ 3.15	$ 6.07	$ 5.04
46,000 LUMEN	$ 4.10	$ 3.15	$ 5.30	$ 5.88
20,000 LUMEN	$ 2.06	N/A	$ 3.87	N/A
METAL HALIDE (OS-II)				
12,000 LUMEN	N/A	$ 1.38	N/A	$ 10.18
12,000 LUMEN	N/A	$ 1.38	N/A	$ 6.55
12,000 LUMEN	N/A	$ 1.38	N/A	$ 17.40
32,000 LUMEN	$ 4.10	$ 3.13	$ 8.77	$ 9.84
32,000 LUMEN	$ 4.10	N/A	$ 15.75	N/A
32,000 LUMEN	$ 4.10	N/A	$ 15.58	N/A
32,000 LUMEN	N/A	$ 3.13	N/A	$ 14.92
100,000 LUMEN	$ 9.46	$ 7.27	$ 17.73	$ 16.01
100,000 LUMEN	$ 9.45	$ 7.27	$ 26.41	$ 27.77
METAL HALIDE (OS-II) PAID UP FRONT				
32,000 LUMEN	$ 4.10	$ 3.13	$ 7.58	$ 6.27
32,000 LUMEN	N/A	N/A	$ 3.48	$ 3.14
MERCURY VAPOR				
7,000 LUMEN	$ 1.71	$ 1.29	$ 3.79	$ 4.01
3,200 LUMEN	$ 0.99	$ 0.75	$ 3.85	$ 5.32
7,000 LUMEN	$ 1.71	$ 1.29	$ 4.20	$ 5.48
9,400 LUMEN	$ 2.42	$ 1.83	$ 8.02	$ 7.20
17,000 LUMEN	$ 3.67	$ 2.92	$ 7.06	$ 8.70
46,000 LUMEN	$ 9.46	$ 7.15	$ 18 75	$ 18.29
17,000 LUMEN	$ 4.15	$ 3.13	$ 10.16	$ 11.54
CUSTOMER-OWNED MISC. STREET/ OUTDOOR LIGHTING (OS-I/II)	$ 0.02549 per KWH	$ 0.01923 per KWH	$ 0.02549 per KWH	$ 0.01923 per KWH

CUSTOMER OWNED

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	Energy Charge		Total Monthly Charge	
Type of Facility	Present	Commission Approved	Commission Present	Approved
W/RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR				
8,500 LUMEN	$ 1.02	$ 0.79	$ 1.34	$ 1.32
20,000 LUMEN	$ 2.06	$ 1.54	$ 2.40	$ 2.08
25,000 LUMEN	N/A	$ 1.92	N/A	$ 2.47
46,000 LUMEN	$ 4.10	$ 3.15	$ 4.44	$ 3.69
8,800 LUMEN	N/A	N/A	$ 0.32	$ 0.53
20,000 LUMEN	N/A	N/A	N/A	$ 0.54
25,000 LUMEN	N/A	N/A	$ 0.35	$ 0.55
46,000 LUMEN	N/A	N/A	$ 0.34	$ 0.54
CUSTOMER OWNED W/RELAMPING SERVICE AGREEMENT - METAL HALIDE				
32,000 LUMEN	$ 4.10	$ 3.13	$ 4.86	$ 3.78
32,000 LUMEN	N/A	N/A	N/A	$ 0.65
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED-CUSTOMER MAINTAINED				
8,800 LUMEN	$ 1.02	$ 0.79	$ 1.02	$ 0.79
20,000 LUMEN	$ 2.06	$ 1.54	$ 2.06	$ 1.54
46,000 LUMEN	$ 4.10	$ 3.15	$ 4.10	$ 3.15
METAL HALIDE - CUSTOMER OWNED/ CUSTOMER MAINTAINED				
32,000 LUMEN	$ 4.10	$ 3.13	$ 4.10	$ 3.13

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COMMISSION APPROVED SHEET (OS-1) AND OUTDOOR (OS-1) LIGHTNING RATES

[SEE TABLE IN ORIGINAL]

Legal Topics:

For related research and practice materials, see the following legal topics:
Administrative LawAgency AdjudicationHearingsGeneral OverviewEnergy & Utilities LawAdministrative ProceedingsPublic Utility CommissionsGeneral OverviewEnergy & Utilities LawTransportation & PipelinesElectricity Transmission

EAP Data Information Solutions, LLC
AD HOC SPECIAL SURVEY REPORT - 0911
PERFORMANCE MANAGEMENT PROCESSES

REPORT DATE: 7/6/2009

CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
1	MERIT INCREASE	Executives	Yes	14	Apr	Apr	May	Mar
		All Other	Yes	14	Apr	Apr	May	Mar
	CASH INCENTIVE	Executives	Yes	28	May	Jun	Jul	Jun
		All Other	Yes	28	May	Jun	Jul	Jun
2	CASH INCENTIVE	Executives	Yes	14	Mar	Mar	Apr	Mar
		All Other	Yes	14	Mar	Mar	Apr	Mar
3	MERIT INCREASE	Executives	Yes	14	Jan	Feb	Mar	Jan
		All Other	Yes	14	Jan	Feb	Mar	Jan
	STRUCTURE ADJUSTMENT	Executives	No					
		All Other	Yes		Nov	Dec	Mar	Dec
4	MERIT INCREASE	Executives	No					
		All Other	Yes	6	Feb	Feb	Mar	Jan
	CASH INCENTIVE	Executives	Yes	6	Feb	Feb	Feb	Jan
		All Other	Yes	6	Feb	Feb	Feb	Feb
5	MERIT INCREASE	Executives	Yes	7	Oct	Nov	Oct	Nov
		All Other	Yes	7	Oct	Nov	Oct	Nov
	STRUCTURE ADJUSTMENT	Executives	Yes	14	Jul	Aug	Oct	Aug
		All Other	Yes	14	Jul	Aug	Oct	Aug

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
6								
	MERIT INCREASE	Executives	No					
		All Other	Yes	15-30	Jan	Feb	Feb	Feb
	CASH INCENTIVE	Executives	No					
		All Other	Yes	15-30	Jan	Feb	Feb	Feb
7								
	MERIT INCREASE	Executives	Yes	1	Feb	Feb	Mar	Feb
		All Other	Yes	10	Feb	Feb	Mar	
	CASH INCENTIVE	Executives	Yes	1	Feb	Feb	Feb	Feb
		All Other	Yes	5	Jan	Feb	Feb	Feb
	RESTRICTED STOCK GRANT	Executives	Yes	1	Feb	Feb	Feb	Feb
		All Other	No					
	PERFORMANCE SHARE GRANT	Executives	Yes	1	Feb	Feb	Feb	Feb
		All Other	No					
8								
	MERIT INCREASE	Executives	Yes	Approved by BOD - presented and approved in 1 day (materials provided one week ahead of time)	Feb	Feb	Mar	Feb
		All Other	Yes	5	Dec	Dec	Jan	Dec
	STRUCTURE ADJUSTMENT	Executives	No					
		All Other	Yes	Approved by Executive Staff - presented and approved in 1 day (materials provided one week ahead of time)	Nov	Nov	Jan	Dec
	CASH INCENTIVE	Executives	Yes	Approved by BOD - presented and approved in 1 day (materials provided one week ahead of time)	Feb	Feb	Mar	Feb
		All Other	Yes	5	Feb	Mar	Mar	Mar
	PERFORMANCE SHARE GRANT	Executives	Yes	Approved by BOD - presented and approved in 1 day (materials provided one week ahead of time)	Feb	Feb	Feb	Feb
		All Other	Yes	Approved by BOD - presented and approved in 1 day (materials provided one week ahead of time)	Feb	Feb	Feb	Feb

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
9	MERIT INCREASE	Executives	Yes	2 weeks	Jan	Mar	Mar	Feb
		All Other	Yes	2 weeks	Jan	Mar	Mar	Feb
	CASH INCENTIVE	Executives	Yes	2 weeks	Jan	Mar	Mar	Mar
		All Other	Yes	2 weeks	Jan	Mar	Mar	Mar
10	MERIT INCREASE	Executives	Yes	see note #3	Nov	Jan	Dec	Feb
		All Other	Yes		Nov	Dec	Dec	Dec
	STRUCTURE ADJUSTMENT	Executives	Yes		Oct	Jan	Dec	Feb
		All Other	Yes		Oct	Dec	Dec	Dec
	CASH INCENTIVE	Executives	Yes		Jan	Feb	Dec	Feb
		All Other	Yes		Jan	Feb	Dec	Feb
	RESTRICTED STOCK GRANT	Executives	Yes		Nov	Jan	Dec	Feb
		All Other	No					
	PERFORMANCE SHARE GRANT	Executives	Yes		Jan	Feb	Dec	Feb
		All Other	No					
11	MERIT INCREASE	Executives	Yes	9	Jan	Jan	May	Jan
		All Other	Yes	9	Feb	Feb	May	
	CASH INCENTIVE	Executives	Yes	9	Jan	Jan	Mar	
		All Other	Yes	9	Feb	Feb		
	RESTRICTED STOCK GRANT	Executives	Yes	9	Jan	Jan	Jan	Jan
		All Other	No					
	STOCK OPTION GRANT	Executives	Yes	9	Jan	Jan	Jan	Jan
		All Other	No					
	PERFORMANCE SHARE GRANT	Executives	Yes	9	Jan	Jan	Jan	Jan
		All Other	No					

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
12								
	MERIT INCREASE	Executives	Yes	5	Jan	Feb	Apr	
		All Other	Yes	5	Jan	Feb	Apr	
	STRUCTURE ADJUSTMENT	Executives	No					
		All Other	Yes	1			Jan	
	CASH INCENTIVE	Executives	Yes	5	Jan	Feb	Mar	
		All Other	Yes	5	Jan	Feb	Mar	
13								
	STRUCTURE ADJUSTMENT	Executives	Yes	driven by survey data, no approval needed	Dec	Jan	Jan	Dec
		All Other	Yes	driven by survey data, no approval needed	Jan	Feb	Mar	Feb
	CASH INCENTIVE	Executives	Yes	30	Jan	Feb	Mar	Feb
		All Other	Yes	30	Jan	Feb	Mar	Feb
	PERFORMANCE SHARE GRANT	Executives	Yes	approved by BOD	Feb	Feb	Jan	Feb
		All Other	No					
14								
	MERIT INCREASE	Executives	Yes	30	Jan	Feb	Apr	Feb
		All Other	Yes	30	Jan	Feb	Apr	Apr
	CASH INCENTIVE	Executives	Yes	7	Feb	Feb	Feb	Feb
		All Other	Yes	7	Feb	Feb	Feb	Feb
	RESTRICTED STOCK GRANT	Executives	Yes	14	Feb	Feb	Feb	Feb
		All Other	Yes	14	Feb	Feb	Feb	Feb
	PERFORMANCE SHARE GRANT	Executives	Yes	14	Feb	Feb	Feb	Feb
		All Other	Yes	14	Feb	Feb	Feb	Feb
15								
	MERIT INCREASE	Executives	Yes	30	Nov	Jan	Feb	Jan
		All Other	Yes	30				

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
16								
	MERIT INCREASE	Executives	Yes	14	Jan	Jan	Jan	Jan
		All Other	Yes	14	Jan	Jan	Apr	Feb
	STRUCTURE ADJUSTMENT	Executives	Yes	NA	Oct	Oct	Jan	Dec
		All Other	Yes	NA	Oct	Oct	Jan	Dec
	CASH INCENTIVE	Executives	Yes	14	Jan		Mar	May
		All Other	Yes	14	Jan		Mar	May
	RESTRICTED STOCK GRANT	Executives	Yes	21	Mar	Mar	Mar	Apr
		All Other	Yes	21	Mar	Mar	Mar	Apr
	PERFORMANCE SHARE GRANT	Executives	Yes	21	Nov	Dec	Jan	Dec
		All Other	No					
17								
	MERIT INCREASE	Executives	Yes	5-7	Nov	Nov	Jan	Dec
		All Other	Yes	5-7	Feb	Feb	Apr	
	STRUCTURE ADJUSTMENT	Executives	Yes	varies	Nov	Dec	Jan	
		All Other	Yes	varies	Nov	Jan	Jan	
	CASH INCENTIVE	Executives	Yes	5-7	Feb	Feb	Mar	Feb
		All Other	Yes	5-7	Feb	Feb	Mar	
	OTHER EQUITY GRANT	Executives	Yes				Feb	Feb
		All Other	No					
18								
	MERIT INCREASE	Executives	Yes	10	Feb	Feb	Apr	Jan
		All Other	Yes	10	Feb	Feb	Apr	
	CASH INCENTIVE	Executives	Yes	10	Feb	Feb	Mar	Jan
		All Other	Yes	10	Feb	Feb	Mar	
	STOCK OPTION GRANT	Executives	Yes	5	Jan	Jan	Jan	Jan
		All Other	No					
	PERFORMANCE SHARE GRANT	Executives	Yes				Mar	Jan
		All Other	No					

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
19								
	MERIT INCREASE	Executives	Yes	7	Feb	Feb	Apr	Feb
		All Other	Yes	14	Feb	Feb	Apr	Feb
	CASH INCENTIVE	Executives	Yes	7	Feb	Feb	Mar	Feb
		All Other	Yes	14	Feb	Feb	Mar	Feb
	STOCK OPTION GRANT	Executives	Yes	7	Feb	Feb	Feb	Feb
		All Other	Yes	14	Feb	Feb	Feb	Feb
	PERFORMANCE SHARE GRANT	Executives	Yes	7	Feb	Feb	Feb	Feb
		All Other	Yes	14	Feb	Feb	Feb	Feb
20								
	MERIT INCREASE	Executives	Yes	10	Jan	Feb	Mar	Feb
		All Other	Yes	10	Jan	Feb	Mar	Feb
	STRUCTURE ADJUSTMENT	Executives	Yes					
		All Other	Yes					
	CASH INCENTIVE	Executives	Yes	5	Jan	Feb	Mar	Feb
		All Other	Yes	5	Jan	Feb	Mar	Feb
	STOCK OPTION GRANT	Executives	Yes	Formula Driven				
		All Other	Yes	Formula Driven				Feb
21								
	MERIT INCREASE	Executives	Yes	45	Jan	Feb	Apr	Feb
		All Other	Yes	18	Mar	Mar	Apr	
	CASH INCENTIVE	Executives	Yes	45	Jan	Feb	Mar	Feb
		All Other	Yes	19	Feb	Feb	Mar	
	RESTRICTED STOCK GRANT	Executives	Yes	45	Jan	Feb	Feb	Feb
		All Other	No					
	STOCK OPTION GRANT	Executives	Yes	45	Jan	Feb	Feb	Feb
		All Other	No					
	PERFORMANCE SHARE GRANT	Executives	Yes	45	Jan	Feb	Feb	Feb
		All Other	Yes	45	Jan	Feb	Feb	Feb

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CODE	PROGRAM	RELEVANT POPULATION	PROVIDES PROGRAM	AVERAGE # OF DAYS ONE LEVEL OF MGMT. GIVEN TO APPROVE PROPOSAL	MONTH PROPOSALS/ APPROVALS BEGIN	MONTH PROPOSALS/ APPROVALS COMPLETED	EFFECTIVE MONTH OF AWARD	MONTH COMP. COMMITTEE APPROVES
22								
	MERIT INCREASE	Executives	Yes	1 week	Jan	Mar	Mar	Mar
		All Other	Yes	1 week	Feb	Feb	Mar	Mar
	STRUCTURE ADJUSTMENT	Executives	Yes	N/A	Dec	Dec	Mar	Mar
		All Other	Yes	N/A	Dec	Dec	Mar	Mar
	CASH INCENTIVE	Executives	Yes	1 week	Feb	Feb	Mar	Feb
		All Other	Yes	1 week	Jan	Feb	Mar	
	RESTRICTED STOCK GRANT	Executives	Yes	1 week	Feb	Feb	Mar	Mar
		All Other	Yes	1 week	Feb	Feb	Mar	Mar
	PERFORMANCE SHARE GRANT	Executives	Yes	1 week	Feb	Feb	Mar	Mar
		All Other	No					

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QUESTIONS 1-3	QUESTION 1			QUESTION 2		QUESTION 3				
Code	Perform Mgt. Process	Freq. (A-Annual); (O-Other); (S-Simi-annual)	If OTHER, describe	Is cycle based on calendar Yr. (C) or Other (O)	If OTHER, state cycle start & end	3A - Are ratings determined as part of performance cycle	If YES to 3A, do ratings cover the entire cycle	If YES to 3A, does rating link to co. wide scale automatically determines amount emp. receives	If YES to 3A, what months are ratings assigned	Are preliminary ratings determined before end of performance
1	Yes	A		O	May 1-Apr 30	Yes	Yes	No	Feb-Mar	No
2	Yes	A		C		Yes	Yes	Yes	March	Yes
3	Yes	A		C		No	No	No		No
4	Yes	A		C		No	No	No		No
5	Yes	A		O	Oct 1-Sep 30	Yes	Yes	No	Nov	No
6	Yes	A		C		Yes	Yes	Yes	Jan	Yes
7	Yes	O	Annually with semi-annual conversations	C		Yes	Yes	Yes	Nov-Jan	No
8	Yes	A		O	Nov 1- Oct 31	Yes	Yes	Yes	Nov	No
9	Yes	A		C		Yes	Yes	No	Feb	Yes
10	Yes	A		C	Oct 1-Sep 30	Yes	Yes	Yes	Nov	No
11	Yes	A		C		Yes	Yes	No	Jan	No
12	Yes	S		C		Yes	Yes	No	Jan	Yes
13	Yes	A	Pay increases are market adjustments and not merit increases. Performance is tied to annual incentives.	C		Yes	Yes	Yes	Jan	No
14	Yes	A		C		Yes	Yes	No	Feb-Mar	No
15	Yes	A				Yes	No	Yes	Dec	Yes
16	Yes	A		C		Yes	Yes	No	Jan	Yes
17	Yes	A		C		Yes	Yes	Yes	Feb/Mar for non-executive mgmt; Dec for executives	No
18	Yes	A		C		Yes	Yes	No	Feb-Mar	No
19	Yes	A		C		Yes	Yes	No	Jan	No
20	Yes	A		C		Yes	Yes	No	Jan	No
21	Yes	A		C		Yes	Yes	No	Jan	No
22	Yes	A		C		Yes	Yes	No	Jan	No

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QUESTIONS 4-6

Code	QUESTION 4: 4A - Do you make pay decisions before end of cycle	If YES to 4A, what pay programs are applicable	If YES to 4A, what are pay decisions based on	Q5 - Do you require emp. to be present/active as of date of actual incentive payout	QUESTION 6: 6A - Each participant in the mgr. incentive program (short or long) has to be nominated through a separate nomination process	If YES to 6A, what level of management approval is required
1	No			Yes	No	
2	Yes	Cash Incentive	preliminary performance rating and formula of target times salary	Yes	No	
3	No			No	No	
4	No			No	No	
5	No			Yes	Yes	CEO
6	No			Yes	No	
7	No			No	No	
8	No			No	No	
9	No			No	No	
10	No			No	Yes	Long term incentive participation is approved each year by the Board of Directors
11	No			Yes	Yes	The "Yes" answer only appies to long term plan awards for the management level just below officers. Approval must come from both the line Senior Vice Prsident and Senior Vicce President, Human Resources.
12	No			Yes	No	
13	No			No	No	
14	No			Yes	No	Only long term incentives have a separate nomination process as typically less than 3% of employees receive long term compensation.
15	Yes	Merit	preliminary performance ratings, position in salary range	No	No	
16	No			No	No	
17	No			Yes	No	
18	No			No	No	
19	No			Yes	No	
20	No			No	No	
21	No			Yes	No	
22	No			Yes	Yes	CEO

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QUESTIONS 7-8

Code	QUESTION 7 - MANAGERS MADE DISCRETIONARY ADJUSTMENTS TO INCENTIVE PAYOUTS BASED ON INDIVIDUAL PERFORMANCE TO: 7A - Mgmt. short-term incentive awards	7B - Long-term incentive awards (i.e. stock grants)	7C - Employee short-term incentive awards	QUESTION 8 - IF YOU CHECKED ANY BOXES TO #7 - HOW MUCH TIME DOES THE MANAGER HAVE TO MAKE ANY DISCRETIONARY ADJUSTMENTS:
1	Yes	No	Yes	If an employee received a poor performance rating, they are precluded from participating in the incentive plan. Final decisions would need to be made by the end of the fiscal year (April 30th).
2	No	No	No	
3	No	No	No	
4	Yes	Yes	Yes	about 5-8 business days, depending on the date of the annual earnings annoucement and the payroll due date
5	Yes	No	Yes	5-7 work days
6	Yes	Yes	Yes	Month
7	No	No	Yes	About 5 business days
8	Yes	No	Yes	1 week
9	Yes	No	Yes	2 weeks
10	No	No	No	
11	Yes	Yes	Yes	Nine business days in 2009
12	No	No	No	
13	No	No	No	
14	Yes	No	Yes	About 1 week
15	No	No	No	
16	Yes	Yes	Yes	2 weeks
17	Yes	No	Yes	Typically about one month or so
18	Yes	No	Yes	2 weeks
19	Yes	No	Yes	2 weeks
20	Yes	No	Yes	5 work days
21	Yes	No	Yes	about 19 calendar days
22	Yes	Yes	No	1 week

*** SUMMARY & NOTES:**

1. THE ORDER OF THE DATA DOES NOT CORRESPOND TO THE ORDER OF THE LISTED PARTICIPANTS.
2. TOTAL NUMBER OF PARTICIPANTS: 22
3. FOR CODE 10 - ON WHY THE PARTICIPANT DID NOT COMPLETE THE AVERAGE NUMBER OF DAYS FOR ONE LEVEL OF MANAGEMENT GIVEN TO APPROVAL THE PROGRAM INCREASE - I didn't complete that column because managers do not approve merit or structure increases. We build a matrix that provides for a specific merit and structure related increase based on performance and position in pay range. For cash incentives, there is a final due date for the proposed amounts but no prescribed number of days for managers to approve - the proposal just needs to be ready to go to the comp committee (for us this is the company executive committee or, in case of stock related awards the BOD comp committee) by a certain due date.

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Participating Companies

Allegheny Energy, Inc.	Ameren Corp.	American Electric Power
Avista Utilities	CenterPoint Energy	Chelan County PUD
CMS Energy Corp.	DTE Energy Company	E.ON U.S. (LG&E)
Entergy	Indianapolis Power & Light Co.	JEA
Nebraska Public Power District	New Mexico Gas	NiSource Inc.
NorthWestern Energy	NSTAR	OGE Energy Corp.
Progress Energy	Puget Sound Energy, Inc.	Salt River Project
Southern Company		

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news

Press Releases

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More Employers Planning to Reverse Pay, Other Cutbacks, Watson Wyatt Survey Finds

WASHINGTON, D.C., August 13, 2009 — The number of employers planning to reverse salary cuts and freezes and restore matching contributions to 401(k) plans has increased in the past two months, according to the latest update to an ongoing series of surveys by Watson Wyatt, a leading global consulting firm. Nevertheless, the survey also found that many employers remain concerned about retaining their top performers.

The survey found that 33 percent of employers that froze salaries plan to unfreeze them within the next six months, up from 17 percent two months ago. Forty-four percent plan to roll back salary cuts in the next six months, compared with 30 percent two months ago. Additionally, 24 percent of employers plan to reverse reductions to 401(k) match contributions in the next six months, versus 5 percent in June. Watson Wyatt's latest bimonthly survey was conducted in August 2009 and includes responses from 175 large employers.

"Some employers are seeing the light at the end of tunnel and feeling optimistic about the prospect of improved business results," said Laura Sejen, global director of strategic rewards consulting at Watson Wyatt. "However, even as some of the program cuts are rolled back, many employees are facing smaller raises, lower bonuses and higher health care costs."

The survey found that 66 percent of respondents that increased the percentage that employees pay for health care premiums do not expect to reverse that decision. Also, 40 percent of respondents are planning to shift more health care benefit costs to workers by increasing the percentage of premiums they pay. Another 41 percent of companies expect to increase the deductibles, copays or out-of-pocket maximums for their 2010 health care plans.

In addition, a majority of employers (52 percent) are now more concerned about retaining their top performers and critical-skill employees than they were before the economic crisis hit. In an effort to keep employees engaged, 83 percent of employers have increased communication and 40 percent have held additional employee forums such as town halls or other interactive sessions to address economy-related concerns. While almost half (47 percent) have changed employee roles to expand responsibilities, a far smaller number is expanding the use of recognition programs (27 percent) or creating special compensation programs for high-performing or at-risk employees (18 percent).

"Even as employers look ahead to an eventual economic recovery, they still face many challenges, such as the potential disengagement of top performers," said Brian Wilkerson, global director of talent management at Watson Wyatt. "Employers can manage this to some extent not only by effectively communicating with employees, but also by ensuring that they are rewarded for the job that they do — in particular taking into account how that job might be changing in the current environment."

Other findings:

- The survey found that almost three in 10 (27 percent) think their company's business results have already bottomed out, and a further 15 percent think they are currently at bottom.
- Looking ahead three to five years, 83 percent expect to see an increase in the number of employees working longer, past their desired retirement ages, and 43 percent of employers expect to see a reduction in staff sizes. Half also expect to see an increase in the difficulty of retaining critical-skill employees, and 46 percent in attracting them.
- More than a third of employers have noticed an increase in the number of employees taking hardship withdrawals (36 percent) and loans (37 percent) from their 401(k) and 403(b) plans in the last two months.

For more information, please visit www.watsonwyatt.com/hrprogramsAug09

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About Watson Wyatt Worldwide

CORE

Phase I

Findings & Recommendations

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Progress Energy

CORE

- Purpose: Conduct a comprehensive market-based assessment and review of Progress Energy's base compensation program including:
  - Evaluation of job families, levels, and titles
  - Competitive job value determination
  - Internally equitable slotting decisions
- Job Evaluation Process
  - Market pricing
  - If market data is not available, internally "slot" job against benchmarked positions based on:
    - Perceived internal value to the company
    - Similar skill set/expertise
- Benchmarks
  - 18 Peer Utility companies
  - 12 major nuclear generating companies
  - Construction companies

Progress Energy

Phase I Scope

- Cross-organizational management and individual contributors in:
  - Engineering
  - Engineering Tech Support
  - Environmental
  - Energy Management System Support
  - NGG Operations
  - NGG Training
  - Occupational Health & Safety
- Ops Support Asst/Tech Support Asst classifications (ED)
- Certain IT&T classifications
- Fuels & Power Optimization department
- Efficiency & Innovative Technology department – commercial positions only
- Miscellaneous uniquely identified positions

268 total classifications included in Phase I (≈2,100 employees)

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Phase I Findings

Organization Where Affected Positions Reside	# of Job Titles Below Market	# of Employees Affected
Admin&CorpRel	3	3
ED-Car	6	12
ED-Car & ED-FL	1	3
Nuclear Ops	47	188
Trans-Car	4	14
Trans-Car & FL	3	8
All Organizations	4	104
Grand Total	68	332

- 13 classifications $\geq$ 2 JVs below market

Progress Energy

Potential Cost Impact Analysis

Actual Cost				
Organization	PEC	PEF	# Employees	Grand Total
Distribution-Carolinas	$14,599	$0	3	$14,599
Transmission-Florida	$0	$270	1	$270
NGG	$6,044	$8,603	22	$14,646
Cost	**$20,642**	**$8,873**	**26**	**$29,515**

- $270 driven by one employee falling below 80% JVI of recommended JV
- All NGG costs are associated with maintaining minimum JVIs for Engineering and Operations positions (90%)
- Dist-Car cost driven by maintaining JVI for one Craft Technical position

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Implementation Options

1. Implement all recommended JV increases now
   - Communication and effective date concurrent with merit
   - Aggressive given recent economic changes and market conditions
   - Total cost impact: $429,718
2. Hold on any adjustments, re-evaluate market and company position at later date
   - Anticipated completion of CORE Phase II in July '09
   - May advance situations of uncompetitive pay
   - No immediate cost impact
3. Implement recommended JV increases for certain critical/key positions or those significantly below market (>2 JVs)
   - Hold all other JV adjustments and re-evaluate market and company position at a later date
   - Communication and effective date concurrent with merit
   - Cost TBD based on identified positions

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Progress Energy

Compensation Ongoing Review & Evaluation

2009

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Progress Energy

CORE Purpose

- **Purpose**
  - Systematically/proactively monitor the market to ensure competitive and equitable base pay
  - Identify and analyze market conditions which dictate a more aggressive review schedule
- **Goals**
  - Review every job in the company on a two to three year cycle
    - Not intended to be a cost savings mechanism for the company
    - Not intended to increase pay for any particular group of employees
- **How:** Benchmarking against a peer group of companies that includes energy/utility companies and other major employers in the Southeast that provide similar services, operate in the same areas, or compete with Progress Energy for talent, including:

Duke Energy	SCANA
Dominion	IBM
FPL	Cisco Systems
Exelon	Bank of America
Southern Company	Entergy

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2008 CORE Scope/Results

- Scope
  - Cross-organizational management and individual contributors in:
    - Engineering
    - Engineering Technical Support
    - Environmental Health & Safety
    - Energy Management System Support
    - NGG Operations/Training
  - Ops Support Asst/Tech Support Asst classifications (ED)
  - Certain IT&T classifications
  - Fuels & Power Optimization department
  - Efficiency & Innovative Technology department – commercial positions only
  - Other "stand alone" uniquely identified positions throughout the organization
- Results
  - SMC approved market findings in December (March 30, 2009 effective date)
  - JV for some positions moved up/down (100+ classifications company-wide)
  - Majority remained unchanged (300+ classifications company-wide)
  - Most employees saw no change to base pay (approx. $40K in NGG due to minimum JVI s)

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8/26/2009

Progress Energy

2009 CORE Scope

- Considerations
  - Corporate/Business Initiatives
  - Known Market "Hot Spots"
  - Attraction/Retention Issues
  - Job "Cross-Over" Concerns

- Scope content:
  - Cross-organizational management and individual contributors in:
    - Project Management-related positions (non-PMCoE)
    - Work Management positions
    - Training
  - NGG/POG – Operations/Maintenance managers
  - IT - remaining individual contributors and managers
  - Audit department – individual contributors and managers

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Job Summary

Department/Group	Job Titles	Employees
NGG	60	323
NPD	2	2
Corporate Dev	3	3
POG	56	310
Transmission FL	12	34
Transmission Car	18	47
Delivery FL	13	30
Delivery Caro	18	133
Customer Market Svcs	9	31
Admin & Corp Relations	2	4
Audit	7	34
Corporate Svcs	12	19
EIT	5	28
External Rels	3	8
Financial Svcs	1	1
ITT	26	101
Total	**247**	**1108**

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Job Value Increases

Department/Group	Jobs w/ JV Increase	# Employees	Incentive Target Increase	Cost (Incentive* Target Only)
NGG	20	111	9	$185,733
NPD	0	0	0	$0
Corporate Dev	0	0	0	$0
POG	5	5	0	$0
Transmission – FL	4	12	0	$0
Transmission – Caro	2	9	0	$0
Delivery FL	1	2	0	$0
Delivery Caro	2	2	0	$0
Customer Market Services	0	0	0	$0
Audit	0	0	0	$0
Corporate Svcs	0	0	0	$0
EIT	0	0	0	$0
External Relations	1	1	0	$0
Financial Svcs	0	0	0	$0
ITT	2	16	0	$0
Total	**37**	**158**	**9**	**$185,733**

*ECIP and MICP targets only – no equity grant impact

Progress Energy

Job Value Decreases

Department/Group	Jobs w/ JV Decrease	# Employees	Incentive Target Decrease	Cost (Incentive* Target Only)
NGG	1	6	1	($8,401)
NPD	0	0	0	0
Corporate Dev	0	0	0	0
POG	6	8	1	($3,801)
Transmission – FL	0	0	0	$0
Transmission – Caro	2	4	1	($2,703)
Delivery FL	0	0	0	$0
Delivery Caro	0	0	0	$0
Customer Market Services	0	0	0	$0
Audit	4	26	2	($21,243)
Corporate Svcs	1	1	0	$0
EIT	0	0	0	$0
External Relations	0	0	0	$0
Financial Svcs	0	0	0	$0
ITT	2	3	0	$0
Total	**16**	**48**	**5**	**($36,148)**

*ECIP and MICP targets only – no equity grant impact

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Reclassification Summary

Department/Group	JV Increase	JV Decrease	No Change	Cost
NGG	53	3	15	$48,844
NPD	0	0	0	$0
Corporate Dev	1	1	1	($736)
POG	3	14	10	($36,625)
Trans – FL	0	0	0	$0
Trans – Car	0	0	1	$0
Delivery FL	0	2	10	($1,628)
Delivery Car	1	1	14	$838
Customer Market Svcs	1	2	12	$950
Audit	0	0	0	$0
Corporate Svcs	0	1	0	($1,384)
EIT	1	20	7	($3,020)
External Relations	0	0	0	$0
Financial Svcs	0	0	0	$0
ITT	0	0	0	$0
Total	**60**	**44**	**70**	**$7,238**

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Legal Entity Cost Summary

Department/Group	PEC	PEF	SVC	Total Cost
NGG (<$1,000 base)	$177,650	$48,527	$0	$226,176
NPD	$0	$0	$0	$0
Corporate Dev	($736)	$0	$0	($736)
POG	($35,114)	($5,312)	$0	($40,426)
Trans – FL	$0	$0	$0	$0
Trans – Car	($1,353)	($1,350)	$0	($2,703)
Delivery FL	$0	($1,628)	$0	($1,628)
Delivery Car	$838	$0	$0	$838
Customer Market Svcs	$950	$0	$0	$950
Audit	$0	$0	($21,243)	($21,243)
Corporate Svcs	$0	$0	($1,384)	($1,384)
EIT	$0	($3,020)	$0	($3,020)
External Relations	$0	$0	$0	$0
Financial Svcs	$0	$0	$0	$0
ITT	$0	$0	$0	$0
Total	**$142,233**	**$37,217**	**($22,627)**	**$156,823**

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Progress Energy

FLSA Compliance

- Job descriptions were reviewed for compliance if:
  - Job represents the first level of exempt work in its functional area
  - Job description contained conflicting information for task complexity, independent discretion and judgment

- Findings: 6 employees were found to be performing non-exempt work in an exempt classification (3 POG, 3 NGG)
  - Action will be taken immediately regardless of implementation date for other CORE changes
  - Will be reclassified into a non-exempt position and paid 2 years back overtime, per company practice
  - Approximately $53K cost impact

- Implement FLSA status changes – August 31

- Back pay liability contained as line item in paycheck – September 4

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Progress Energy

Proposed Implementation

- Implement all changes January 1, 2010
  - Avoids 2009 incentive target pro-ration
  - Enables integration with 2010 budget planning
  - Facilitates advance communication

- Future CORE Schedule
  - Establish January 1 as the on-going, consistent annual effective date for future CORE phases
    - Facilitates planning around business priorities
    - Promotes consistent schedule and communication to employees

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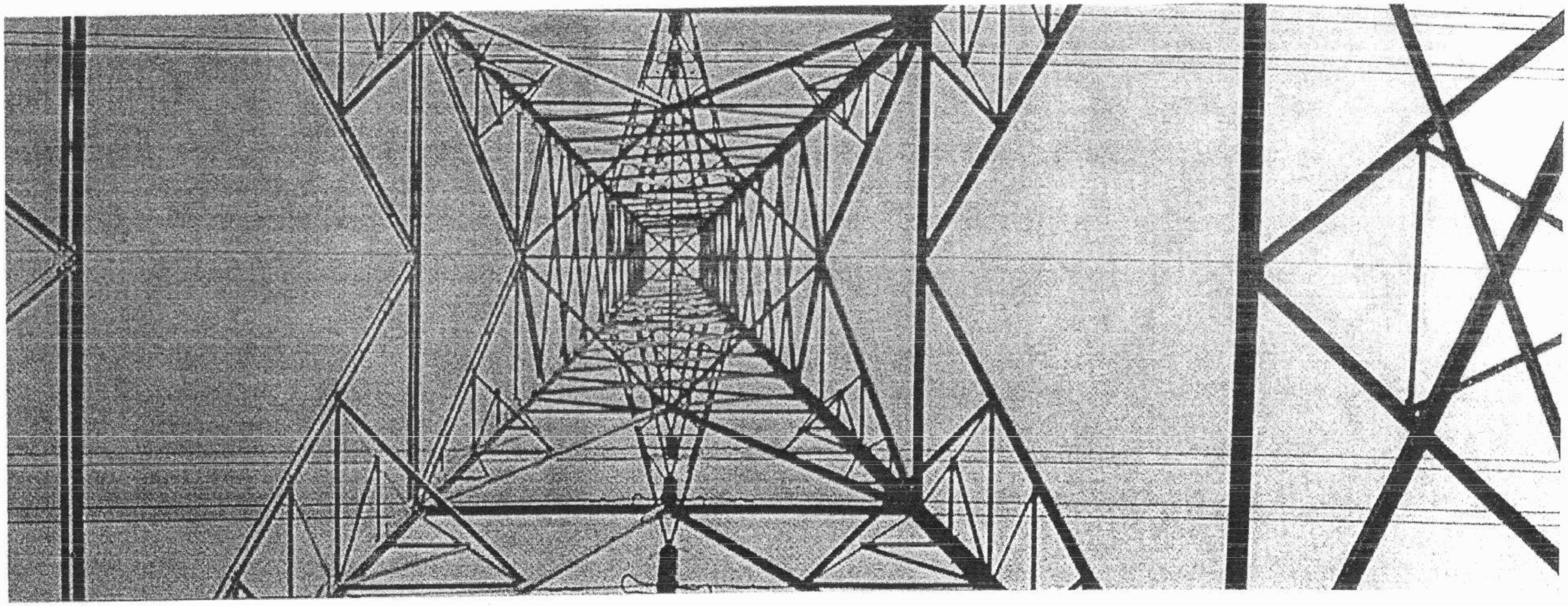
Progress Energy

Implementation Strategy

- Incorporate into 2010 budget planning – August
- Implement FLSA status change and resolve back pay liability - August
- Implement communication plan
  - Compensation communicates final results back to HR and CORE Team members – by Sept 14
  - Compensation provides communication materials to SMC – by Sept 14
  - SMC communication to VPs – by Oct 1
  - Managers communicate new job values and incentive targets (if applicable) to affected employees – by Nov 16
  - Effective date/viewable in Peoplesoft – January 1, 2010
- Quarter 4 – CORE 2010 kickoff

Progress Energy



Progress Energy, Inc. | June 2009

Top 5 Proxy Analysis

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Hewitt Consulting

Hewitt

Background

- Progress Energy, Inc. (PGN) has asked Hewitt Associates to provide "Top 5" compensation data from the Benchmarking Peer Group.
- The analysis includes compensation for the following:
  - By function; and
  - By total compensation rank.
- Results are presented on a raw (i.e., not regressed) basis—market values presented in February and used to make recommendations **are** adjusted for size

Hewitt Consulting Hewitt

Methodology

Using the most recently disclosed proxy filings (2009), Hewitt examined the following components of pay:

- Base salary earned during last fiscal year, updated to reflect 2009 salaries (where applicable)
- Actual annual incentives paid/earned, including both discretionary and performance-based annual incentives
- Long-term incentive reflect grant-date value
  - Based on awards disclosed in the Grants of Plan-Based Awards table
  - Annualized one-time grants (where appropriate)

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Peer Group

Benchmarking Peer Group

Company Name	FY 2008 Revenues ($Mil)	May 2009 Market Cap ($Mil)
Allegheny Energy, Inc.	$3,385.9	$4,235.0
Ameren Corporation	$7,839.0	$4,967.4
American Electric Power Company Inc	$14,440.0	$12,557.9
Dominion Resources Inc.	$16,290.0	$18,754.8
DTE Energy Company	$9,329.0	$4,957.3
Duke Energy Corporation	$13,207.0	$18,212.7
Edison International	$14,112.0	$9,526.7
Entergy Corporation	$13,093.8	$14,633.2
Exelon Corporation	$18,859.0	$31,626.8
FirstEnergy Corp.	$13,580.0	$11,519.7
FPL Group, Inc.	$16,410.0	$23,222.1
PG&E Corporation	$14,628.0	$13,522.6
Pinnacle West Capital Corporation	$3,367.1	$2,794.9
PPL Corporation	$8,044.0	$12,210.3
SCANA Corporation	$5,319.0	$3,657.1
The Southern Company	$17,127.0	$22,228.9
TECO Energy, Inc.	$3,375.3	$2,388.5
Xcel Energy Inc.	$11,203.2	$7,814.6
25th %ile	$7,890.3	$4,959.8
Median	***$13,150.4***	***$11,865.0***
75th %ile	$14,581.0	$17,317.8
Progress Energy, Inc.	$9,167.0	$9,908.7

- Benchmarking group is the Committee-approved benchmarking peer group
- Peer group is ultimately disclosed in CD&A
- Same peer group used in annual survey benchmarking analysis

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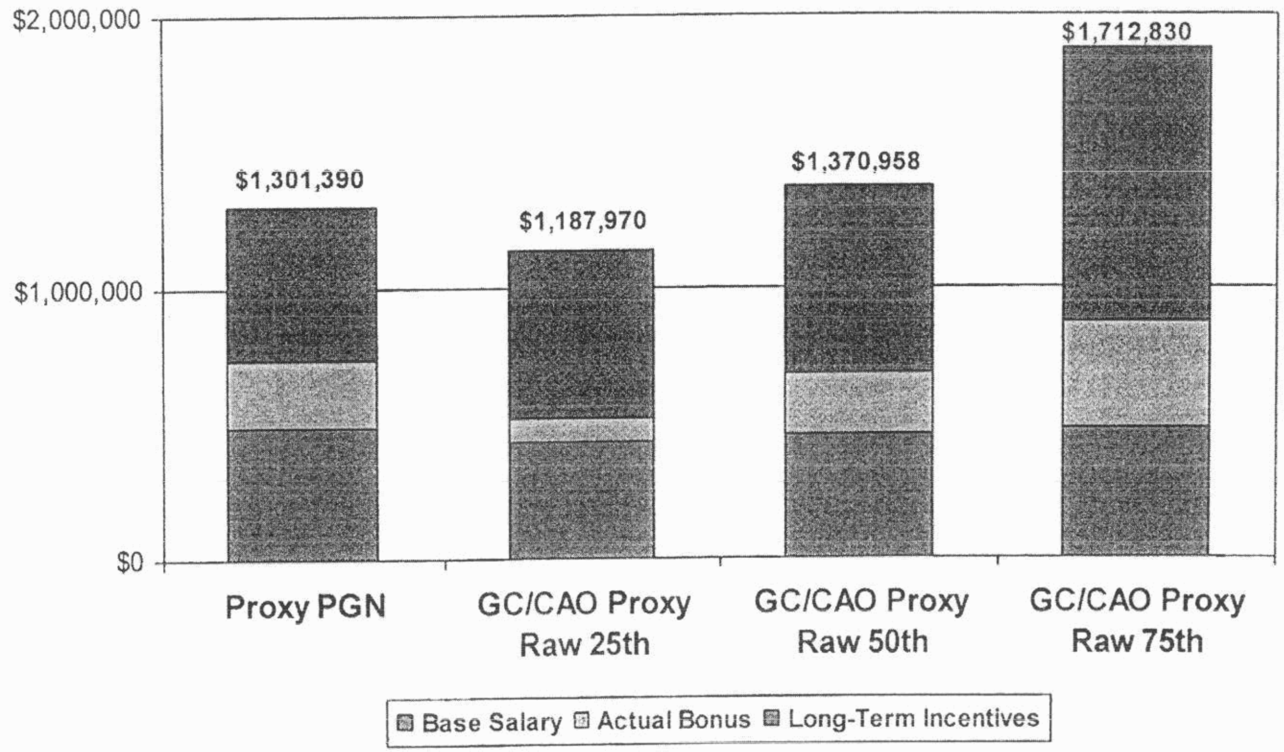
Actual Net Total Compensation—Comparison

McArthur—EVP and Corporate Secretary



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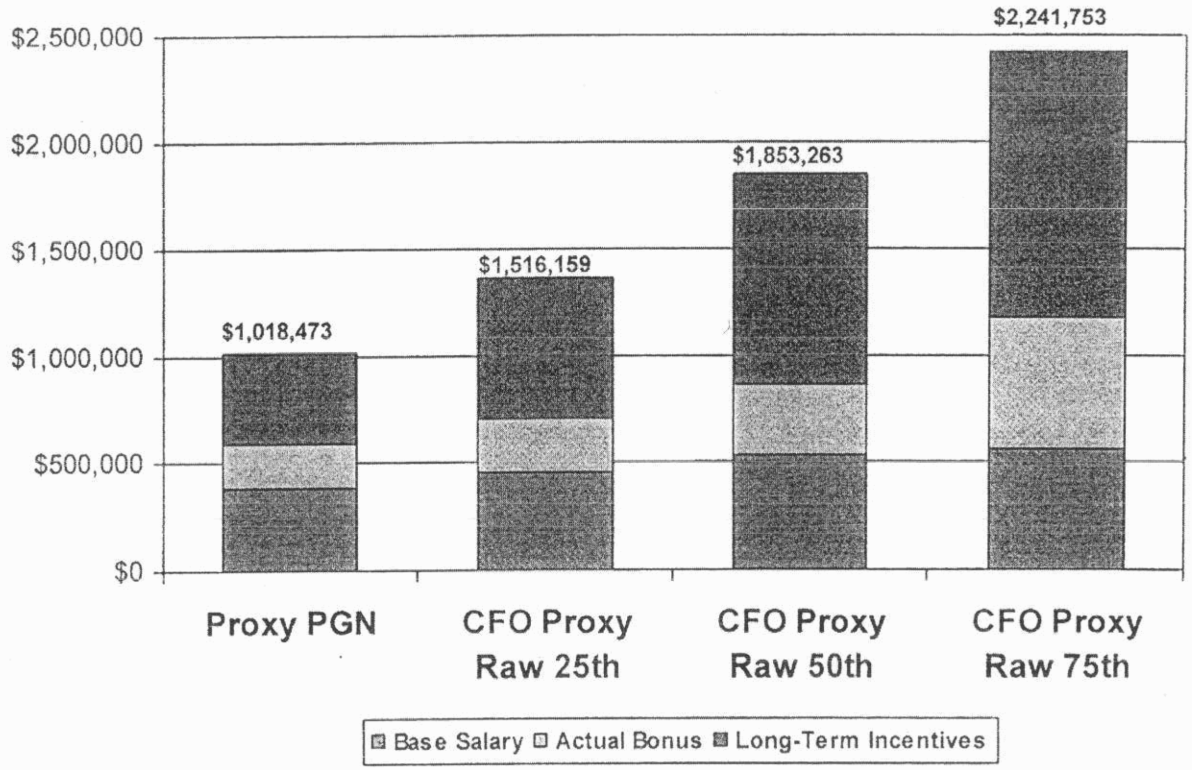
Actual Net Total Compensation—Comparison

Mulhern—SVP-Chief Financial Officer



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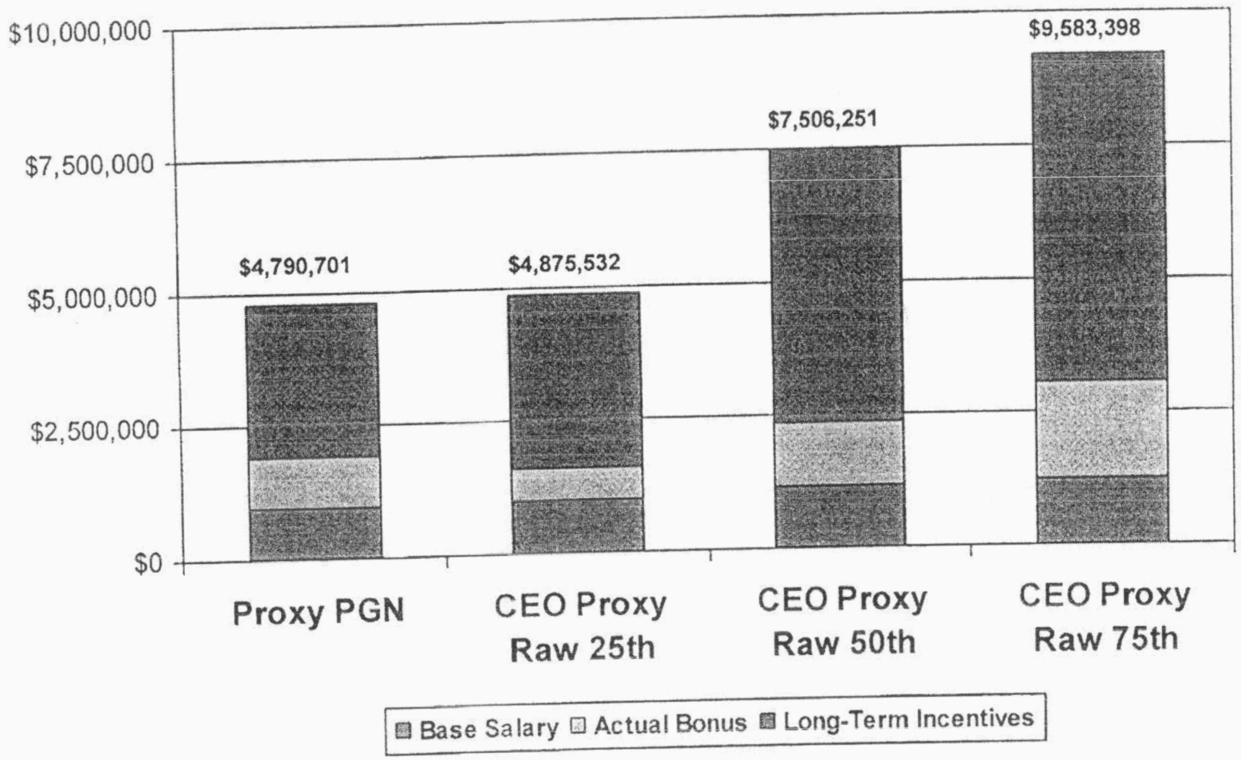
Actual Net Total Compensation—Comparison

Johnson—Chairman, CEO & President



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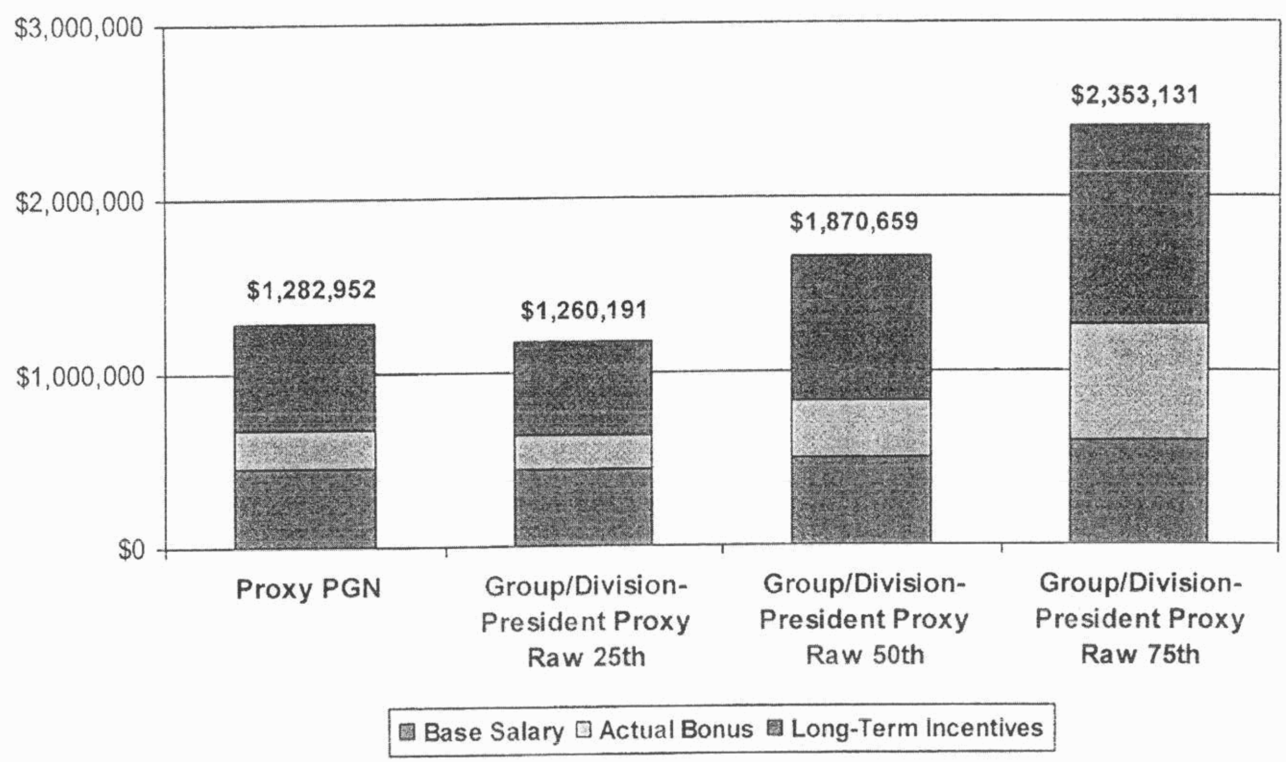
Actual Net Total Compensation—Comparison

Lyash—Pres/CEO-Group (Progress Energy FL)



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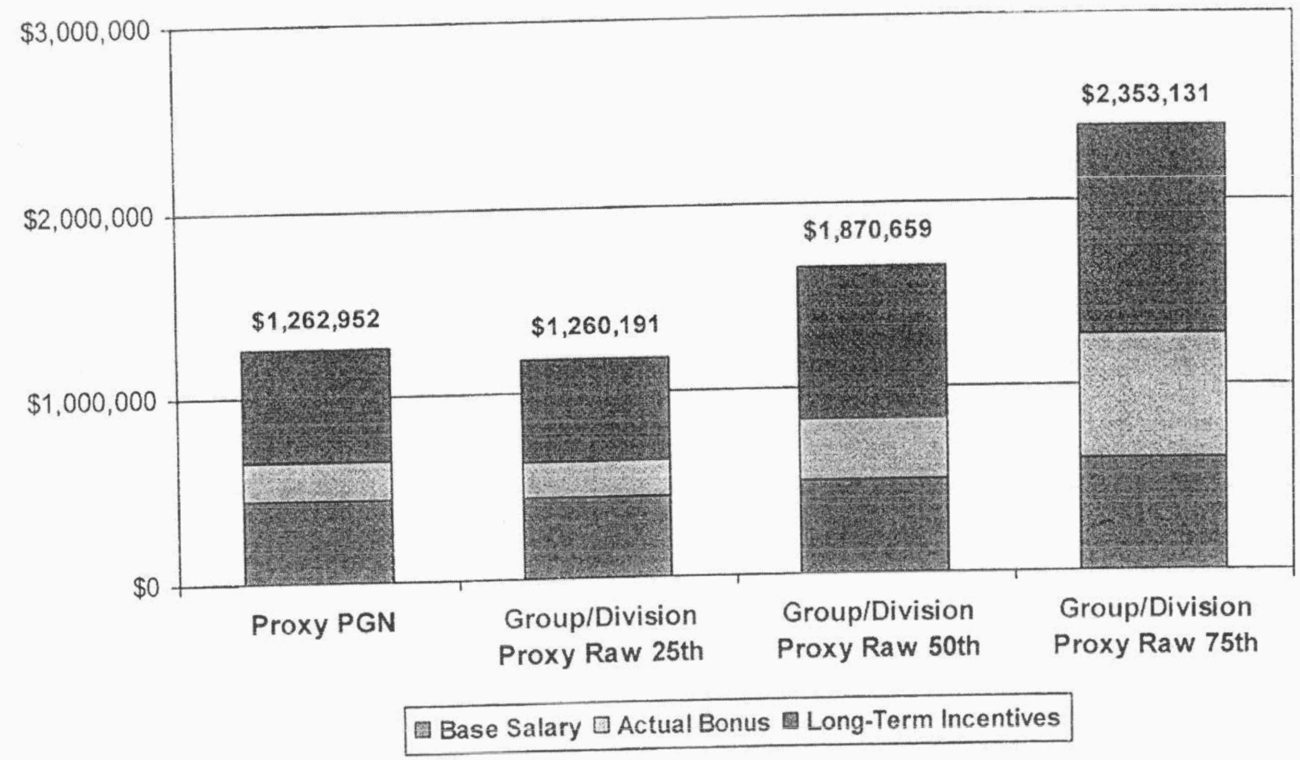
Actual Net Total Compensation—Comparison

Yates—Pres/CEO-Group (Progress Energy Carolinas)



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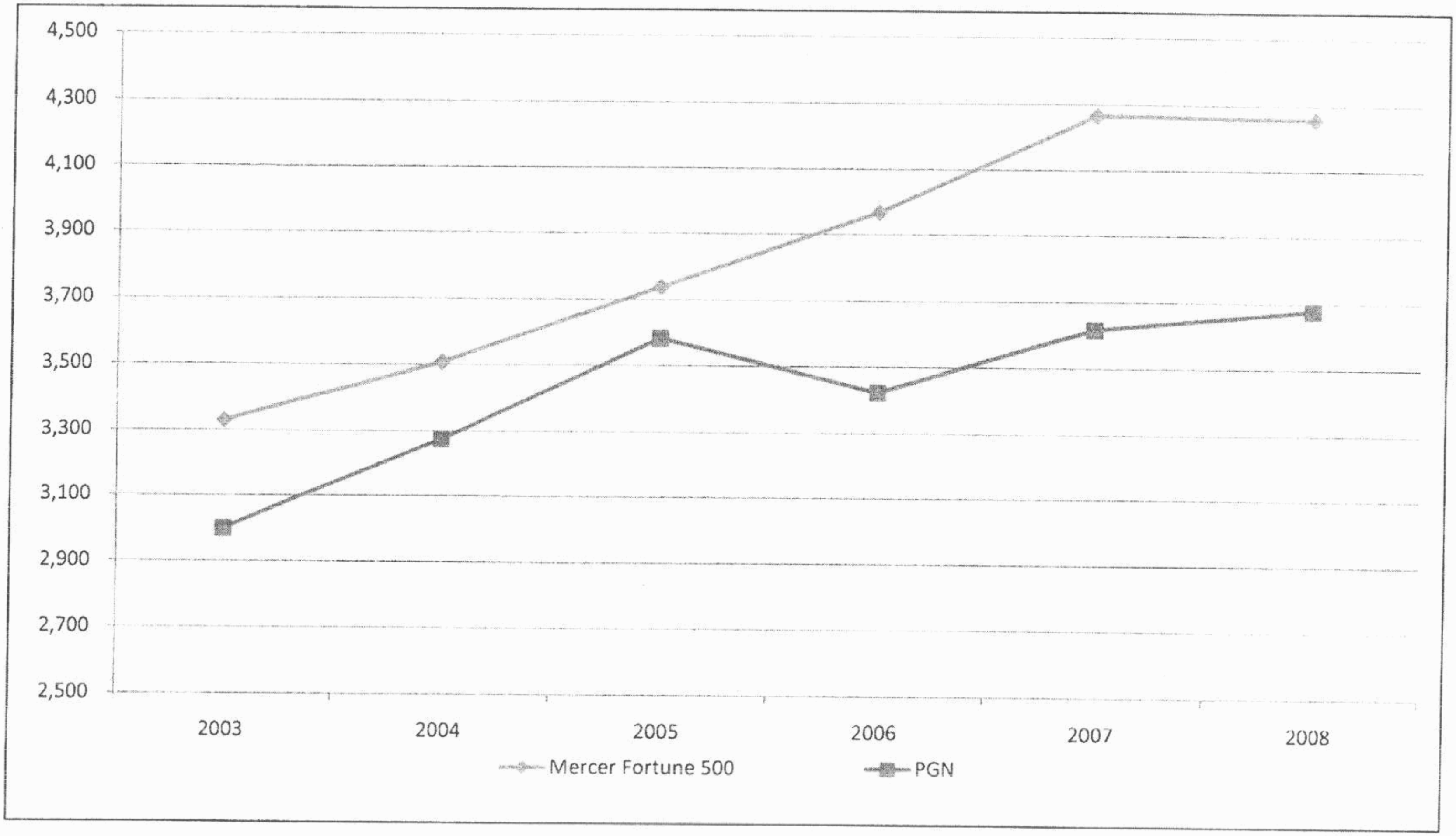
Average Healthcare Costs Per Member (including dependents)
Progress Energy vs. Fortune 500
2003 - 2008



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Sources: Mercer National Survey of Employer-Sponsored Health Plans, PGN cost report